AVISTA

2018
Natural Gas
Integrated Resource Plan

August 31, 2018

Safe Harbor Statement

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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 risks, uncertainties and other 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.

TABLE OF CONTENTS

Executive Summary

Avista's 2018 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 evaluates 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.

Chapter Highlights

- An increase in customer forecast over 20 years versus the 2016 IRP
- Lower use per customer
- Higher DSM potential
- RNG and Hydrogen considered in the available resource stack for the first time
- Landfill RNG is a chosen resource in the High Growth & Low Prices scenario

IRP Process and Stakeholder Involvement

The IRP is a coordinated effort by several Avista departments with input from our Technical Advisory Committee (TAC), which includes Commission Staff, peer utilities, customers, and other stakeholders. The TAC is a vital component of our IRP process that provides a forum for discussing multiple perspectives, identifies issues and risks, and improves analytical planning methods. TAC topics include natural gas demand forecasts, price forecasts, demand-side management (DSM), supply-side resources, modeling tools, distribution planning, and policy issues. The IRP process produces a resource portfolio designed to serve our customers' natural gas needs while balancing cost and risk.

Planning Environment

A long-term resource plan addresses the uncertainties inherent in any planning exercise. Natural gas is an abundant North American resource with expectations for sufficient supplies for many decades because of continuing technological advancements in extraction. The use of natural gas in liquefied natural gas (LNG) exports, natural gas vehicles, power generation and exports to Mexico will add demand for natural gas. We model various sensitivities and scenarios to account for the uncertainties surrounding supply and demand.

Demand Forecasts

Avista defines eleven distinct demand areas in this IRP structured around the pipeline transportation and storage resources that serve them. Demand areas include Avista's service territories (Washington; Idaho; Medford/Roseburg, Oregon; Klamath Falls, Oregon and La Grande, Oregon) and then disaggregated by the pipelines serving them. The Washington and Idaho service territories include 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.

Weather, customer growth and use-per-customer are the most significant demand influencing factors. Other demand influencing factors include population, employment, age and income demographics, construction levels, conservation technology, new uses (e.g. natural gas vehicles), and use-per-customer trends.

Customers may adjust consumption in response to price, so Avista analyzed factors that could influence natural gas prices and demand through price elasticity. These factors include:

- **Supply:** shale gas, industrial use, and exports to Mexico and of LNG.
- **Infrastructure:** regional pipeline projects, national pipeline projects, and storage.
- **Regulatory:** subsidies, market transparency/speculation, and carbon regulation.
- **Other:** drilling innovations, thermal generation and energy correlations (i.e. oil/gas, coal/gas, and 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 alternate demand scenarios for detailed analysis. Table 1 summarizes these demand scenarios, which represent a broad range of potential scenarios for planning purposes. 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

2018 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard
80% below 1990 emissions

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. Table 2 shows the Average and Expected Case demand forecasts:

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

Year	Annual Average Daily Demand	Peak Day Demand	Non-coincidental Peak Day Demand
2018	93,900	377,206	347,228
2037	94,205	427,852	392,601

Annual Average Daily Demand – Expected average day, system-wide core demand increases from an average of 93,900 dekatherms per day (Dth/day) in 2018 to 94,205 Dth/day in 2037. This is an annual average growth rate of 0.02 percent and is net of projected conservation savings from DSM programs. Appendix 3.1 shows gross demand, conservation savings and net demand.

Peak Day Demand – The peak day demand for the Washington, Idaho and La Grande service territories is modeled on and around February 15 of each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20 each year. Expected coincidental peak day, or the sum of demand from each territories modeled peak, the system-wide core demand increases from a peak of 377,206 Dth/day in 2018 to 427,852 Dth/day in 2037. Forecasted non-coincidental peak day demand, or the sum of demand from the highest single day including all forecasted territories, peaks at 347,228 Dth/day in 2018 and increases to 392,601 Dth/day in 2037, a 0.71 percent average annual growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

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

Figure 1: Average Daily Demand (Net of DSM Savings)

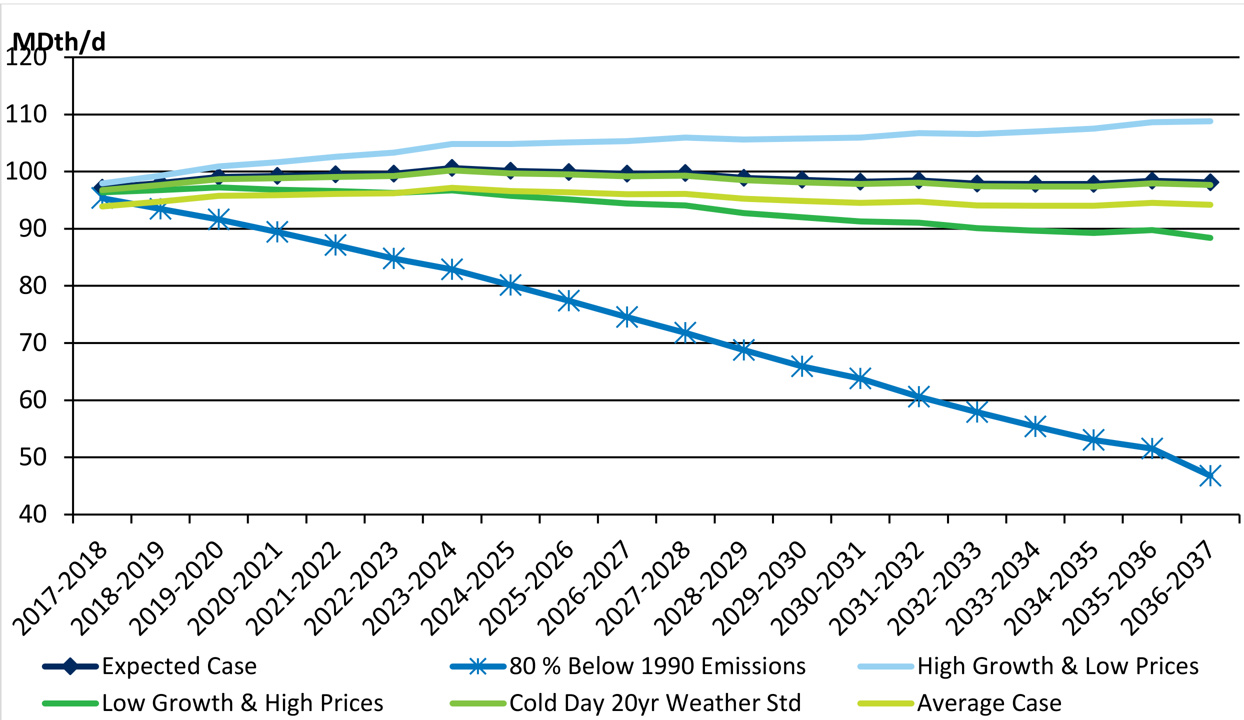
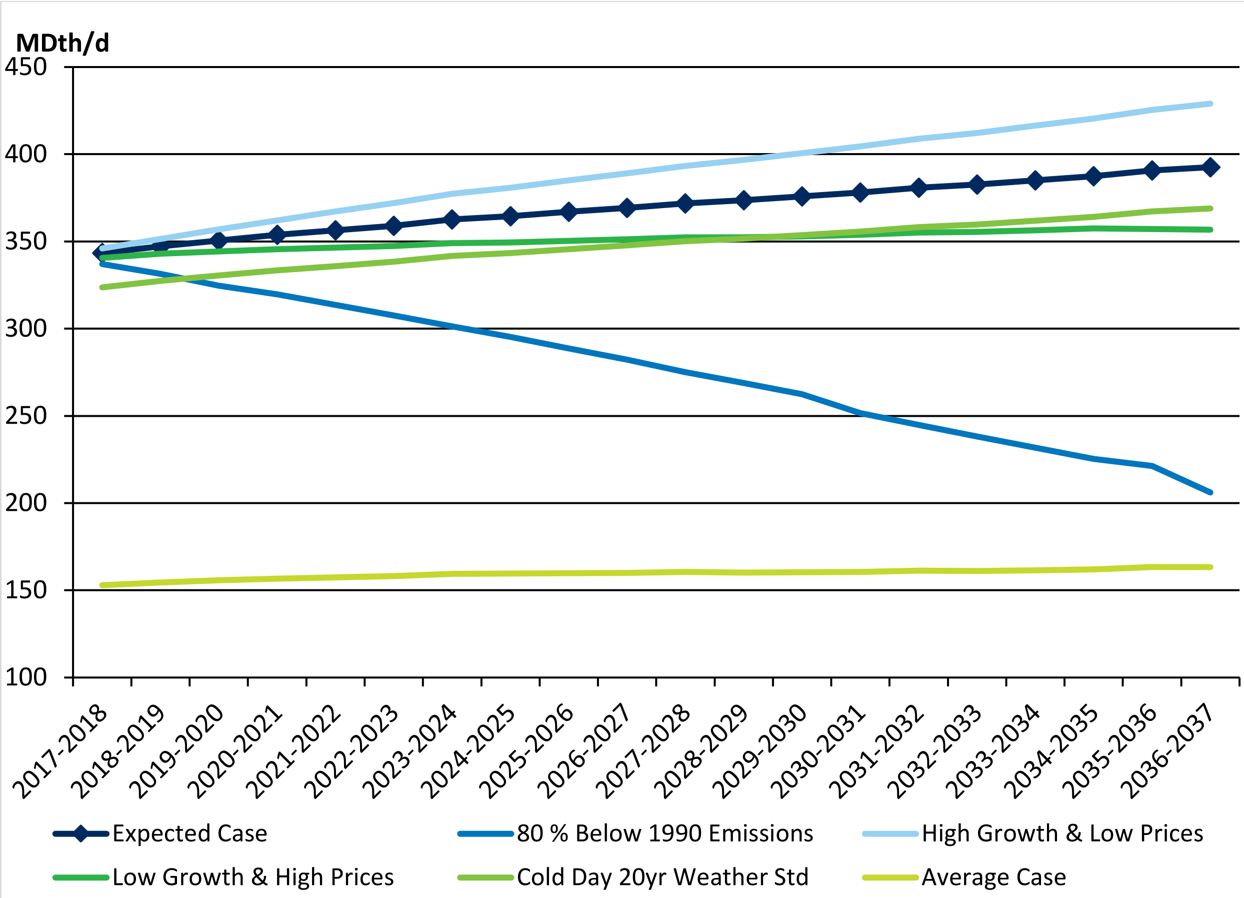


Figure 2 shows forecasted system-wide peak day demand for the six demand scenarios modeled over the IRP planning horizon.

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



Natural Gas Price Forecasts

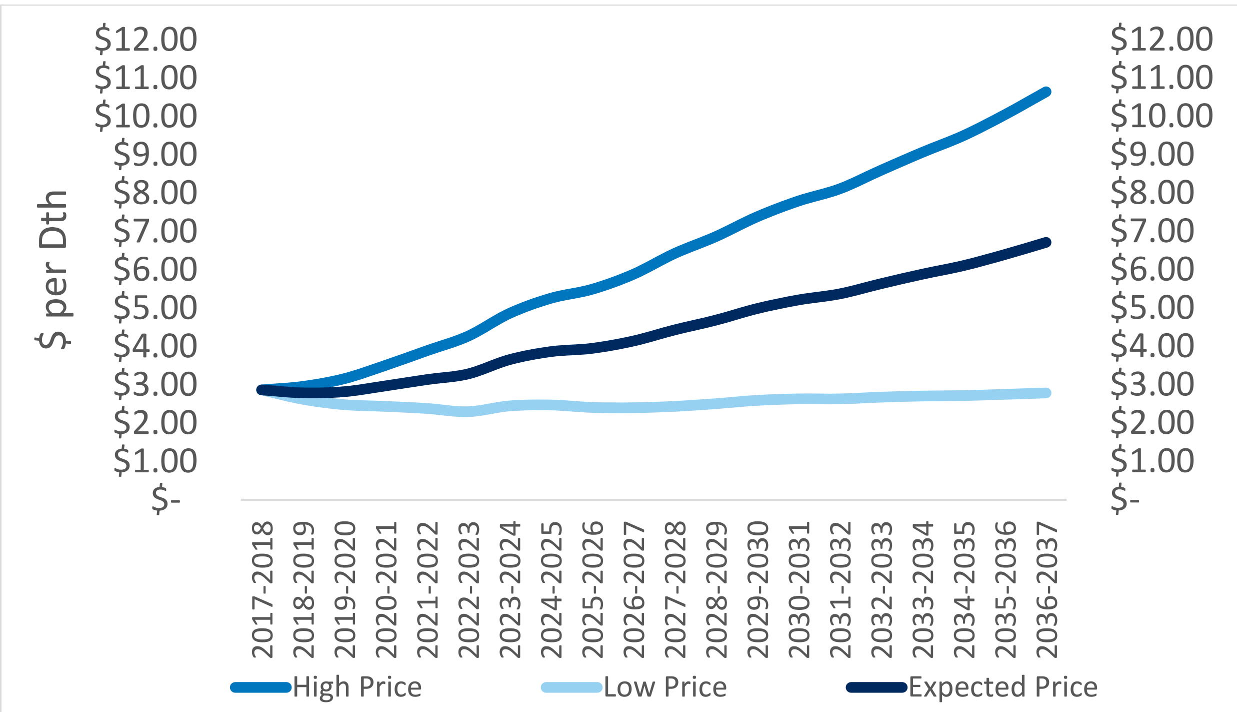
Natural gas prices are a fundamental component of integrated resource planning as the commodity price is a significant element to the total cost of a resource option. Price forecasts affect the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas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

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

Avista expects carbon legislation at the state level through a cap and trade (Oregon) or a tax mechanism (Washington). Current IRP price forecasts include a considerably higher carbon adder in Oregon and Washington, but no carbon cost in Idaho. Avista analyzed three carbon sensitivities and their impact on demand forecasts to address the uncertainty about carbon legislation.

Avista combined forward prices with two fundamental price forecasts from credible industry sources for an expected price strip at the Henry Hub. A high and low price were developed to vary the price in a symmetrical fashion based off of the expected price curve. These three price curves represent a reasonable range of pricing possibilities for this IRP analysis. The array of prices provides necessary variation for addressing uncertainty of future prices. Figure 3 depicts the price forecasts used in this IRP.

Figure 3: Low/Medium/High Henry Hub Forecasts (Nominal $/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 of -0.10, for every 10% of price movement, as found in our Medford/Roseburg service territory, and applied it under various scenarios and sensitivities.

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. Beginning in Avista's 2020 IRP and all future planning documents and analysis thereafter, Avista intends to include conservation as a potential resource addition.

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 utilizes 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. Avista actively promotes cost-effective DSM measures to our customers as one component of a comprehensive strategy to arrive at a mix of best cost/risk adjusted resources.

Resource Needs

In all cases, except for the High Growth and Low price scenario, the analysis showed no resource deficiencies in the 20-year planning horizon given Avista's existing supply resources. Avista is not resource deficient in the Expected Case in the 20-year planning horizon.

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, and more specifically where a resource deficiency is nearly present as shown in Figure 6 & 8, Avista has time to carefully monitor, plan and take action on potential resource additions as described in the Ongoing Activities section of Chapter 9 – Action Plan. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management of long- and short-term resources provides the flexibility to meet firm customer demand in a reliable and cost-effective manner as described in Supply Side Resources – Chapter 4.

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

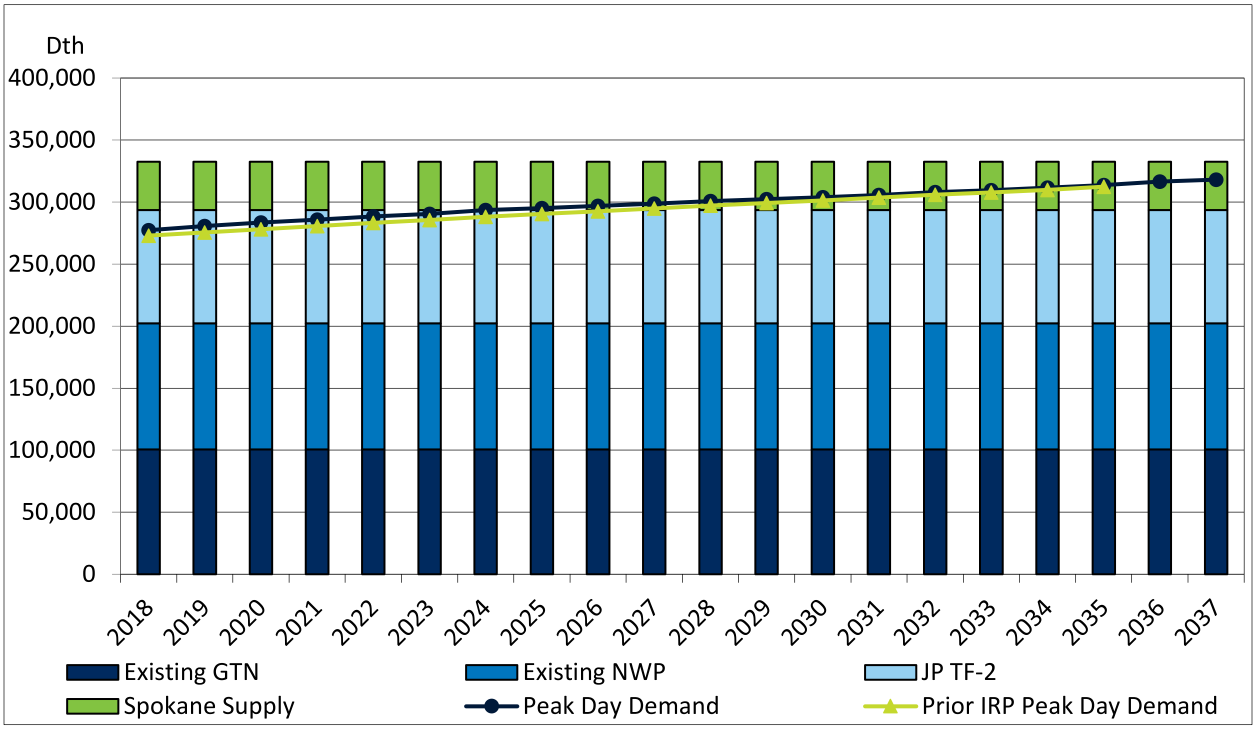


Figure 6: Expected Case – Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)

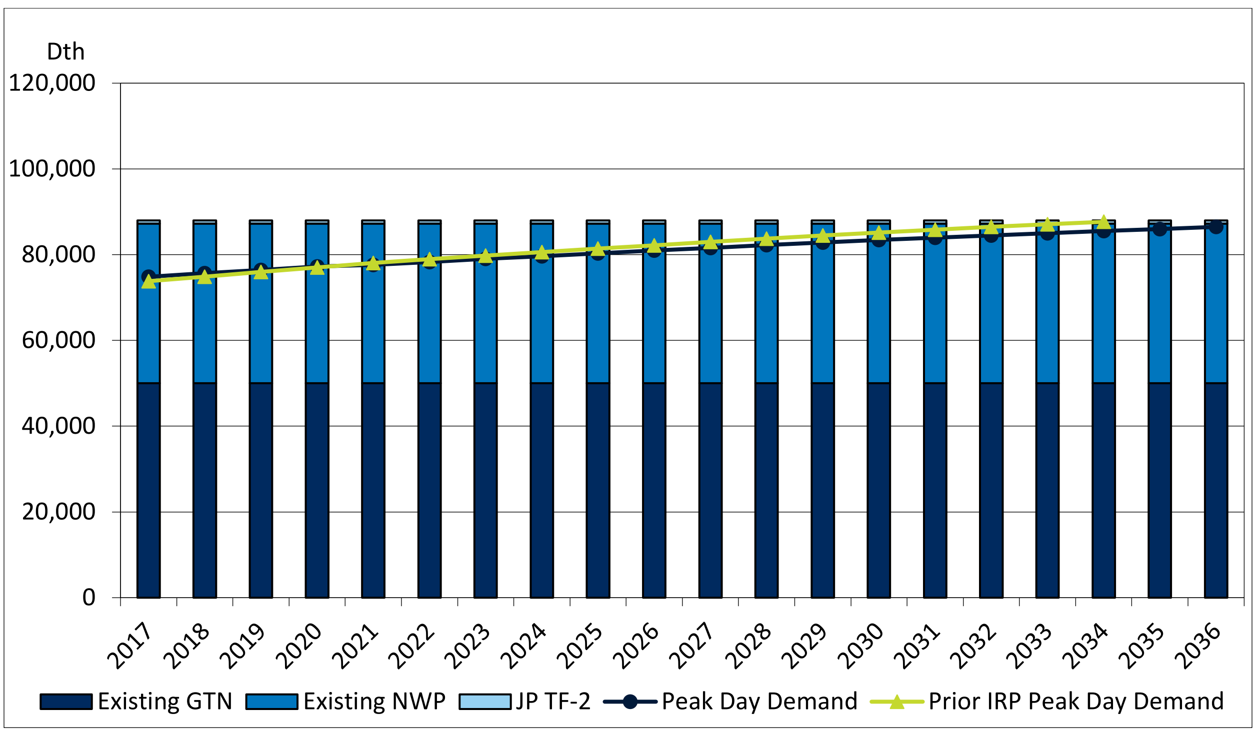


Figure 7: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)

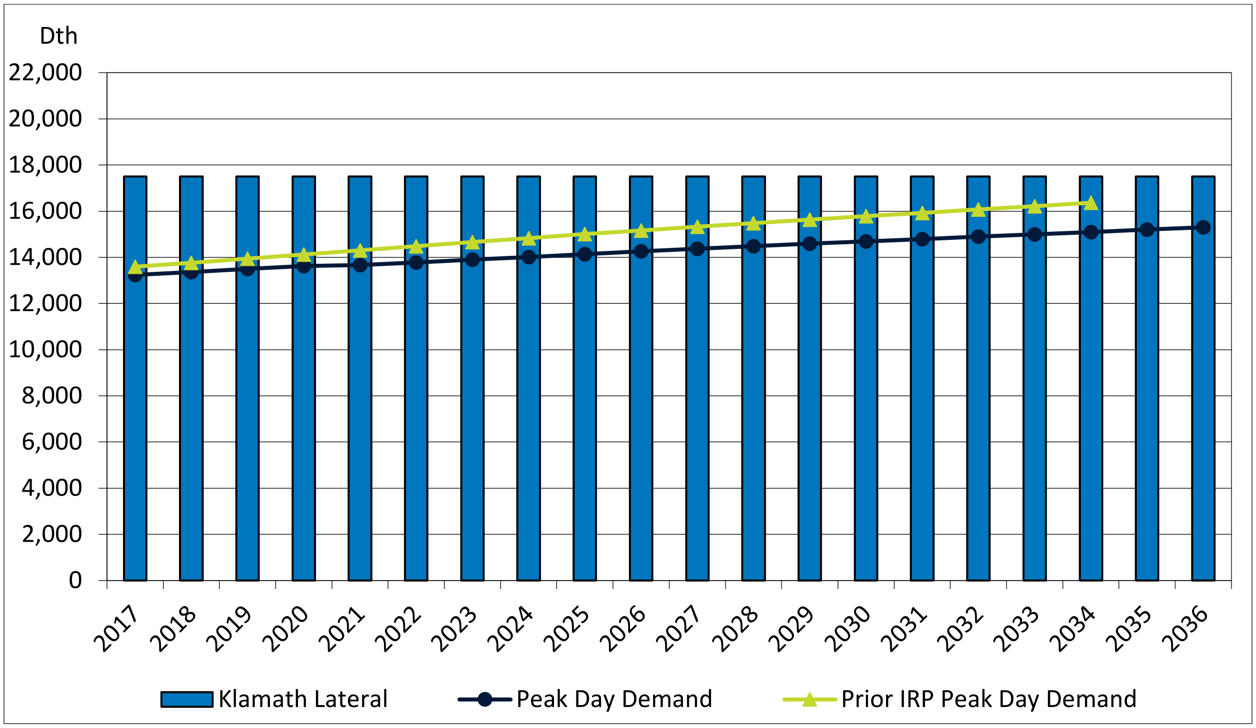
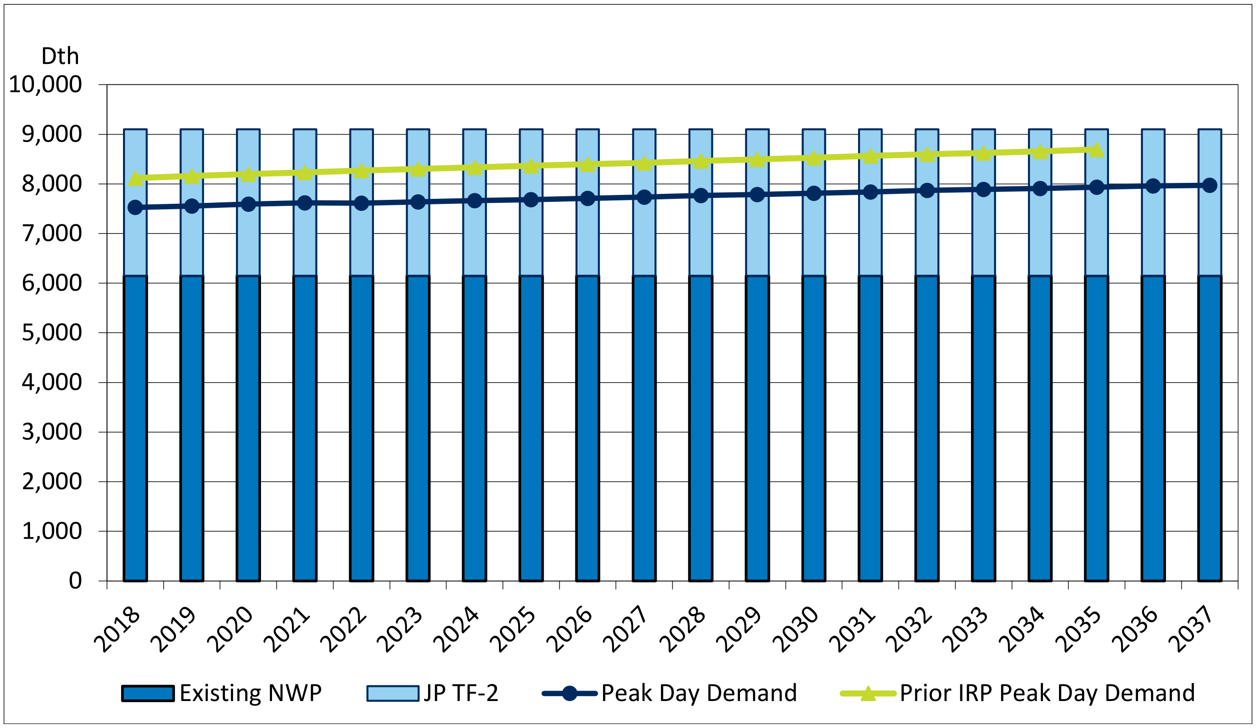
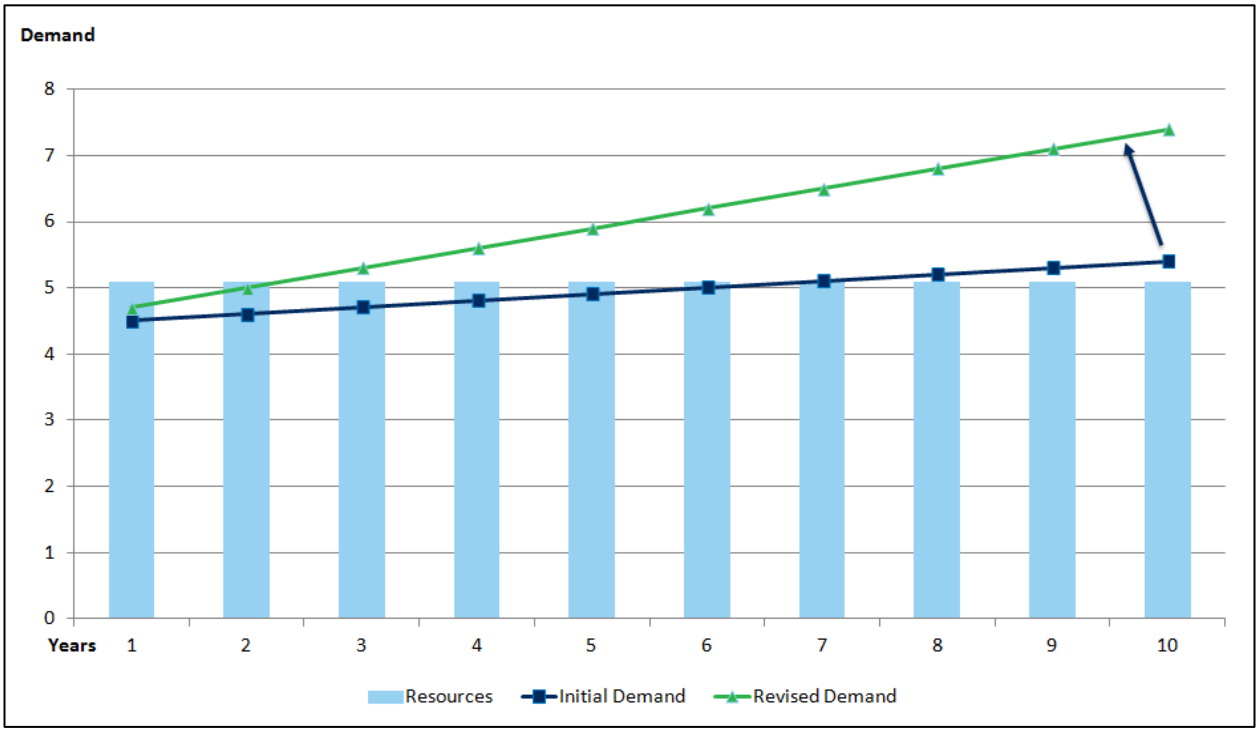


Figure 8: Expected Case – La Grande Existing Resources vs. Peak Day Demand (Net of DSM)



A critical risk remains in the slope of forecasted demand growth, which although increasing continues to be 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 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 accelerates by five years under the revised demand case to year three. This "flat demand risk" requires close monitoring of accelerating demand, as well as careful evaluation of lead times to acquire the preferred incremental resource.

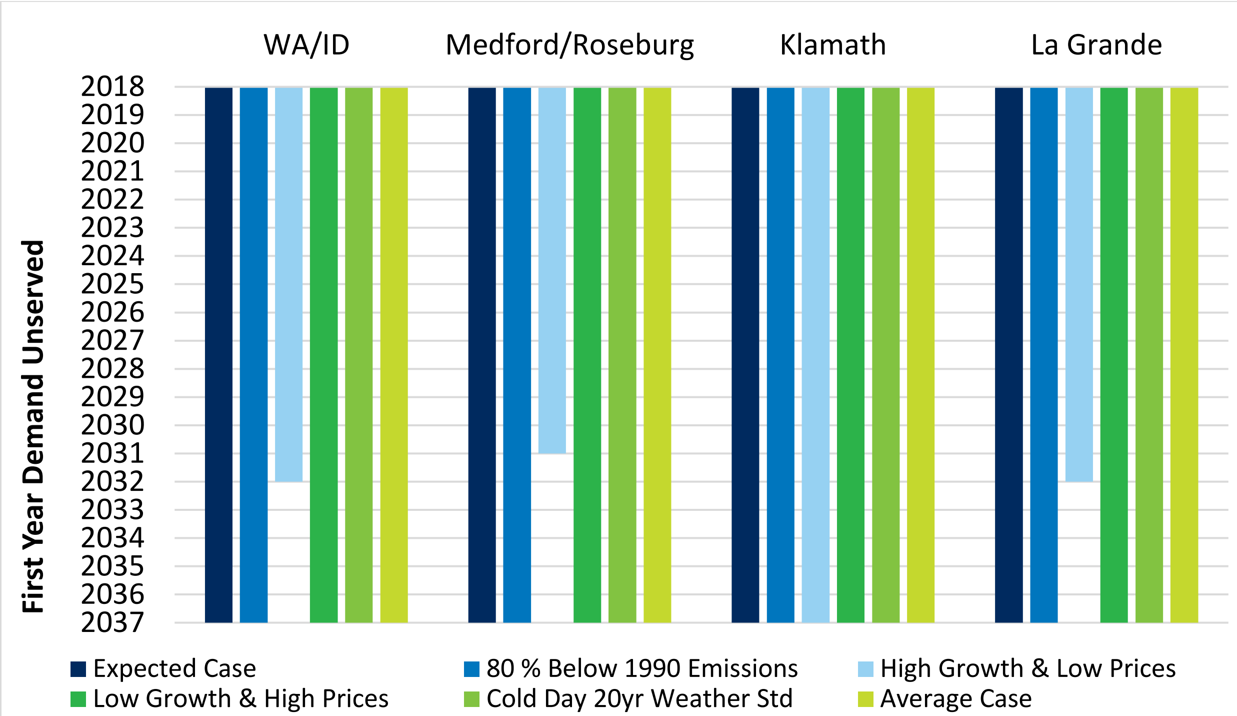
Figure 9: Hypothetical Flat Demand Risk Example



Alternate Demand Scenarios

Avista performed the same analysis for five other demand scenarios: Average, High Growth/Low Price, 80 Percent Below 1990 Emissions, 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 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.

Demand Issues

Although the future customer growth trajectory in Avista's service territory has slightly increased compared to the 2016 IRP, the need in considering a range of demand scenarios provides insight into how quickly resource needs can change if demand varies from the Expected Case.

With a rise in natural gas supply and subsequent low costs, there is increasing interest in using natural gas. Avista does not anticipate traditional residential and commercial customers will provide increased growth in demand. Power generation from natural gas is increasingly being used to back up solar and wind technology as well as replacing retired coal plants. Exports of LNG and to Mexico currently have a demand of over 7 Bcf/day. With additional LNG plants forecasted to come online in the next few years combined with additional pipeline infrastructure build into Mexico increases demand from these areas to nearly 13.5 Bcf. There is already a higher demand for exports to Mexico and more LNG plants have come online and are now looking for 4 Bcf per day on average.

Most of these emerging markets will not be core customers of the LDC, but could affect regional natural gas infrastructure and natural gas pricing if an LNG export facility is built in the area.

Price Issues

Shale oil and gas drilling technology is adding an abundant amount of supply at low cost. This is primarily due to increasingly efficient drilling technology and the rapid advancement in understanding of drilling shale wells. In areas such as the eastern United States, shale production is so prolific the entire flow of gas on the pipeline infrastructure has changed and is now flowing out of the highest demand areas in the US. This supply also flows into Canada and across the U.S. In western Canada there are some large and very capital intensive oil sands projects where production will continue regardless of the price of natural gas. In the past, this natural gas would commonly find its home in the U.S. Canadian natural gas has become somewhat stranded within the western half of North America and is creating a very low price environment. This new paradigm, benefits Northwest consumers as the prices for Canadian gas have deep discounts as compared to the Henry Hub.

LNG Exports

Liquefied natural gas is a process of chilling natural gas to -260 degrees Fahrenheit to create a condensed version, 1/600 the volume, of natural gas. This process acts as a virtual pipeline taking domestic production to nearly any location in the world. For years the U.S. was expected to be an importer of LNG. This is a stark contrast to reality as in 2017 the export of LNG from the U.S. has quadrupled led by two projects, Sabine Pass in Louisiana and Cove Point in Maryland. In recent history, this market dynamic has changed from fixed price gas contracts to more spot purchases of LNG. The three largest countries for U.S. LNG exports are Mexico, South Korea and China. Waiting in the wings to provide more LNG supply are four additional export facilities located mostly in the gulf coast region of the U.S. and will bring the total export capacity to nearly 10 Bcf per day by 2019. In 2020, the U.S. is expected to become the third largest exporter of LNG in the world. Canadian LNG is on a slower construction pace, but has a new ray of light in the LNG Canada project. Though as a whole and when compared to the U.S., environmental concerns and policies are having a larger impact on investment decisions in these projects. If and when LNG plants are constructed, exporting LNG can 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 2019-2020 Action Plan outlines activities for study, development and preparation for the 2020 IRP. The purpose of the Action Plan 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 natural gas industry trends Avista will monitor as a part of its ongoing planning processes (Chapter 9 – Action Plan).

Key ongoing components of the Action Plan include:

1. Avista's 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
2. Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.
3. Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.
4. Revisit coldest on record planning standard and discuss with TAC for prudency.
5. Provide additional information on resource optimization benefits and analyze risk exposure
6. DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.
7. Carbon Costs – consult Washington State Commission's *Acknowledgement Letter Attachment* in its 2017 Electric IRP (Docket UE-161036), where emissions price modelling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.
8. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:

- Natural gas infrastructure investment not included as discrete projects in IRP
  - Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
    - Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
  - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely requires additional capital to comply
    - Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
  - Construction of gas infrastructure associated with growth
  - Other special contract projects not known at the time the IRP was published
- Other non-IRP investments common to all jurisdictions that are ongoing, for example:
  - Enterprise technology projects & programs
  - Corporate facilities capital maintenance and improvements

Ongoing Activities

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.

Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

Conclusion

Slightly higher customer growth continues to be offset by lower use-per-customer and an increased amount of DSM. This 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. The combination of low priced natural gas in addition to carbon taxes or other programs has led to a higher potential for DSM measures as compared to the previous three IRP's. The IRP has many objectives, but foremost is to ensure that proper planning enables Avista to continue delivering safe, reliable, and economic natural gas service to our customers.

1: Introduction

> **Chapter Highlights**
> - High amount of uncertainty in long-term forecasting
> - Sensitivities help to understand risk of uncertainty
> - Seasonal demand
> - 348,000 natural gas customers

Avista is involved in the production, transmission and distribution of natural gas and electricity, as well as other energy-related businesses. Avista, founded in 1889 as Washington Water Power, has been providing reliable, efficient and reasonably priced energy to customers for over 130 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, Washington. In 1991, Avista added 63,000 customers with the acquisition of CP National Corporation's Oregon and California properties. Avista 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 348,000 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's Natural Gas Service Territory

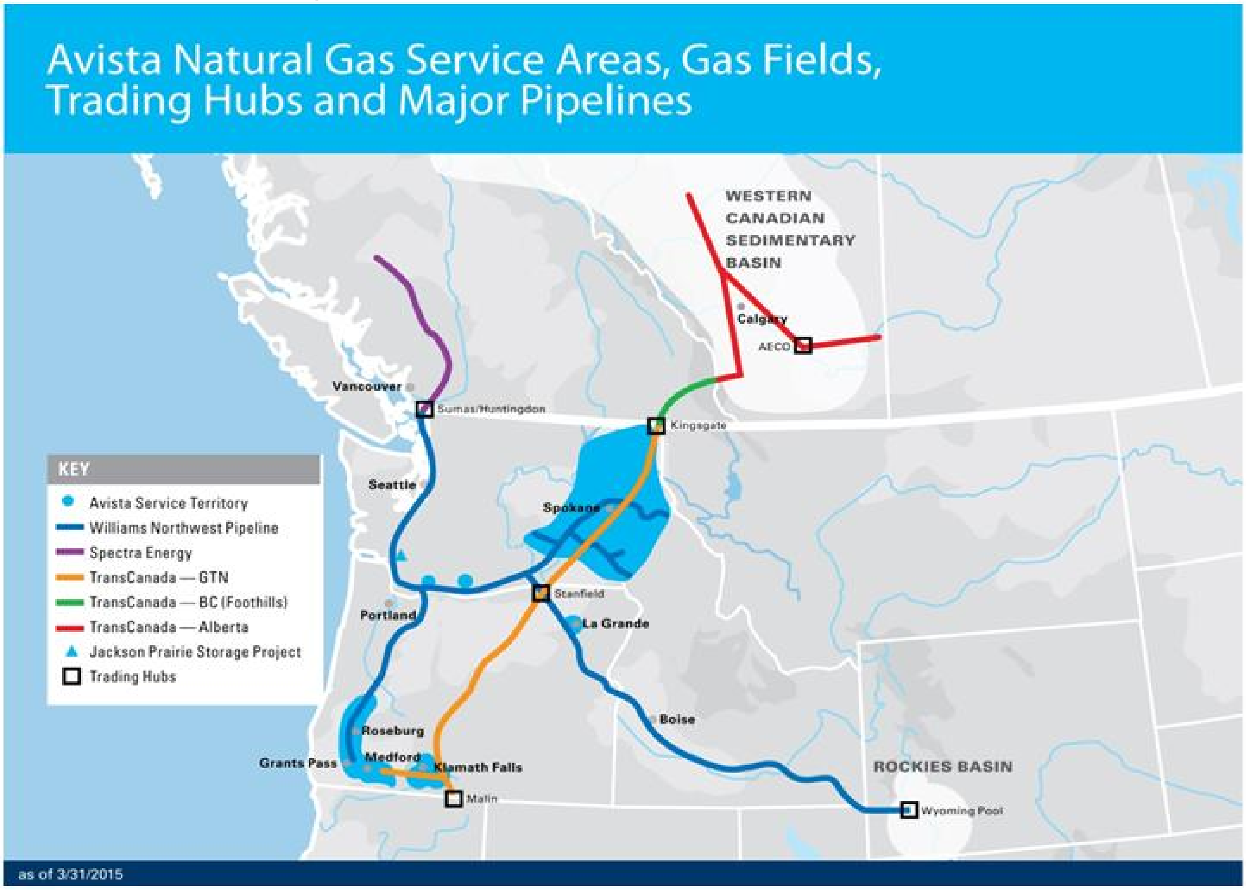
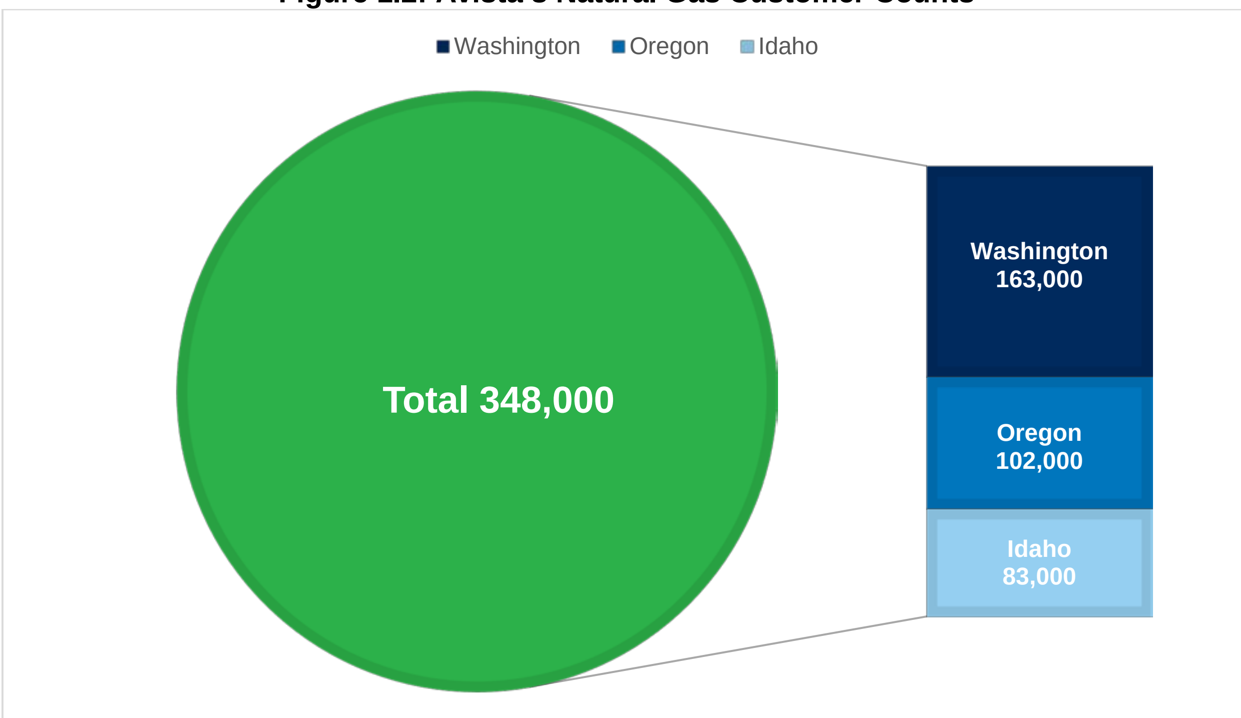


Figure 1.2: Avista's Natural Gas Customer Counts



Avista's natural gas operations covers 30,000 square miles in eastern Washington, northern Idaho and portions of southern and eastern Oregon, with a population of 1.6 million. The company manages its natural gas operation through the North and South operating divisions:

- The North Division includes Avista's eastern Washington and northern Idaho service area which is home to over 800,000 people. 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 490,000 followed by the Lewiston, Idaho/Clarkston, Washington, and Coeur d'Alene, Idaho, areas. The North Division has about 75 miles of natural gas transmission pipeline and 5,400 miles in the distribution system. The North Division receives natural gas at more than 40 points along interstate pipelines for distribution to over 246,000 customers.
- The South Division serves four counties in southern Oregon and one county in eastern Oregon. The combined population of these areas is over 500,000 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 297,000. The South Division consists of about 15 miles of natural gas transmission main and 2,400 miles of distribution pipelines. Avista receives natural gas at more than 20 points along interstate pipelines and distributes it to more than 102,000 customers.

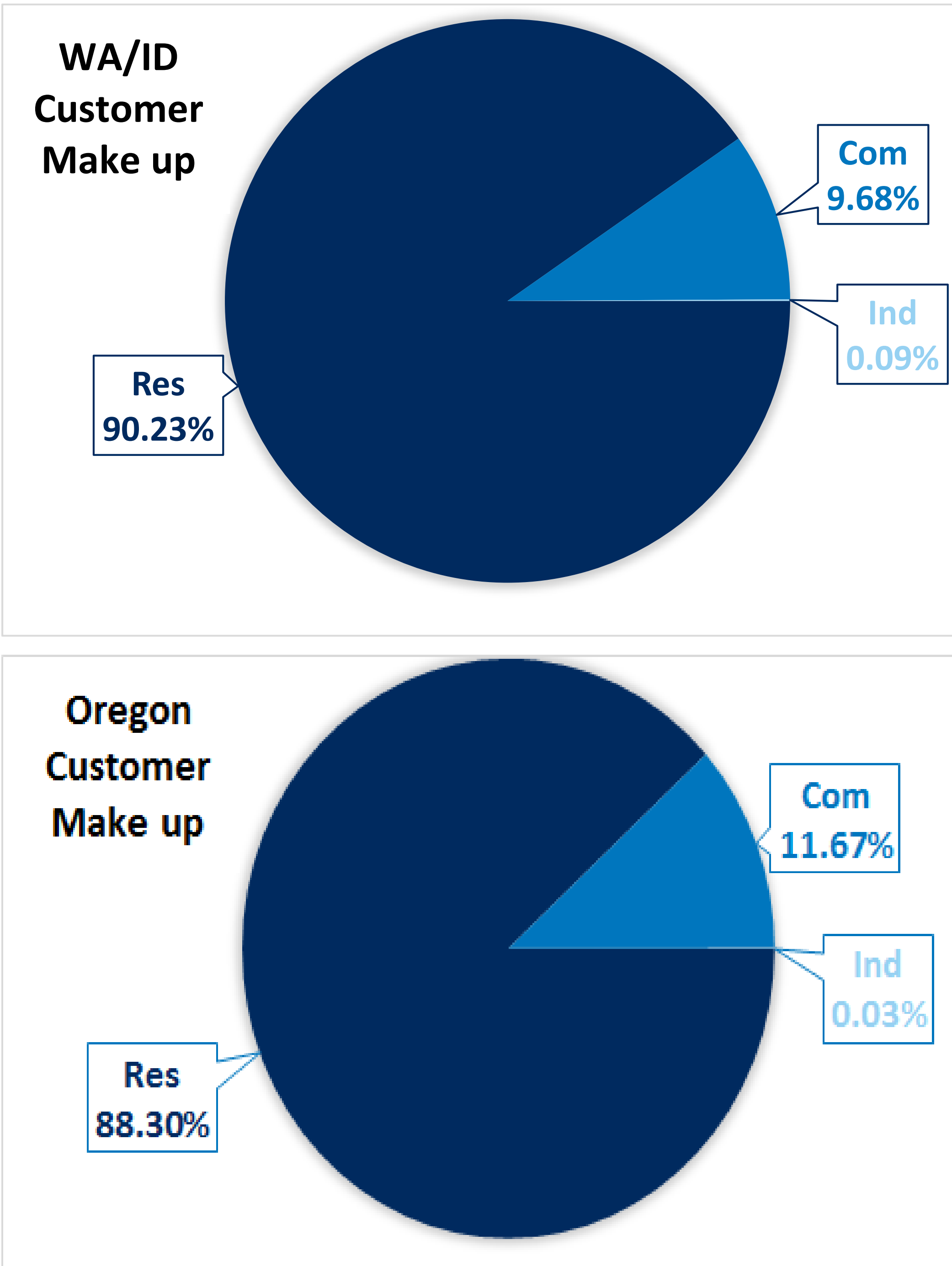
Customers

Avista provides natural gas services to both 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 natural gas they require. Some core customers are on interruptible rate schedules. These customers pay a lower rate than firm customers because 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 natural 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 natural gas and utilize their own interstate pipeline transportation contracts. However, distribution planning includes these customers.

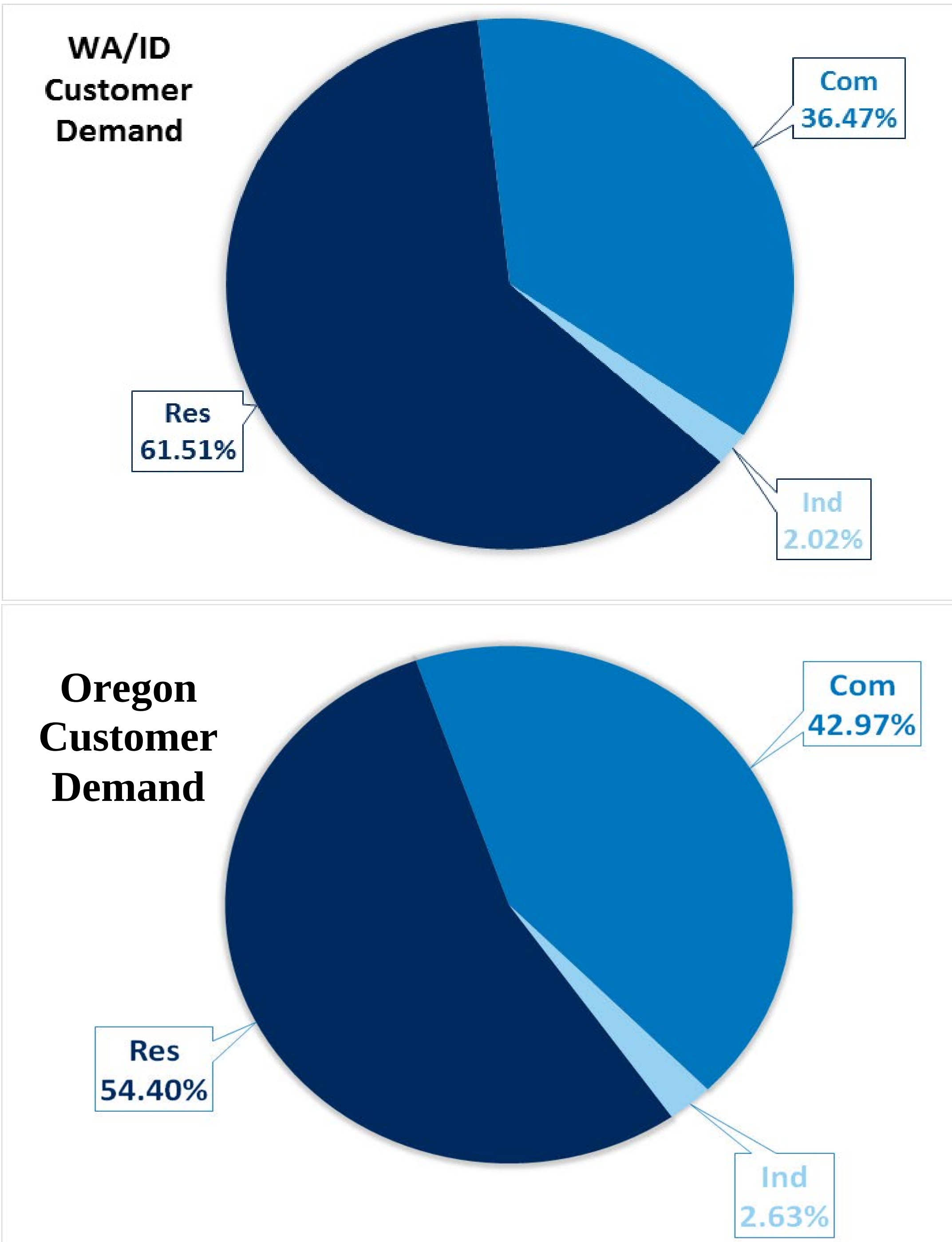
Avista's core or retail customers include residential, commercial and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

Figure 1.3: Firm Customer Mix



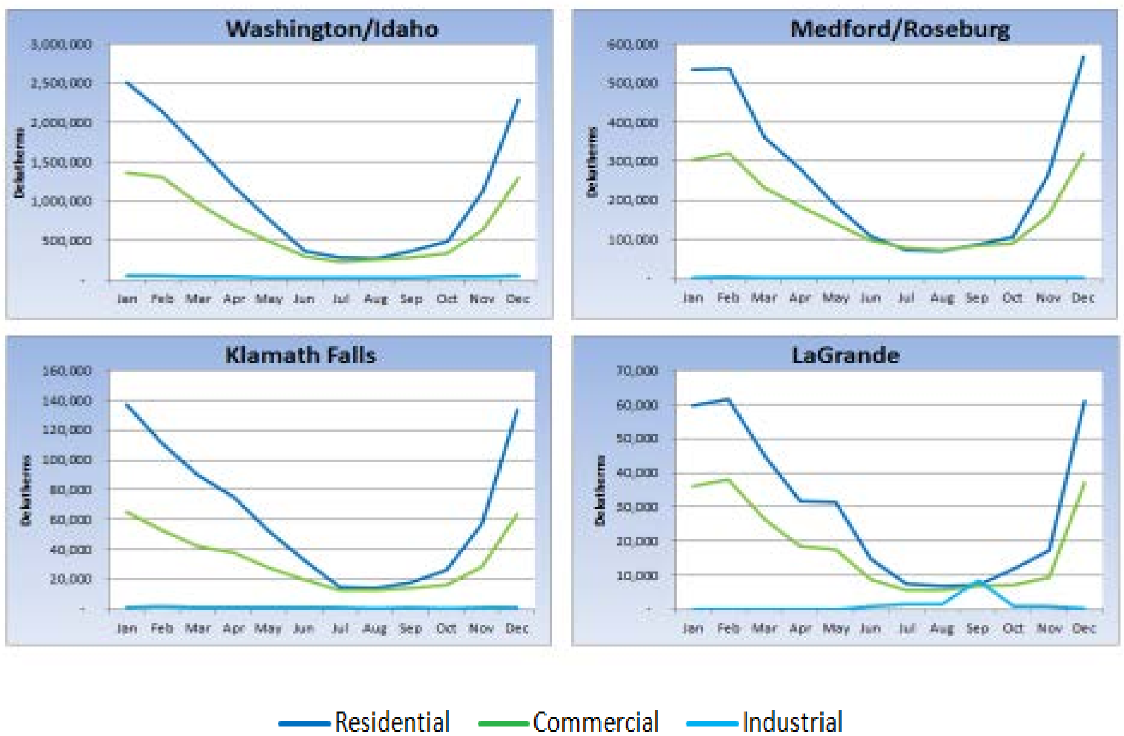
The customer mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.

Figure 1.4 Therms by Class



Core customer demand is seasonal, especially residential accounts in Avista's 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 reasonable price. The IRP evaluates, identifies, and plans for the acquisition of an optimal combination of existing and future resources using expected costs and associated risks to meet average daily and peak-day demand delivery requirements over a 20-year planning horizon.

Purpose of the IRP

Avista's 2018 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; and
- Meets Washington, Idaho and Oregon regulations, commission orders, and other applicable guidelines.

Avista's IRP Process

The natural gas IRP process considers:

- Customer growth and usage;
- Weather planning standard;
- Conservation opportunities;
- Existing and potential supply-side resource options;
- Current and potential legislation/regulation;
- Risk; and
- Least cost mix of supply and conservation.

Public Participation

Avista's TAC members play a key role and have a significant impact in developing the IRP. TAC members included Commission Staff, peer utilities, government agencies, and other interested parties. TAC members provide input on modeling, planning assumptions, and the general direction of the planning process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2018 IRP. The first meeting convened on January 25, 2018 and the last meeting occurred on May 10, 2018. 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 and results. TAC members received a draft of this IRP on July 2, 2018 for their review. Avista appreciates all of the time and effort TAC members contributed to the IRP process; they provided valuable input through their participation in the TAC process. A list of these organizations can be found below (Table 1.1).

Table 1.1: TAC Member Participation

Cascade Natural Gas	Northwest Industrial Gas Users	Oregon Public Utility Commission
Fortis	Northwest Natural Gas	Puget Sound Energy
Idaho Public Utilities Commission	Williams - Northwest Pipeline	TransCanada
Northwest Gas Association	Washington Utilities and Transportation Commission	

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 a natural gas IRP to the public utility commissions in Idaho, Oregon and Washington on or before August 31 every two years as required by state regulation. 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 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 and associated costs;
- Existing and potential natural gas supply availability and pricing;

- Revenue requirements on all new asset additions;
- Weather assumptions; and
- Conservation.

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); and
- 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 every two years, the process is ongoing with new information and industry related developments. In normal circumstances, the process can become complex as underlying assumptions evolve, impacting previously completed analyses. 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 and Mexico exports and industrial uses. One of the most prominent risks in the IRP involves policies meant to decrease the use of natural gas as outlined in Chapter 5. These policies are becoming more frequent in Oregon and Washington with of goal of reducing the amount of direct use natural gas. However, there is uncertainty about the timing and size of those policy decisions.

IRP Planning Strategy

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

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

With these objectives in mind, Avista developed a strategy encompassing all required planning criteria. This produced an 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. The following chart summarizes significant changes from the 2016 IRP (Table 1.2).

Table 1.2: Summary of changes from the 2016 IRP

Chapter	Issue	2018 Natural Gas IRP	2016 Natural Gas IRP
Demand	Expected Customer Growth	Expected Case – system wide – growth is slightly higher at 1.2%.	Expected Case customer growth is 1.1% compounded annually.
DSM	CPA potential	Higher price curve and conservation potential as a system. Cumulative Savings over 20 years: ID: 21.1 Million Therms OR: 17.2 Million Therms WA: 41.4 Million Therms	Lower Price curve can drive the conservation potential-downward.
Environmental Issues	Carbon Dioxide Emission (Carbon)	Carbon costs are now broken out by state allowing for different policy considerations across jurisdictions. ID: No federal or State initiatives ($0) OR: HB 4001 & SB 1507 ($17.86 – $51.58) WA – SSB 6203 ($10 - $30) *Prices are in dollars per MTCO2e	Three sensitivities on level of carbon tax ($/ton) were compared. The expected case has a probability of 2 sigma of the likely policy. The remainder of probability equally assumed to Low and Washington State's I-732 were used to represent the tails in a normal distribution. The base carbon case is the expected case. The high and low cases help bracket the base case results.
Prices	Price Curve	A higher price curve with slightly higher conservation potential.	Lower Price curve can drive the conservation potential-downward.
Supply Side Resources	Supply Side Scenarios	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Avista solved this case by using existing resources plus added contracted capacity on GTN. Landfill RNG is also selected as a resource in , Idaho. Also selected is the upsized compressor on the Medford lateral.	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Avista solved this case by using existing resources plus added contracted capacity on GTN for WA/ID. In Klamath Falls, Medford and Roseburg an upsized compressor would be added on the Medford lateral.

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.

Chapter Highlights

- An increase in customer forecast over 20 years versus the 2016 IRP
- Lower use per customer
- Geographic demand areas are now broken up by state and territory
- Weather analysis points to sustained risk of peak weather, compared to a base period, in most areas

Demand Areas

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

Table 2.1 Geographic Demand Classifications

Demand Area	Service Territory	Division
Washington NWP	Spokane	North
Washington GTN	Spokane	North
Washington Both	Spokane	North
Idaho NWP	Coeur D' Alene	North
Idaho GTN	Coeur D' Alene	North
Idaho Both	Coeur D' Alene	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 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 planning purposes.

Peak weather analysis aids in assessing resource adequacy and any differences in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

Demand Modeling Equation

Developing daily demand forecasts is essential because natural gas demand can vary widely from day-to-day, especially in winter months when heating demand is at its highest. 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.

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 daily degree days

Customer Forecasts

Avista's customer base includes firm 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, national 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 – Economic Outlook and Customer Count Forecast. 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 Avista departments' use these forecasts including Finance, Accounting, Rates, and Gas Supply. The natural gas distribution engineering group utilizes the forecast data for system optimization and planning purposes (see discussion in Chapter 8 – Distribution Planning).

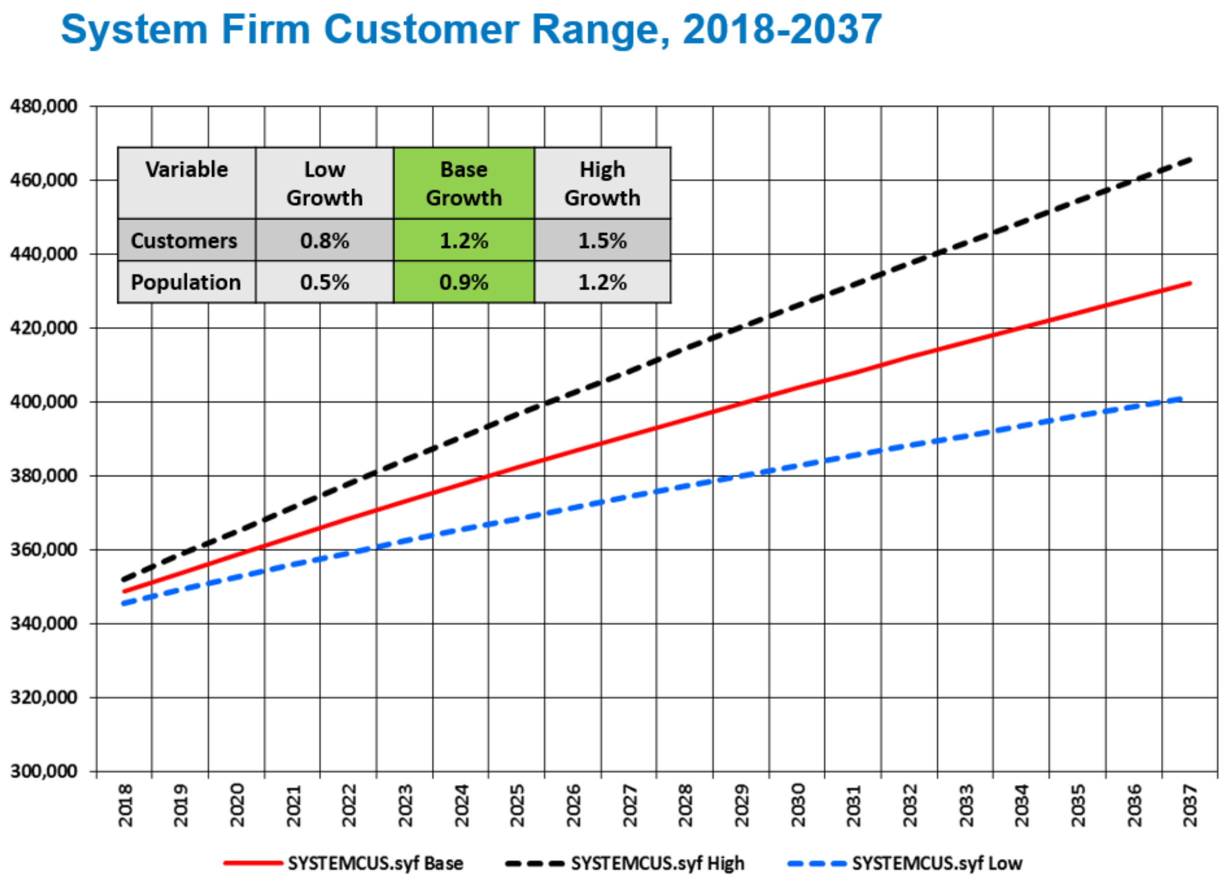
Forecasting customer growth is an inexact science, so it is important to consider different forecasts. Two alternative growth forecasts were developed for this IRP. Avista developed High and Low Growth forecasts to provide potential paths and test resource adequacy. Appendix 2.1 contains a description of how these alternatives were developed.

Figure 2.1 shows the three customer growth forecasts. The expected case customer counts are higher than the last IRP. This has impacted forecasted demand from both the average and peak day perspective. Detailed customer count data by region and class for all three scenarios is in Appendix. 2.2 – Customer Forecasts by Region. In comparison to Avista's 2016 IRP, the base forecast for customer growth increases by nearly 12,000 new customers converting from electric to natural gas. This emerging natural gas demand is attributed to both the Line Excess Allowance Program (LEAP) [1] and Fuel Efficiency programs. Since conversion costs can be expensive, it is common for customers who participate in the LEAP program to also apply for a fuel conversion rebate resulting in a large overlap in participation between the two programs. It was estimated that in 2017

[1] https://www.myavista.com/about-us/services-and-resources/natural-gas

approximately 77% of LEAP participants also participated in the fuel conversion program offerings.

Figure 2.1: Customer Growth Scenarios

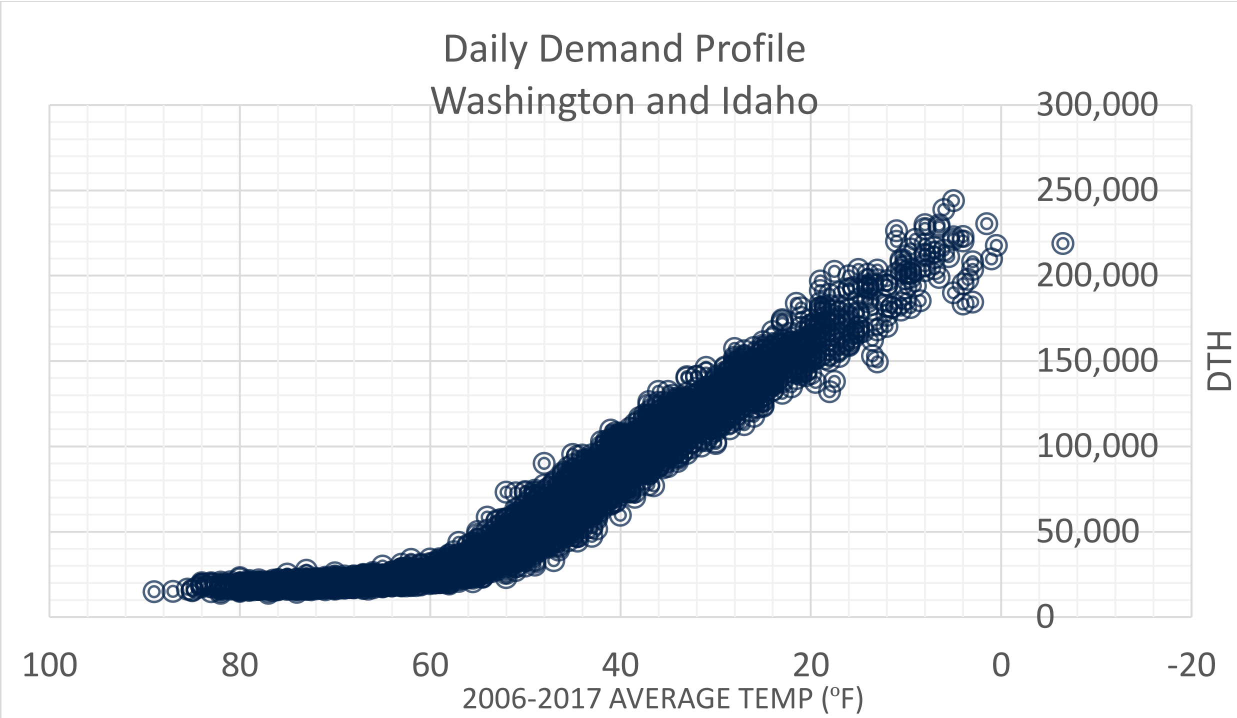


Variable	Low Growth	Base Growth	High Growth
Customers	0.8%	1.2%	1.5%
Population	0.5%	0.9%	1.2%

Use-per-Customer Forecast

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to heating degree day (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

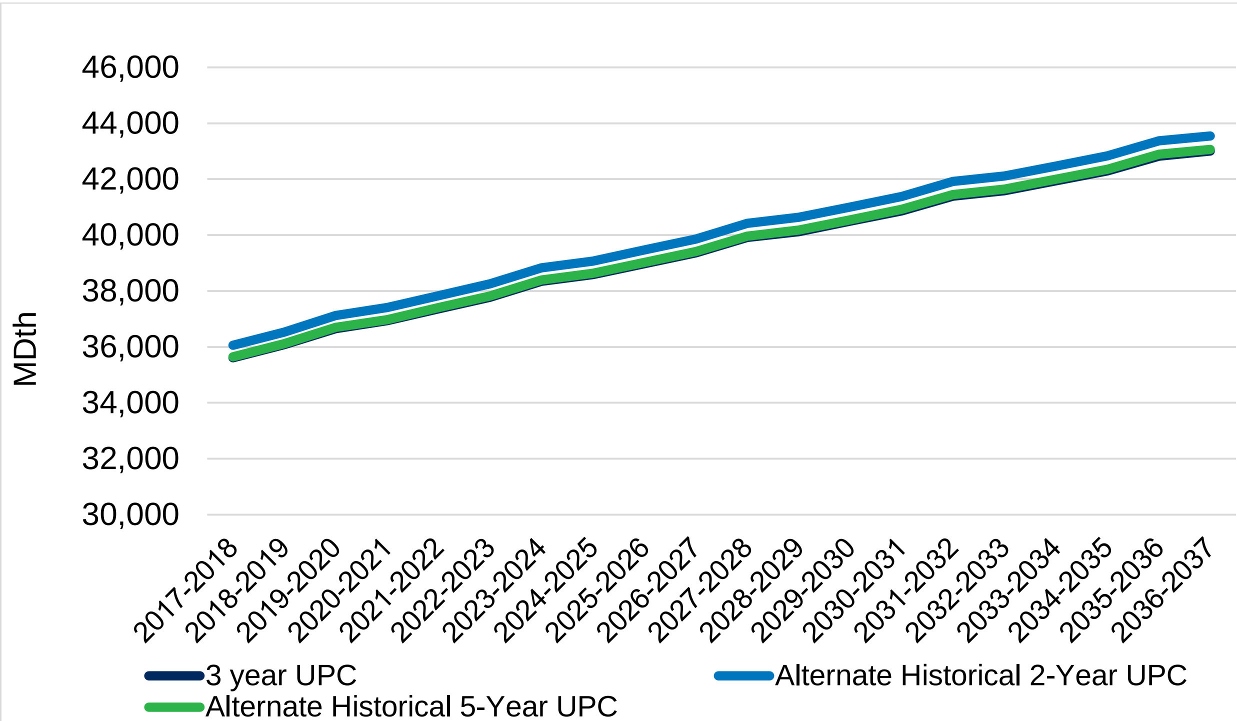


The first step in developing demand coefficients was gathering daily historical gas flow data for all of Avista's city gates. The use of city gate data over revenue data is due to the tight correlation between weather and demand. The revenue system does not capture data on a daily basis and, therefore, 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 as sensitivities. When comparing five years of historical use-per-customer to three years of data, the five-year data had slightly higher use-per-customer, which may overstate use as efficiency and use-per-customer-per-HDD have been on a downward trend since 2006. The two-year use-per-customer was much more pronounced for demand, likely based off of some cold weather in Avista's territories and a shorter timeframe for weather to impact the overall use-per-customer. 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.

You can see the three year and 5 year coefficients are very close, with the two year coefficient clearly higher.

Figure 2.3: Annual Demand – Demand Sensitivities 2-Year, 3-Year and 5-Year Use-per-Customer



The base usage calculation used three years of July and August 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.

Weather Forecast

The last input in the demand modeling equation is weather (specifically HDDs). The most current 20 years of daily weather data (minimums and maximums) from the National Oceanic Atmospheric Administration (NOAA) is used to compute an average for each day; this 20-year daily average is used as a basis for the normal weather forecast. NOAA data is obtained from five weather stations, corresponding to the areas where Avista provides natural gas services (four in Oregon and one for Washington and Idaho), where this same 20-year daily average weather computation is completed for all five areas. The HDD weather patterns between the Oregon areas are uncorrelated, while the HDD weather patterns amongst eastern Washington and northern Idaho portions of the service area are correlated. Thus, Spokane Airport weather data is used for all Washington and Idaho demand areas.

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.

For, Washington and Idaho service areas, the coldest day on record observed in Spokane was an 82 HDD that occurred on December 30, 1968. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 51 years for this area; however, within that same time period, 80, 79 and 78 HDD events occurred on December 29, 1968, December 31,1978 and December 30, 1978, respectively.

Medford experienced the coldest day on record, a 61 HDD, on December 9, 1972. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 47 years; however, it has also experienced 59 and 58 HDD events on December 8, 1972 and December 21, 1990, respectively.

The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on three separate occasions: December 21, 1990, December 8, 2013 and most recently on January 6, 2017; in La Grande a 75 HDD occurred on January 31, 1996; and a 55 HDD occurred in Roseburg on December 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 regionally accepted planning standard. While remote, peak days do occur, as on January 6, 2017, 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. Washington and Idaho service area use 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 52 HDD, equivalent to an average daily temperature of 13 degrees Fahrenheit. In Roseburg, the coldest day in 20 years is a 48 HDD, equivalent to an average daily temperature of 17 degrees Fahrenheit. In Klamath Falls, the coldest day in 20 years is a 72 HDD, equivalent to an average daily temperature of -7 degree Fahrenheit. In La Grande, the coldest day in 20 years is a 66 HDD, equivalent to an average daily temperature of -1 degree Fahrenheit. The HDDs by area, class and day entered into SENDOUT® are in Appendix 2.4 – Heating Degree Day Data.

Average rolling 20 year weather is the current methodology used in Avista's planning in this IRP. Unlike many peer utilities, Avista has some extreme weather that can have deadly consequences to both persons and property if observed. If taken into consideration, wind chill has the potential to drastically change our planning standard. During Spokane's coldest on record weather event the average temperature was -17 degrees Fahrenheit or 82HDD[2]; if combined with a 7mph wind chill, would create a temperature of -33 Fahrenheit[3]. This would add an additional 16 HDD's to Avista's planning standard, consequently increasing our new planning standard to 99 HDD. The coldest in the past 20 years occurred on January 5, 2004 as Spokane International Airport's observed mean temperature of -10 Fahrenheit combined with an average wind speed of 3 mph. The average temperature converts to 75 HDDs and when paired with the wind-chill factor -18 Fahrenheit, would be 83 HDDs or 1 degree colder than our planning standard. With the wind chill included, these temperatures appear to be reasonable as these extreme events have been experienced in recent history. In Oregon territories, specifically Klamath Falls and La Grande, the coldest on record has occurred multiple times in the past 30 years.

[2] Weather Underground: www.wunderground.com/history
[3] http://www.wpc.ncep.noaa.gov/html/windchillbody_txt.html

As discussed in TAC 2, warming trends are beginning to emerge in Roseburg and Medford, though the volatility surrounding the peak is still present as seen in Figures 2.5 and 2.8. This indicates that although temperatures specifically in the Roseburg and Medford areas are deviating from the base years of 1950-1981, the peaking potential remains the same. The following figures show this same analysis for all weather areas.

Figure 2.4: Spokane

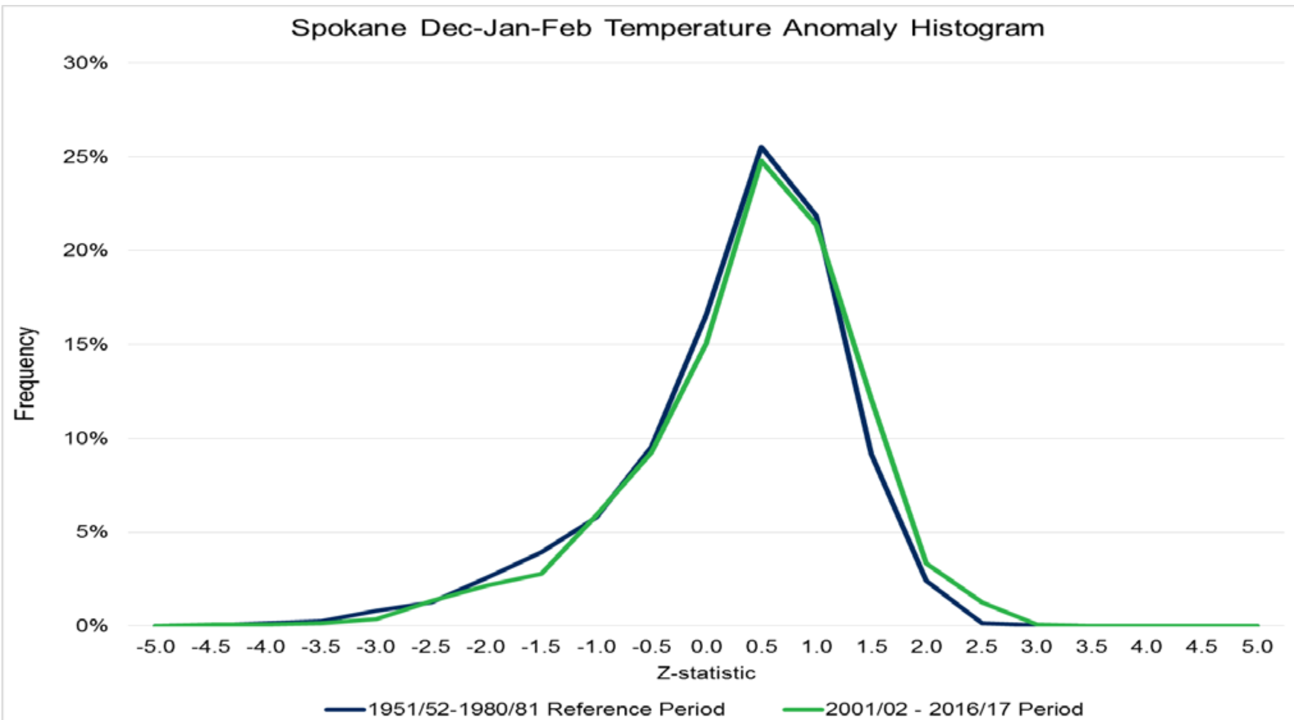


Figure 2.5: Medford

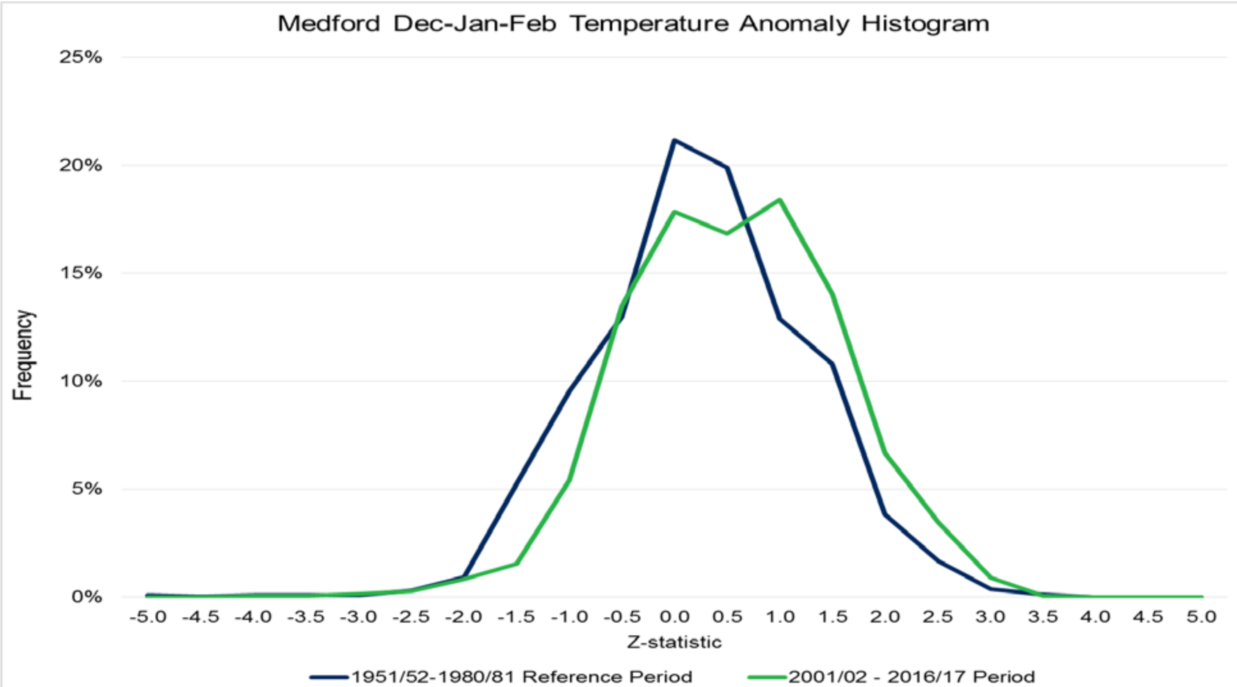


Figure 2.6: La Grande

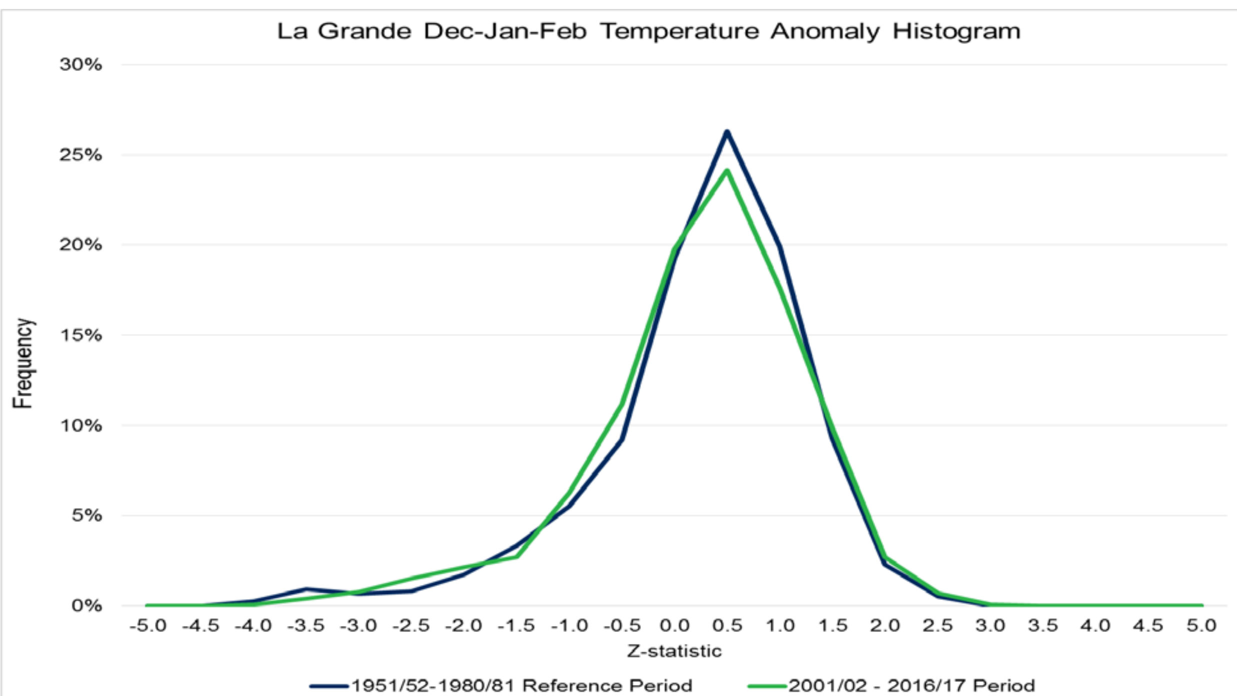


Figure 2.7: Klamath Falls

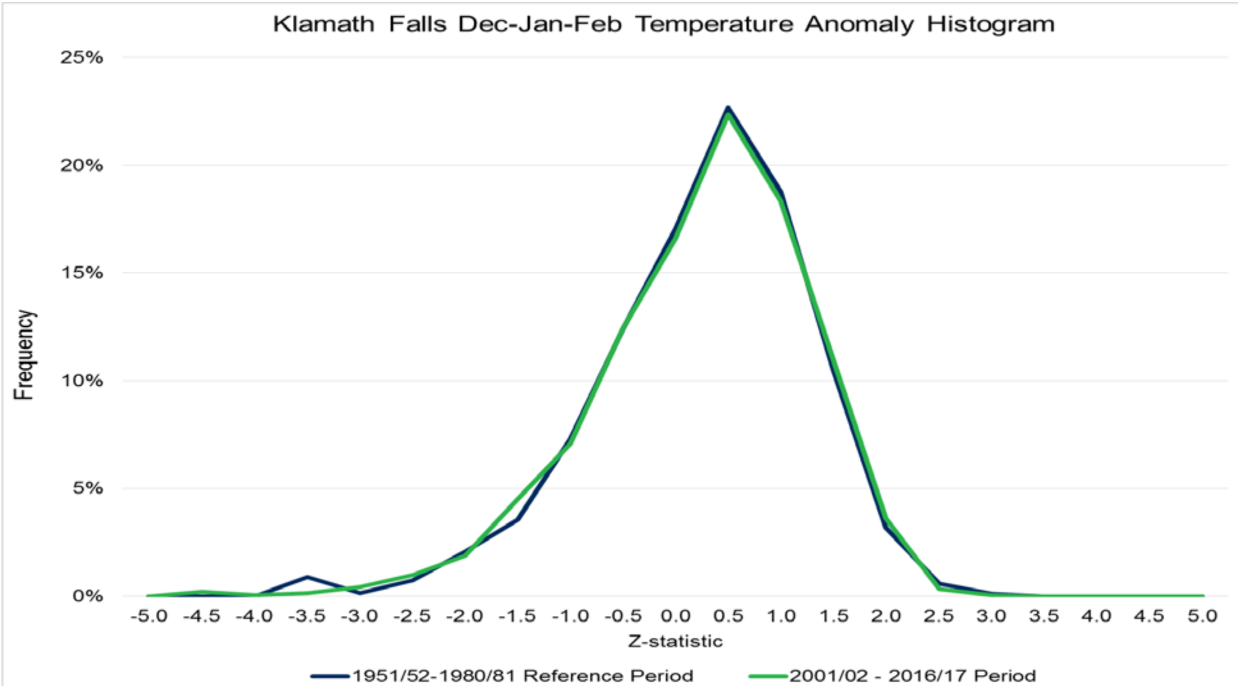
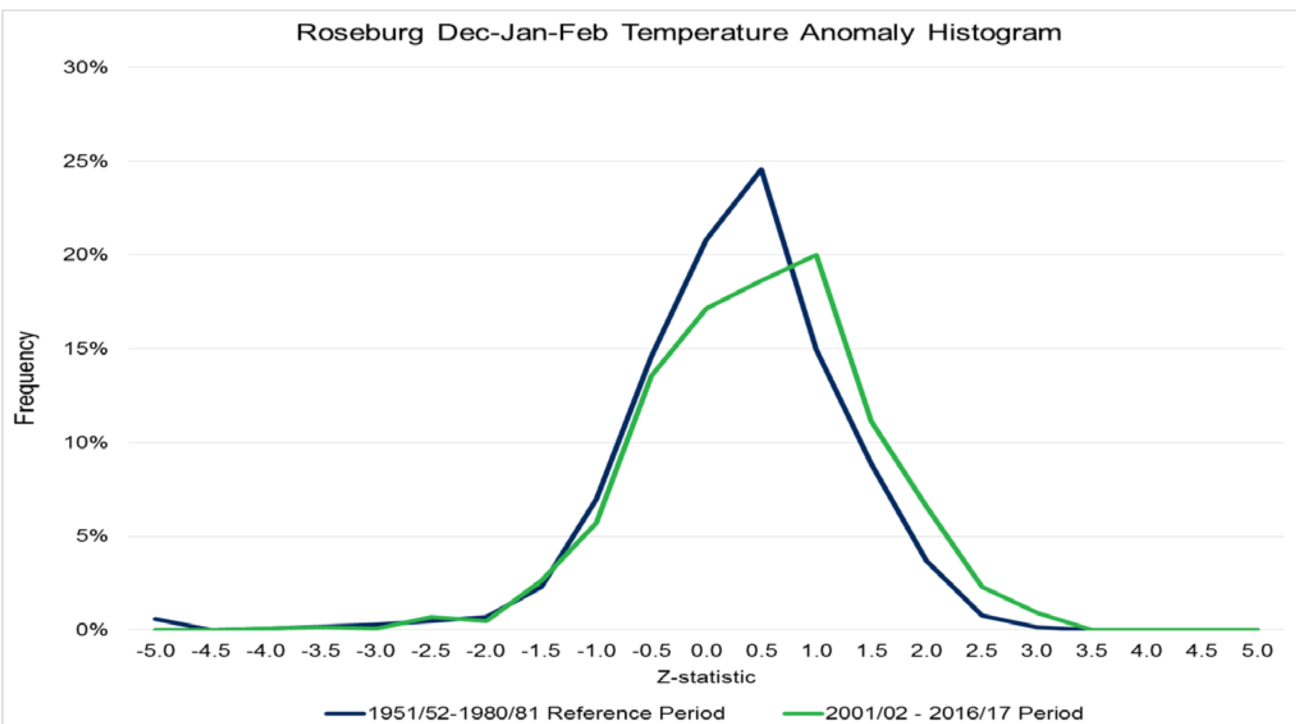


Figure 2.8: Roseburg



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.

Figure 2.4: Reference Case Assumptions

1. **Customer Compound Annual Growth Rates**

Area	Residential	Commercial	Industrial
Washington/ Idaho	1.1%	0.6%	0.0%
Klamath Falls	1.3%	0.9%	0.0%
La Grande	0.6%	0.4%	0.1%
Medford	1.3%	1.0%	0.0%
Roseburg	1.1%	0.2%	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 (1998-2017)
4. **Elasticity**
   None
5. **Conservation**
   None

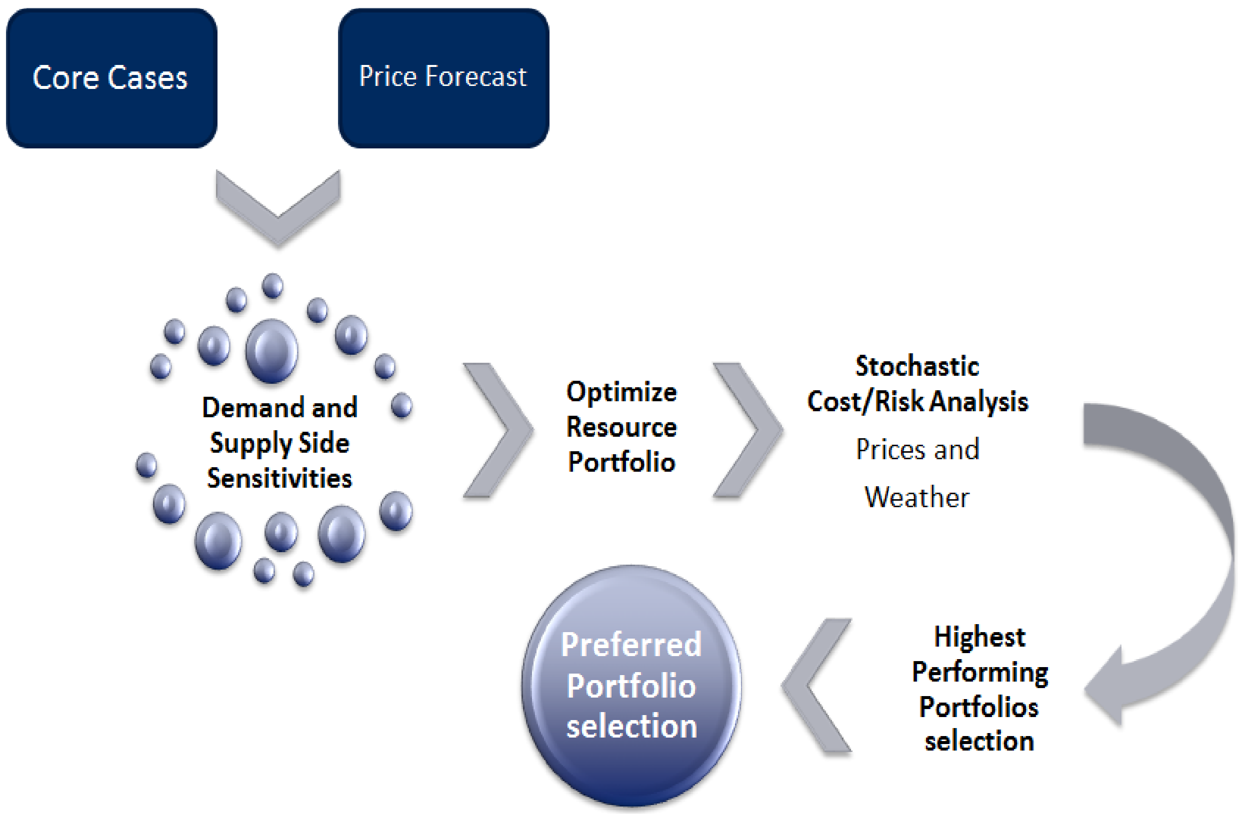
Dynamic Demand Methodology

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; and
- Matching demand scenarios with supply scenarios to identify unserved demand.

Figure 2.5 represents Avista's methodology of starting with sensitivities, progressing to portfolios, and ultimately selecting a preferred portfolio.

Figure 2.5: Sensitivities and Preferred Portfolio Selection



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.

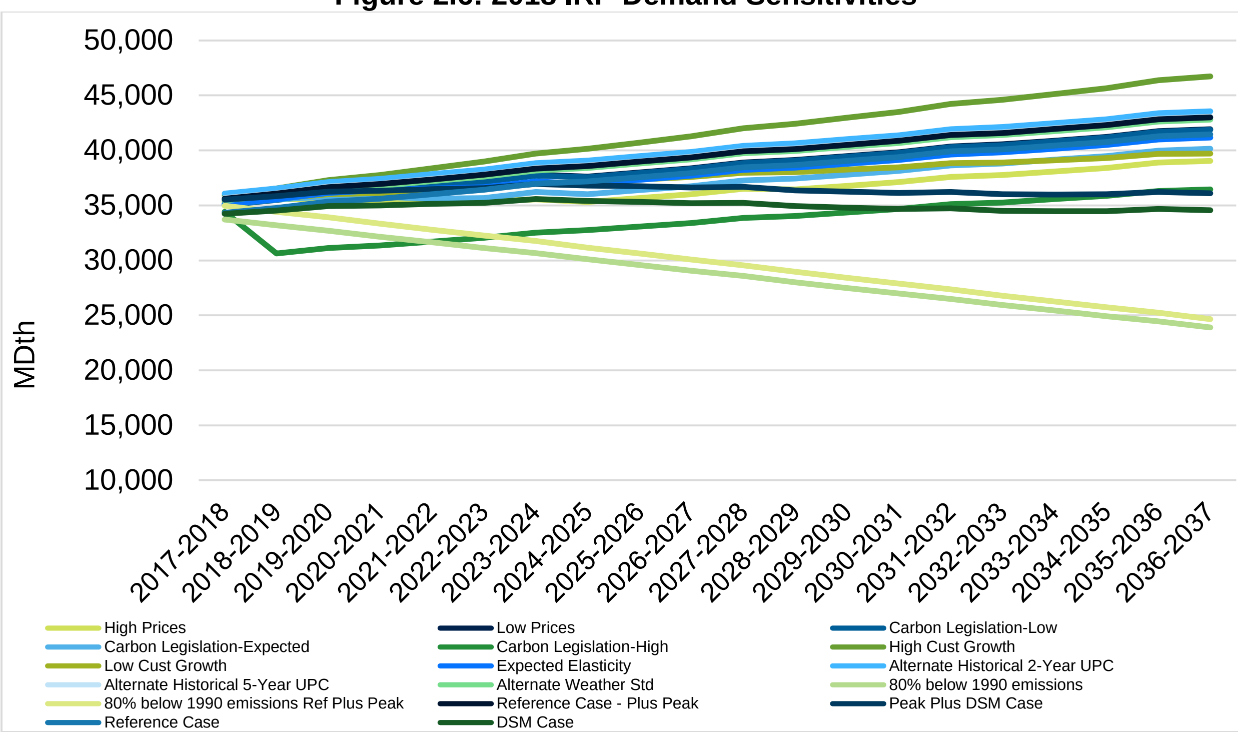
Sensitivity assumptions reflect incremental adjustments not captured in the underlying Reference Case forecast. Avista analyzed 18 demand sensitivities to determine the results relative to the Reference Case. Table 2.4 lists these sensitivities. Detailed information about these sensitivities is in Appendix 2.6 – Demand Forecast Sensitivities and Scenarios Descriptions.

Table 2.4: Demand Sensitivities

			DEMAND INFLUENCING - DIRECT									PRICE INFLUENCING - INDIRECT			
INPUT ASSUMPTIONS	Reference Case	Reference Plus Peak Case	Low Cust Growth	High Cust Growth	Alternate Weather Std	DSM Case	Peak plus DSM Case	80% below 1990 emissions Reference Case	80% below 1990 emissions Reference Plus Peak	Alternate Historical 2 Year UPC	Alternate Historical 5 Year UPC	Expected Elasticity	Low Prices	High Prices	Carbon Legislation
Customer Growth Rate	Reference		Low Growth	High Growth	Reference										
Use per Customer	3 Year Historical							3 Year Historical less demand destruction		2 Year Historical	5 Year Historical	3 Year Historical			
Weather Planning Standard	20 Year Average	Coldest on Record			Coldest in 20yrs	20 Year Average	Coldest on Record	20 Year Average	Coldest on Record						
Demand Side Management Programs Included	None					Expected		None							
Prices Price curve	Expected												Low	High	Expected
Price curve adder ($/Dth)	None														High/Expected /Low
Elasticity	None											Expected			

Figure 2.6 shows the annual demand from each of the sensitivities modeled for this IRP.

Figure 2.6: 2018 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 for this IRP. The Average 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. The 80% below 1990 emissions scenario is intended to show a progressive loss of demand in the areas of Oregon and Washington (Idaho is unaffected) from policies targeting methane and carbon dioxide emissions to an estimated emissions levels. It makes no assumptions as to how the reduction in emissions are obtained just the levelized trend of overall use based on 2050 targets. 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

2018 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard
80% below 1990 emissions

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 customer's consumption change in response to a price change. Typically, the factor is a negative number as customers 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.[4] 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. This IRP includes a price elasticity of demand factor of -0.10 for every 10% change in price as measured in the Roseburg and Medford service territories. We assume the same elasticity for all service areas in this study. When putting this elasticity into our model, it allows the use-per-customer to vary 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 increased investments in energy DSM measures, building code improvements, behavioral changes, and heightened focus of consumers' household budgets.

Results

During 2018, the Average Case demand forecast indicates Avista will serve an average of 348,000 core natural gas customers with 33,219,431 Dth of natural gas. By 2037, Avista projects 412,000 core natural gas customers with an annual demand of over 36,154,721 Dth. In Washington/Idaho, the projected number of customers increases at an average annual rate of 1.30 percent, with demand growing at a compounded average

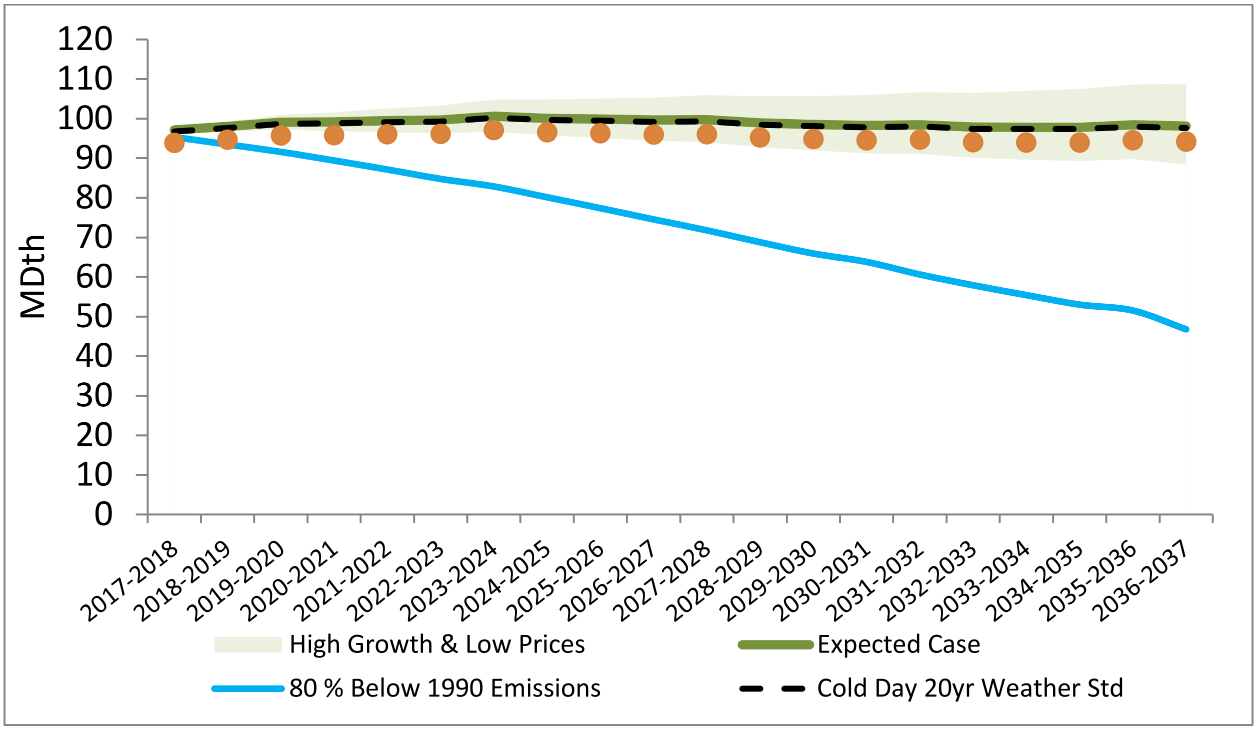
[4] Bernstein, M.A. and J. Griffin (2005). Regional Differences in Price-Elasticity of Demand for Energy, Rand Corporation.

annual rate of 0.36 percent. In Oregon, the projected number of customers increases at an average annual rate of 0.9 percent, with demand growing 0.70 percent per year.

During 2018, the Expected Case demand forecast indicates Avista will serve an average of 348,000 core natural gas customers with 34,369,993 Dth of natural gas. By 2037, Avista projects 412,000 core natural gas customers with an annual demand of 37,536,603 Dth.

Figure 2.7 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[5]

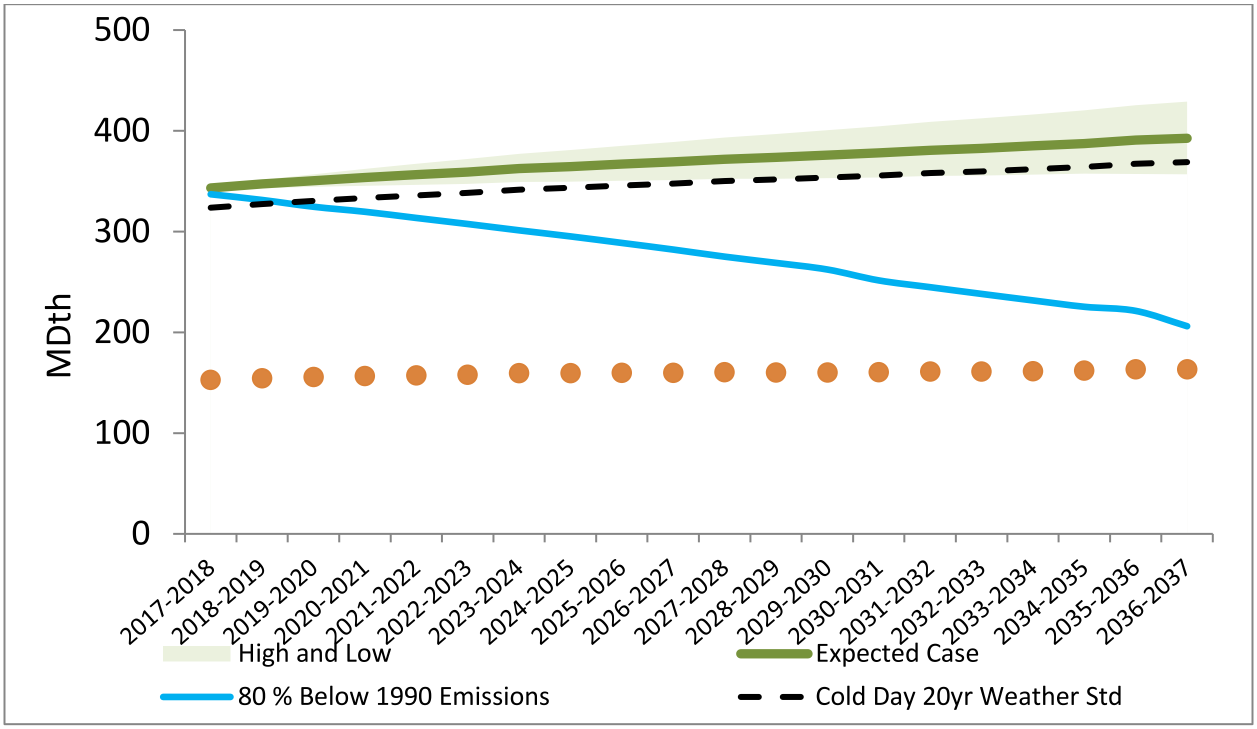
Figure 2.7: Average Daily Demand – 2018 IRP Scenarios



[5] Appendix 2.1 shows gross demand, conservation savings and net demand.

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 – Demand Before and After DSM.

Figure 2.8: February 15th – Peak Day – 2016 IRP Demand Scenarios



The IRP balances 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 DSM 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 uses methods that enhance forecast accuracy, facilitate meaningful variance analysis, and allows for modeling flexibility to incorporate different assumptions. Avista believes the IRP 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 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 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.

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 a declining use-per-customer. Use-per-customer seems to have stabilized, though it is still on a downward trajectory.

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 than expected.

Emerging Natural Gas Demand

The shale gas revolution has fundamentally changed the long-term availability and price of natural gas. An ever growing demand for natural gas-fired generation to integrate variable wind and solar resources along with an increasing demand from coal retirements and fuel switching has developed over the last few years. This demand is expected to increase due to the availability of natural gas combined with its lower carbon emissions. Other areas of emerging demand include everything from methanol plants to food processors, and interest in industrial processes using natural gas as a feedstock is growing.

Conclusion

Avista's 20 year outlook for customer growth has increased as a whole by nearly 12,000 customers, as compared to Avista's 2016 IRP. Much of this demand is from a conversion program offered in Washington and Idaho helping electric customer's assistance in converting to natural gas. With an increased amount of energy efficiency, known as DSM, measures going into new construction and purchased through Avista's programs, homes are becoming better equipped to keep the heat in. This in turn leads to a decreasing amount of natural gas usage. Until a point is reached where maximum efficiency is found, these trends will likely continue to decline in nature.

3: Energy Efficiency & Demand-Side Resources

Chapter Highlights

- Increased DSM potential
- ETO manages Avista's DSM programs in Oregon
- In future IRP's we will visit new methodology to look at DSM by scenario
- Distribution will be a primary area of research for potential integration in avoided costs and as a supply side resource

Overview

Avista is committed to offering natural gas Energy Efficiency portfolios to residential, low income, commercial and industrial customer segments when it is feasible to do so in a cost-effective manner as prescribed within each jurisdiction. Avista began offering natural gas energy efficiency programs to its customers in 1995. Program delivery includes both prescriptive and site-specific offerings. Prescriptive programs, or standard offerings, provide cash incentives for standardized products such as the installation of qualifying high-efficiency heating equipment. Delivering programs through a prescriptive approach works in situations where uniform products or offerings are applicable for large groups of homogeneous customers and primarily occur in programs for residential and small commercial customers. Site specific is the most comprehensive offering of the nonresidential segment. Avista's Account Executives work with nonresidential customers to provide assistance in identifying energy efficiency opportunities. Customers receive technical assistance in determining potential energy and cost savings as well as identifying and estimating incentives for participation. Other delivery methods build off these approaches and may include upstream buy downs of low cost measures, free-to-customer direct install programs, and coordination with regional entities for market transformation efforts.

Recently, programs with the highest impacts on natural gas energy savings include the residential prescriptive HVAC measures, residential water heat measures, and nonresidential prescriptive and site-specific HVAC. In the 2017 program year, conservation programs exceeded the IRP savings targets in both Washington and Idaho.

Improved drilling and extraction techniques of natural gas has led to declines in natural gas prices in recent years which has made offering cost-effective DSM programs challenging using the Total Resource Cost Test (TRC) to test cost-effectiveness. Since January 1, 2016, Washington and Idaho programs utilize the Utility Cost Test (UCT). Effective January 1, 2017, all Oregon DSM programs, with the exception of low-income conservation, are delivered and administered by the Energy Trust of Oregon (ETO)[1].

[1] As part of the settlement for the Avista 2015 Oregon General Rate case

In Washington, a $10/MTCO2e ($0.53/Dth) carbon cost starting July 2019 was included to account for the potential carbon reduction approaches currently occurring in the state. Idaho has no assumed carbon costs.

Conservation Potential Assessment Methodology Overview

During 2017, Avista issued an RFP and chose Applied Energy Group (AEG) to perform an external independent evaluation of Avista's conservation potential. Included with this evaluation was the technical, economic and achievable conservation potential for each of Avista's three jurisdictions over a 20-year planning horizon (2018-2037). As potential for 2038 was also estimated for reference purposes but not utilized within the IRP, the remainder of this chapter will refer only to the 20-year planning horizon. This process involves indexing AEG's existing nationally recognized Conservation Potential Assessment (CPA) tool, LoadMAP™, to the Avista service territory load forecast, housing stock, end-use saturations, recent conservation accomplishments, 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 and Conservation Council (NPCC), adapted for use in modeling natural gas DSM programs.

The process described above results in 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 is rerun against the modified (reduced) load requirements. The resulting avoided costs are compared to those obtained from the previous iteration of SENDOUT® avoided costs. This process continues until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial. The resulting avoided costs were provided to AEG to use in selecting cost-effective potential within Avista's Washington and Idaho service territories. The cost-effectiveness test used for Washington and Idaho was the UCT.

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.

Conservation Potential Assessment Methodology

Prior to the development of potential conservation estimates, AEG created a baseline end-use projection to quantify the use of natural gas by end use in the base year (2015), and projections of consumption in the future in the absence of future utility programs and naturally occurring conservation (through 2038). The end-use forecast includes the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates defined as of February 2018 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future DSM programs as well as the metric against which potential savings are measured.

Inputs to the baseline forecast include current economic growth forecasts (e.g. customer growth and income growth), natural gas price forecasts, trends in fuel shares and equipment saturations developed by AEG, existing and approved changes to building codes and equipment standards, and Avista's internally developed load forecast. Since actual billing data was available for 2016 and 2017, AEG calibrated the model to reflect recent consumption trends and weather-actual consumption before aligning with Avista's weather-normal load forecast in 2018.

According to the CPA, the residential sector natural gas consumption for all end uses and technologies increases primarily due to the projected 1.3 percent annual growth in the number of households for Washington, and 1.5 percent annual growth for Idaho. This projection aligns well with Avista's official forecast, diverging in the later years due to two end-use modeling assumptions. The first is the projected impact of the AFUE 92% federal furnace standard being phased in over time (starting in 2021), resulting in slower primary space heating growth compared to the other end uses. Furthermore, impacts of the 2015 Washington State Energy Code (2015 WSEC) further reduce space heating consumption in Washington, where very efficient building shell requirements reduce the annual runtime requirements on primary heating systems.

For the commercial sector, natural gas use grows slowly over the 20-year planning horizon as new construction increases the overall square footage in this sector. Growth in the heating end use mirrors overall sector growth while food preparation and miscellaneous consumption outpace it. Food preparation, though a small percentage of total usage, grows at a higher rate than the other end uses. Consumption by miscellaneous equipment and process heating are also projected to increase.

Growth in the industrial sector is tied closely to historical trend and planned facility closures. This is observed in Washington, where consumption drops by 0.3% annually between 2018 and 2037. In Idaho, consumption between 2018 and 2037 remains quite flat for all end uses.

Table 3.1 illustrates the baseline consumption broken out by state and sector for selected years over the 20-year planning horizon. The overall baseline consumption is expected to increase 14 percent over the 20-year planning horizon corresponding to an annualized growth of 0.7 percent. The forecast projects steady growth over the next 20 years with growth in the residential sector making up for the flat or declining sales in the industrial sector. Idaho is projected to experience a higher level of growth than Washington due to less stringent energy codes and a flat industrial baseline.

Table 3.1: Baseline Forecast Summary (Dth)

End Use	2016	2018	2019	2020	2027	2037	% Change ('18-'37)	Avg. Growth
Residential	14,154,582	16,039,605	16,350,394	16,623,717	17,862,303	19,126,196	19.2%	0.9%
Commercial	8,479,816	9,247,911	9,242,949	9,243,720	9,362,277	9,736,948	5.3%	0.3%
Industrial	449,174	491,562	491,983	492,546	477,257	460,222	-6.4%	-0.3%
Total	**23,083,572**	**25,779,078**	**26,085,326**	**26,359,983**	**27,701,837**	**29,323,366**	**13.7%**	**0.7%**
Washington	15,837,527	17,221,900	17,418,177	17,594,636	18,413,613	19,406,251	12.7%	0.6%
Idaho	7,246,045	8,557,178	8,667,149	8,765,347	9,288,224	9,917,115	15.9%	0.8%
Total	**23,083,572**	**25,779,078**	**26,085,326**	**26,359,983**	**27,701,837**	**29,323,366**	**13.7%**	**0.7%**

The next step in the study is the development of three types of potential: technical, achievable technical, and achievable economic. Technical potential is the theoretical upper limit of conservation potential. This assumes that all customers replace equipment with the efficient option available and adopt the most efficient energy use practices possible at every opportunity without regard to cost-effectiveness.

Achievable technical potential refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. The Seventh Electric Power Plan’s ramp rates, which also include potential realized from delivery mechanisms outside utility DSM programs, were used as a starting point when developing these factors.

Achievable economic potential further refines achievable technical potential by applying an economic screen, measured by the utility cost test (UCT), which assesses cost-effectiveness from the utility’s perspective. Please note that while AEG estimated potential under a balanced total resource cost (TRC) test as a secondary test, results from this sensitivity were not used for IRP modeling and are excluded from this discussion.

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-loading clothes washers. Weather-sensitive measures are those which are influenced by heating degree day factors and include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing chimney heat). Weather-sensitive measures are often referred to as winter load shape measures and were valued using a higher avoided cost (due to summer-to-winter natural gas pricing differentials) while base-load measures, often called annual load shape measures, are valued at a lower, year-round avoided cost.

Conservation measures are offered to residential, non-residential and low-income[2] customers. 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 Agencies. Non-residential customers have access to various prescriptive and site-specific conservation measures. Site-specific measures are customized to specific applications and have cost and therm savings that are unique to the individual facility.

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

Table 3.2: Conservation Measures

Residential Measures	Commercial and Industrial Measures
Furnace - Direct Fuel	Furnace - Efficient Heating
Boiler - Direct Fuel	Boiler - Efficient Heating
Fireplace	Unit Heater - Efficient Heating
Water Heating - Efficient Heating	Water Heater - Efficient Water Heating
Appliances - Clothes Dryer	Food Preparation - Oven
Appliances - Stove/Oven	Food Preparation - Conveyor Oven
Pool Heater - Efficient Water Heating	Food Preparation - Double Rack Oven
Insulation - Ceiling, Installation	Food Preparation - Fryer
Insulation - Ceiling, Upgrade	Food Preparation - Broiler
Insulation - Slab Foundation	Food Preparation - Griddle
Insulation - Basement Sidewall	Food Preparation - Range
Insulation – Ducting	Food Preparation - Steamer
Insulation - Infiltration Control (Air Sealing)	Food Preparation - Other Food Prep
Insulation - Floor/Crawlspace	Pool Heater - Efficient Heater
Insulation - Wall Cavity, Upgrade	Insulation - Roof/Ceiling
Insulation - Wall Cavity, Installation	Insulation - Wall Cavity
Insulation - Wall Sheathing	Insulation - Ducting
Ducting - Repair and Sealing	HVAC - Duct Repair and Sealing
Doors - Storm and Thermal	Windows - High Efficiency
Windows - High Efficiency	Gas Boiler - Maintenance
Thermostat – Programmable	Gas Furnace - Maintenance

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

Residential Measures	Commercial and Industrial Measures
Thermostat - Wi-Fi/Interactive	Gas Boiler - Hot Water Reset
Gas Furnace - Maintenance	Steam Trap Maintenance
Gas Boiler - Hot Water Reset	Gas Boiler - High Turndown
Gas Boiler - Steam Trap Maintenance	Gas Boiler - Burner Control Optimization
Gas Boiler - Maintenance	HVAC - Shut Off Damper
Gas Boiler - Pipe Insulation	HVAC - Demand Controlled Ventilation
Water Heater - Drainwater Heat Recovery	Gas Boiler - Stack Economizer
Water Heater - Faucet Aerators	Gas Furnace Tube Inserts
Water Heater - Low Flow Showerhead (2.0 GPM)	Gas Boiler - Insulate Steam Lines/Condensate Tank
Water Heater - Low Flow Showerhead (1.5 GPM)	Gas Boiler - Insulate Hot Water Lines
Water Heater - Temperature Setback	Space Heating - Heat Recovery Ventilator
Water Heater - Thermostatic Shower Restriction Valve	Thermostat - Programmable
Water Heater - Pipe Insulation	Thermostat - WiFi Enabled
Water Heater - Solar System	Water Heater - Ozone Laundry
Pool Heater - Solar System	Water Heater - High MEF Commercial Laundry Washers
ENERGY STAR Dishwashers	Water Heater - Motion Control Faucet
ENERGY STAR Clothes Washers	Water Heater - Faucet Aerator
ENERGY STAR Homes	Water Heater - Drainwater Heat Recovery
Combined Boiler + DHW System (Storage Tank)	Water Heater - Efficient Dishwasher
Combined Boiler + DHW System (Tankless)	Water Heater - Pre-Rinse Spray Valve
	Water Heater - Central Controls
	Water Heater - Solar System
	Destratification Fans (HVLS)
	Kitchen Hood - DCV/MUA
	Pool Heater - Night Covers
	Building Automation System
	Steam System Efficiency Improvements
	Commissioning - HVAC
	Retrocommissioning - HVAC
	Strategic Energy Management
	Process - Insulate Heated Process Fluids
	Process Heat Recovery
	Commissioning
	Retrocommissioning

Conservation Potential Assessment Results

Based upon the previously described methodology and baseline forecasts, AEG developed technical, achievable technical, and achievable economic potentials by state and segment over a full 20-year horizon. Although early-year potential differs by state due to maturity of DSM programs[3], 20-year steady-state potential is quite similar between the two states since ramp rates reach 85% for all non-emerging measures.

The technical potential for the overall Avista service territory for the full 20-year IRP horizon period ultimately reaches 29.5 percent of the baseline end-use forecast.

Achievable technical potential applies customer participation and market penetration factors to the technical potential. By the end of the 20-year timeframe, cumulative savings, including non-utility delivery mechanisms, reach 24.7 percent of the baseline energy forecast.

Achievable economic potential applies the cost-effectiveness metric from the utility's perspective to DSM measures identified within the achievable technical potential and quantify the impact of the adoption of only those DSM measures that are cost-effective. By the end of the 20-year timeframe this represents 20.6 percent of the baseline energy forecast. Although falling natural gas avoided costs would significantly affect potential from a TRC perspective, the UCT is quite similar to achievable technical in all years. This is because utility incentives were developed using existing, approved Avista tariffs for current measures and incentives for similar measures for identified new measures.

Tables 3.3 and 3.4 summarize cumulative conservation for each potential type for selected years across the 20-year CPA and IRP horizon. As the largest sector in both states, the residential sector accounts for a majority of both early and late-year potential. Industrial includes only Avista's core customers (e.g. customers that consume gas rather than transport it), making the sector a small contributor to overall consumption and potential. For more specific detail, please refer to the natural gas CPA provided in Appendix 3.1.

[3] In May 2012, Avista proposed to suspend its Washington and Idaho natural gas DSM programs due to decreased natural gas prices. The WUTC guided utilities to continue natural gas programs using the Utility Cost Test (UCT). Avista requested and was given approval to suspend Avista's Idaho natural gas DSM programs under the TRC and did not have programs in 2013, 2014 and 2015 (2013 saw some activity due to prior commitments). After the review of Avista's avoided cost methodology and with an IPUC ruling that allows companies to emphasize the UCT when seeking prudence for their DSM programs, Avista filed for and was approved to reinstate its Idaho Natural Gas DSM programs January 1, 2016.

Table 3.3: Summary of Cumulative Technical, Achievable Technical, and Achievable Economic Conservation Potential (Dth)

Washington	2018	2019	2020	2027	2037
Baseline Forecast (Dth)	17,221,900	17,418,177	17,594,636	18,413,613	19,406,251
Potential Forecasts (Dth)					
Achievable Economic	17,160,621	17,284,602	17,367,858	16,799,979	15,397,752
Achievable Technical	17,188,007	17,345,078	17,286,475	16,373,787	14,624,564
Technical	17,135,511	17,232,112	16,934,070	15,584,410	13,703,268
Cumulative Savings (Dth)					
Achievable Economic	61,279	133,576	226,777	1,613,635	4,008,500
Achievable Technical	33,893	73,100	308,161	2,039,826	4,781,688
Technical	86,389	186,065	660,565	2,829,203	5,702,984
Energy Savings (% of Baseline)					
Achievable Economic	0.4%	0.8%	1.3%	8.8%	20.7%
Achievable Technical	0.2%	0.4%	1.8%	11.1%	24.6%
Technical	0.5%	1.1%	3.8%	15.4%	29.4%

Idaho	2018	2019	2020	2027	2037
Baseline Forecast (Dth)	8,557,178	8,667,149	8,765,347	9,288,224	9,917,115
Potential Forecasts (Dth)					
Achievable Economic	8,530,838	8,608,797	8,665,006	8,480,677	7,879,230
Achievable Technical	8,547,332	8,644,716	8,627,624	8,261,653	7,466,149
Technical	8,519,855	8,585,623	8,450,043	7,851,146	6,976,401
Cumulative Savings (Dth)					
Achievable Economic	26,340	58,352	100,341	807,547	2,037,885
Achievable Technical	9,846	22,432	137,724	1,026,571	2,450,966
Technical	37,324	81,526	315,305	1,437,078	2,940,714
Energy Savings (% of Baseline)					
Achievable Economic	0.3%	0.7%	1.1%	8.7%	20.5%
Achievable Technical	0.1%	0.3%	1.6%	11.1%	24.7%
Technical	0.4%	0.9%	3.6%	15.5%	29.7%

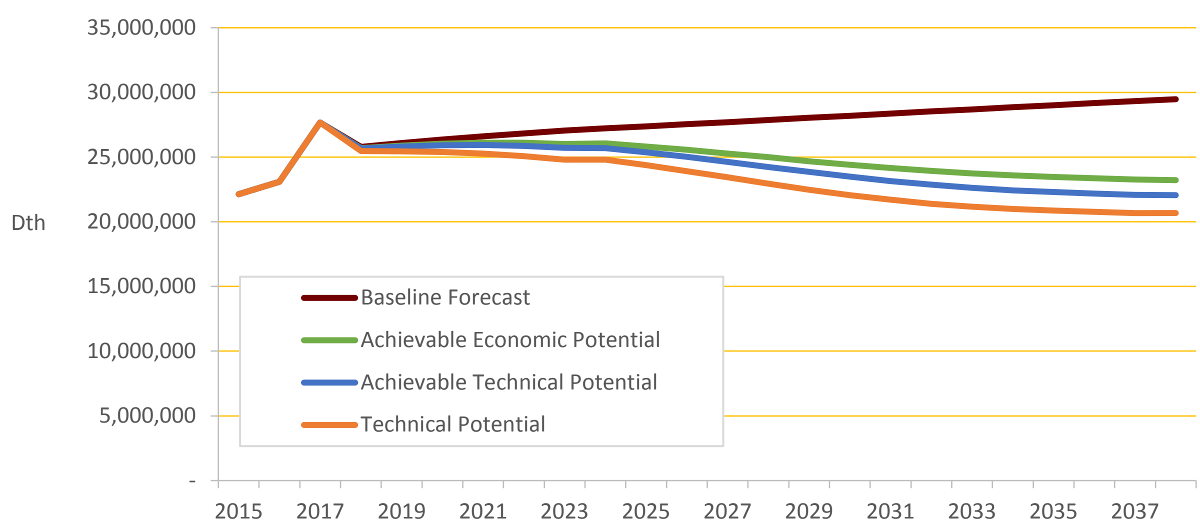
The overall achievable potential is presented first by state and by sector in the following table.

Table 3.4: Summary of Cumulative Achievable Economic Potential by State and Sector (Dth)

Cumulative Savings (Dth)	2018	2019	2020	2027	2037
Washington	61,279	133,576	226,777	1,613,635	4,008,500
Idaho	26,340	58,352	100,341	807,547	2,037,885
Total	**87,619**	**191,927**	**327,118**	**2,421,181**	**6,046,385**
Cumulative Savings (Dth)	**2018**	**2019**	**2020**	**2027**	**2037**
Residential	58,333	129,227	223,729	1,727,462	4,565,013
Commercial	28,148	60,428	99,963	681,712	1,461,531
Industrial	1,138	2,272	3,427	12,007	19,840
Total	**87,619**	**191,927**	**327,118**	**2,421,181**	**6,046,385**

Figure 3.1 illustrates the impact of the conservation potential forecast upon the end-use baseline absent of any conservation acquisition.

Figure 3.1 - Conservation Potential Energy Forecast (Dth)



Potential Results – Residential

Single-family homes represent 61 percent of Avista's residential natural gas customers, but account for 65 percent of the sector's consumption in 2018. In the current IRP, residential provides the largest opportunity for cumulative savings over the next 20 years. Table 3.5 provides a distribution of achievable economic potential by state for the residential sector. Although potential as a percent of baseline is similar between the two states, there is one notable difference. The less strict energy codes in Idaho should result in higher residential potential, but this effect is counteracted by the recent "re-start" of DSM programs in the state of Idaho, which lowers early-year potential as the programs "ramp" up.

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

Cumulative Savings (Dth)	2018	2019	2020	2027	2037
Baseline Projection (Dth)					
Washington	10,773,426	10,971,347	11,144,590	11,877,363	12,636,101
Idaho	5,266,179	5,379,047	5,479,126	5,984,940	6,490,095
Total	**16,039,605**	**16,350,394**	**16,623,717**	**17,862,303**	**19,126,196**
Natural Gas Cumulative Savings (Dth)					
Washington	39,979	88,051	151,815	1,131,013	3,003,789
Idaho	18,354	41,176	71,914	596,450	1,561,225
Total	**58,333**	**129,227**	**223,729**	**1,727,462**	**4,565,013**
% of Total Residential Savings					
Washington	69%	68%	68%	65%	66%
Idaho	31%	32%	32%	35%	34%

Table 3.6 identifies the top 10 residential measures by cumulative 2020 savings. Furnaces, windows, tankless water heaters, and learning thermostats are the top measures. These are ranked by their combined contribution to Washington and Idaho savings.

Table 3.6 Residential Top Measures, 2020

Rank	Measure / Technology	WA	ID	Total	% of Total
1	Furnace - Direct Fuel - AFUE 95%	69,659	40,893	110,552	49%
2	Windows - High Efficiency - Double Pane LowE CL22	28,074	4,076	32,150	14%
3	Water Heater <= 55 gal. - Instantaneous - ENERGY STAR	18,893	8,936	27,829	12%
4	Insulation - Floor/Crawlspace - R-30	5,646	3,861	9,507	4%
5	Thermostat - Wi-Fi/Interactive - Interactive/learning thermostat	6,147	3,040	9,187	4%
6	Insulation - Ceiling, Installation - R-38 (Retro only)	3,286	1,638	4,923	2%
7	Insulation - Wall Cavity, Installation - R-11	2,850	1,426	4,276	2%
8	ENERGY STAR Homes - Built Green spec (NC Only)	2,480	1,229	3,709	2%
9	Boiler - Direct Fuel - AFUE 96%	2,175	1,069	3,244	1%
10	Water Heater - Low Flow Showerhead (1.5 GPM)	1,853	922	2,775	1%
	Subtotal	**141,063**	**67,090**	**208,153**	**93%**
	Total Savings in Year	**151,815**	**71,914**	**223,729**	**100%**

The bulk of the residential potential exists in space heating end-uses followed by water heating applications. Appliances and miscellaneous end-use loads contribute a small percentage of potential. Based on measure-by-measure findings of the potential study the greatest sources of residential achievable potential across both jurisdictions are:

- High-efficiency furnaces;
- High-efficiency tankless water heaters;
- Low-emissivity windows;
- Shell measures and insulation;
- Thermostats and home energy monitoring systems;
- Water-saving devices (low-flow showerheads and faucet aerators); and
- ENERGY STAR/Built Green Washington new homes.

Avista does not capture end-use savings that are attributable to new construction homes through “New Homes pathways” as the Energy Trust of Oregon (ETO) does. The New Homes pathways are packages of savings in new construction homes that span several end-uses. ETO assigns an end-use to each of the offered New Homes pathways based on the most significant saving end-use of the package[4].

Conservation Potential Results – Commercial and Industrial

The commercial sector provides the next biggest opportunities for savings. Compared to their portion of baseline consumption, early-year potential in Idaho is significantly lower than in Washington. Similar to the residential sector, this is a result of the recent “re-start” of DSM programs in the state of Idaho.

As seen in Table 3.4 above, Avista’s core industrial customers represent a low fraction of the load, and correspondingly comprise a small percentage of overall potential. Additionally, since early-year consumption in the industrial sector is very similar between Washington and Idaho, potential is split roughly in half.

Table 3.7 and Table 3.8 below details the achievable economic conservation potential by sector for selected years.

[4] Avista 2018 IRP Draft DSM Chapter - Energy Trust of Oregon

Table 3.7 Commercial Achievable Economic Potential by Selected Years

Cumulative Savings (Dth)	2018	2019	2020	2027	2037
Baseline Projection (Dth)					
Washington	6,197,173	6,197,918	6,202,429	6,303,022	6,553,728
Idaho	3,050,738	3,045,031	3,041,291	3,059,255	3,183,220
Total	**9,247,911**	**9,242,949**	**9,243,720**	**9,362,277**	**9,736,948**
Natural Gas Cumulative Savings (Dth)					
Washington	20,731	44,393	73,253	476,648	994,795
Idaho	7,417	16,035	26,709	205,064	466,736
Total	**28,148**	**60,428**	**99,963**	**681,712**	**1,461,531**
% of Total Residential Savings					
Washington	74%	73%	73%	70%	68%
Idaho	26%	27%	27%	30%	32%

Table 3.8 Industrial Cumulative Achievable Economic Potential by Selected Years

Cumulative Savings (Dth)	2018	2019	2020	2027	2037
Baseline Projection (Dth)					
Washington	251,300	248,912	247,626	233,229	216,423
Idaho	240,261	243,071	244,930	244,029	243,799
Total	**491,562**	**491,983**	**492,546**	**477,257**	**460,222**
Natural Gas Cumulative Savings (Dth)					
Washington	569	1,132	1,709	5,974	9,916
Idaho	569	1,140	1,718	6,034	9,924
Total	**1,138**	**2,272**	**3,427**	**12,007**	**19,840**
% of Total Residential Savings					
Washington	50%	50%	50%	50%	50%
Idaho	50%	50%	50%	50%	50%

Table 3.9 identifies the top 20 commercial measures by cumulative savings in 2020. Boilers are the top measure, followed food preparation and custom HVAC measures. These are ranked by their combined contribution to Washington and Idaho savings.

Table 3.9 C&I Top Measures, 2020

Rank	Measure / Technology	WA	ID	Total	% of Total
1	Boiler - AFUE 97%	22,515	5,909	28,423	27%
2	Fryer - ENERGY STAR	5,648	1,887	7,535	7%
3	Insulation - Roof/Ceiling - R-38	4,061	2,288	6,349	6%
4	Insulation - Wall Cavity - R-21	3,638	1,993	5,631	5%
5	Gas Boiler - Insulate Steam Lines/Condensate Tank - Lines and condensate tank insulated	3,331	1,975	5,306	5%
6	HVAC - Demand Controlled Ventilation - DCV enabled	2,985	1,679	4,664	5%
7	Water Heater - TE 0.94	3,559	975	4,534	4%
8	Gas Boiler - Hot Water Reset - Reset control installed	3,936	532	4,468	4%
9	Steam Trap Maintenance - Cleaning and maintenance	2,546	1,334	3,880	4%
10	Gas Boiler - Insulate Hot Water Lines - Insulated water lines	2,224	1,318	3,542	3%
	Subtotal	**54,442**	**19,890**	**74,332**	**72%**
	Total Savings in Year	**74,962**	**28,427**	**103,389**	**100%**

Most of the commercial and industrial conservation potential exists within space heating and water heating applications. Food preparation, process and miscellaneous represents a smaller proportion of potential. One large measure that is not represented in the achievable economic potential is commercial HVAC retrocommissioning. For this measure, AEG updated the savings assumption from the Seventh Plan's value of roughly 15% of heating load to 7% to reflect space heating's higher end-use share of consumption. For further details on this adjustment and other top measures, please refer to the natural gas CPA provided in Appendix 3.1. Primary sources of commercial and industrial sector achievable savings are:

- Equipment upgrades for furnaces, boilers and unit heaters;
- High R-value roof/ceiling and wall insulation
- Energy management systems and programmable thermostats:
- High thermal efficiency water heaters
- Boiler operating measures such as maintenance;
- Hot water reset and efficient circulation; and
- Food service equipment.

Achievable Economic Conservation Potential Results

Tables 3.10 and 3.11 provide the 2018-2020 CPA identified conservation opportunity for Washington and Idaho, respectively.

Table 3.10: Washington Natural Gas Target (2018-2020)

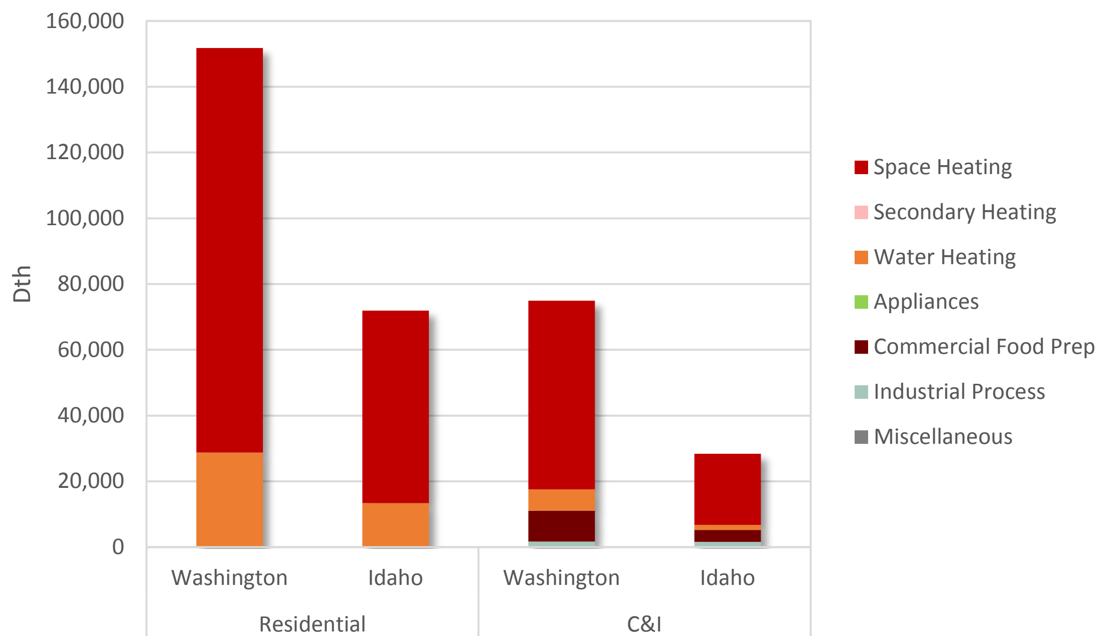
Incremental Annual Savings (Dth)	2018	2019	2020
Residential	39,979	48,188	63,970
Commercial & Industrial	21,300	24,330	29,665
Total	**61,279**	**72,518**	**93,635**

Table 3.11: Idaho Natural Gas Target (2018-2020)

Incremental Annual Savings (Dth)	2018	2019	2020
Residential	18,354	22,851	30,784
Commercial & Industrial	7,986	9,232	11,343
Total	**26,340**	**32,083**	**42,127**

Figure 3.2 presents the cumulative energy savings for the 2018 to 2020 period by end use, for each sector and state. Space heating makes a majority of the potential, followed by water heating. Food preparation equipment upgrades provide savings in the Commercial sector.

Figure 3.2 – Conservation Potential by End Use, 2020 (Dth)



Achievable Potential Factor Application

The development of achievable potential factors is an important step when estimating achievable levels of potential. As part of the CPA, AEG took steps to more closely align with the NPCC's Seventh Electric Power Plan Methodology. As part of the Plan, the NPCC developed a suite of achievable "ramp rates" based on accomplishment data for various electric EE measures and programs. They then projected them forward on a diffusion curve, capping achievability at 85% of technical potential by the end of the 20-year planning period for non-emerging measures.

As a starting point for the CPA, AEG applied these ramp rates to similar natural gas measures where an electric analog was available. Since these were developed with electric DSM programs in mind, AEG then adjusted the ramp rates following a similar course of action. AEG reviewed Avista's recent program accomplishment data and either 1) reassigned ramp rates or 2) accelerated/decelerated the mapped ramp rates to align with actual participation in Avista's natural gas DSM programs. Remapping was used primarily when a measure's actual performance was significantly different than the electric ramp rate suggested while acceleration/deceleration was used for more moderate adjustments. The result of this step was a remapping of heating and food preparation equipment measures to faster ramp rates and deceleration of weatherization measure installations to reflect lower program participation. This process was conducted for the Washington and Idaho territories separately, resulting in lower early-year potential in Idaho to reflect the DSM program re-start referenced in the sections above.

In the longer-term, all of the Seventh Plan's non-emerging ramp rates reach a steady-state achievability of 85% of technical potential. This value is intended to represent both potential realized within utility DSM programs and potential through non-utility delivery mechanisms such as naturally occurring efficiency, market transformation, and new future codes and standards. Using this methodology, potential captured after the first year or two of the CPA includes a portion of additional potential outside Avista's direct control. To account for this and provide Avista with the utility-specific targets in Table 3.8 and Table 3.9, AEG slowed the "ramp-up" of these measures by 50% in years two and three then re-accelerated the ramp rates, so they re-align after year six. This adjustment is intended to estimate utility-specific goals for the program planning process yet capture all achievable, cost-effective potential (even potential realized through non-utility DSM mechanisms) in the later years of the study period.

Natural Gas IRP Target - Historical Trends 2014-2020

Figure 3.3 and 3.4 below illustrate the historical trend in natural gas IRP targets since 2014. 2018 targets were selected by the 2016 IRP and align well, but are not an exact match with the CPA results for 2018.

Figure 3.3: Washington Natural Gas IRP Targets

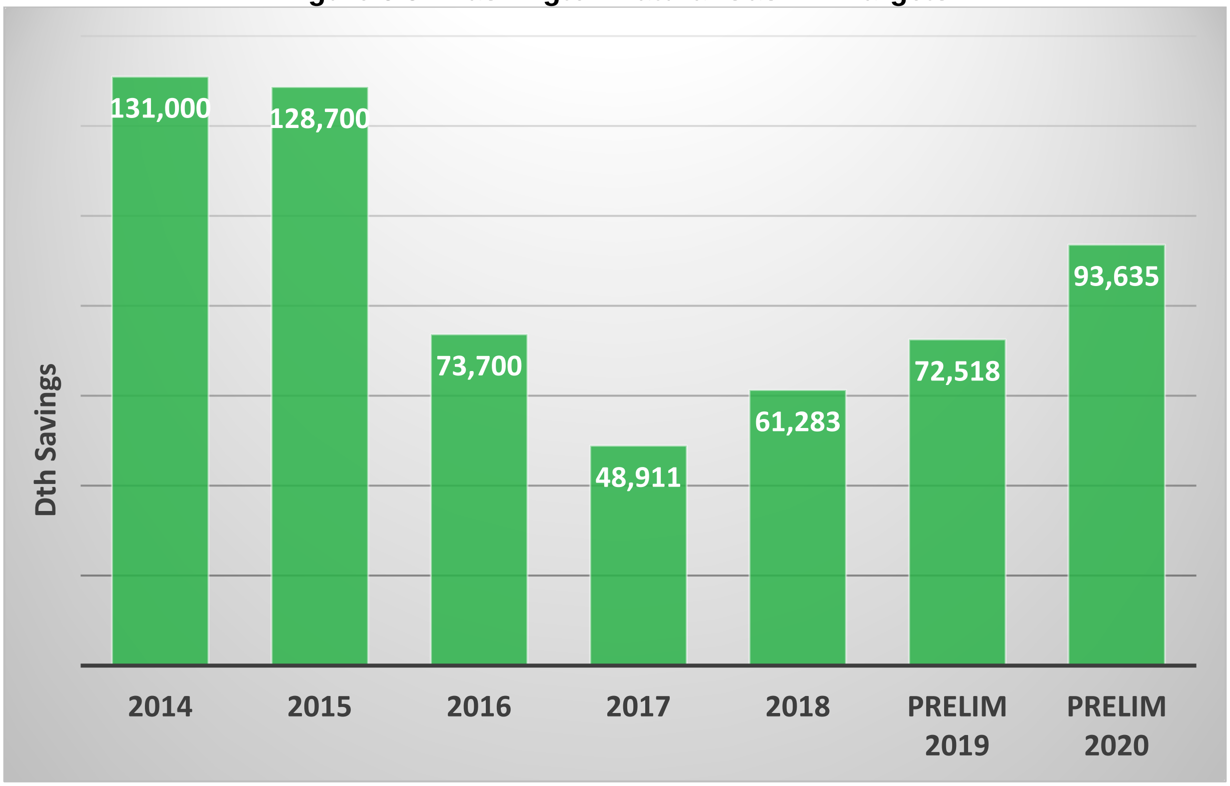
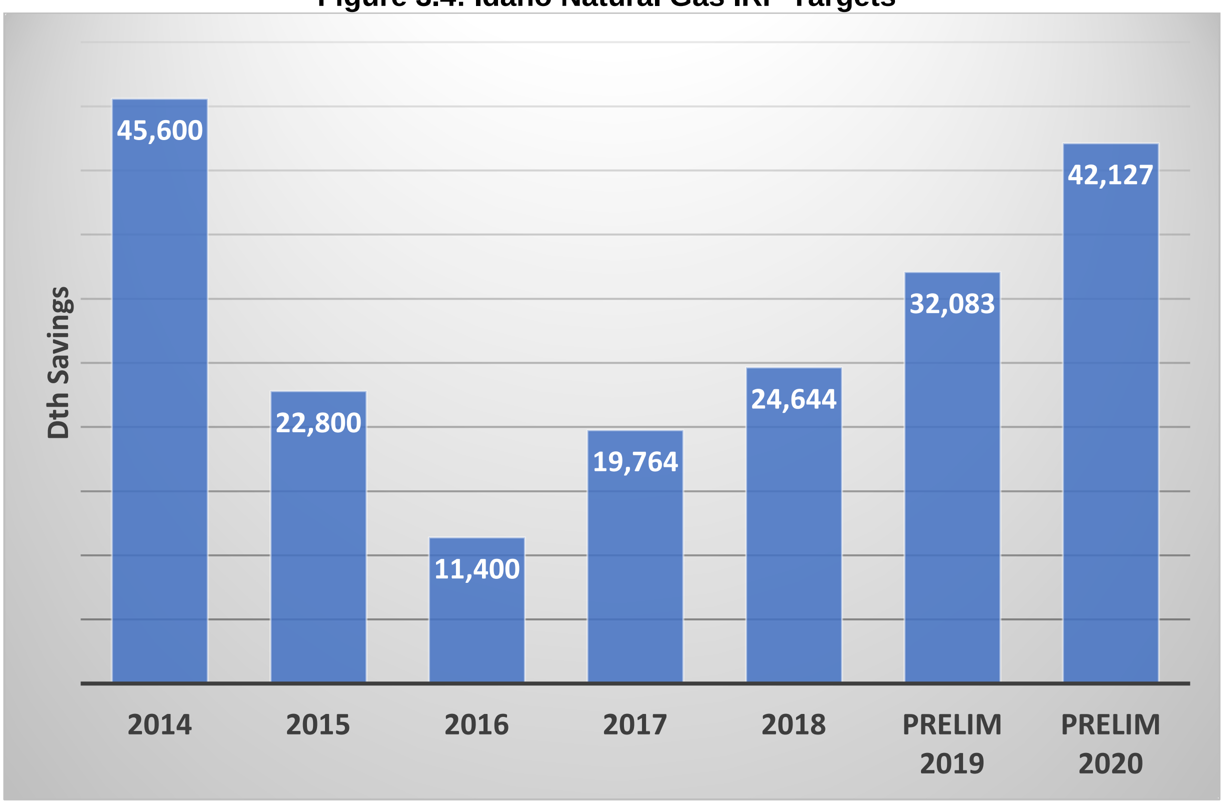


Figure 3.4: Idaho Natural Gas IRP Targets[5]



[5] Avista's Idaho natural gas DSM programs were suspended in 2013, 2014 and 2015 (2013 saw some activity due to prior commitments). Avista filed for and was approved to reinstate its Idaho Natural Gas DSM programs January 1, 2016.

Uses and Applications of the CPA

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 conservation resources. Activities outside the immediate scope of the IRP process include the formal annual conservation planning and annual cost-effectiveness and acquisition reporting processes in addition to the ongoing management of the DSM portfolio.

The IRP leads to the establishment of a 20-year avoided cost stream that is essential to determining the quantity of DSM resources that are cost-effective when compared to the CPA-identified conservation supply curve and the management of the DSM portfolio between the two-year IRP cycles. The many related and coordinated processes all 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 conservation planning process is of particular note. The CPA is regarded as a high-level tool that is useful for establishing aggregate targets and identifying general target markets and target measures. However, the CPA of necessity must make certain broad assumptions regarding key characteristics that are fine-tuned as part of the creation of an operational business plan. Some of the assumptions that are most frequently modified include market segmentation, customer eligibility, measure definition, incentive level, interaction between measures and the opportunities for packaging measures or coordinating the delivery of measures.

One issue that inevitably arises as part of moving from the CPA analysis to the annual conservation 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.

A second issue that often arises is the "clumpiness" that often occurs with large commercial and industrial projects. Large natural gas conservation projects typically have long lead times with multiple years between the original customer contact and design of a project to the final completion with any required measurement and verification. These projects can lead to over or underperforming targets in individual years but typically average out over the 20-year time frame of an IRP.

Conservation Action Plan

The analytical process for the CPA is based on a deterministic model as compared to the assumptions within the Expected Case. In order to further enhance the Company's analytical methodology, Avista will focus on the following:

- Recreate the Sendout model and inputs into a new Excel based methodology. This methodology will allow flexibility to model DSM and other potential supply side resources on a case by case basis.

Energy Trust of Oregon: Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping utility customers in Oregon and southwest Washington benefit from saving energy and generating renewable power. Energy Trust funding comes exclusively from utility customers and is invested on their behalf in lowest-cost energy efficiency and clean, renewable energy. In 1999, Oregon energy restructuring legislation (SB 1149) required Oregon's two largest electric utilities—PGE and Pacific Power—to collect a public purpose charge from their customers to support energy conservation in K-12 schools, low-income housing energy assistance, and energy efficiency and renewable energy programs for residential and business customers.[6]

In 2001, Energy Trust entered into a grant agreement with the Oregon Public Utility Commission (OPUC) to invest the majority of revenue from the 3 percent public purpose charge in energy efficiency and renewable energy programs. Every dollar invested in energy efficiency by Energy Trust will save residential, commercial and industrial customers nearly $3 in deferred utility investment in generation, transmission, fuel purchase and other costs. Appreciating these benefits, natural gas companies asked Energy Trust to provide service to their customers—NW Natural in 2003, Cascade Natural Gas in 2006 and Avista in 2017. These arrangements stemmed from settlement agreements reached in Oregon Public Utility Commission processes.

Energy Trust's model of delivering energy efficiency programs unilaterally across the service territories of the five gas and electric utilities they serve has experienced a great deal of success. Since the inception of the organization in 2002, Energy Trust has saved more than 607 aMW of electricity and 52 million annual therms. This equates to more than 20 million tons of CO2 emissions avoided and is a significant factor relatively flat or lower energy sales observed by both gas and electric utilities from 2007 to 2016, as shown in OPUC utility statistic books.[7]

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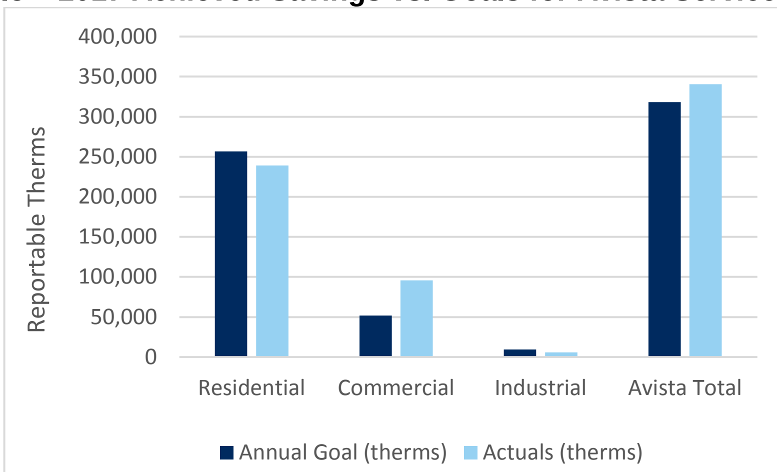
[6] In 2007, Oregon's Renewable Energy Act (SB 838) allowed the electric utilities to capture additional, cost-effective electric efficiency above what could be obtained through the 3 percent charge, thereby avoiding the need to purchase more expensive electricity. This new supplemental funding, combined with revenues from natural gas utility customers, increased Energy Trust revenues from about $30 million in 2002 to $148.9 million in 2016.

[7] OPUC 2016 Stat book – 10 Year Summary Tables: http://www.puc.state.or.us/docs/statbook2016WEB.pdf

Energy Trust serves residential, commercial and firm industrial customers in Avista's natural gas service territory in the areas of Medford, Klamath Falls, and La Grande, Oregon. 2017 was the first full year of Energy Trust's service to Avista customers and programs achieved 107% of goal – 341K therms achieved of the 318K therms goal, as shown in 3.5.

Figure 3.5 – 2017 Achieved Savings vs. Goals for Avista Service Territory



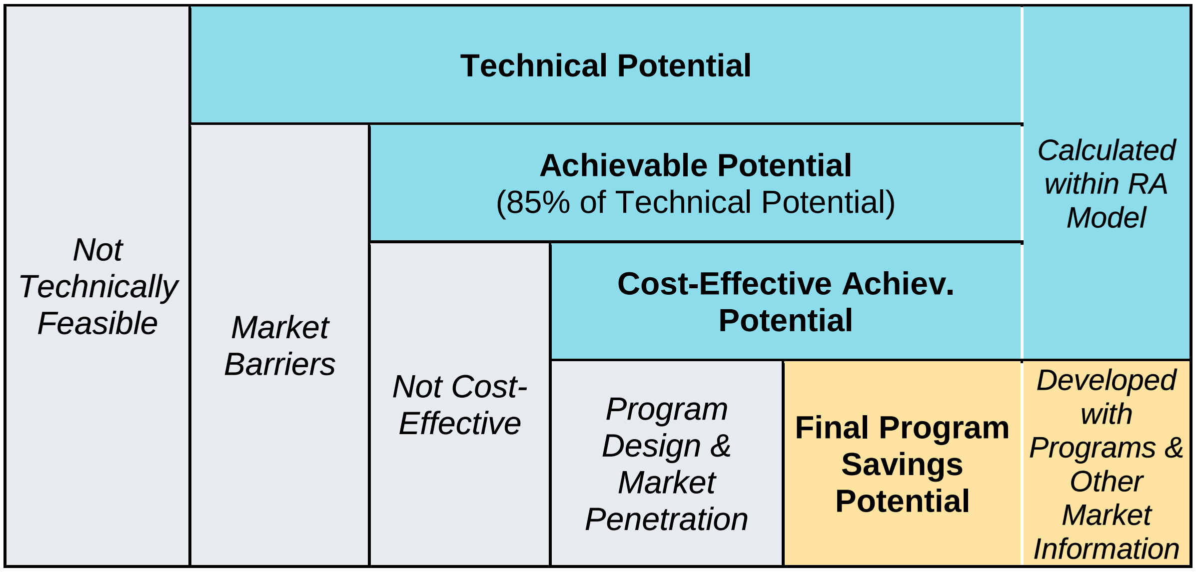
In addition to administering energy efficiency programs on behalf of the utilities, Energy Trust also provides each utility with a 20-year DSM resource forecast to identify cost-effective savings potential. This forecast also examines how much of that potential is estimated to be achieved by Energy Trust over the 20-year period. The results are used by Avista and other utilities in Integrated Resource Plans (IRP) to inform the resource potential in their territory and reduce their load forecast over the IRP period to meet their customer's projected load.

Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a 20-year DSM resource forecast for Avista using Energy Trust's DSM resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost-effective modeled savings potential, which is 'deployed' exogenously of the model to estimate the final savings forecast. There are four types of potential that are calculated to develop the final savings potential estimate, which are shown in 3.6 and discussed in greater detail in the sections below.

Figure 3.6: Types of Potential Calculated in 20-year Forecast Determination



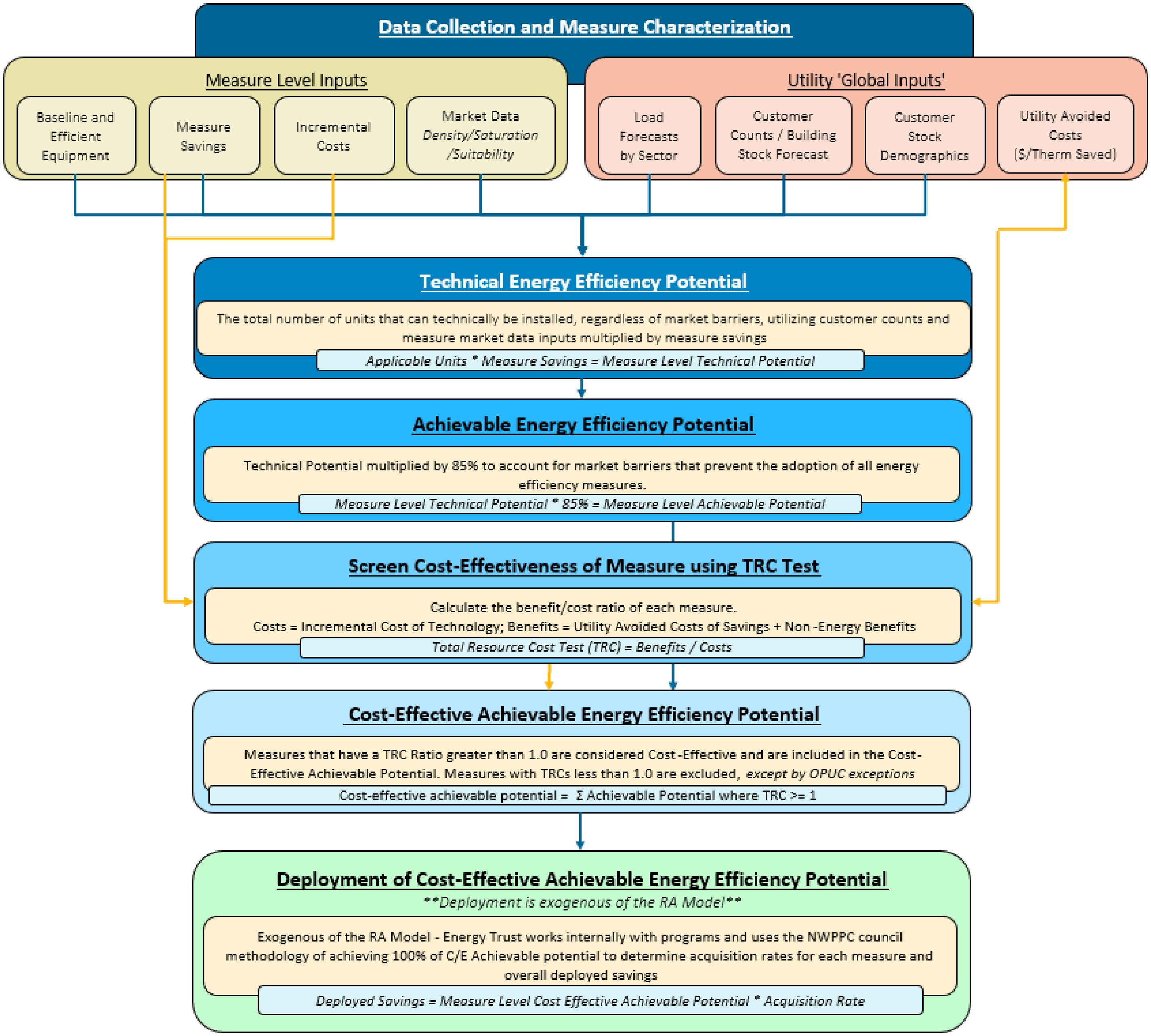
The RA Model utilizes the modeling platform Analytica®[8], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to Avista for inclusion in in their SENDOUT® Model as a reduction to demand on the system.

20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed savings, as shown in Figure 1.7. The first five steps in the varying shades of blue nodes - *Data Collection and Measure Characterization* to *Cost-Effective Achievable Energy Efficiency Potential* - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail each of the steps shown below.

[8] http://www.lumina.com/why-analytica/what-is-analytica1/

Figure 3.7: Energy Trust's 20-Year DSM Forecast Determination Flow Chart



1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles and loads a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[9] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as ‘global inputs’).

- ***Measure Level Inputs:***

  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[10], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:

  1. ***Measure Definition and Equipment Identification***: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a 95% EF furnace replacing an 80% EF baseline furnace). A measure’s replacement type is also determined in this step – Retrofit (RET), Replace on Burnout (ROB), or New Construction (NEW).

  2. ***Measure Savings****:* the kWh or therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.

  3. ***Incremental Costs****:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a RET measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a ROB or NEW measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.

  4. ***Market Data****:* Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average

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[9] An emerging technology is defined as technology that is not yet commercially available, but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

[10] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA’s Residential and Commercial Building Stock Assessments (RBSA and CBSA)

number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs are all generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA).

- ***Utility Global Inputs:***

  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:

  1. ***Customer and Load Forecasts**:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that Avista serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.

  2. ***Customer Stock Demographics**:* These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).

  3. ***Utility Avoided Costs**:* Avoided costs are the net present value of avoided energy purchases and delivery costs associated with energy efficiency savings represented as $s per therm saved. These values are provided by Avista and the components are discussed in other sections of this IRP. Avoided costs are the primary 'benefit' of energy efficiency in the cost-effectiveness screen.

2. Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g. # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does <u>not</u> take into account the various market barriers that will limit a 100 percent adoption rate.

3. **Calculate Achievable Energy Efficiency Potential**
   Achievable potential is simply a reduction to the technical potential by 15 percent, to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85 percent of the technical potential is the generally accepted method employed by many industry experts, including the Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL).

Achievable Potential =	*Technical Potential * 85%*

4. **Determine Cost-effectiveness of Measure using TRC Screen**
   The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure, and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

   TRC = Present Value of Benefits / Present Value of Costs

   Where the Present Value of Benefits includes the sum of the following two components:

   a) Avoided Costs: The present value of natural gas energy saved over the life of the measure, as determined by the total therms saved multiplied by Avista's avoided cost per therm. The net present-value of these benefits is calculated based on the measure's expected lifespan using the company's discount rate.

b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. water savings from low-flow showerheads, operations and maintenance (O&M) cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

Incentives paid to the participant; and

a) The participant's remaining out-of-pocket costs for the installed cost of the measures after incentives, minus state and federal tax credits.

b) The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures, unless an exception has been granted by the OPUC.

5. **Quantify the Cost-Effective Achievable Energy Efficiency Potential**

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then achievable savings (85% of technical potential) from a measure is included in this potential. If the measure does not pass the TRC test above, the measure is not included in cost-effective achievable potential. However, the cost-effectiveness screen is overridden for some measures under two specific conditions:

1. The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,

2. When the measure isn't cost-effective using utility specific avoided costs but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

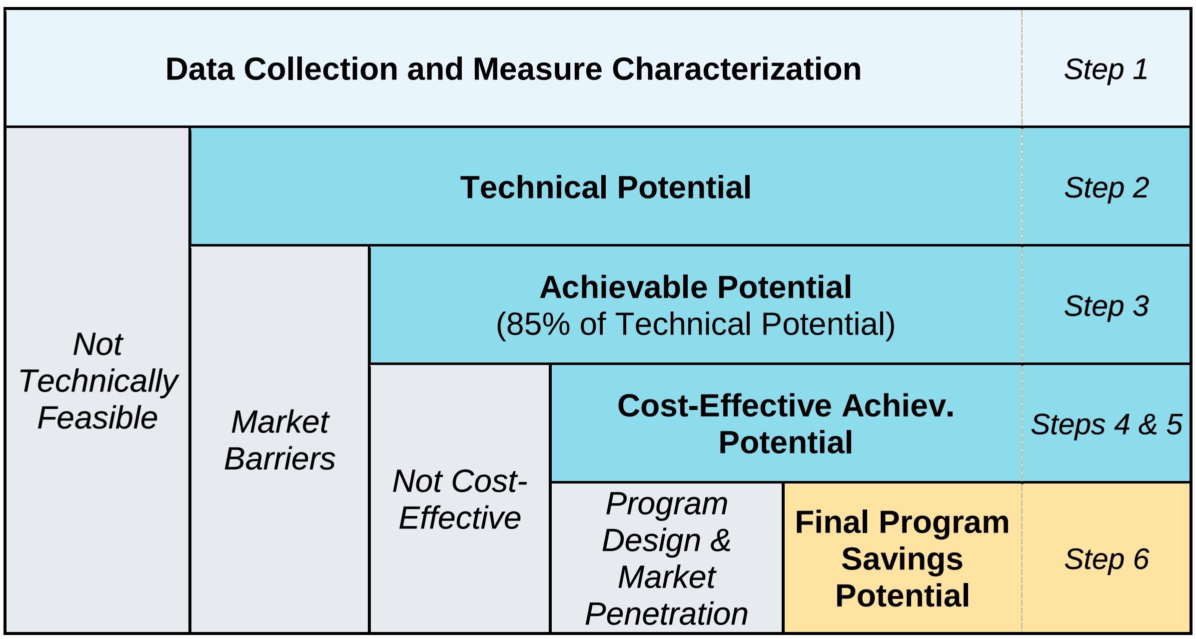
6. **Deployment of Cost-Effective Achievable Energy Efficiency Potential**

After determining the 20-year cost-effective achievable modeled potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that will result in a reduction of load on Avista's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy

Trust is describing as a ‘megaproject adder’. The ‘megaproject adder’ is characterized as savings that account for large unidentified projects that consistently appear in Energy Trust’s historic savings record and have been a source of overachievement against IRP targets in prior years for other utilities that Energy Trust serves.

3.8 below reiterates the types of potential shown in 3.6, and how the steps described above and in the flow chart fit together.

Figure 3.8 - The Progression to Program Savings Projections



Forecast Results

The results will be shown in several different sections, as the RA model and the final savings projections have different output capabilities. The RA model provides outputs in a variety of different ways, including by segment, end use, and supply curves. The final savings projection is provided by segment and program delivery type.

RA Model Results – Technical, Achievable and Cost-Effective Achievable Potential

The RA Model produces results by potential type, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings by Sector

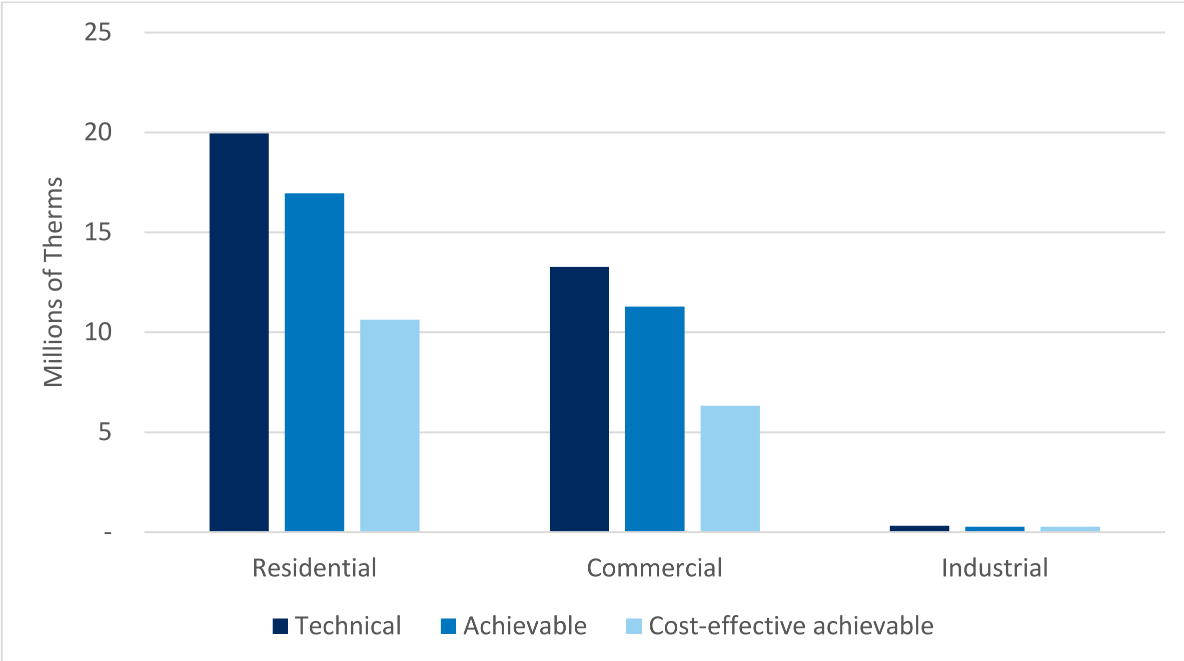
Table summarizes the technical, achievable, and cost-effective potential for Avista's system in Oregon. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Figure and Figure . Modeled savings represent the full spectrum of potential identified in Energy Trust's resource assessment model through time, prior to deployment of these savings into the final annual savings projection.

Table 3.12 - Summary of Cumulative Modeled Savings Potential - 2018–2037

Sector	Technical Potential (Million Therms)	Achievable Potential (Million Therms)	Cost-Effective Achievable Potential (Million Therms)
Residential	20.0	17.0	10.6
Commercial		11.3	6.3
Industrial	0.3	0.3	0.3
Total		**28.5**	**17.2**

Figure 3.9 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in Avista's service territory. Residential sales make up the majority of Avista's service in Oregon, which is reflected in the potential. Firm industrial sales represent a low percentage of the total sales in Oregon for Avista, and subsequently shows very little savings potential (Avista's interruptible and transport customers are not eligible to participate in Energy Trust programs). 83% of the industrial technical potential is cost-effective, while the residential and commercial sectors cost-effective achievable potential are 53% and 47% of technical potential respectively.

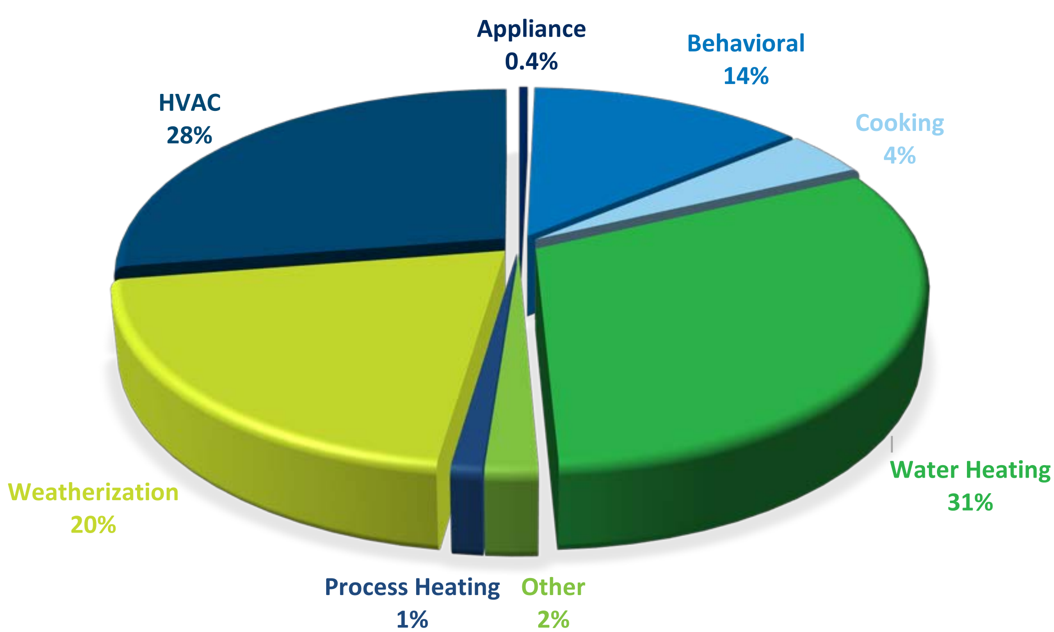
Figure 3.9 - Savings Potential by Sector – Cumulative 2018–2037 (Millions of Therms)



Cost-Effective Achievable Savings by End-Use

Figure 3.10 below provides a breakdown of Avista's 20-year cost-effective DSM savings potential by end use.

Figure 3.10: 20-year Cost-Effective Cumulative Potential by End Use



As expected for a gas utility, the top saving end uses are water heating, HVAC and weatherization. A large portion of the water heating end-use is attributable to new construction homes due to how Energy Trust assigns end uses to the offered New Homes pathways. The New Home pathways are packages of savings in new construction homes that span several end-uses. Energy Trust assigns an end-use to each of the offered New Homes pathways based on the most significant saving end-use of the package. For example, the most cost-effective New Home pathway that was identified by the model (because it achieves the most savings for the least cost) was designated as a water heating end-use, though the package includes several other efficient gas equipment measures.

In addition to the New Homes pathway savings, the water heating end-use includes water heating equipment from all sectors, as well as showerheads and aerators. Weatherization and HVAC end uses represent the savings associated with space heating equipment, retrofit add-ons, and new construction packages. Behavioral consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to identify operations and maintenance changes that make a difference in a building's energy use.

Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies (ETs) in its model. The emerging technologies included in the model are listed in 3.13.

Table 3.13 - Emerging Technologies Included in the Model

Residential	Commercial	Industrial
• Path 5 Emerging Super Efficient Whole Home	• Advanced Ventilation Controls	• Gas-fired HP Water Heater
• Window Replacement (U<.20)	• DOAS/HRV	• Wall Insulation- VIP, R0-R35
• Window Attachments	• DHW Circulation Pump	
• Absorption Gas Heat Pump Water Heaters	• Gas-fired HP HW	
• Advanced Insulation	• Gas-fired HP, Heating	
• Behavior Competitions	• Zero Net Energy Path	
	• AC Heat Recovery, HW	

Energy Trust recognizes that emerging technologies are inherently uncertain, and utilizes a risk factor to hedge against that risk. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for ETs to produce reliable future savings. This risk factor was determined based on qualitative metrics of:

- Market risk
- Technical risk
- Data source risk

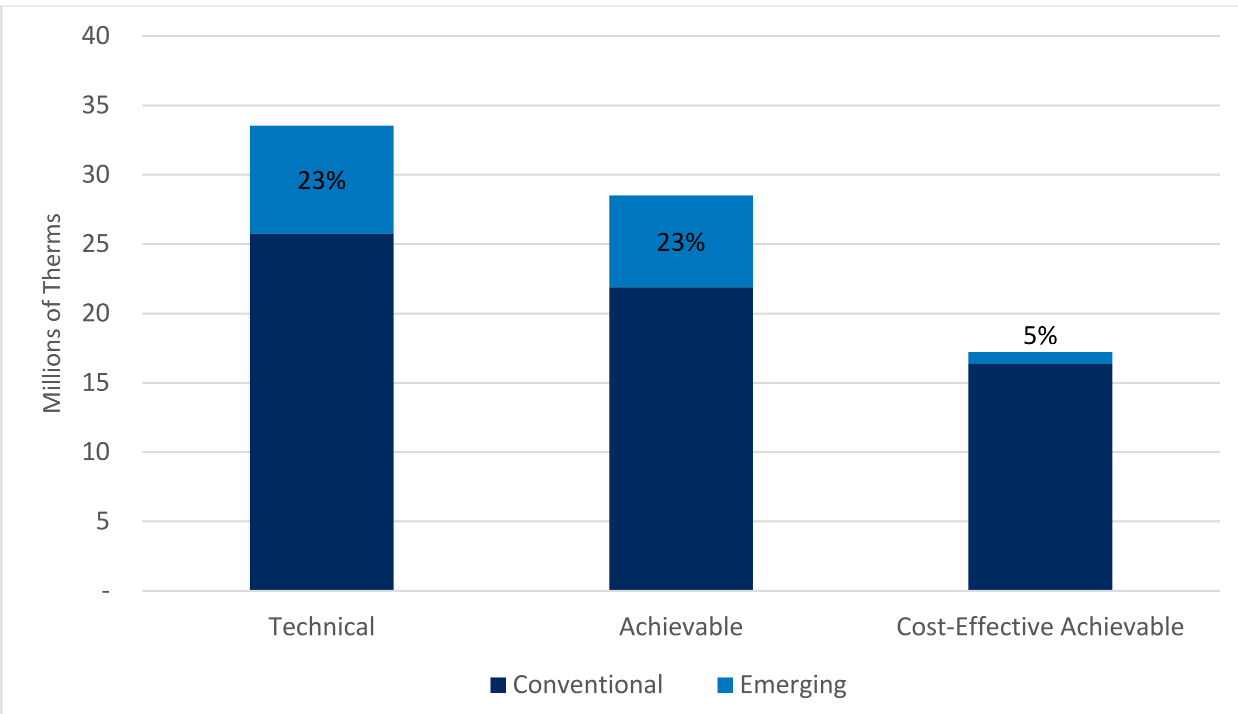
The framework for assigning the risk factor is shown in Table 3.14.14. Each ET was assessed within each risk category; a total weighted score was then calculated. Well-established and well-studied technologies have lower risk factors while nascent, unevaluated technologies (e.g., gas absorption heat pump water heaters) have higher risk factors. This risk factor was then used as a multiplier of the incremental savings potential of the measure.

Table 3.14 - Emerging Technology Risk Factor Score Card

ET Risk Factor					
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk **(25% weighting)**	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist.			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk **(25% weighting)**	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk **(50% weighting)**	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third party case studies

Figure 3.11 below shows the amount of emerging technology savings within each type of DSM cumulative potential. While emerging technologies make up a relatively large percentage of the technical and achievable potential, nearly 25%, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops significantly to about 5% of total cost-effective achievable potential. This is due to the fact that many of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time, some are still never cost-effective over the planning horizon or do not become cost-effective until later years.

Figure 3.11 – Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

3.15 shows the savings potential in the RA model that was added by employing the cost-effectiveness override option in the model. As discussed in the methodology section, the cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria:

1. A measure is offered under an OPUC exception.

2. When the measure isn't cost-effective using Avista-specific avoided costs but the measure is cost-effective when using blended gas avoided costs for all of the gas utilities Energy Trust serves and is therefore offered by Energy Trust programs.

Table 3.15 - Cumulative Cost-Effective Potential (2018-2037) due to Cost-effectiveness override (millions of therms)

Sector	Yes CE Override	No CE Override	Difference
Residential	10.63	8.33	2.30
Commercial	6.32	6.32	-
Industrial	0.26	0.26	-
Total DSM:	**17.21**	**14.91**	**2.30**

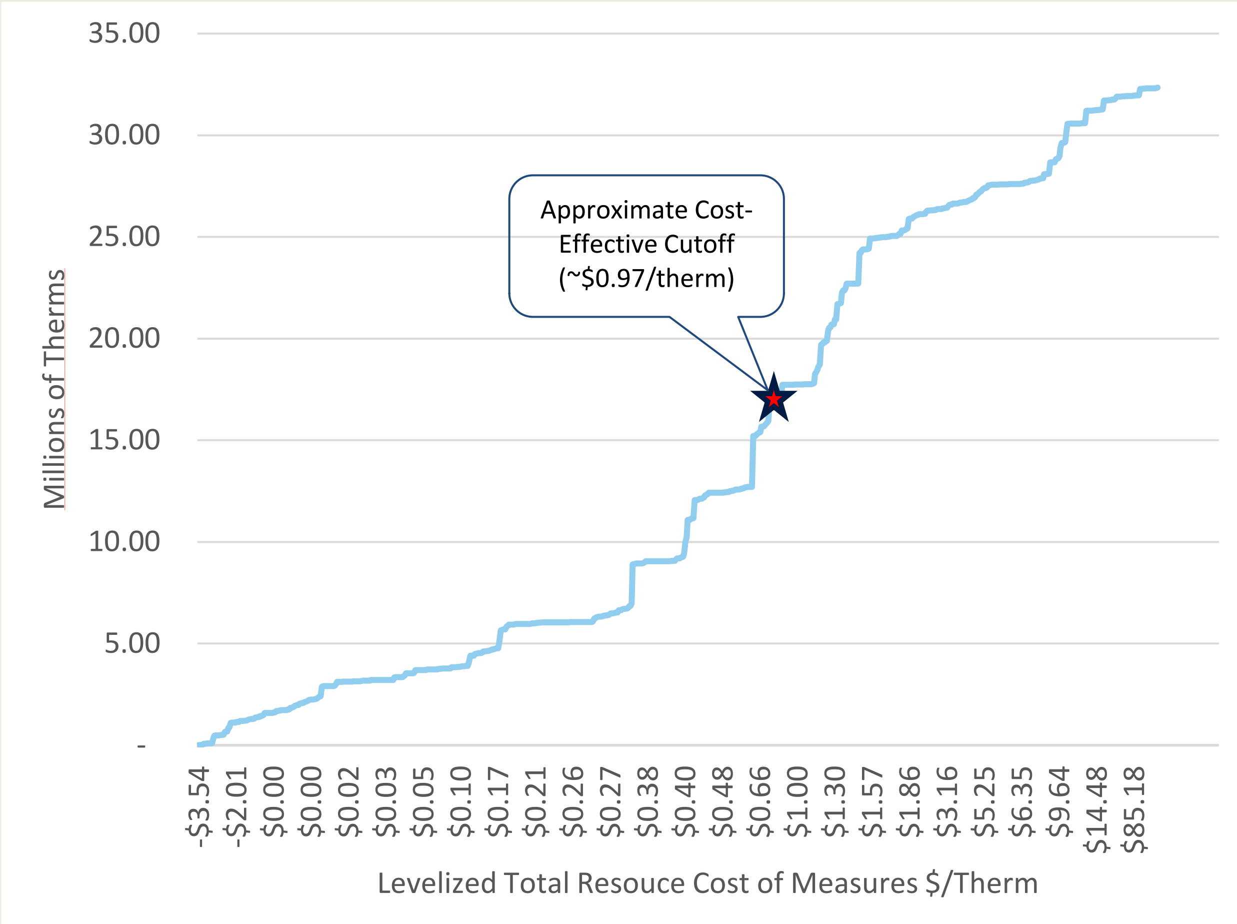
In this IRP, 13% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures with exceptions. The measures that had this option applied to them included 0.67-0.69 Efficiency factor (EF) gas storage water heaters and attic, floor, and wall insulation in the Residential Sector.

Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential therms that could be saved at various costs for all measures. The levelized cost for each measure is determined by calculating the present value of the total cost of the measure over its economic life, per therm of energy savings ($/therm saved). The levelized cost calculation starts with the customer's incremental TRC of a given measure. The total cost is amortized over an estimated measure lifetime using the Avista's discount rate provided to Energy Trust. The annualized measure cost is then divided by the annual therms savings. Some measures have negative levelized costs because non-energy benefits amortized over the life of the measure are greater than the total cost of the measure over the same period.

Figure 3.12 below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The cost threshold shown with a star on the supply curve line represents the approximate levelized cost cutoff that corresponds with the amount of TRC determined cost-effective DSM potential identified by the RA Model in the 2018, when ordering all measures based on their levelized cost.

Figure 3.12 – Gas Supply Curve ($ per therm saved)



Deployed Results – Final Savings Projection

The results of the final savings projection show that Energy Trust can save 1.65 million therms across Avista's system in Oregon in the next five years from 2018 to 2022 and over 8.5 million therms by 2037. This represents an 8.7 percent cumulative load reduction by 2037 and is an average of just under a 0.5 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 3.16 compared to the technical, achievable and cost –effective achievable potential.

Table 3.16: 20-Year Cumulative savings potential by type, including final savings projection (Millions of Therms)

	Technical Potential	Achievable Potential	Cost-Effective Potential	Energy Trust Deployed Savings Projection
Residential	20.0	17.0	10.6	5.2
Commercial	13.3	11.3	6.3	3.3
Industrial	0.3	0.3	0.3	0.2
All DSM	**33.5**	**28.5**	**17.2**	**8.8**

The final deployed savings projection is just over half of the modeled cost-effective achievable potential. There are several reasons for this additional step down in savings:

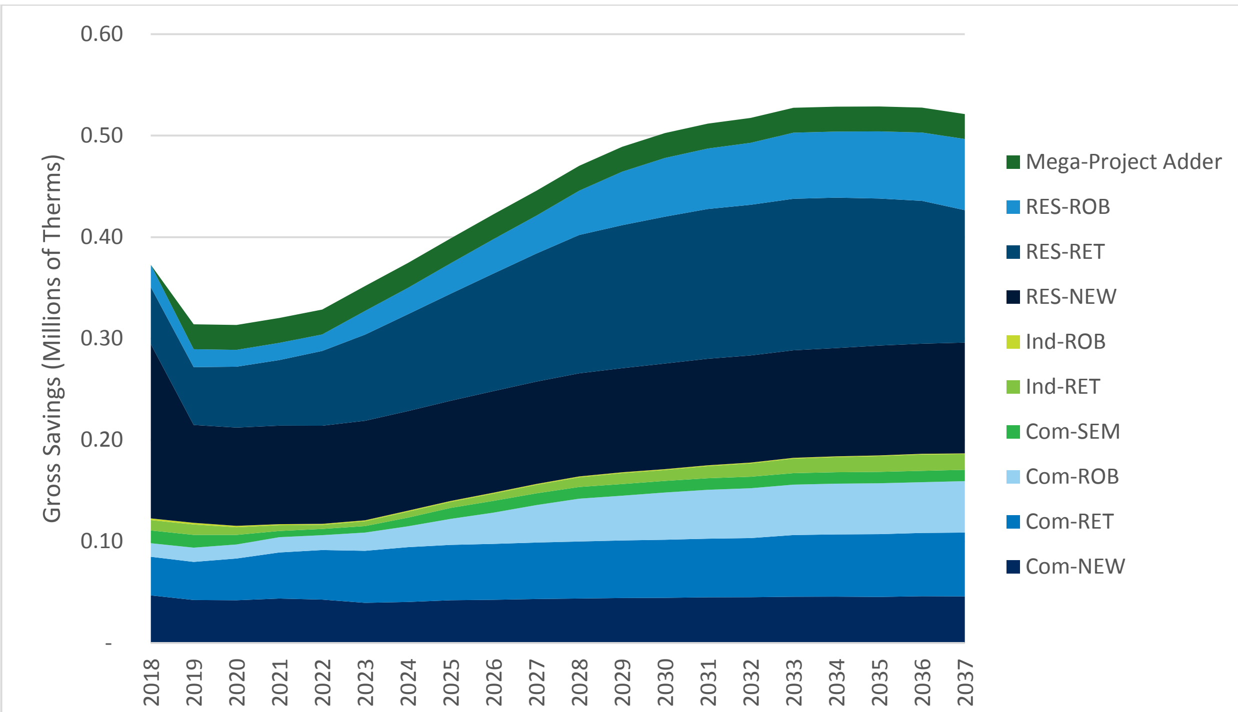
1. "Lost Opportunity Measures" – Measures that are meant to replace failed equipment (ROB) or new construction measures (NEW) are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment over code baseline when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if a program administrator misses the opportunity to influence the installation of more efficient equipment, the opportunity is lost until the equipment fails again. Energy Trust expects that most of these opportunities will be met in later years as efficient equipment becomes more readily adopted. However, in early years, the level of acquisition for these opportunities is smaller and ramps higher as time progresses.

2. "Hard to Reach Measures" – some measures that show high savings potential are notoriously hard to reach and are capped at 67% of total retrofit potential. These measures include insulation and windows.

3. New service territory – Avista is a new service territory for Energy Trust as of 2016 and it takes a few years for Energy Trust trade ally networks and systems become established in new areas, which is reflected in this deployment. In territories where programs are already established, Energy Trust expects to achieve 100% penetration of all cost-effective retrofit potential and ramp to 100% penetration of lost opportunity measure potential in the later years of the 20-year forecast. For this forecast, these metrics have been reduced to 85% to reflect that Energy Trust programs are not yet fully established in Avista territory.

Figure 3.13 below shows the annual savings projection by sector and measure type. The initial drop in savings from 2018 to 2019 is due to the expiration of market transformation savings being claimed by the Residential New Homes program from past building code changes. Most other sector and measure types ramp up over the forecast period, reflecting the NWPCC ramp rates and methodology to achieve as much cost-effective potential as possible.

Figure 3.13 – Annual Deployed Final Savings Potential by Sector and Measure Type (Millions of Therms)



Finally, Figure 3.14 shows the annual and cumulative savings as a percentage of Avista's load forecast in Oregon. Annually, the savings as a percentage of load varies from about 0.35% at its lowest to 0.53% at its highest, as represented on the *left* Y-axis of the graph and the blue line. Cumulatively, the savings as a percentage of load builds to 8.7% by 2037, shown on the *right* Y-axis and the gold line.

Figure 3.14 – Annual and Cumulated Forecasted Savings as a Percentage of Annual and Cumulative Load Forecasts

Deployed Results – Peak Day Results

In the state of Oregon and around the region, there is an increased focus on peak day savings contributions of energy efficiency and their impact on capacity investments. This new focus has led some utilities to embark on targeted load management efforts for avoiding or delaying distribution system reinforcements. Additionally, the OPUC is recommending that all investor-owned gas utilities review and consider the DSM capacity contribution analysis that NW Natural developed in recent years. Therefore, Avista and Energy Trust have collaborated to develop estimates of peak day contributions from the energy efficiency measures that Energy Trust forecasts to install.

Peak day coincident factors are the percentage of annual savings that occur on a peak day over the total year, which are shown in Table 3.17 below. As mentioned, Avista is still reviewing this methodology and for the purpose of this analysis, Energy Trust utilized the peak day factors that are currently being used in Energy Trust's avoided costs. These include residential and commercial space heating factors developed by NW Natural in 2016and hot water, process load (flat) and clothes washer factors sourced from the Northwest Power and Conservation Council for electric measures that are analogous to gas equipment. The peak day factors are the highest for the space heating load shapes, which aligns with a typical winter system peak of natural gas utilities. These peak day factors will be reviewed and updated by Avista to be specific to Avista's Oregon service territory in the next IRP.

Table 3.17 - Peak Day Coincident Factors by Load Profile

Load Profile	Peak Day Factor	Source
Residential Space Heating	2.10%	NW Natural
Commercial Space Heating	1.80%	NW Natural
Water Heating	0.40%	NWPCC
Clothes Washer	0.20%	NWPCC
Process Load	0.30%	NWPCC

Figure 3.15 below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast. Each measure analyzed is assigned a load shape and the appropriate peak day factor is applied to the annual savings to calculate the overall DSM contribution to peak day capacity. Cumulatively, this is equal to 110,551 therms, or 1.3% of the total deployed savings potential in Avista's Oregon service territory over the 20-year forecast, as shown in Table 3.18 below.

Figure 3.15: Annual Deployed Peak Day DSM Savings Contribution by Sector (Therms)

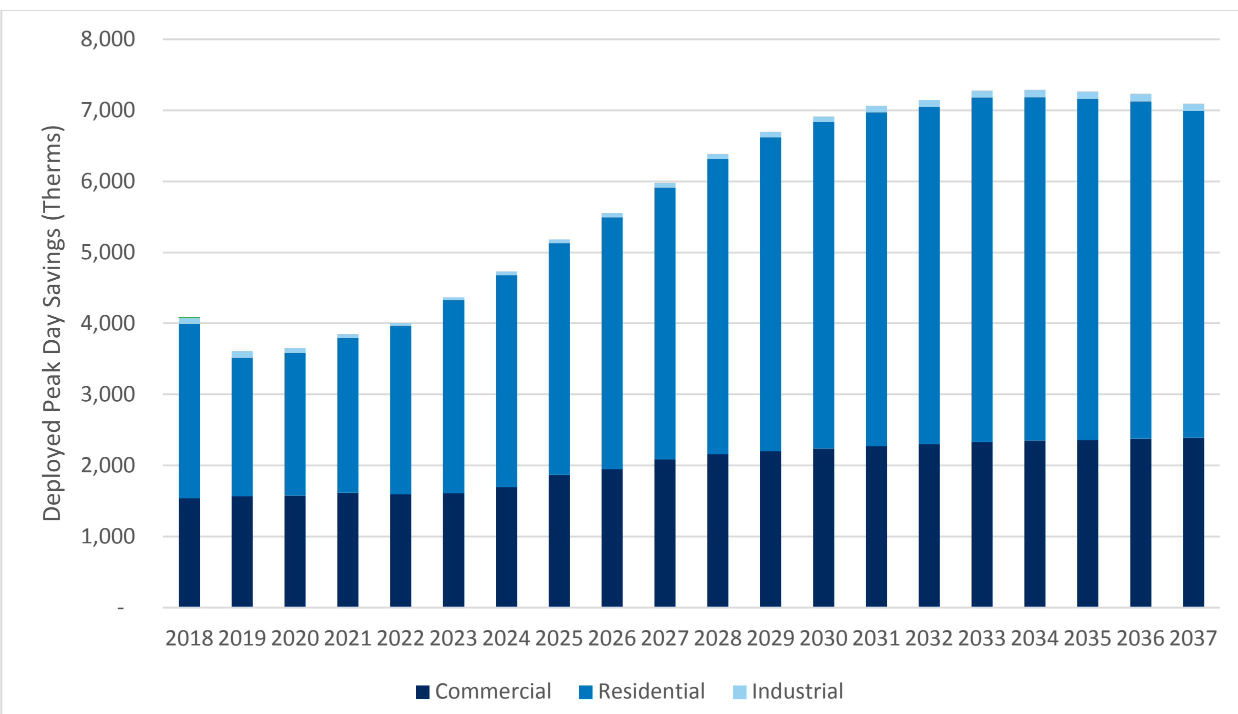


Table 3.18: Cumulative Deployed Peak Day DSM Savings Contribution by Sector (Therms)

Sector	Cumulative Peak Day Savings (Therms)	% of Overall Sector Savings
Commercial	35,263	0.7%
Residential	73,749	2.2%
Industrial	1,538	0.7%
Total	**110,551**	**1.3%**

Conclusion

Avista has a long-term commitment to responsibly pursuing all available and cost-effective efficiency options as an important means to reduce its customer's energy cost. Cost-effective demand-side management options are a key element in the Company's strategy to meet those commitments. Falling avoided costs and lower growth in customer demand have led to a reduced role for conservation in the overall natural gas portfolio compared with IRPs done prior to 2012, however, a regulatory shift to utilizing the UCT in Washington and Idaho DSM programs will continue to provide a vital role in offsetting future natural gas load growth. The company transitioned its Oregon DSM regular income, commercial, and industrial customer programs to the Energy Trust of Oregon (ETO), with the ETO being the sole administrator effective January 1, 2017. Avista is continuing to adaptively manage its DSM programs in response to the ever-shifting economic climate.

Perhaps of most importance in the long-term are the Company's ongoing efforts to work with key regional players to develop a regional natural gas market transformation organization and portfolio. The Northwest Energy Efficiency Alliance (NEEA) has been executing the first stages of their 2015 - 2019 Natural Gas Market Transformation Business Plan. While there has not yet been any savings realized, there has been many studies and efforts towards meeting their goals. NEEA is currently working to develop their 2020 – 2024 Business Plan and we look forward to the conservation opportunities that arise out of their work in the coming years.

Market transformation is not itself called out within the CPA since the CPA focuses upon conservation potential without regard to how that potential is achieved. The prospect for a regional market transformation entity will potentially bring a valuable tool to bear in working towards the achievement of the cost-effective conservation opportunities identified within the natural gas CPA.

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 identifies methods to mitigate these risks.

Chapter Highlights

- Actively optimize resources to drive down customer costs
- An increased drilling efficiency in production per rig, year over year
- The Pacific Northwest is geographically located in some of the lowest prices for natural gas in the world

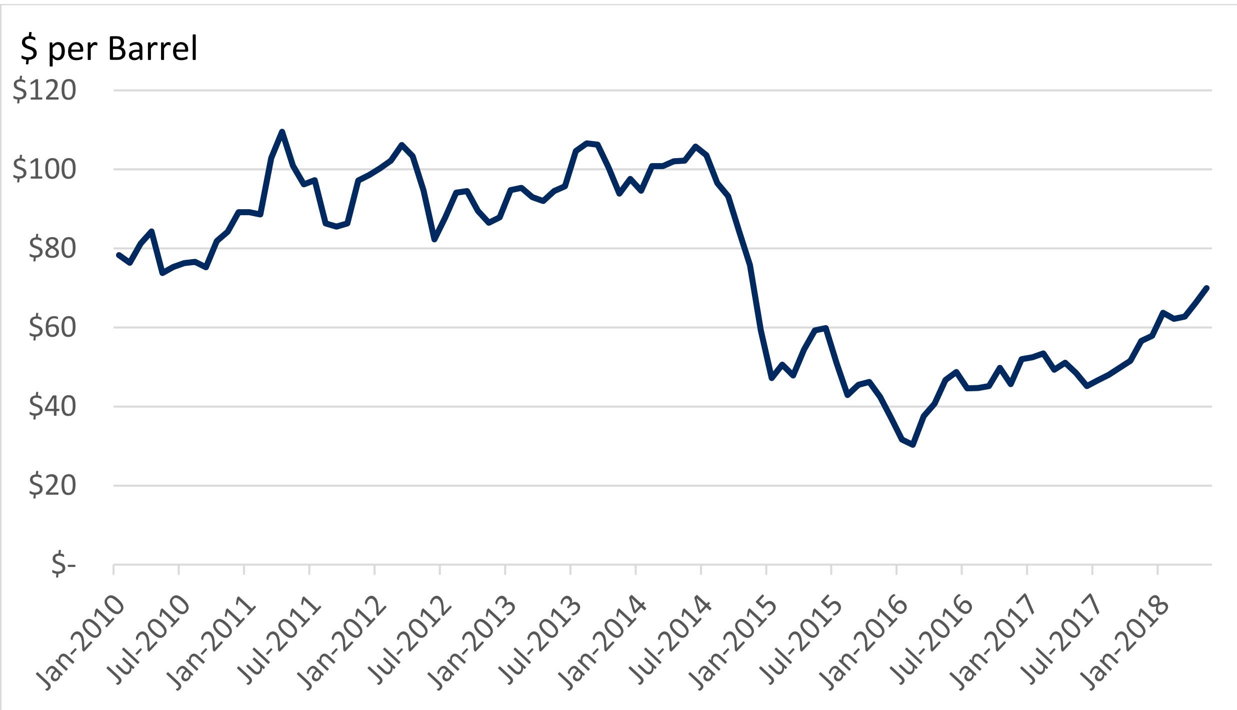
Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve core customers. Supply options include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines, and storage. Because Avista's 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

The Northwest continues to enjoy a low cost commodity environment with abundant supply availability, especially when compared across the globe. This is primarily due to increasing production in areas of the Northeast and Southern United States. New large-capacity pipelines, like the Rover pipeline located in Ohio and Michigan, are entering service and increasing the take away capacity from these prolific production areas. This supply is serving an increasing amount of demand in the population heavy areas in the middle and eastern portions of Canada and the U.S displacing supplies that had historically been delivered from the Western Canadian Sedimentary Basis (WCSB). Current forecasts show a long-term regional price advantage for Western Canada and Rockies gas basins as the need for this gas diminishes. To put this into perspective, 2005 Canadian imports accounted for nearly 20% of the U.S. demand. Fast forward to 2017 and this number is less than 10%, showing the sheer growth in U.S. supply. This glut of Canadian gas paired with limited options for flowing gas into demand areas has created a deeply discounted commodity in the Northwest when compared to the Henry Hub. Adding to these fundamentals is the recent increase in the price of West Texas Intermediate (WTI) oil to levels not seen since 2014 (figure 4.3). This is leading to an increased level of drilling for oil throughout North America and with it a large amount of associated gas.

Figure 4.3: WTI Spot Price FOB



Access to these abundant supplies of natural gas and to major markets across the continent has also led to the construction of multiple LNG plants. Sabine Pass and Cove Point are both operational and will be supplying the world with a total of over 3 Bcf of natural gas daily. There are currently eighteen export terminals[1] proposed in North America, awaiting FERC review and approval which have a liquefaction capacity of over 23 Bcf per day. A listing of facilities awaiting approval for import or export in North America is showing a large number of projects with pending applications. In the western U.S. there is one proposed project the Jordan Cove export facility in Oregon. After initially being rejected for approval to export, Jordan Cove has refiled their application and is expecting a FERC decision by the second half of 2019. A Canadian project – LNG Canada located in Kitimat B.C., has received National Energy Board (NEB) approval and is awaiting a final investment decision expected Q3 or Q4 2018. Its initial capacity, like Jordan Cove, is roughly 1 Bcf per day, but contains an option for up to 3.5 Bcf per day in total. The large increase of natural gas demand by either of these facilities moving forward could cause pressure on commodity prices with the limited infrastructure in the Pacific Northwest.

Another relatively new demand area is Mexico. In 2013, Mexico reformed its energy sector allowing new market participants, innovative technologies and foreign investment. This market reformation opened up new opportunities for natural gas export to Mexico.. Since these market changes, Mexican imports which were historically less than 2 Bcf per day have more than doubled and are expected to rise to more than triple by just 2021.

Recent estimates from both the EIA and Natural Resources Canada reflect a large potential supply of natural gas in North America of over 4,000 trillion cubic feet (Tcf) or enough supply to last 100's of years at current demand levels. This estimate, is based on known geological areas combined with the ability to economically recover natural gas as infrastructure expands and technology improves.

Regional Market Hubs

There are numerous regional market hubs in the Pacific Northwest 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 geographically diverse 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 produces 90 percent of Canada's natural gas.

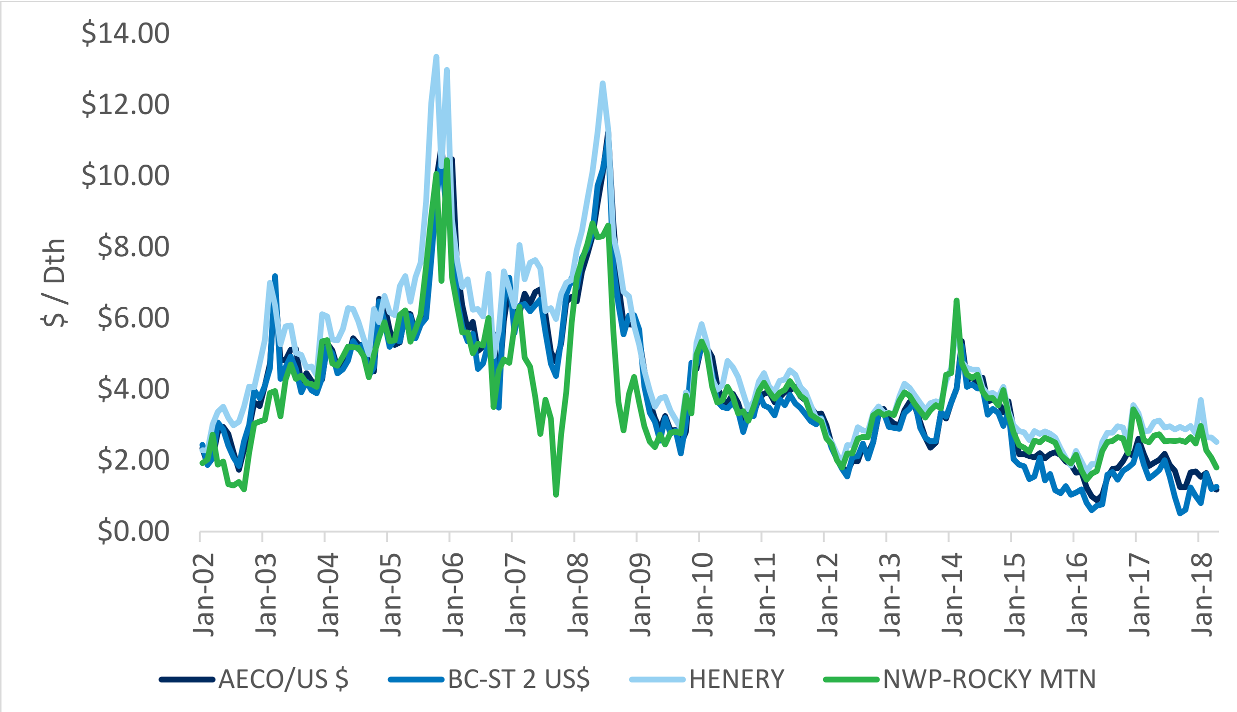
[1] https://www.ferc.gov/industries/gas/indus-act/lng.asp

- **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, New Mexico and Wyoming.
- **Sumas/Huntingdon** – The Sumas, Washington pricing point is on the U.S./Canadian border where the northern end of the NWP system connects with Enbridge's Westcoast Pipeline and predominantly markets Canadian natural gas from Northern British Columbia.
- **Malin** – This pricing point is at Malin, Oregon, on the California/Oregon border where TransCanada's Gas Transmission Northwest (GTN) and Pacific Gas & Electric Company connect.
- **Station 2** – Located at the center of the Enbridge's 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. 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, Station 2, Rockies and Henry Hub. The figure has changed in recent years due to a change in flows of natural gas specifically coming from Western Canada. In 2017 the United States flipped from being a net importer to a net exporter.

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 regional 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:

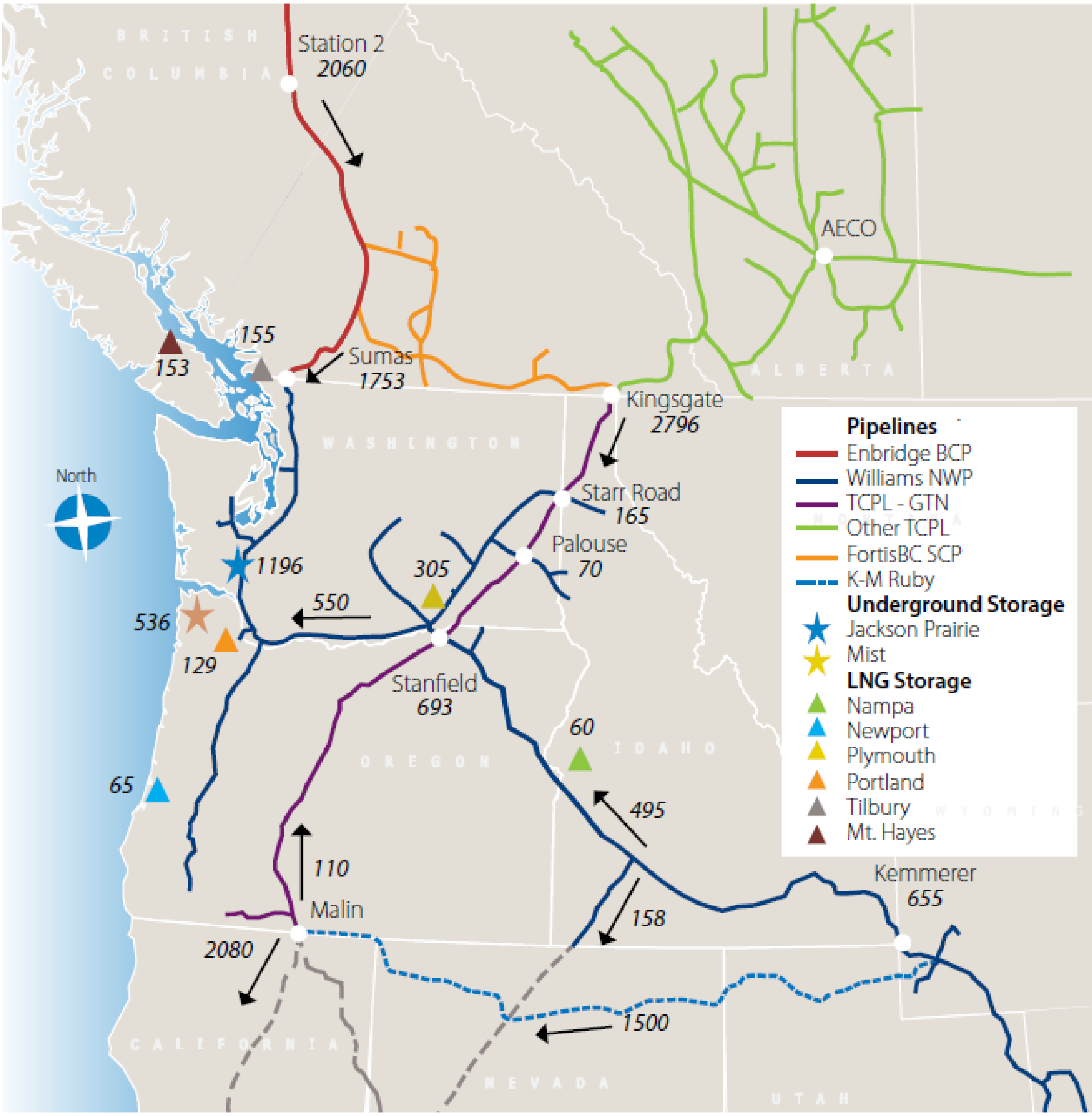
- **Firm vs. Non-Firm:** Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.

- **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.

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 transportation 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.



*NWGA 2017 outlook

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 (NGTL):** 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.
- **Enbridge - 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 core customers. Table 4.1 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages with different expiration dates; however, all have the right to be renewed by Avista. This gives Avista and its customer's available capacity to meet existing core demand now and in the future.

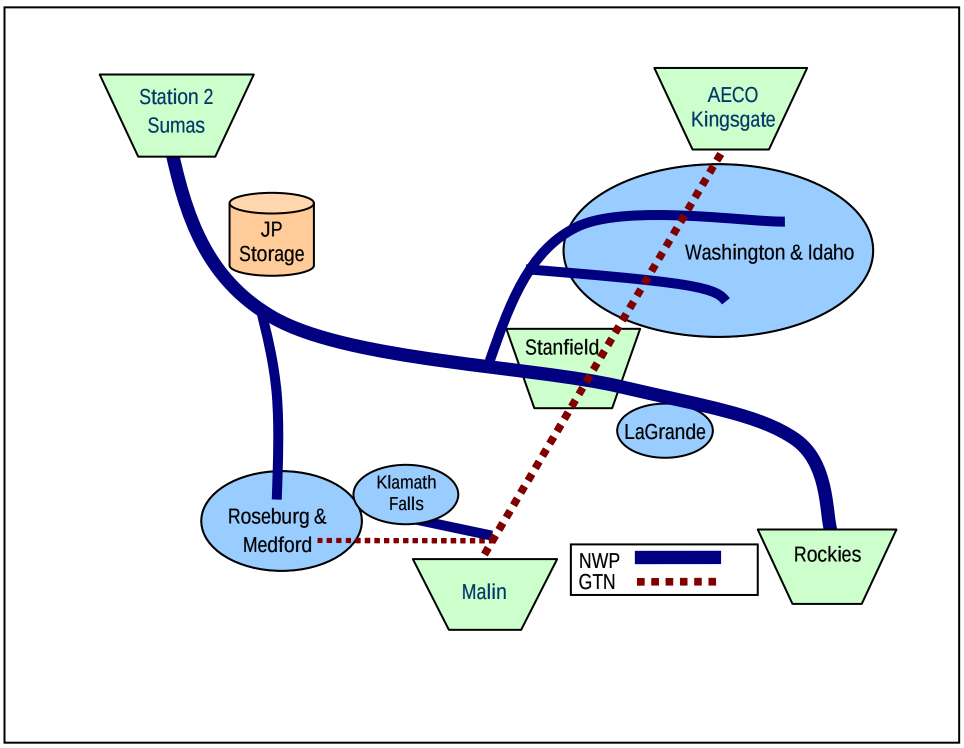
Table 4.1: Firm Transportation Resources Contracted (Dth/Day)

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

** Represents original contract amounts after releases expire.*

Avista defines two categories of interstate pipeline capacity. Direct-connect pipelines deliver supplies directly to 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. Firm Storage Resources - Max Deliverability is specifically tied to Avista's withdrawal rights at the Jackson Prairie storage facility and is based on our one third ownership rights. This number only indicates how much we can withdraw from the facility as transport on NWP is needed to move it from the facility itself. Figure 4.2 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[2]

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 distinct service territories and geography relative

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

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 is effectively a fully-contracted. With the exception of La Grande, OR, Avista's service territories lie at the end of NWP pipeline laterals. The Spokane, Coeur d'Alene and Lewiston laterals serve Washington and 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 runs from the Kingsgate trading point on the Idaho-Canadian border down to Malin on the Oregon-California border. This pipeline runs directly through or near most of Avista's service territories. Mileage based rates provide an attractive option for securing incremental resource needs. Until recently, GTN had a large amount of unsubscribed capacity. However as prices continue their downward fall, producers are increasingly contracting for this excess capacity in order to move gas down to more favorable markets themselves rather than relying on current market dynamics. This may have some future pricing implications on the commodity side.

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. Northwest Pipeline (NWP) 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 – Current Transportation/Storage Rates and Assumptions). 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 their cost of service.

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 generally the same as firm transportation, there are no demand or reservation charges in these transportation contracts.. 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 done on semi-annual basis and through the IRP. Active management of underutilized transportation capacity either through the capacity release market or engaging in optimization transactions to recover some transportation costs. Timely analysis is also important to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise (See Chapter 6 – Integrated Resource Portfolio for a description of the management of underutilized pipeline resources).

Avista manages existing resources through optimization to mitigate the costs incurred by customers until the resource is required to meet demand. The recovery of transportation costs is often market based with rules governed by the FERC. The management of long- and short-term resources ensures the goal to meet firm customer demand in a reliable and cost-effective manner. Unutilized resources like supply, transportation, storage and capacity can be combined 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. 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 natural gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the natural 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.

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; and
- Additional supply point diversity.

While there are several storage facilities available in the region, Avista's existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie Storage facility.

Avista optimizes storage as part of its asset management program. This helps to ensure a controlled cost mechanism is in place to manage the large supply found within the storage facility. An example of this storage optimization is selling today at a cash price and buying a forward month contract. Since forward months have risks or premiums built into the price the result is Avista locking in a given spread. All optimization of assets go directly to the customer to reduce their monthly billing.

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 natural 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.

Capacity Release Recall

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 evaluates if or when to recall some or all long-term releases.

Existing Available Capacity

In some instances, there is available capacity on existing pipelines. NWP's mainline is fully subscribed and while GTN has recently seen a significant increase in contracting activity, they currently maintain the ability to flow additional supply from Kingsgate to Spokane as noted in Chapter 7. Avista has modeled access to the GTN capacity as an option to meet future demand needs in addition to some capacity in the La Grande area where some quantities are available on NWP.

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 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 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 require matching pipeline transportation. Matching pipeline transportation is creating equivalent volumes on different pipelines from the basin to the delivery point in order to fully utilize subscribed capacity. Expansions may also provide increased reliability or access to supply that cannot be obtained through existing pipelines. This is the case with the Pacific Connector pipeline being proposed as the connecting feedstock for the Jordan Cove LNG facility in Oregon. The pipeline's current path connects into Northwest Pipelines Grants Pass Lateral where capacity is limited. The Pacific Connector pipeline would add an additional 50,000 Dth/day of capacity along that lateral flowing south from the Roseburg interconnect.

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 Association

- **FortisBC Southern Crossing Expansion:**

  The Southern Crossing pipeline system is a bidirectional pipeline connecting Westcoast T South system at Kingsvale, BC and TransCanada's BC. This expansion would include over 90 miles of pipeline looping allowing access to an additional 300-400 MMcf/d of bi-directional capacity, tying together station 2 and AECO markets.

- **TransCanada GTN Trail West/N-MAX**

  The pipeline taking natural gas off of GTN and onto NWP hub near Molalla is referred to as Trail West/N-MAX. TransCanada GTN, Northwest Natural and Northwest Pipeline are the project sponsors of this 106-mile, 30-inch diameter pipeline. The initial design capacity of this pipeline is 500 MMcf/d and expandable up to 1,000 MMcf/d. This could be an important project if built as it would bring more gas into the I-5 corridor where unused pipeline capacity is quickly disappearing based on the demand for natural gas and population increase.

- **Sumas Express**

  NWP continues to explore options to expand service from Sumas, Wash., to markets along the Interstate-5 corridor. This project could help relieve the congestion along this highly populated geographical region in both Washington and Oregon. Various methods could be used to add this additional capacity including looping, additional compression and increasing the pipe size and can be scaled based off of demand.

- **Enbridge/FortisBC T-South System Looping**

  FortisBC and Enbridge are system enhancement on the T-South pipeline. Removing constraints will allow expansion of Endbridge'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 Enbridge system to Kingsgate would increase capacity by 190MMcf/d. This would add incremental gas into the Huntington/Sumas market through looping and compressor station upgrades along the system.

- **Pacific Connector**

  Pembina is currently attempting to acquire approval for a 232-mile, 36-inch diameter pipeline designed to transport up to 1.2 billion cubic feet of natural gas per day from interconnects near Malin, Oregon, to the Jordan Cove LNG terminal in Coos Bay, Oregon. The pipeline would deliver the feedstock to the LNG terminal providing natural gas to international markets, but also to the Pacific Northwest. The pipeline will connect with Williams' Northwest Pipeline on the Grants Pass lateral. This ties in directly within Avista's service territory and will bring in an additional 50,000 Dth/day of capacity into that area. This new option could provide Avista's customers in the area new capacity for growth and supply diversity.

- **NGTL – West Path expansion**

  In order to meet existing aggregate demand in southern AB and incremental long-term delivery commitments at the A/BC border, NGTL is proposing this project underpinned by long-term contracts to increase the delivery point capacity at the A/BC border by 288,000 GJ/day. This project would operationally true-up capacity differences between NGTL and Foothills and provide additional export capacity into the US.

Avista supports proposals that bring supply diversity and reliability to the region. Supply diversity provides a varied supply base in the procurement of natural gas. Since there are few options in the Northwest, supply diversity provides options and security when constraints or high demand are present. Avista engages in discussions and analysis of the potential impact of each regional proposal from a demand serving and reliability/supply diversity perspective. In most cases, for Avista to consider them a viable incremental resource to meet demand needs would require combining them with additional capacity on existing pipeline resources. 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 natural gas from storage can be delivered to Avista's 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 the financial and reliability impact to customers. Due to the fast paced growth in the region, and the need for new resources, a future expansion is possible, though a robust analysis would be required to determine feasibility. Currently, there are no 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 natural 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 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 natural gas liquefaction, storage and vaporization service under its LS-1, LS-2F and LS-3F tariffs. An example ratio of injection and withdrawal rates show that it can take more than 200 days to fill to capacity, but only three to five 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. With available capacity, Plymouth LNG was considered in our supply side resource modeling but was not selected.

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. Avista modeling included LNG, but it was not selected as a resource when compared to existing resources.

Renewable Natural Gas (RNG)

Renewable Natural Gas, or biogas, typically refers to a mixture of gases produced by the biological breakdown of organic matter in the absence of oxygen. RNG can be produced by anaerobic digestion or fermentation of biodegradable materials such as woody biomass, manure or sewage, municipal waste, green waste and energy crops. Depending on the type of RNG there are different factors for the amount of methane saved by its capture as methane has been found to have a multiplier effect on global warming of, at a minimum, 25[3] times that of carbon dioxide. Each type of RNG has a different carbon intensity as compared to natural gas as shown in table 4.2.

[3] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

Table 4.2 Carbon intensity[4]:

Source	Carbon Intensity (g CO2e/MJ)	Carbon Intensity as compared to Natural Gas	lbs. of carbon per Dth
Natural Gas	78.37	100%	117
Landfill	46.42	41%	48
Dairy	-276.24	-452%	(529)
WWT	19.34	75%	88
Solid Waste	-22.93	-129%	(151)

RNG is a renewable fuel, so it may qualify for renewable energy subsidies. Once contained, RNG can be used by boilers for heat, as power generation, compressed natural gas vehicles for transportation or directly injected into the natural gas grid. The further down this line greater the need for pipeline quality gas.

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 considered biogas as a resource in this planning cycle, as depending on the location of the facility it may be cost effective. This is especially the case when found within Avista's internal distribution system where transportation and fuel costs can be avoided.

Avista's Natural Gas Procurement Plan

No company can accurately predict future natural gas prices, but market conditions and experience help shape the overall approach to procurement. 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 of time and establish hedge phases when portions of future demand are physically and/or financially hedged. Avista views hedging as a type

[4] California Air Resources Board

of risk insurance and an appropriate part of a diversified procurement plan with a ***mission to provide a diversified portfolio of reliable supply and a level of price certainty in volatile markets***. 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. In utilizing

Avista uses a disciplined, but flexible hedging approach. Avista's hedging strategy begins with the prompt month and extends for up to thirty six months out based on market availability of winter and summer pricing strips. This program is run through a mechanism utilizing an upper and lower control limit or bands to help control market cost and risk. These control limits measure the volatility in the market place, by basin, and will adjust inward toward the price, when rising, or allow the lower control limit to fall with volatility when prices go down. Also, in response to the Washington Utilities and Transportation Commission (WUTC) hedging policy UG-132019, Avista is also developing an additional methodology to measure the total value at risk (VaR) of its entire portfolio of hedges. This methodology is based off of market volatility and statistical measurements of the marketplace and may allow Avista to hedge less based on current market fundamentals, while also controlling the financial risk of a rising market.

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 types of risk and approaches to risk management. The 2018 IRP focuses on two areas of risk: the financial risk of the cost of natural gas 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 Gas Supply, 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.

Supply Scenarios

The 2018 IRP includes two supply scenarios. Additional details about the results of the supply scenarios are in Chapters 6 and 7.

- **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, NWP, capacity release recalls, RNG, Hydrogen and LNG.

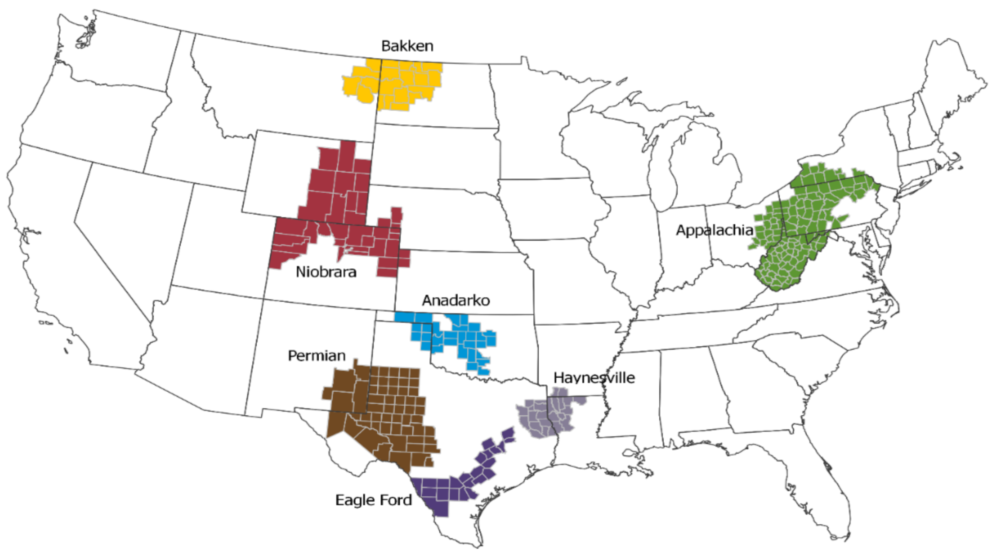
Supply Issues

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

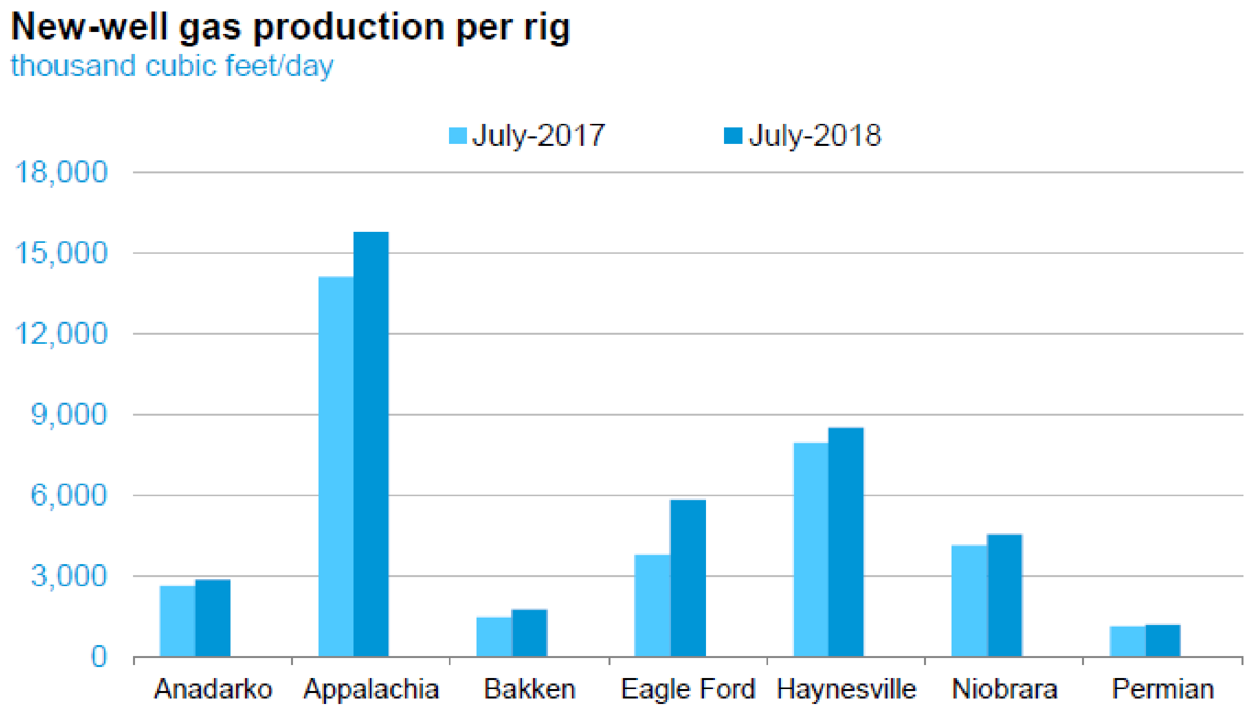
Hydraulic fracturing (commonly referred to as fracking) was invented by Hubbert and Willis of Standard Oil and Gas Corporation back in the late 1940's. The process involves a technique to fracture shale rock with a pressurized liquid. In the past 15 years, the techniques and materials used have become increasingly perfected opening up large deposits of shale gas formations at a low prices. The Energy Information Administration (EIA) tracks production per well in the seven key oil and natural gas production formations in the United States as shown in Figure 4.4. Figure 4.5 shows the continued increase in efficiency of production compared to just a year ago as shown by the EIA's Drilling Productivity Report 4.5[5].

Figure 4.4 – seven major drilling regions in the United States



[5] Drilling Productivity Report, https://www.eia.gov/petroleum/drilling/pdf/summary.pdf

Figure 4.5 – June 2018 Drilling Productivity Report, EIA



With the increasingly prevalent use of hydraulic fracturing came concerns of chemicals used in the process. The publicity caused by movies, documentaries and articles in national newspapers about "fracking" has plagued the natural gas and oil industry. There is concern that hydraulic fracturing is contaminating aquifers, increasing air pollution and causing earthquakes. One common misconception with the process is that hydraulic fracturing causes earthquakes. The actual cause of earthquakes is wastewater injection used in operations at the well site. Based on research at the U.S. Geological Survey, only a small number of these earthquakes are from fracking itself.[6] Additionally, wastewater injections are used for all wells, not just those where fracking is involved.

The wide-spread publicity generated interest in the production process and caused some states to issue bans or moratoriums on drilling until further research was conducted. To help combat these fears, Frac Focus[7] was created and is a chemical disclosure registry allowing users to view chemicals used by over 125,000 wells throughout North America. This information, voluntarily submitted by Exploration and production companies, provides a detailed list of materials used to frack each individual well.

[6] https://profile.usgs.gov/myscience/upload_folder/ci2015Jun1012005755600Induced_EQs_Review.pdf

[7] https://fracfocus.org/

Pipeline Availability

The Pacific Northwest has efficiently utilized its relatively sparse network of pipeline infrastructure to meet the region's 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.

There are currently a few industrial plants being considered in the Pacific Northwest. The project with the highest likelihood is the project located in Washington's Port of Kalama. This process uses large amounts of natural gas as a feedstock for creating methanol, which is used to make other chemicals and as a fuel. At over 300,000 Dth per day this plant would consume large amounts of natural gas.

Ongoing Activity

Without resource deficiencies or a need to acquire incremental supply-side resources to meet peak day demands over the next 20 years, Avista will focus on normal activities in the near term, including:

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, supply dynamics and marketplace, and pipeline and storage infrastructure availability.
- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

Conclusion

Abundant supply availability around the Northwest may lead to an increased demand in this planning horizon by large industrials. While keeping a watchful eye on the market, Avista has continued to make adjustments to its procurement plan to help reduce short term volatility and is actively engaged in new strategies and mechanisms to help manage overall financial risk related to hedging. Our supply mix is diversified between multiple basins with firm take away rights thus helping to reduce the risk of not meeting demand on a cold day. This in combination with the optimization of our storage, transportation and basin resources have helped Avista to provide natural gas reliably to our customers at a fair and reasonable price.

5: Policy Considerations

Regulatory environments regarding energy topics such as renewable energy and greenhouse gas regulation continue to evolve since publication of the last IRP. Current and proposed regulations by federal and state agencies, coupled with political and legal efforts, have implications for the development and continued use of coal and natural gas-fired generation. This chapter discusses pertinent public policy issues relevant to the IRP.

Chapter Highlights

- Electrification has become an increasingly recurrent topic in the Northwest
- Avista's Climate Policy Council monitors greenhouse gas legislation and environmental regulation issues
- Both Washington and Oregon are actively creating bills to tax, trade, or charge a fee for releasing carbon dioxide into the atmosphere

Environmental Issues

The evolving and sometimes contradictory nature of environmental regulation from state and federal perspectives creates challenges for resource planning. The IRP cannot add renewables or reduce emissions in isolation from topics such as system reliability, least cost requirements, price mitigation, financial risk management, and meeting changing environmental requirements. Each generating resource has distinctive operating characteristics, cost structures, and environmental regulatory challenges that can change significantly based on timing and location. All resource choices have costs and benefits requiring careful consideration of the utility and customer needs being fulfilled, their location, and the regulatory and policy environment at the time of procurement.

Renewable energy technologies such as renewable natural gas (RNG) have different benefits and challenges. Renewable resources have low or no fuel costs and few, if any, direct emissions. Renewable resources are often located to maximize capability rather than proximity to load centers. The need to site renewable resources in remote locations often requires significant investments in distribution and capacity expansion, as well as mitigating possible wildlife and aesthetic issues. Transportation costs and logistics also complicate the location of RNG plants.

The long-term economics of renewable resources also faces some uncertainties. Federal investment and production tax credits are set to expire. The extension credits and grants may not be sustainable given their impact on government finances and the maturity of wind and solar technologies. Many relatively unpredictable factors affect renewables, such as renewable portfolio standards (RPS), construction and component prices, international trade issues and currency exchange rates. Decreasing capital costs for wind and solar may slow or stop.

The design and scope of greenhouse gas regulation is in a state of flux due to legal challenges and evolving political realities. As a result, greenhouse gas policy-making is shifting from the federal to the state and local level. Since the 2016 IRP publication, changes in the approach to greenhouse gas emissions regulation and supporting programs, include:

- The EPA proposed actions to regulate greenhouse gas emissions under the Clean Air Act (CAA) through the proposed Clean Power Plan (CPP) were stayed by the U.S. Supreme Court on February 9, 2016;
- On August 20, 2018 the EPA proposed a CPP replacement rule, referred to as the "Affordable Clean Energy Rule", establishing individual plant greenhouse gas emissions in contrast to the CPP which targeted emission's across each states energy sector;
- The President signaled a shift in federal priorities through Executive Orders as well as proposed budgets.
- The State of Washington invalidated the Clean Air Rule
- Regulations or laws placing a monetary value on the cost of carbon through a tax, fee or cap-and-trade program are becoming increasingly recurrent in the states of Oregon and Washington.

Natural Gas System Emissions

The physical makeup of the natural gas system includes extraction rigs, pipelines and storage; each of these facilities have fugitive emissions. Fugitive emissions are the unintended or irregular releases of natural gas as part of the production cycle. The EPA introduced the Natural Gas STAR Program in 1993 in response to these emissions concerns. This Natural Gas STAR Program is a voluntary program allowing the self-reporting of emission reduction technologies and practices and includes all of the major industry sectors. In May 2016, the EPA finalized rules to reduce methane emissions from wells under the CAA. The program requires natural gas well owners to find and repair leaks at the well site no less than twice per year and four times per year at compressor stations. The EPA placed a 90-day delay on portions of the rule to allow additional comments.

Natural gas wells utilizing shale deposits have a high production curve at the beginning of the extraction process and then dramatically levels off. If not constructed properly, there is a risk of leakage that may lower the return on investment. In addition, risk of increased regulation incentivizes producers to manage emissions as effectively as possible as more regulations generally increase costs and reduce return on investments. Over time a smaller return on investment could mean the difference in survival outcomes for each producer. Natural gas emissions in 1990, as shown in table 7.1, were higher than in 2016 even though the production was just slightly over 50 Bcf/day compared to roughly 78 Bcf/day in 2016. This is nearly equivalent to reducing emissions by half when accounting for the additional production.

Table 5.1: Non-combustion CO2 Emissions from Natural Gas Systems (kt)[1]

	1990	2005	2012	2013	2014	2015	2016
Exploration	404	1,761	1,323	1,159	851	287	138
Production	871	1,709	2,683	3,003	3,278	3,396	3,212
Processing	28,338	18,875	19,120	20,508	21,044	21,044	22,009
Transmission and Storage	166	140	135	142	148	147	143
Distribution	51	27	15	14	14	14	14
Total	**29,831**	**22,512**	**23,276**	**24,827**	**25,336**	**24,888**	**25,516**

Note: Totals may not sum due to independent rounding.

Avista's Climate Change Policy Efforts

Avista's Climate Policy Council is an interdisciplinary team of management and other employees that:

- Facilitates internal and external communications regarding climate change issues;
- Analyzes policy impacts, anticipates opportunities, and evaluates strategies for Avista Corporation; and
- Develops recommendations on climate related policy positions and action plans.

The core team of the Climate Policy Council includes members from Environmental Affairs, Government Relations, External Communications, Engineering, Energy Solutions, and Resource Planning groups. Other areas participate for topics as needed. The meetings for this group include work for both immediate and long-term concerns. Immediate concerns include reviewing and analyzing proposed or pending state and federal legislation and regulation, reviewing corporate climate change policy, and responding to internal and external requests about climate change issues. Longer-term issues involve emissions measurement and reporting, different greenhouse gas policies, actively participating in legislation, and benchmarking climate change policies and activities against other organizations.

EPA Regulations

EPA regulations, or the States' authorized versions, directly, or indirectly, affecting electricity generation include the CAA, along with its various components, including the Acid Rain Program, the National Ambient Air Quality Standard, the Hazardous Air Pollutant rules, and Regional Haze Programs. The U.S. Supreme Court ruled the EPA has authority under the CAA to regulate greenhouse gas emissions from new motor vehicles and the EPA has issued such regulations. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program. Both of these programs apply to power plants and other commercial and industrial facilities. In 2010, the EPA issued a final rule, known as the Tailoring Rule, governing the application of these programs to stationary sources, such as power plants. EPA proposed a rule in early 2012, and modified in 2013, setting

[1] Source is from "3-80 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016" Pg. 80 https://www.epa.gov/sites/production/files/2018-01/documents/2018_chapter_3_energy.pdf

standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units and for existing sources through the draft CPP in June 2014. The EPA released the final CPP rules and the Carbon Pollution Standards (CPS) as published in the Federal Register on October 23, 2015, when they were both challenged thorough a series of lawsuits. Standards under Section 111(d) of the CAA are currently stayed by the Supreme Court. The EPA also finalized new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired generation under CAA section 111(b).

EPA Mandatory Reporting Rule

Any facility emitting over 25,000 metric tons of greenhouse gases per year must report its emissions to EPA. The Mandatory Reporting Rule requires greenhouse gas reporting for natural gas distribution system throughput, fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and from natural gas storage facilities. Washington requires mandatory greenhouse gas emissions reporting similar to the EPA requirements and Oregon has similar reporting requirements.

State and Regional Level Policy Considerations

The lack of a comprehensive federal greenhouse gas policy encouraged states, such as California, to develop their own climate change laws and regulations. Climate change legislation takes many forms, including economy-wide regulation under a cap and trade system, a carbon tax, and emissions performance standards for power plants. Comprehensive climate change policy can include multiple components, such as renewable portfolio standards, DSM standards, and emission performance standards. Washington enacted all of these components, but other Avista jurisdictions have not. Individual state actions produce a patchwork of competing rules and regulations for utilities to follow and may be particularly problematic for multi-jurisdictional utilities such as Avista.

Idaho Policy Considerations

Idaho does not regulate greenhouse gases. There is no indication Idaho is moving toward regulation of greenhouse gas emissions beyond federal regulations.

Oregon Policy Considerations

The State of Oregon has a history of greenhouse gas emissions and renewable portfolio standards legislation. The Legislature enacted House Bill 3543 in 2007, calling for, but not requiring, reductions of greenhouse gas emissions to 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050. Compliance is expected through a combination of the RPS and other complementary policies, like low carbon fuel standards and DSM measures. The state has been working towards the adaptation of comprehensive requirements to meet these goals. HB 2135, or the cap and trade bill, is under consideration at the time this chapter is being written. This bill would repeal the greenhouse gas emissions goals stated above and would require the Environmental Quality Commission to adopt greenhouse gas emissions goals for 2025, and set limits for years 2035 and 2050.

These reduction goals are in addition to a 1997 regulation requiring fossil-fueled generation developers to offset carbon dioxide (CO_2) emissions exceeding 83 percent of the emissions of a state-of-the-art gas-fired combined cycle combustion turbine by funding offsets through the Climate Trust of Oregon.

Oregon's Cap-and-Trade

A set of cap-and-trade bills were included in the Oregon Legislature, but did not make it out due to the short session. In spite of this, a joint legislative committee announced plans to create a "cap-and-invest" program in time for the 2019 session. This committee will be funded by $1.4 million to help fund a Carbon Policy Office and to determine how these programs would impact Oregon's economy, jobs and emissions. These two bills, HB 4001 and SB 1507 would both create a cap and trade system for entities emitting over 25,000 metric tons of carbon annually. In 2021, the Oregon Environmental Quality Commission would set a statewide emissions on about 100 companies who would need to reduce emissions or buy allowances. The revenue from these programs would be invested in clean energy or emissions mitigation programs leading to the final goal of 80% emissions reduction by 2050.

Oregon RNG

In Oregon, Senate Bill 334[2] was passed to help develop, update, and maintain the biogas inventory available. This includes the sites and potential production quantities available in addition to the quantity of renewable natural gas available for use to reduce greenhouse gas emissions. This bill will also help promote RNG and identify the barriers and removal of barriers to develop and utilize RNG. A report is due by September 2018.

Washington State Policy Considerations

Former Governor Christine Gregoire signed Executive Order 07-02 in February 2007 establishing the following GHG emissions goals:

- 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050 or 70 percent below Washington's expected emissions in 2050;
- Increase clean energy jobs to 25,000 by 2020; and
- Reduce statewide fuel imports by 20 percent.

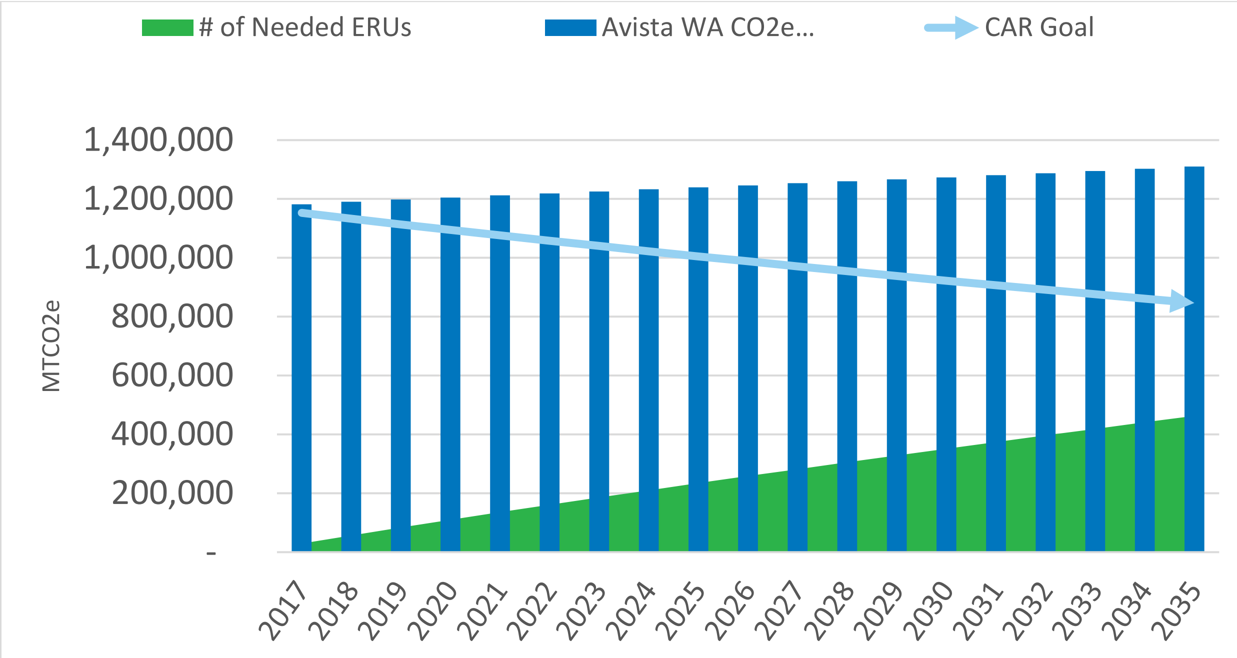
The Washington Department of Ecology adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA's regulation of greenhouse gas emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities.

[2] https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB334

April 29, 2014, Washington Governor Jay Inslee issued Executive Order 14-04, “Washington Carbon Pollution Reduction and Clean Energy Action.” The order created a “Climate Emissions Reduction Task Force” tasked with providing recommendations to the Governor on designing and implementing a market-based carbon pollution program to inform possible legislative proposals in 2015. The order also called on the program to “establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits.” The order also states that the Governor’s Legislative Affairs and Policy Office “will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal.” The Task Force issued a report summarizing its efforts, which included a range of potential carbon-reducing proposals. Subsequently, in January 2015, at Governor Inslee’s request, the Carbon Pollution Accountability Act was introduced as a bill in the Washington legislature. The bill includes a proposed cap and trade system for carbon emissions from a wide range of sources, including fossil-fired electrical generation, “imported” power generated by fossil fuels, natural gas sales and use, and certain uses of biomass for electrical generation. The bill was not enacted during the 2015 legislative session. After the conclusion of the 2015 legislative sessions, Governor Inslee directed the Department of Ecology to commence a rulemaking process to impose a greenhouse gas emission limitation and reduction mechanism under the agency’s CAA authority to meet the future emissions limits established by the Legislature in 2008. This resulted in Washington’s Clean Air Rule (CAR).

The CAR intended to impose new compliance obligations on sources identified by Ecology. The rule imposes caps and requirements to reduce or offset emissions on large emitting facilities, fuel providers and natural gas distribution companies. It initially applies to 29 entities. Compliance obligations for energy-intensive trade-exposed industries, including pulp and paper manufacturers, steel and aluminum manufacturers and food processors, are deferred for three years. When fully implemented, the CAR could cover as many as 70 emitters who account for about two-thirds of Washington’s emissions. The CAR caps emissions for facilities emitting more than 100,000 metric tons per year, and reduces the emissions threshold by 5,000 metric tons per year, until covering all entities emitting over 70,000 metric tons by 2035. The Washington Commission may implement rules regarding RCW 70.235, from the Executive Order 07-02. The CAR became effective January 1, 2017, but was ruled invalid on December 15, 2017 in Thurston County Superior Court. This ruling found that local distribution companies are not emitters, and have no choice under the law to meet the supply demands of its customers. On May 14, 2018 the Department of Ecology appealed this ruling with the Washington State Supreme Court. If a policy comes into law comparable to the CAR, the number of ERU’s required for Avista’s natural gas customers would create a demand for renewable energy. This would likely lead to the procurement of RNG, but due to the large amount of needed MTCO2e offsets would also drive the need for wind and solar. Figure 5.1 shows a potential outcome of a program like the CAR and its impacts on Avista’s Washington customers.

Figure 5.1: Avista – Washington only CO2e emissions reduction estimate from CAR



Deep Decarbonization

In December of 2016 Governor Inslee's office commissioned a deep decarbonization pathway study on reducing emissions required to curb a global temperature increase to below two degrees Celsius. This study lists three possible scenarios seen as a pathway for Washington State to reduce 1990 emission to below 80% 2050. These methods are electrification, renewable pipeline and innovation. Electrification involves electrifying end-uses to the greatest extent possible while reducing natural gas use. The second involves creating a renewable pipeline where all gas comes from decarbonized biogas, synthetic natural gas and hydrogen. Finally innovation is seen as both electrifying end-uses coupled with innovation in the areas of electric and autonomous vehicles, fuel cells, and offshore wind. In order to show demand impacts of this type of scenario within Avista's natural gas operations, we modeled this scenario as "80% below 1990 emissions". This scenario does not assume the technology, costs involved, or methods used to reduce emissions. Rather, the intent is to show the overall loss of demand if the resource mix is solely natural gas with no renewable supply resources. Please refer to Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis for results.

Washington RNG

Washington State House Bill 2580[3] was signed by Governor Jay Inslee on March 22, 2018 and will become effective on July 1, 2018 bringing into law a bill to help encourage production of renewable natural gas (RNG). This bill requires the Washington State University Extension Energy Program and the Department of Commerce (DOC) along with the consulting of the Washington State Utilities and Transportation Commission, to submit recommendations on promoting the sustainable development of RNG. The DOC will consult with natural gas utilities and other state agencies to explore developing voluntary gas quality standards for the injection of RNG into natural gas pipeline systems in the state. The tax incentive is equal to the value of the product multiplied by the rate of the specific commodity or product as detailed in the bill.

[3] http://apps2.leg.wa.gov/billsummary?Year=2017&BillNumber=2580&Year=2017&BillNumber=2580

6: Integrated Resource Portfolio

Chapter Highlights

- No resource shortage in the expected case
- An increase in DSM potential in Washington and Oregon
- Idaho is now broken out into its own demand area
- Higher Carbon Costs vs. 2016 IRP

Overview

This chapter combines the previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter provides an analysis of potential resource options to meet resource deficiencies as exhibited in the High Growth, Low Prices scenario.

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 as described in Chapter 2 – Demand Forecasts. This IRP utilizes coldest day on record and average weather data for each demand region. 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 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 to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers, so IRP analysis of demand-serving capabilities only includes the firm residential, commercial and industrial classes. 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 increase between 1.0 percent and 3.0 percent on both an annual and peak-day basis to account for additional supplies purchased primarily for pipeline compressor station fuel. The range of 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 modeling. Avista purchased the SENDOUT® model in April 1992 and has used it to prepare all IRPs since then. Avista has a maintenance agreement with Ventyx for software updates and enhancements. Enhancements include software corrections and improvements driven by industry needs.

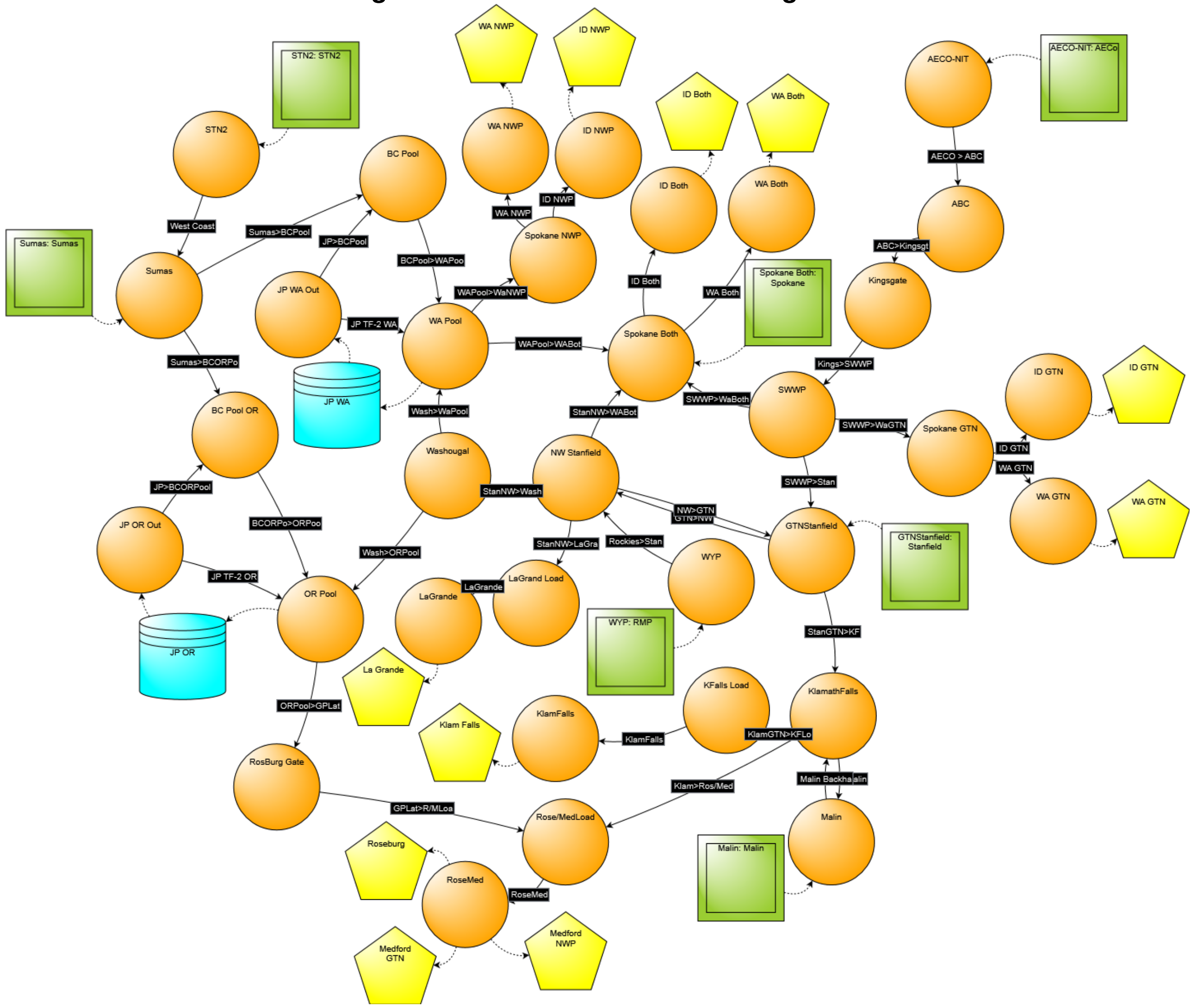
SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique to solve minimization/maximization problems. SENDOUT® analyzes the complete problem at one time within the study horizon, while accounting for physical limitations and contractual constraints.

The software analyzes thousands of variables and evaluates possible solutions to generate a least cost solution given a set of constraints. The model considers 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.
- Conservation potential.

Figure 6.1 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 6.1 SENDOUT® Model Diagram



The SENDOUT® model provides a flexible tool to analyze 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 conservation;

- Weather pattern testing and analysis;
- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

SENDOUT® also includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis. The SENDOUT® model is used by many LDC's across the U.S., however it is becoming increasingly outdated for the current regulatory environment. Because of this, Avista will be looking into additional software products or alternatives to help increase the necessary flexibility when modeling the future IRPs.

Resource Integration

The following sections summarize the comprehensive analysis bringing demand forecasting and existing and potential supply and demand-side resources together to form the 20-year, least-cost plan.

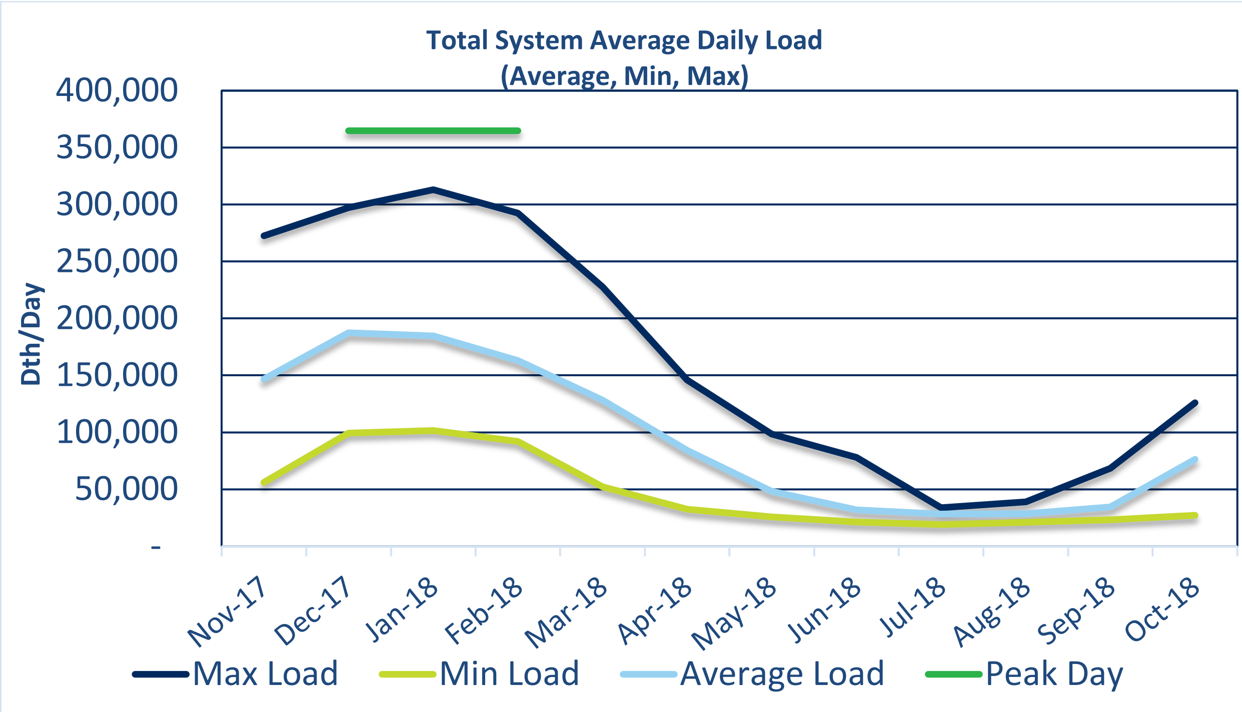
Demand Forecasting

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

Avista forecasts demand in the SENDOUT® model in eleven service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington and Idaho (each state is 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 6.2 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 6.2: Total System Average Daily Load (Average, Minimum and Maximum)



Natural Gas Price Forecasts

Natural gas prices play a central part of the IRP and has the largest impact on the costs used for determining the cost-effectiveness of DSM measures as well as new potential resources. The price of natural gas also influences consumption, so price elasticity is part of the demand evaluation shown in Chapter 2 – Demand Forecasts.

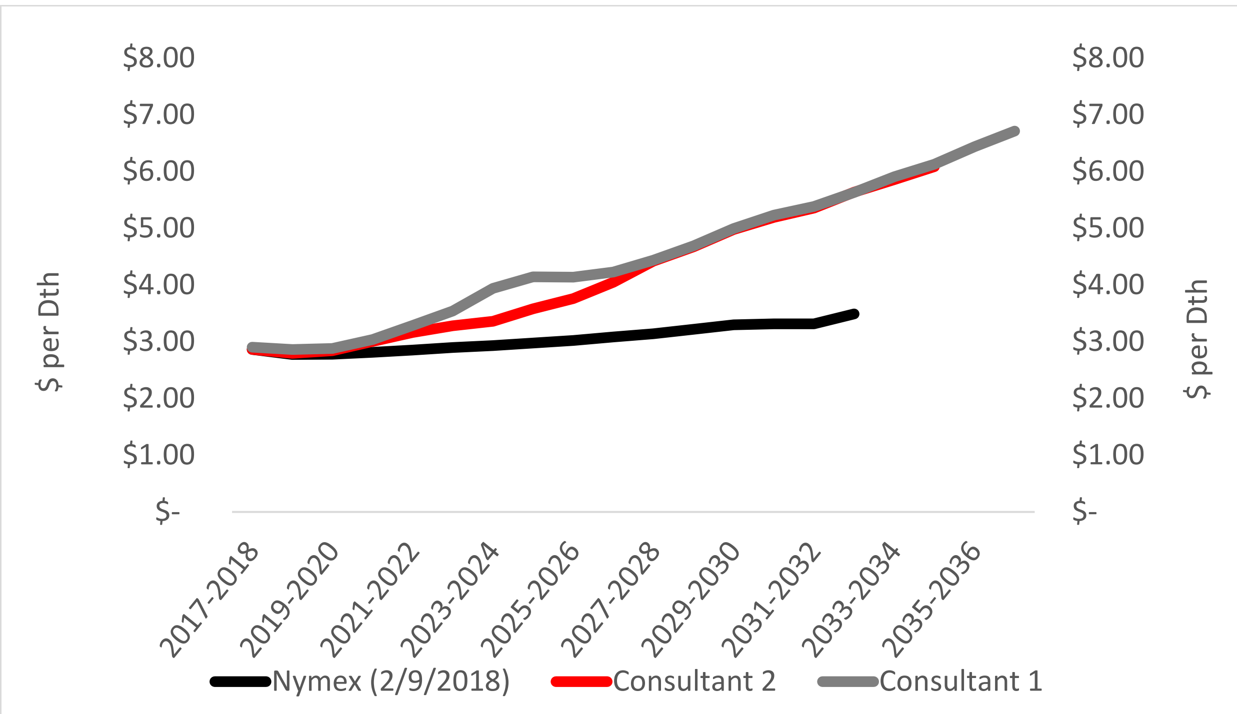
The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry including drilling methods and technology used in oil and natural gas production, export demand from Mexico and LNG. These factors combined with the renewable energy standards and the increased need to back these resources up with natural gas-fired generation are creating. The rapidly changing environment and uncertainty in predicting future events and trends, requires modeling a range of forecasts.

The two consultants end up in the same expected price by around 2027 timeframe, though differ in the timing of LNG export facilities and industrial demand, causing a split in pricing around the 2021 timeframe. Both consultants expect similar power burn reaching levels of around 50 Bcf per day by 2035. The Nymex forward curve expects sufficient supply to provide additional demand throughout its time horizon causing a flat price curve.

Many additional factors influence natural gas pricing and volatility, such as regional supply/demand issues, weather conditions, 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 industry experts. Figure 6.3 depicts the price forecasts considered in the IRP analyses.

Figure 6.3: Henry Hub Forecasted Price (Nominal $/Dth)



The expected curve was a blended price derived from two consulting services subscriptions along with the New York Mercantile Exchange (NYMEX) forward strip on February 9, 2018. The expected price curve was weighted heavily toward the NYMEX prices in the first few years

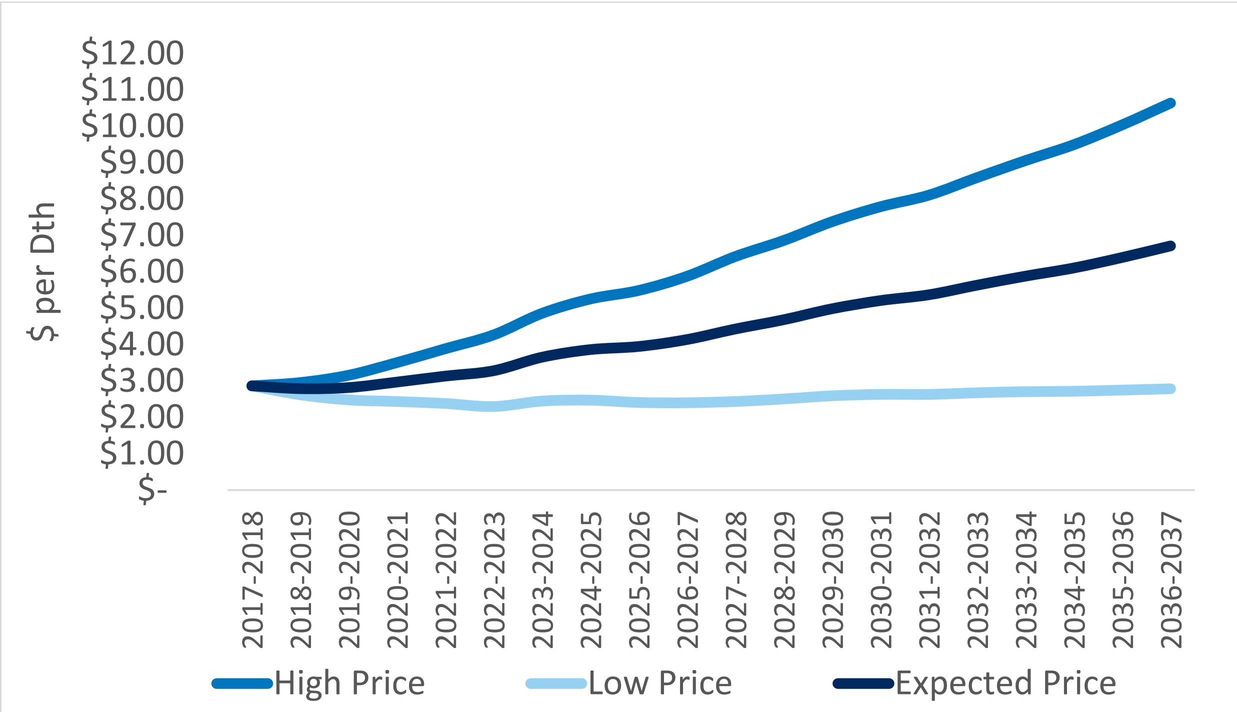
In the outer years the fundamental curves from the two consultants were more heavily weighted. This is based on the premise that the market knows more than any single entity or model in the near term. Below is the specific methodology used to develop the expected price curve:

- Two fundamental forecasts (Consultant #1 & Consultant #2)
- Forward prices

1. Year 1 - forward price only
2. Year 2 - 75% forward price / 25% average consultant forecasts
3. Year 3 - 50% forward price / 50% average consultant forecasts
4. Year 4 – 6 25% forward price / 75% average consultant forecasts
5. Year 7 - 50% average consultant without CO2 / 50% average consultant with CO2

The high and low price curves were derived by varying the price from the expected price to create a reasonably higher and lower curve while maintaining symmetry. These high and low prices provide a way to measure pricing risk all while maintaining the balance to the expected price. The curves are in nominal dollars in Figure 6.4. Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis. With the assistance of the TAC, Avista selected high, expected and low price curves to consider possible outcomes and their impact on resource planning.

Figure 6.4 Henry Hub Forecasts for IRP Low/ Expected/ 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 NYMEX futures contracts. Consequently, all other trading points tend to be priced off of the Henry Hub with a positive or negative basis differential and is based off of a consultant forecast. Of the two consultants Avista uses, only one has basis pricing going throughout the twenty year timeframe and at the points modeled. Two of the market points modeled by Avista, Kingsgate and Stanfield, do not have a futures market making it difficult to derive a price expectation without a global model of the North America gas supply landscape.

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 (Western Canada and the Rockies).

Table 6.1 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 6.1: Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	79.0%	89.7%	89.7%	92.8%	90.5%
Consultant2 Forecast Average	68.4%	86.0%	92.8%	101.9%	97.9%
Historic Cash Three Year Average	67.3%	88.2%	90.5%	94.4%	90.7%
2016 IRP	88.5%	95.5%	96.8%	98.9%	97.5%

This IRP used monthly prices for modeling purposes because of Avista's winter-weighted demand profile. Table 6.2 depicts the monthly price shape used in this IRP. A slight change to the shape of the pricing curve occurred since the 2016 IRP. Supply availability drove this change because the forecasted differential between winter and summer pricing has decreased to some extent compared to historic data.

Table 6.2: Monthly Price as a Percent of Average Price

	Jan	Feb	Mar	Apr	May	Jun
Consultant1	104.2%	103.8%	100.5%	95.0%	95.6%	96.7%
Consultant2	100.4%	100.3%	98.8%	97.9%	98.4%	99.8%
2016 IRP	107.0%	107.2%	97.5%	95.2%	95.6%	96.2%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consultant1	100.3%	101.9%	100.4%	100.7%	98.3%	102.5%
Consultant2	100.9%	101.6%	101.2%	100.7%	100.1%	100.1%
2016 IRP	97.6%	98.4%	98.3%	98.6%	101.8%	106.7%

Avista selected a blend of Consultant 1 and Consultant 2's forecast of regional prices and monthly shapes. Appendix 6.1 – Monthly Price Data by Basin contains detailed monthly price data behind the summary table information discussed above.

Carbon Policy

Avista models carbon as an incremental price adder to address any potential policy. Carbon adders increase the price of a dekatherm of natural gas and can impact resource selections and demand through expected elasticity (Chapter 2 – Demand Forecasts, Price Elasticity). The price of carbon in Oregon was based on the 2018 California annual auction reserve price of $14.53 per greenhouse gas emissions allowance while growing by the 5% plus the rate of inflation as indicated by the program structure section 95911 of the California Cap-and-Trade Regulation.[1] The starting price for Oregon was assumed to be similar to California's cap and trade system where the initial floor was set at $17.86 per metric tons of carbon dioxide equivalent (MTCO_2e) and begins in January 2021[2] rising to $51.58 by 2037. Washington State was modeled at $10 per MT$CO_2$e starting in 2019 and rising to $30 per MTCO2e by 2030. These carbon tax figures were based on the initial proposed carbon legislation from Governor Inslee known as Senate Bill 6203.[3] The State of Idaho does not have a carbon adder as there is no current or proposed state or federal legislation associated with carbon in that jurisdiction. Avista also completed sensitivities with both a lower and higher than expected price of carbon. These derived values were taken from the EPA calculations of the social cost of carbon as updated on January 19, 2017.[4] The low carbon price is based on 5 percent average (discount rate and statistic) and begins at $11.60 per MT$CO_2$e in 2018 and increases to $21.20 by 2037. The high carbon price is the EPA's high impact scenario of the average of 95 percent of results at a 3 percent discount rate. This rate produces much higher cost of carbon beginning in 2018 at $115.80 and increasing to $174 per MT$CO_2$e by 2037. The effect of these modeled carbon prices, combined with our expected elasticity as described in Chapter 2 Demand Forecasts, change demand as shown in Figure 6.5.

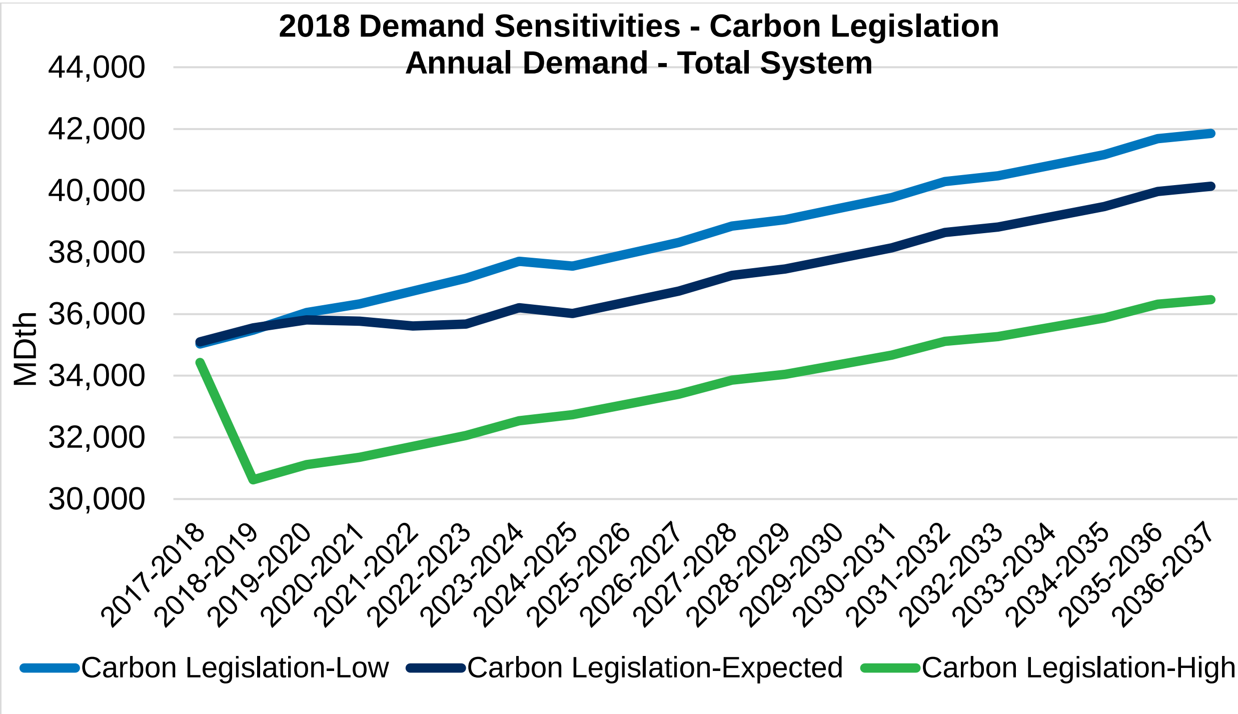
[1] Article 5 California Cap on Greenhouse gas emissions and market-based compliance mechanisms. https://www.arb.ca.gov/cc/capandtrade/capandtrade/unofficial_ct_100217.pdf

[2] Senate Bill 1070 https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB1070

[3] Senate Bill 6203 http://lawfilesext.leg.wa.gov/biennium/2017-18/Pdf/Bills/Senate%20Bills/6203-S.pdf

[4] Social cost of carbon EPA https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

Figure 6.5: Carbon Legislation sensitivities



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 6.6 and 6.7.

Figure 6.6: Existing Firm Transportation Resources – Washington & Idaho

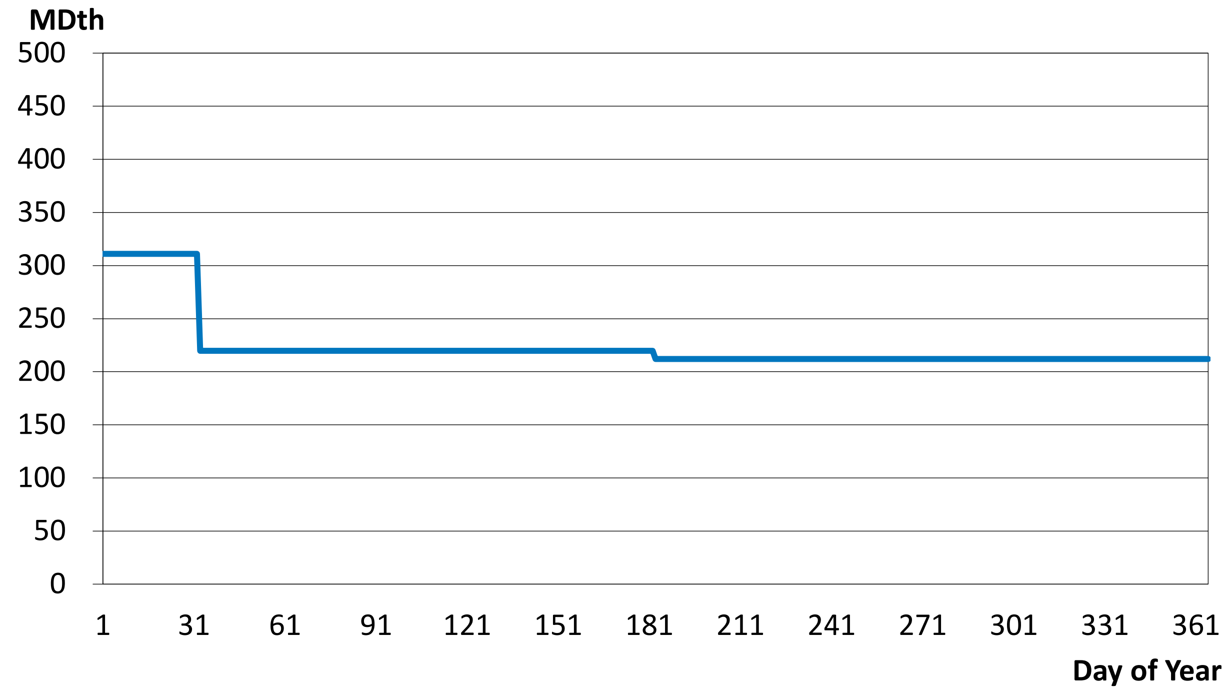
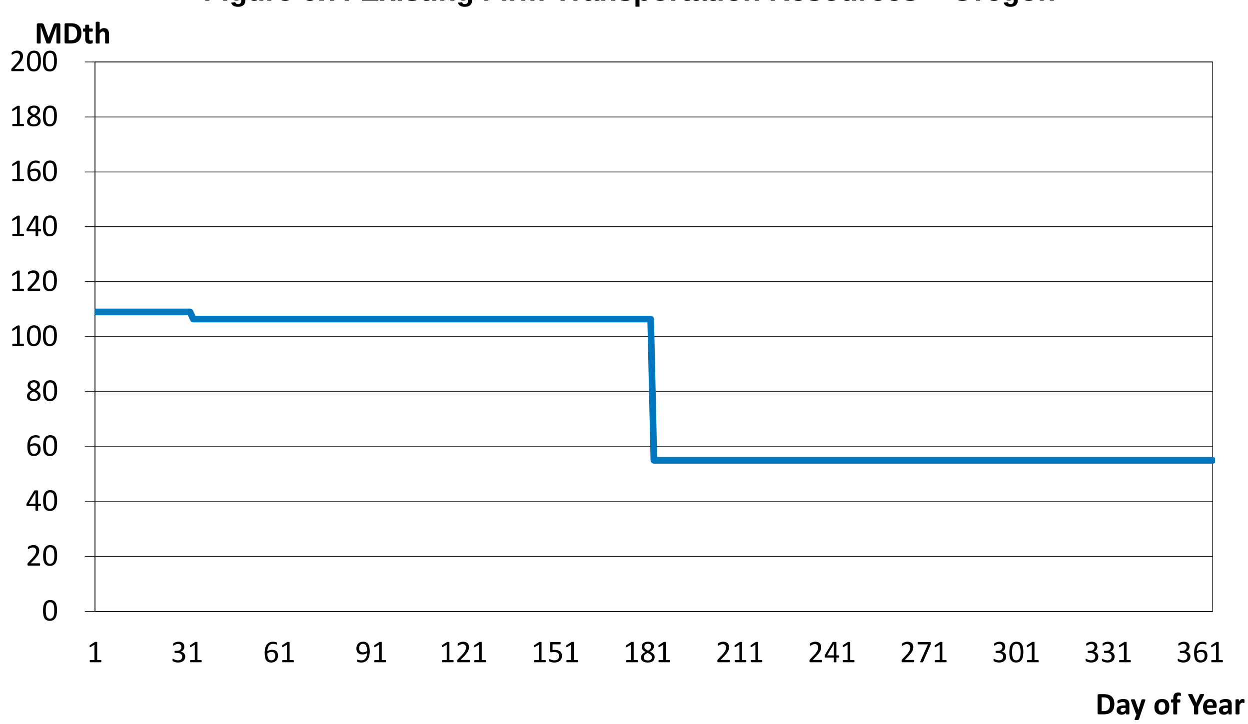


Figure 6.7: Existing Firm Transportation Resources – Oregon



Current rates for capacity are in Appendix 6.1 – Monthly Price Data by Basin. Forecasting future pipeline rates can be challenging 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 pipeline rate cases. This IRP assumes pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 6.2 – Weighted Average Cost of Capital).

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 2.9.

Figures 6.8 through 6.11 provide graphic summaries of Average Case demand as compared to existing resources on a peak day. This demand is net of conservation 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 6.8: Average Case – Washington/Idaho Existing Resources vs. Peak Day Demand – February 15th

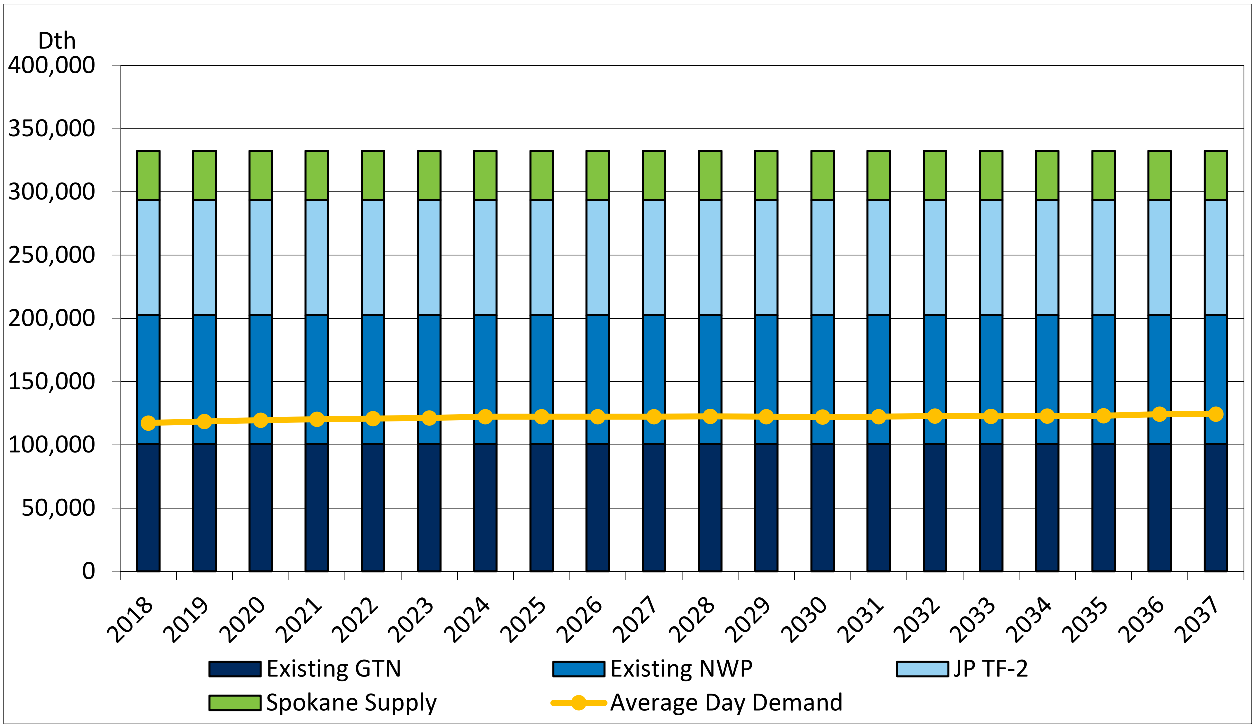


Figure 6.9: Average Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

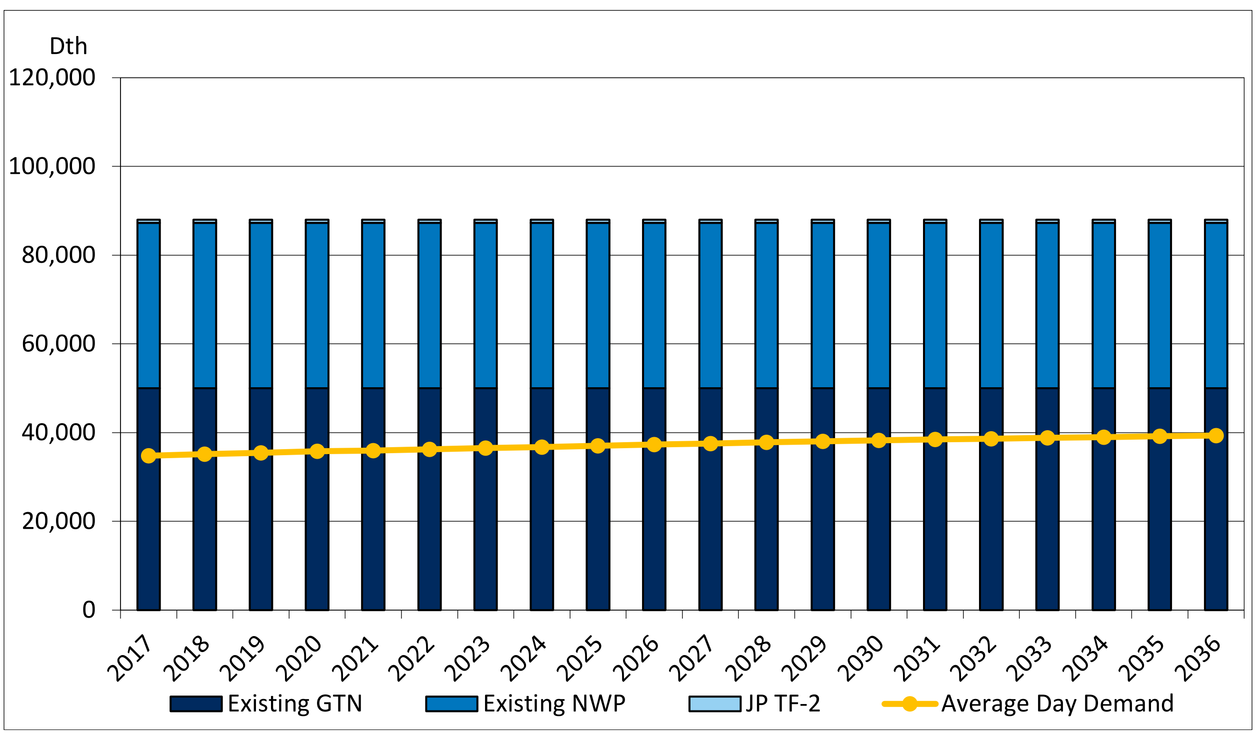


Figure 6.10: Average Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

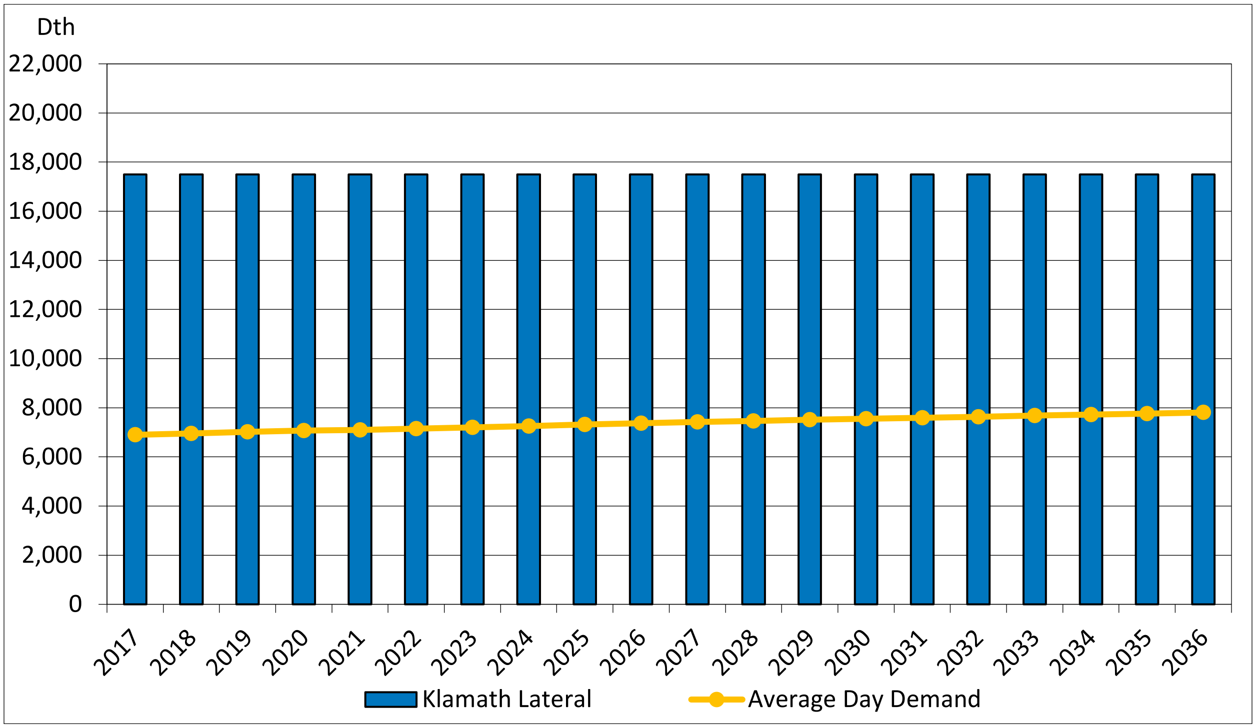
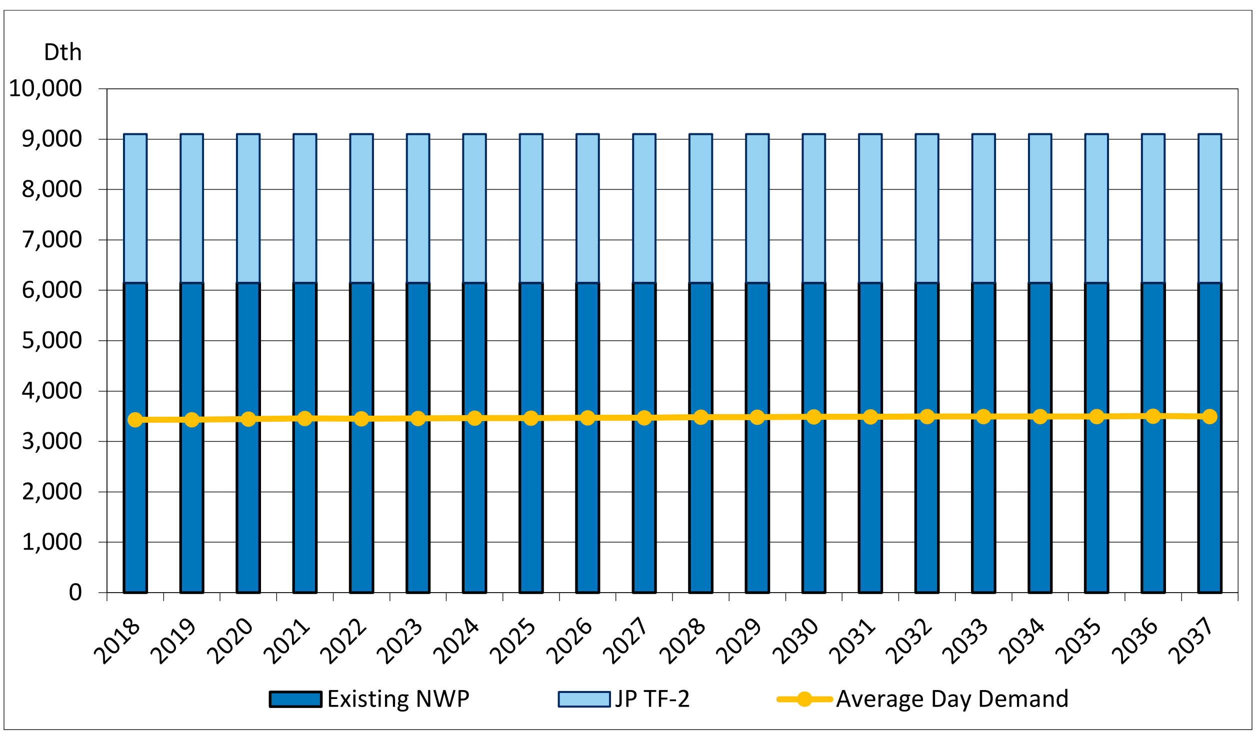


Figure 6.11: Average Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



Figures 6.12 through 6.15 summarize Expected Case peak day demand compared to existing resources, as well as demand comparisons to the 2016 IRP. This demand is net of conservation savings. Based on this information, and more specifically where a resource deficiency is nearly present as shown in Figure 6.9, Avista has time to carefully monitor, plan and take action on potential resource additions as described in the Ongoing Activities section of Chapter 9 – Action Plan. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management, of both long- and short-term resources, ensures the goal to meet firm customer demand in a reliable and cost-effective manner as described in Supply Side Resources – Chapter 4.

Figure 6.12: Expected Case – Washington & Idaho Existing Resources vs. Peak Day Demand – February 15th

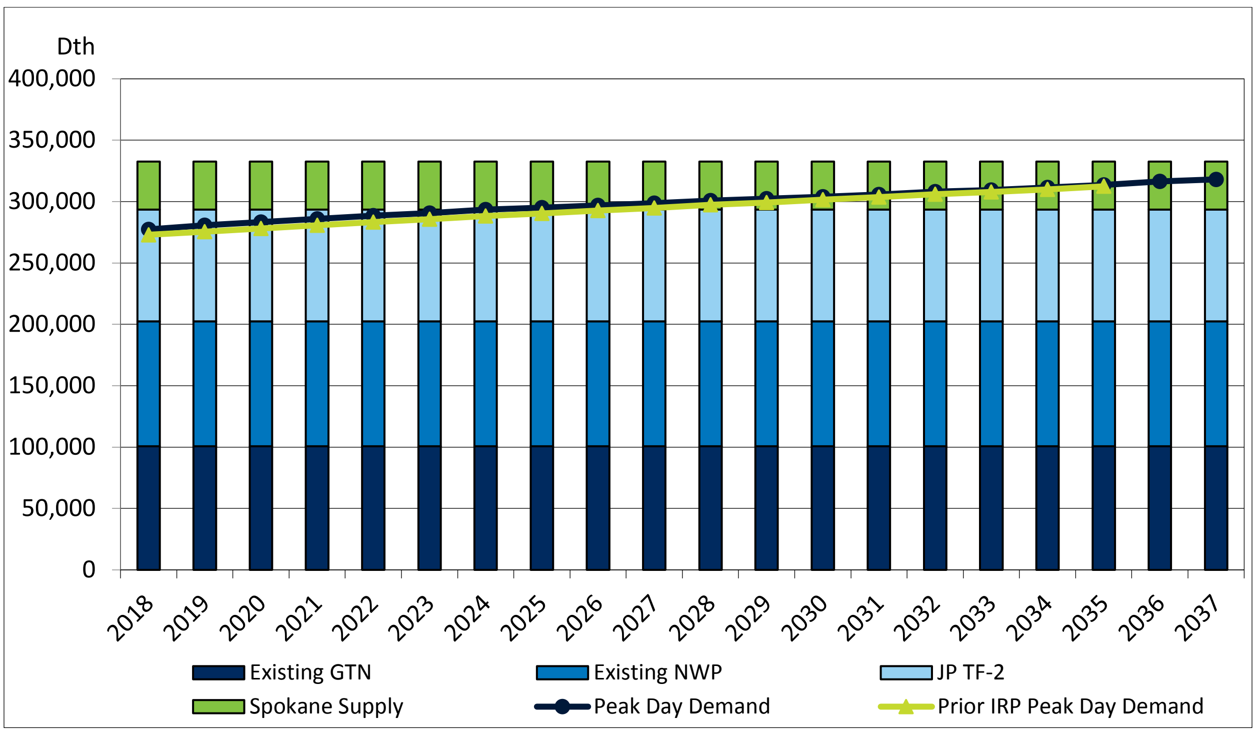


Figure 6.13: Expected Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

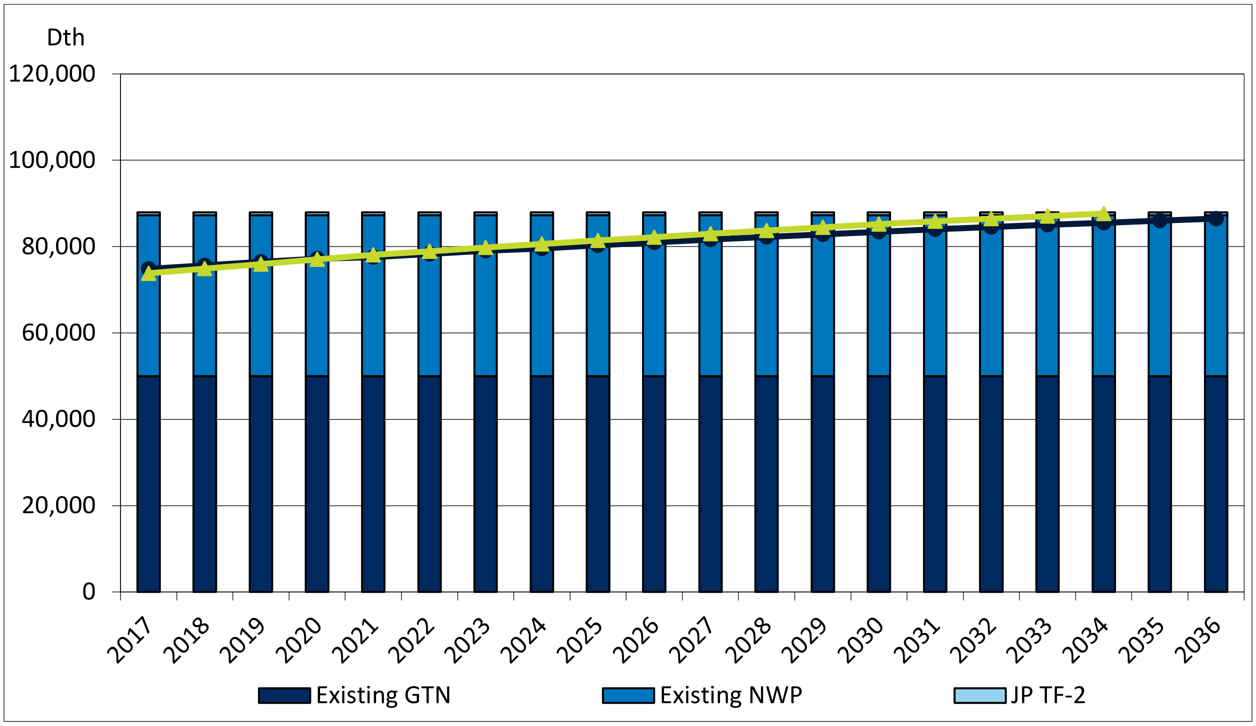


Figure 6.14: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

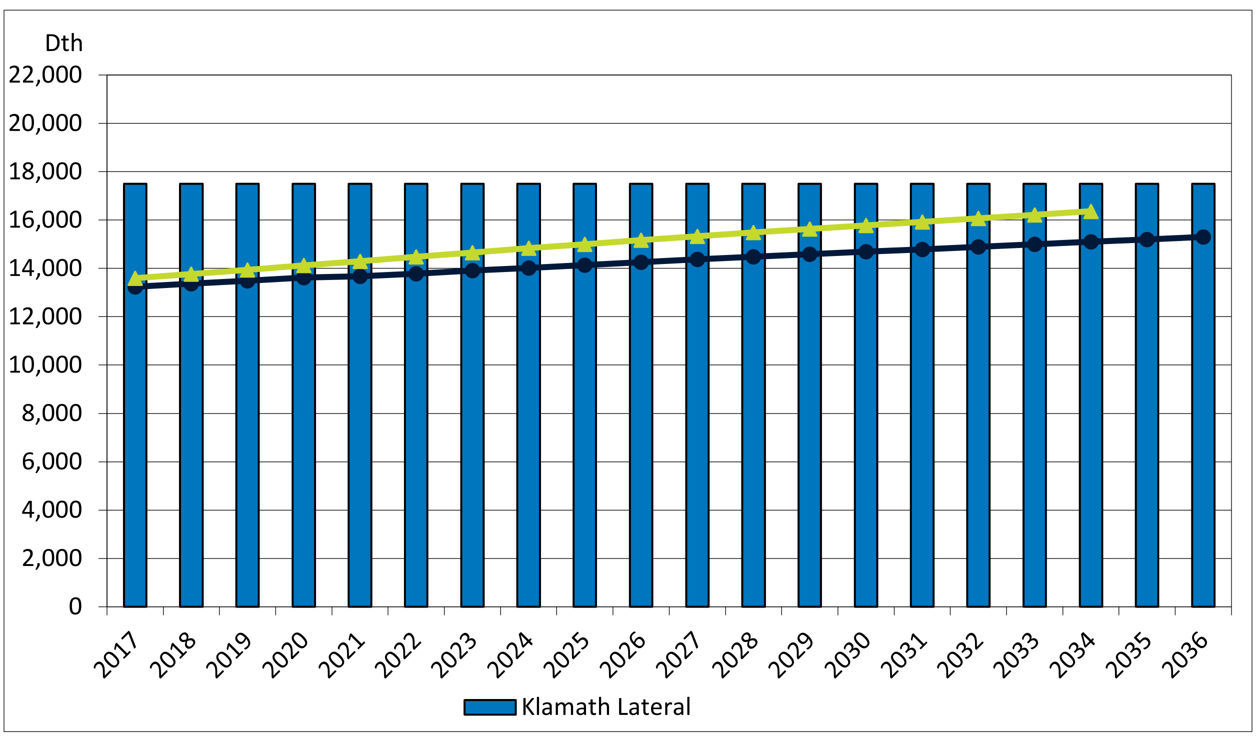
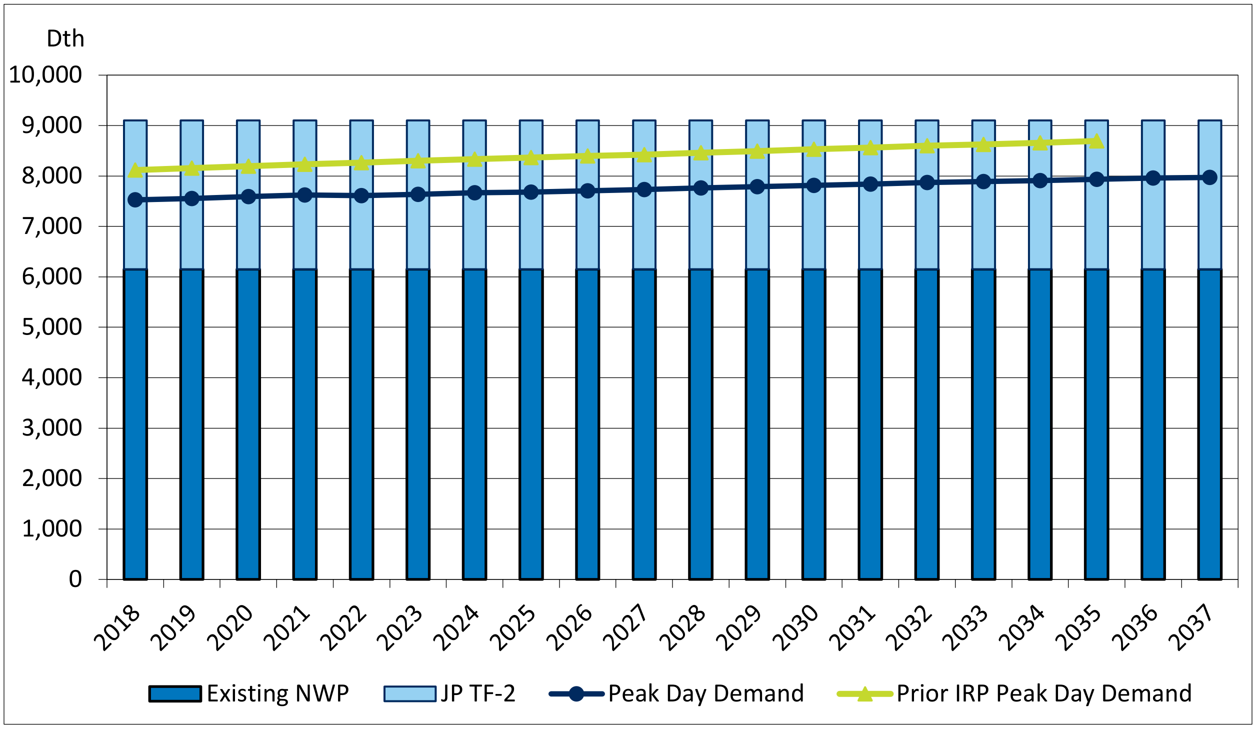


Figure 6.15: Expected Case – La Grande Existing Resources vs. Peak Day Demand – February 15th



If demand grows faster than expected, the need for new resources will be earlier. Flat demand risk requires close monitoring for signs of increasing demand and reevaluation 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 6.3 quantifies the forecasted total demand net of conservation savings and unserved demand from the above charts.

Table 6.3: Peak Day Demand – Served and Unserved (MDth/day)

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served	WA Served	WA Unserved	WA Total	WA % of Peak Day Served
Expected	2017-2018	7.53	-	7.53	100%	89.42	-	89.42	100%	187.91	-	187.91	100%
Expected	2018-2019	7.55	-	7.55	100%	90.47	-	90.47	100%	190.17	-	190.17	100%
Expected	2019-2020	7.59	-	7.59	100%	91.51	-	91.51	100%	191.91	-	191.91	100%
Expected	2020-2021	7.62	-	7.62	100%	92.53	-	92.53	100%	193.44	-	193.44	100%
Expected	2021-2022	7.61	-	7.61	100%	93.41	-	93.41	100%	195.00	-	195.00	100%
Expected	2022-2023	7.64	-	7.64	100%	94.23	-	94.23	100%	196.28	-	196.28	100%
Expected	2023-2024	7.67	-	7.67	100%	95.33	-	95.33	100%	198.21	-	198.21	100%
Expected	2024-2025	7.68	-	7.68	100%	95.88	-	95.88	100%	199.17	-	199.17	100%
Expected	2025-2026	7.71	-	7.71	100%	96.57	-	96.57	100%	200.42	-	200.42	100%
Expected	2026-2027	7.73	-	7.73	100%	97.22	-	97.22	100%	201.57	-	201.57	100%
Expected	2027-2028	7.76	-	7.76	100%	97.98	-	97.98	100%	202.86	-	202.86	100%
Expected	2028-2029	7.79	-	7.79	100%	98.54	-	98.54	100%	203.71	-	203.71	100%
Expected	2029-2030	7.81	-	7.81	100%	99.22	-	99.22	100%	204.74	-	204.74	100%
Expected	2030-2031	7.84	-	7.84	100%	99.95	-	99.95	100%	205.78	-	205.78	100%
Expected	2031-2032	7.87	-	7.87	100%	100.90	-	100.90	100%	207.14	-	207.14	100%
Expected	2032-2033	7.89	-	7.89	100%	101.59	-	101.59	100%	207.92	-	207.92	100%
Expected	2033-2034	7.91	-	7.91	100%	102.50	-	102.50	100%	209.03	-	209.03	100%
Expected	2034-2035	7.93	-	7.93	100%	103.47	-	103.47	100%	210.17	-	210.17	100%
Expected	2035-2036	7.96	-	7.96	100%	104.68	-	104.68	100%	211.74	-	211.74	100%
Expected	2036-2037	7.97	-	7.97	100%	105.53	-	105.53	100%	212.56	-	212.56	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
Expected	2017-2018	13.24	-	13.24	100%	74.84	-	74.84	100%
Expected	2018-2019	13.36	-	13.36	100%	75.65	-	75.65	100%
Expected	2019-2020	13.49	-	13.49	100%	76.43	-	76.43	100%
Expected	2020-2021	13.62	-	13.62	100%	77.22	-	77.22	100%
Expected	2021-2022	13.67	-	13.67	100%	77.59	-	77.59	100%
Expected	2022-2023	13.78	-	13.78	100%	78.29	-	78.29	100%
Expected	2023-2024	13.91	-	13.91	100%	79.02	-	79.02	100%
Expected	2024-2025	14.02	-	14.02	100%	79.60	-	79.60	100%
Expected	2025-2026	14.14	-	14.14	100%	80.28	-	80.28	100%
Expected	2026-2027	14.26	-	14.26	100%	80.95	-	80.95	100%
Expected	2027-2028	14.37	-	14.37	100%	81.61	-	81.61	100%
Expected	2028-2029	14.48	-	14.48	100%	82.24	-	82.24	100%
Expected	2029-2030	14.59	-	14.59	100%	82.86	-	82.86	100%
Expected	2030-2031	14.69	-	14.69	100%	83.44	-	83.44	100%
Expected	2031-2032	14.79	-	14.79	100%	83.99	-	83.99	100%
Expected	2032-2033	14.89	-	14.89	100%	84.52	-	84.52	100%
Expected	2033-2034	15.00	-	15.00	100%	85.03	-	85.03	100%
Expected	2034-2035	15.10	-	15.10	100%	85.52	-	85.52	100%
Expected	2035-2036	15.20	-	15.20	100%	86.01	-	86.01	100%
Expected	2036-2037	15.30	-	15.30	100%	86.49	-	86.49	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 customer 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. However, 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 one to five or more years to put in service. Open season processes to determine interest in proposed pipelines, planning and permitting, environmental review, design, construction, and testing contribute 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 gas 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 resources 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 with transportation 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. The lumpiness of new resources provides a cushion for future growth. Economies of scale for pipeline construction provide the opportunity to secure resources to serve future demand increases.

Competition

LDCs, end-users and marketers compete for regional resources. The Northwest has efficiently utilized 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 6.2) 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 6.3 – Supply Side Resource Options for a list of available options) using PVRR analysis to determine which resource is a least cost/least risk resource.

Demand-Side Resources

Integration by Price

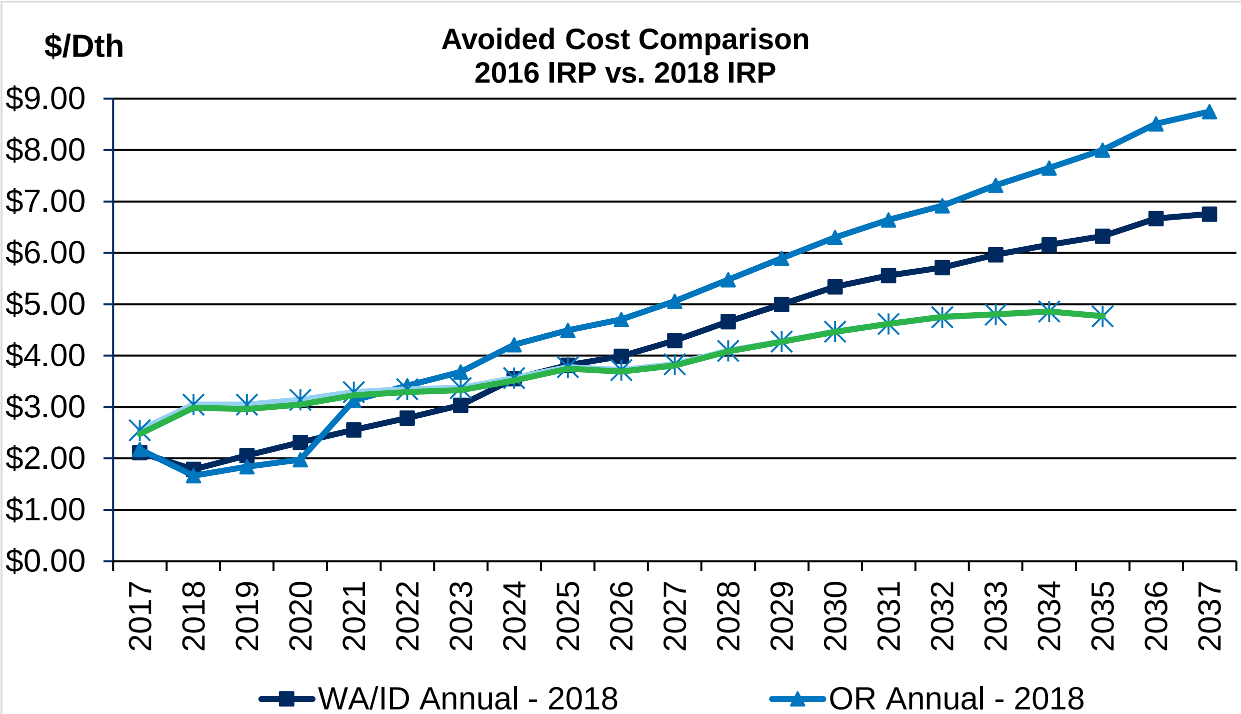
As described in Chapter 3 – Demand-Side Resources, the model runs without future DSM programs. This preliminary model run provides an avoided cost curve for Applied Energy Group (AEG) to evaluate the cost effectiveness of DSM programs against the initial avoided cost curve using the Utility Cost Test, Program Administrator Costs Test, Total Resource Cost Test, and Participant Cost Test. 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 6.16. The detailed data is in Appendix 6.4 – Avoided Cost Details. 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 – Environmental Externalities discusses this concept more fully and includes specific requirements required in modeling for the Oregon service territory.

Figure 6.16: Avoided Cost (Includes Commodity & Transport Cost – 2016 vs. 2018 $/Dth)



Conservation Potential

Using the avoided cost thresholds, AEG selected all potential cost effective DSM programs. Table 6.4 shows potential DSM savings in each region from the selected conservation potential for the Expected Case. The conservation potential includes anticipated annual acquisition and is cumulative.

Table 6.4: Annual and Average Daily Demand Served by Conservation

Case	Gas Year	Annual Klamath DSM (MDth)	Daily Klamath DSM (MDth/Day)	Annual La Grande DSM (MDth)	Daily La Grande DSM (MDth/Day)	Annual Medford/ Roseburg DSM (MDth)	Daily Medford/ Roseburg DSM (MDth/Day)	Annual Oregon DSM (MDth)	Daily Oregon DSM (MDth/Day)
Expected	2017-2018	4.83	0.01	3.20	0.01	23.02	0.06	31.05	0.09
Expected	2018-2019	9.75	0.03	6.63	0.02	47.05	0.13	63.44	0.17
Expected	2019-2020	14.50	0.04	9.85	0.03	70.44	0.19	94.79	0.26
Expected	2020-2021	19.34	0.05	13.00	0.04	94.37	0.26	126.71	0.35
Expected	2021-2022	24.31	0.07	16.13	0.04	118.99	0.33	159.43	0.44
Expected	2022-2023	29.61	0.08	19.46	0.05	145.15	0.40	194.22	0.53
Expected	2023-2024	35.27	0.10	23.04	0.06	172.98	0.47	231.28	0.63
Expected	2024-2025	41.29	0.11	26.84	0.07	202.63	0.56	270.75	0.74
Expected	2025-2026	47.68	0.13	30.90	0.08	234.03	0.64	312.61	0.86
Expected	2026-2027	54.43	0.15	35.22	0.10	267.14	0.73	356.79	0.98
Expected	2027-2028	61.56	0.17	39.81	0.11	302.03	0.83	403.40	1.11
Expected	2028-2029	69.00	0.19	44.63	0.12	338.35	0.93	451.98	1.24
Expected	2029-2030	76.67	0.21	49.58	0.14	375.74	1.03	502.00	1.38
Expected	2030-2031	84.50	0.23	54.67	0.15	413.85	1.13	553.02	1.52
Expected	2031-2032	92.42	0.25	59.87	0.16	452.37	1.24	604.67	1.66
Expected	2032-2033	100.48	0.28	65.21	0.18	491.54	1.35	657.24	1.80
Expected	2033-2034	108.58	0.30	70.61	0.19	530.88	1.45	710.07	1.95
Expected	2034-2035	116.68	0.32	76.04	0.21	570.22	1.56	762.93	2.09
Expected	2035-2036	124.76	0.34	81.48	0.22	609.46	1.67	815.70	2.23
Expected	2036-2037	132.75	0.36	86.86	0.24	648.32	1.78	867.93	2.38

Case	Gas Year	Annual Washington DSM (MDth)	Daily Washington DSM (MDth/Day)	Annual Idaho DSM (MDth)	Daily Idaho DSM (MDth/Day)	Annual Total System DSM (MDth)	Daily Total System DSM (MDth/Day)
Expected	2017-2018	51.07	0.14	24.40	0.07	106.52	0.29
Expected	2018-2019	121.53	0.33	58.59	0.16	243.55	0.67
Expected	2019-2020	211.24	0.58	102.30	0.28	408.34	1.12
Expected	2020-2021	323.71	0.89	159.15	0.44	609.57	1.67
Expected	2021-2022	474.20	1.30	238.08	0.65	871.71	2.39
Expected	2022-2023	666.23	1.83	340.08	0.93	1,200.53	3.29
Expected	2023-2024	774.13	2.12	391.72	1.07	1,397.14	3.83
Expected	2024-2025	999.43	2.74	510.85	1.40	1,781.02	4.88
Expected	2025-2026	1,272.34	3.49	656.39	1.80	2,241.34	6.14
Expected	2026-2027	1,564.45	4.29	810.54	2.22	2,731.78	7.48
Expected	2027-2028	1,865.97	5.11	969.05	2.65	3,238.42	8.87
Expected	2028-2029	2,169.90	5.94	1,127.52	3.09	3,749.40	10.27
Expected	2029-2030	2,465.74	6.76	1,280.95	3.51	4,248.69	11.64
Expected	2030-2031	2,745.42	7.52	1,425.00	3.90	4,723.43	12.94
Expected	2031-2032	3,005.70	8.23	1,557.75	4.27	5,168.12	14.16
Expected	2032-2033	3,243.05	8.89	1,677.50	4.60	5,577.78	15.28
Expected	2033-2034	3,458.48	9.48	1,785.00	4.89	5,953.55	16.31
Expected	2034-2035	3,651.12	10.00	1,880.62	5.15	6,294.67	17.25
Expected	2035-2036	3,825.66	10.48	1,967.14	5.39	6,608.51	18.11
Expected	2036-2037	3,982.80	10.91	2,045.06	5.60	6,895.78	18.89

Conservation Acquisition Goals

The avoided cost established in SENDOUT®, the conservation potential selected, and the amount of therm savings is the basis for determining conservation acquisition goals and subsequent DSM 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 plans to meet firm customer 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 natural gas is transported or not, and a much smaller variable charge which is incurred only when natural gas is transported. An additional fuel charge is assessed to account for the compressors required to move the natural 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; and
- Combination of available resources.

Pipeline Contract Terms

Some 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 only 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 usually required 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 where available. Avista currently has some seasonal transportation contracts on TransCanada GTN, TransCanada BC and TransCanada Alberta. These pipelines match up transport capacity 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 the withdrawal capacity at Jackson Prairie with pipeline transport to Avista's service territories. 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 increased 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 the long-term to meet current and future peak demand requirements. Avista develops strategies to ensure this does not happen on a regular basis if at all possible.

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 the 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 Avista's customers to a third party until it is needed to meet customer demand.

Many variables determine the value of natural gas transportation. Certain pipeline paths are more valuable and this can vary by year, season, month and day. The term, volume and conditions present 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. Market terms and conditions 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.

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. An example of segmentation is if the original receipt and delivery points are from Sumas to Spokane. Avista can alter this path from Sumas to Sipi, Sipi to Jackson Prairie, Jackson Prairie to Spokane. This segmentation allows Avista to flow three times the amount of natural gas on most days or non-peak weather events. In the event of a peak day, and the transport needs to be firm, the transportation can be rolled back up to ensure the natural gas will be delivered into the original firm path.

Storage

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

Storage allows lower summer-priced natural 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 future higher priced market. This allows Avista to manage storage capacity and delivery to meet growing peak day requirements when needed.

The injection of natural 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 natural gas, transport it on existing unutilized capacity, and sell it into a higher priced market to capture the cost of the natural gas purchased and recover some pipeline charges. The amount of recovery is market dependent and may or may not recover all pipeline costs, but does mitigate 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 resource utilization and provide products that no individual component can satisfy. These products provide more cost recovery of the fixed charges incurred for the resources while maintaining the rights to utilize the resource for future customer needs.

Resource Utilization Summary

As determined through the IRP modeling of demand and existing resources, new resources under the Expected Case are not required over the next 20 years. 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 meets firm customer demand in a reliable and cost-effective manner.

Conclusion

Choosing reliable information and methods to utilize in these analyses help Avista determine an expected criteria. To do this, Avista utilizes industry experts to help determine an expected price and market environment, decades of historic weather by major service area, daily weather adjusted usage metrics combined with a statistical based customer forecast all help to provide a reasonable range of expectations for this planning period. There are no expected resource deficiencies during this 20-year forecast in either the Average Case or Expected Case in this IRP. Avista will rely on its Expected Case for peak operational planning activities and in its optimization programs to sufficiently plan for cold day events.

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 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

7: Alternate Scenarios, Portfolios and Stochastic Analysis

Chapter Highlights

- High Growth and Low Price case results in unserved demand
- Multiple portfolios considered to help measure range of possible outcomes
- RNG and Hydrogen are considered in the available resource stack for the first time
- Landfill RNG is selected as a resource in the High Growth and Low Price case

Overview

Avista applied the IRP analysis in Chapter 6 – Integrated Resource Portfolio to 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 conditions.

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 7.1 summarizes these scenarios and Chapter 2 – Demand Forecasts and Appendices 2.6 and 2.7 describes them in detail. The scenarios consider different demand influencing factors and price elasticity effects for various price influencing factors.

Table 7.1: 2018 IRP Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case	Cold Day 20yr Weather Std	Average Case	Low Growth & High Prices	80 % below 1990 emissions	High Growth & Low Prices
Customer Growth Rate	Reference Case Cust Growth Rates			Low Growth Rate	Reference Case growth with emissions 80% below 1990 target	High Growth Rate
Use per Customer	3 yr Flat + Price Elasticity					3 yr Flat + Price Elasticity
Demand Side Management	Yes					
Weather Planning Standard	Historical Coldest Day	Coldest in 20 years	20 year average	Historical Coldest Day		
Prices Price curve	Expected			High	Low	
Carbon Legislation ($/Metric Ton)	$10-$30 WA $17.86-$51.58 OR $0 ID					None
RESULTS						
First Gas Year Unserved						
Washington	N/A	N/A	N/A	N/A	N/A	2032
Idaho	N/A	N/A	N/A	N/A	N/A	2032
Medford	N/A	N/A	N/A	N/A	N/A	2031
Roseburg	N/A	N/A	N/A	N/A	N/A	2031
Klamath	N/A	N/A	N/A	N/A	N/A	N/A
La Grande	N/A	N/A	N/A	N/A	N/A	2032
Scenario Summary						
	Most aggressive peak planning case utilizing Average Case assumptions as a starting point and layering in coldest weather on record. The likelihood of occurrence is low.	Evaluates adopting an alternate peak weather standard. Helps provide some bounds around our sensitivity to weather.	Case most representative of our average (budget, pga, rate case) planning criteria.	Stagnant growth assumptions in order to evaluate if a shortage does occur. Not likely to occur.	Reduction of the use of natural gas to 80% below 1990 targets in OR and WA by 2050. The case assumes the overall reduction is an average goal before applying figures like elasticity and dsm.	Aggressive growth assumptions in order to evaluate when our earliest resource shortage could occur. Not likely to occur.

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

Figure 7.1 Peak Day (Feb 15) – 2018 IRP Demand Scenarios

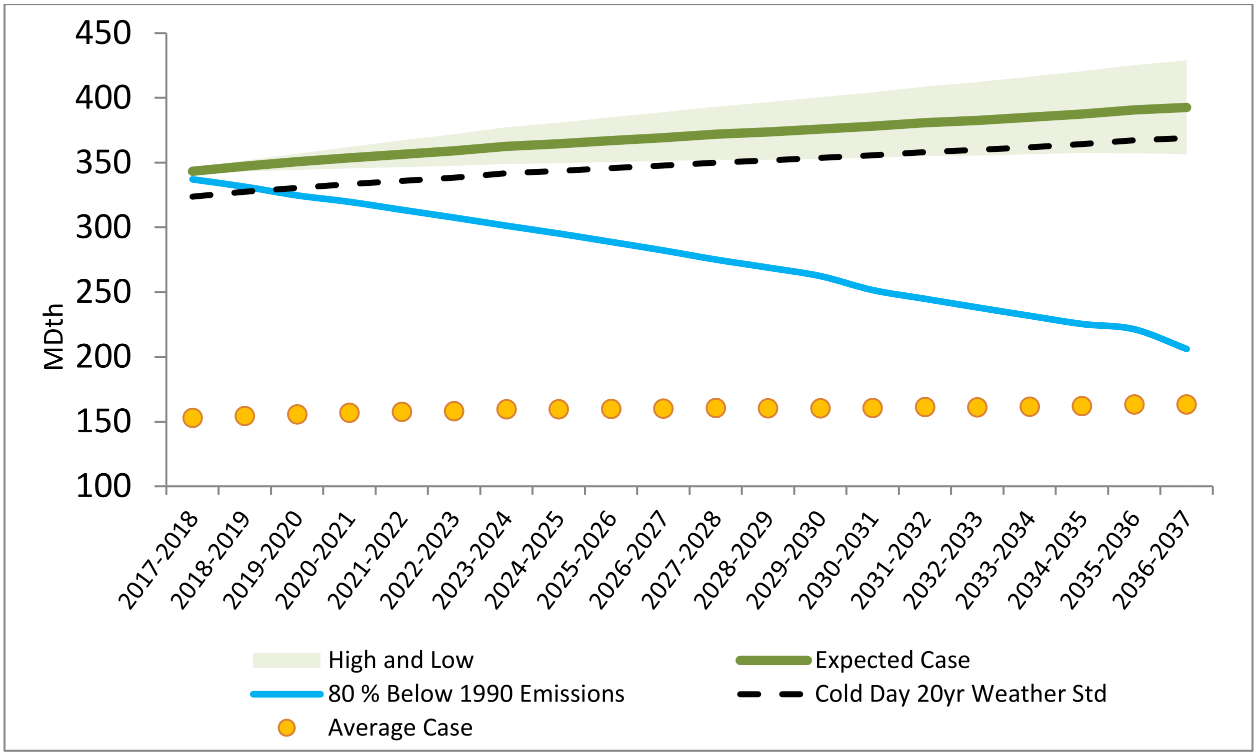
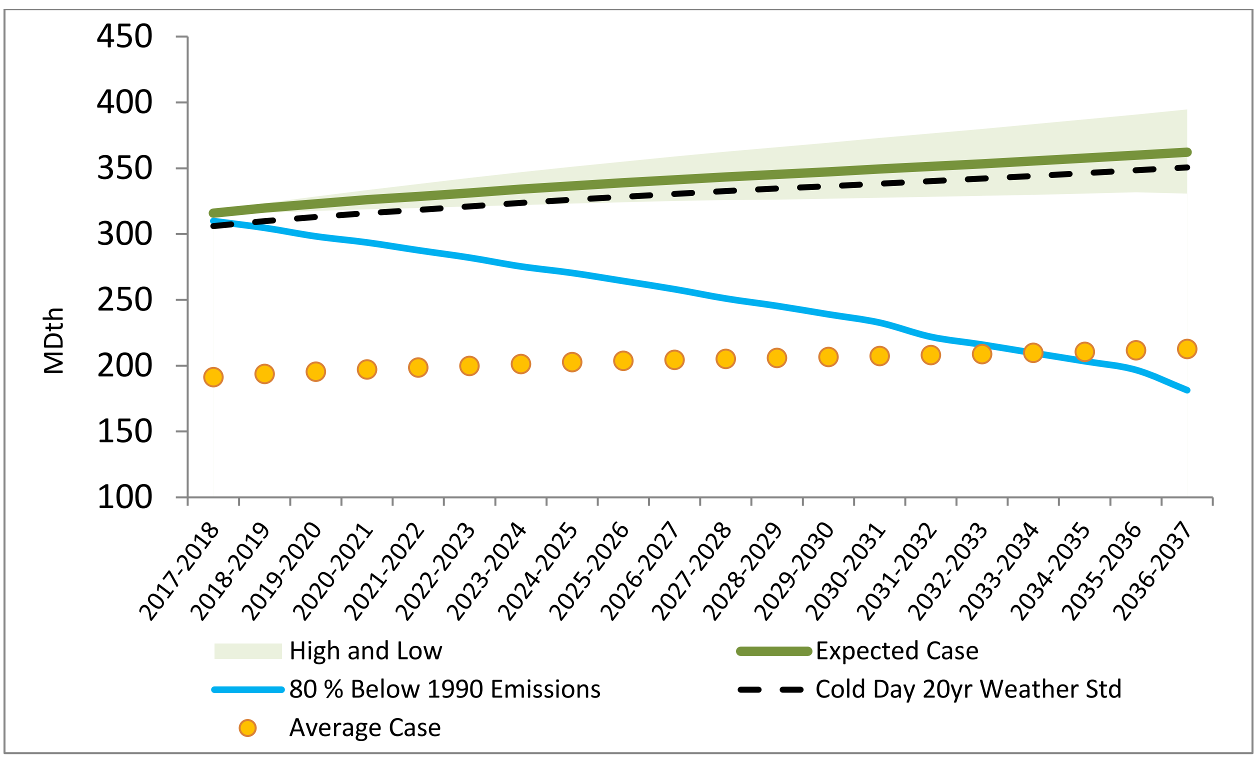
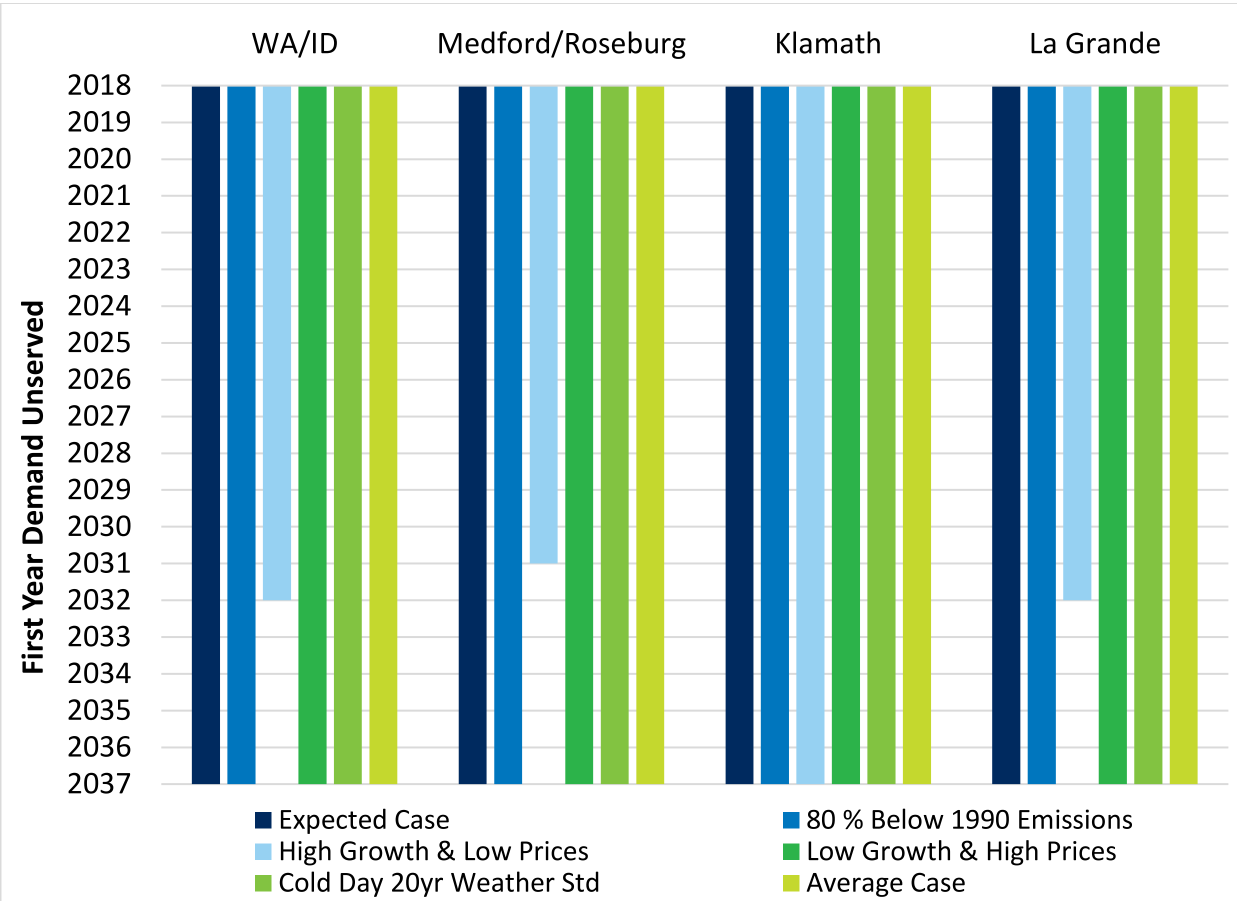


Figure 7.2 Peak Day (Dec 20) – 2018 IRP Demand Scenarios



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 six demand scenarios (see Appendix 2.7 for a complete listing of portfolios considered). This deterministic analysis identified the first year unserved dates for each scenario by service territory shown in Figure 7.3.

Figure 7.3: First Year Peak Demand Not Met with Existing Resources



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 9 – Action Plan. The remaining scenarios do not identify resource deficiencies in the planning horizon.

Alternate Supply Resources

Avista identified supply-side resources that could meet resource deficiencies or provide a least cost solution. There are other options Avista considered in its modeling approach to solve for High Growth & Low Price unserved conditions and to determine whether the Expected Case with existing resources is least cost/least risk. A list of the modeled available supply resources are included in Table 7.2 and potential future resources are included in Table 7.3.

Table 7.2: Available Supply Resources

Additional Resource	Size	Cost/Rates			Availability	Notes
		WA	ID	OR		
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate			Now	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Exp	50,000 Dth / Day	$35M capital + GTN Rate			2019	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Hydrogen	166 Dth / Day	$48 / Dth	$40 / Dth	$46 / Dth	2020	Cost estimates obtained from a consultant; levelized cost includes revenue requirements, expected carbon adder and assumed retail power rate
Renewable Natural Gas – Distributed Landfill	635 Dth / Day	$13 / Dth	$13 / Dth	$13 / Dth	2020	Costs estimates obtained from a consultant for each specific type of RNG, levelized costs include revenue requirements, distribution costs, and projected carbon intensity adder/(savings). This cost also includes any incentives from bills such as Washington House Bill 2580 or Oregon Senate Bill 334
Renewable Natural Gas – Centralized Landfill	1,814 Dth / Day	$11 / Dth	$11 / Dth	$12 / Dth	2020	
Renewable Natural Gas – Dairy	635 Dth / Day	$34 / Dth	$39 / Dth	$33 / Dth	2020	
Renewable Natural Gas – Waste Water	513 Dth / Day	$19 / Dth	$18 / Dth	$19 / Dth	2020	
Renewable Natural Gas – Food Waste to (RNG)	298 Dth / Day	$38 / Dth	$39 / Dth	$38 / Dth	2020	
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate			2018	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO's to create firm transport

Table 7.3: Future Supply Resources

Future Supply Resources	Size	Cost/Rates	Availability	Notes
Co. Owned LNG	600,000 Dth w/ 150,000 of deliverability	$75 Million plus $2 Million annual O&M	2024	On site, in service territory liquefaction and vaporization facility
Various pipelines – Pacific Connector, Cross-Cascades, etc.	Varies	Precedent Agreement Rates	2022	Requires additional mainline capacity on NWPL or GTN to get to service territory
Large Scale LNG	Varies	Commodity less Fuel	2024	Speculative, needs pipeline transport
In Ground Storage	Varies	Varies	Varies	Requires additional mainline transport to get to service territory
Satellite LNG	90,000 Dth with 30,000 deliverability	$13M capital cost plus 665k O&M	2022	provides for peaking services and alleviates the need for costly pipeline expansions. $3,000 per m3 with O&M assumed at 5.4%.

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. Current tariff prices were used to model additional GTN capacity and Plymouth LNG, while an estimate was provided from GTN for the upsized Medford lateral compressor combined with tariff rates in order to flow the gas. For those costs specifically related to all four RNG projects and hydrogen Avista contracted with a consultant to provide cost estimates for these types of facilities. Some of the major costs include: Capital, O&M, Avista's revenue requirement, federal income tax, and depreciation. Avista also included any subsidies known at the time of modeling. These projects include a cost of carbon adder for any amount of carbon intensity still associated with each project type. Specifically, dairy and solid waste have a negative carbon intensity as compared to natural gas as a fuel source (Table 4.2). The net effect of using this is the removal of carbon from the atmosphere. Finally, Renewable Identification Number (RIN)[1] values were not included in the valuation of RNG as it is assumed that these RIN's would be needed to provide proof of Avista's utilization of RNG or in complying with new environmental legislation.

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 natural gas hydrates 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 9 – Action Plan.

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 the proposed export LNG terminal in Oregon is approved and a pipeline built to supply that facility, it potentially could bring new supply through Avista's service territory. Avista will monitor (Chapter 9 – Action Plan) this situation through industry publications and daily operations to consider inclusion of this supply scenario for future IRPs.

Deterministic – 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 placed in the model as predicted future conditions that the supply portfolio will have to satisfy via least cost and least risk strategies. This creates bounds for analyzing the Expected Case by creating high and low boundaries for customer count, weather and pricing. Each portfolio runs through SENDOUT® where the supply resources

[1] https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-numbers-rins-under-renewable-fuel-standard

(Chapter 4 – Supply Side Resources) and conservation resources (Chapter 3 – Demand Side Management – see tables 3.2, 3.3 and 3.4) are compared and selected on a least cost basis. Once new resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

Table 7.4: PVRR by Portfolio

Scenario	System Cost (PVRR)
Expected Case	$ (5,035,892)
High Growth & Low Prices	$ (3,093,097)
80% Below 1990 Levels	$ (2,990,501)
Average Case	$ (4,900,092)
Cold Day 20yr Weather Std	$ (5,018,719)
Low Growth & High Prices	$ (6,087,380)

Stochastic Analysis[2]

The scenario (deterministic) analysis described earlier in this chapter 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 particular portfolio's response to cost and risk, through 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 the other.

[2] 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.

Weather

In order to evaluate weather and its effect on the portfolio, Avista developed 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 7.5) 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 7.5: Example of Monte Carlo Weather Inputs – Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	867	1,110	1,170	935	799	541	318	140	31	40	194	523
HDD Std Dev	111	133	179	129	99	87	81	51	26	31	73	86
HDD Max	1,374	1,519	1,759	1,389	1,059	740	494	260	168	144	363	695
HDD Min	609	839	850	703	561	269	146	12	-	-	59	334

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 7.4 through 7.8 for the number of peak day occurrences by weather area.

Figure 7.4: Frequency of Peak Day Occurrences – Spokane

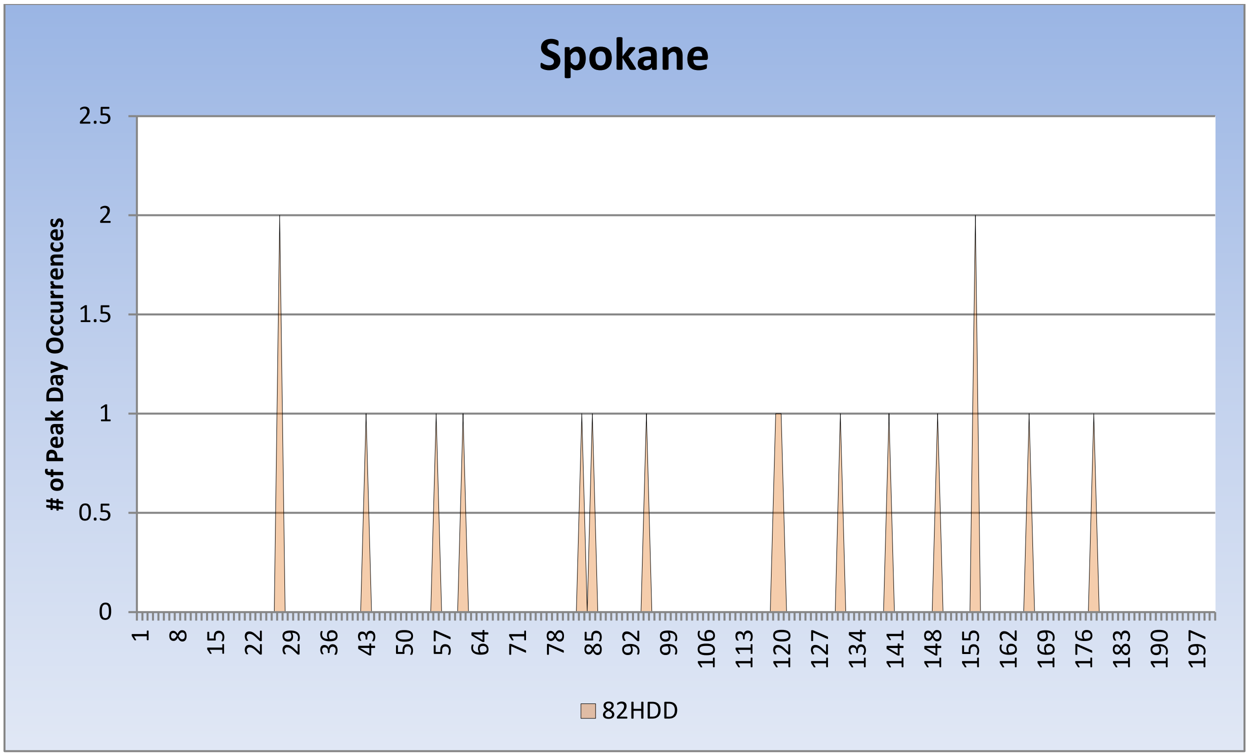


Figure 7.5: Frequency of Peak Day Occurrences – Medford

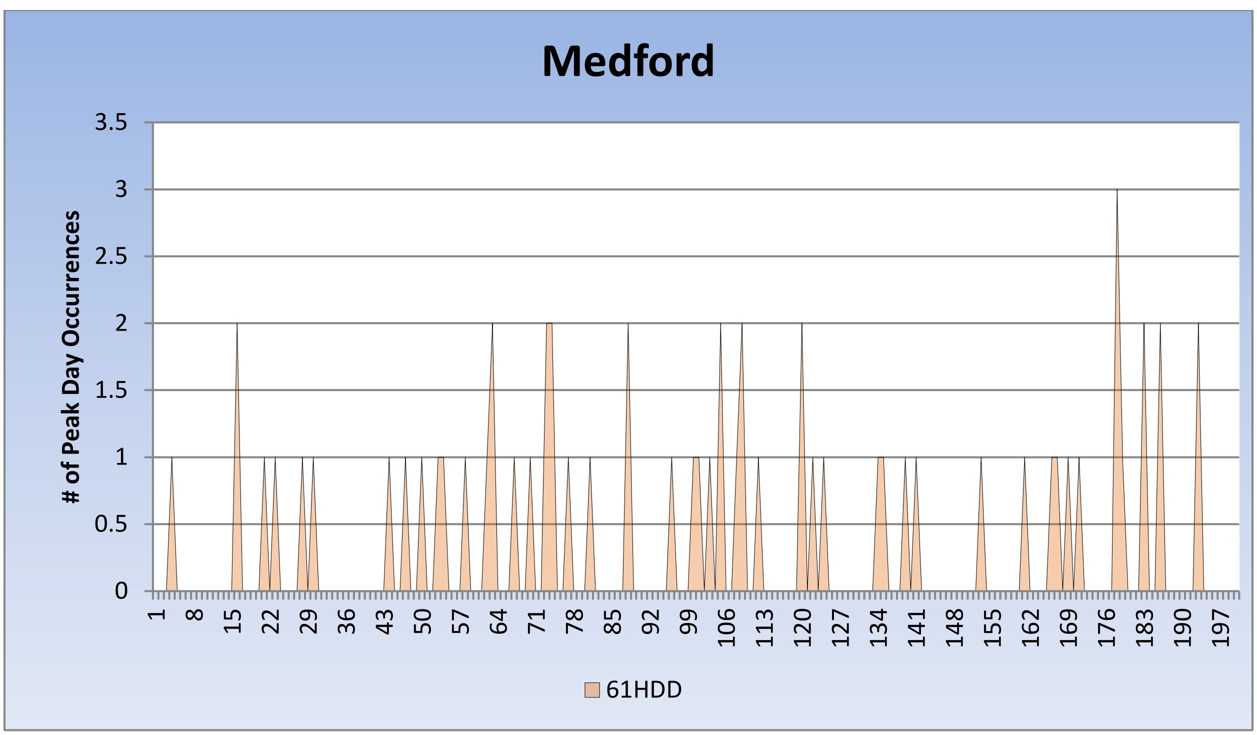


Figure 7.6: Frequency of Peak Day Occurrences – Roseburg

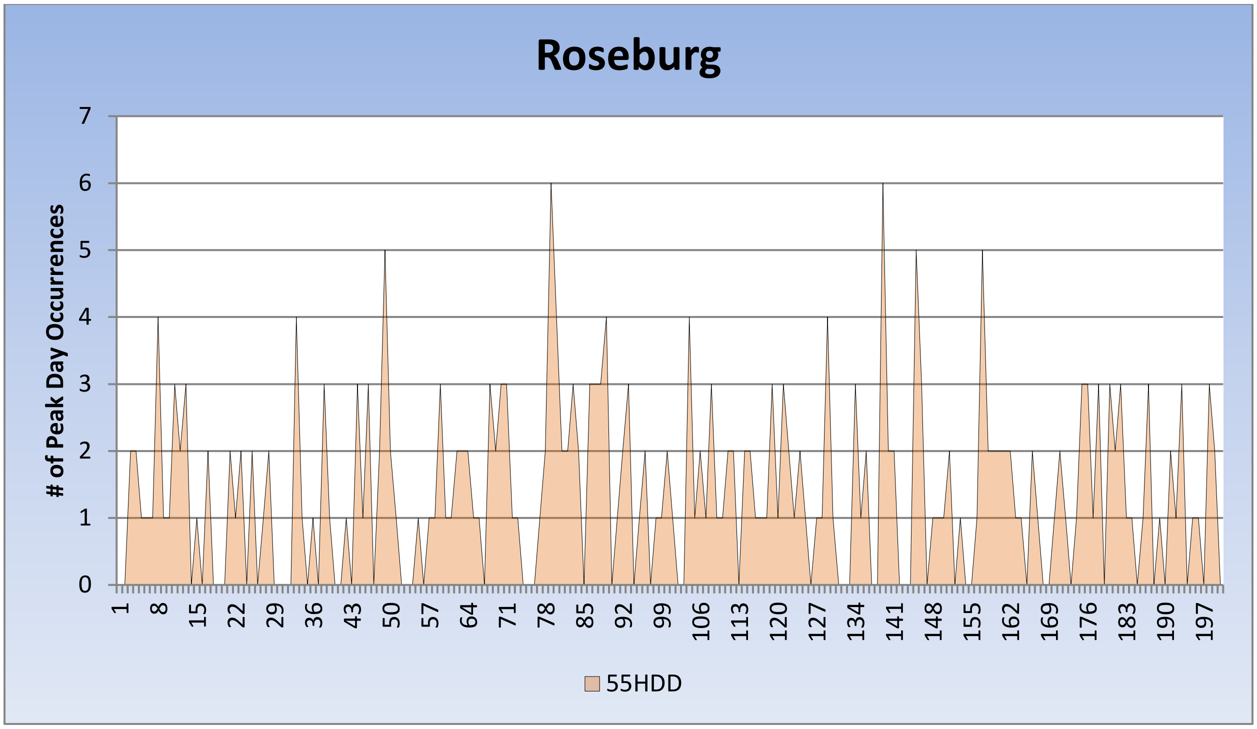


Figure 7.7: Frequency of Peak Day Occurrences – Klamath Falls

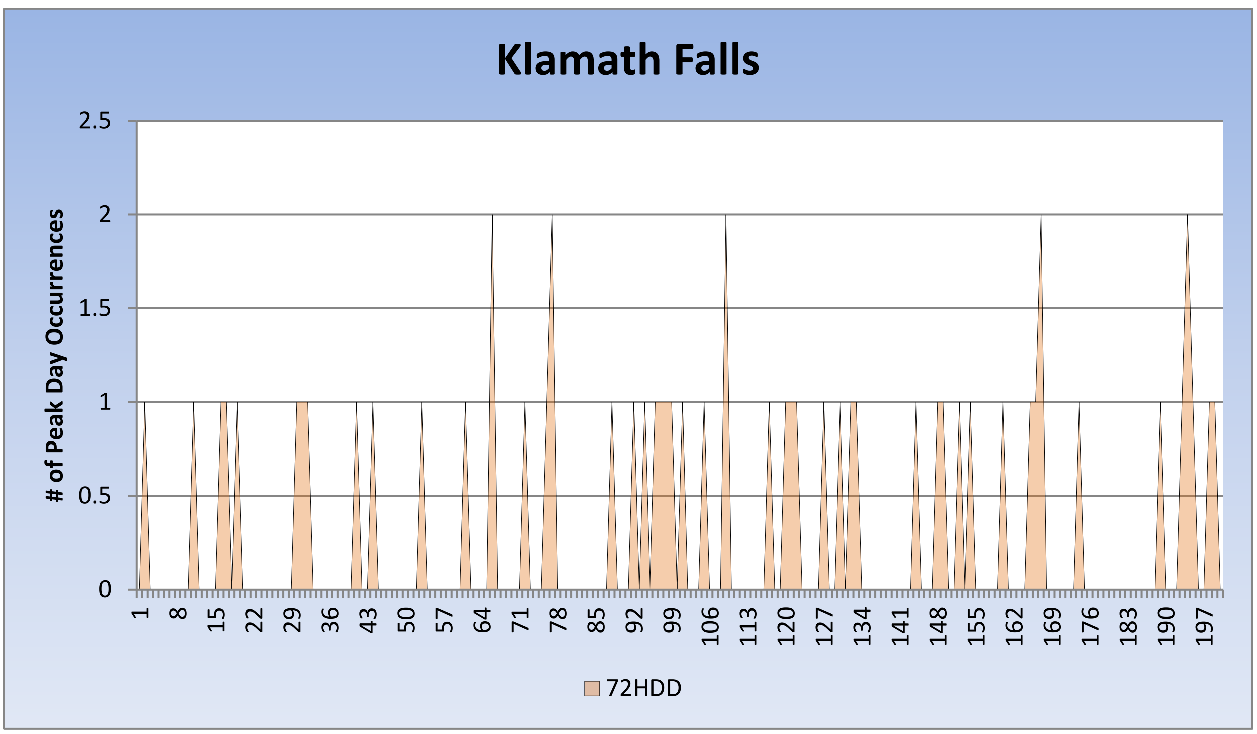
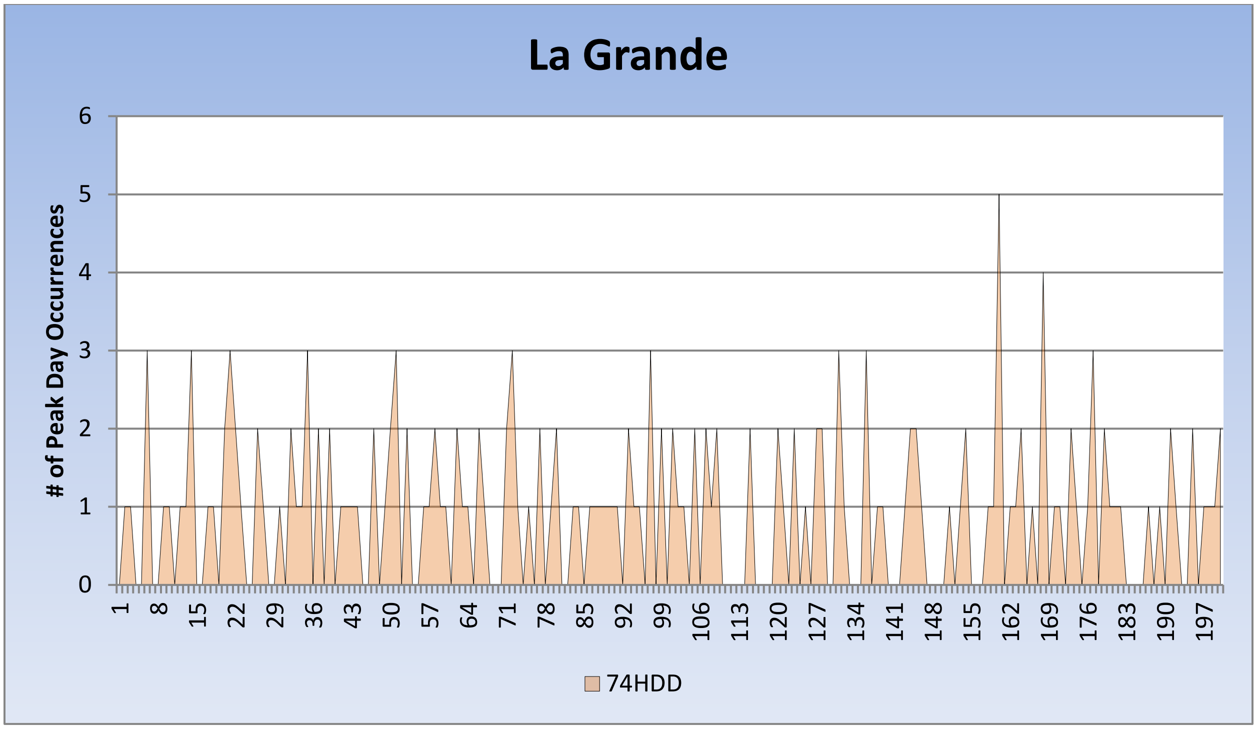


Figure 7.8: Frequency of Peak Day Occurrences – La Grande

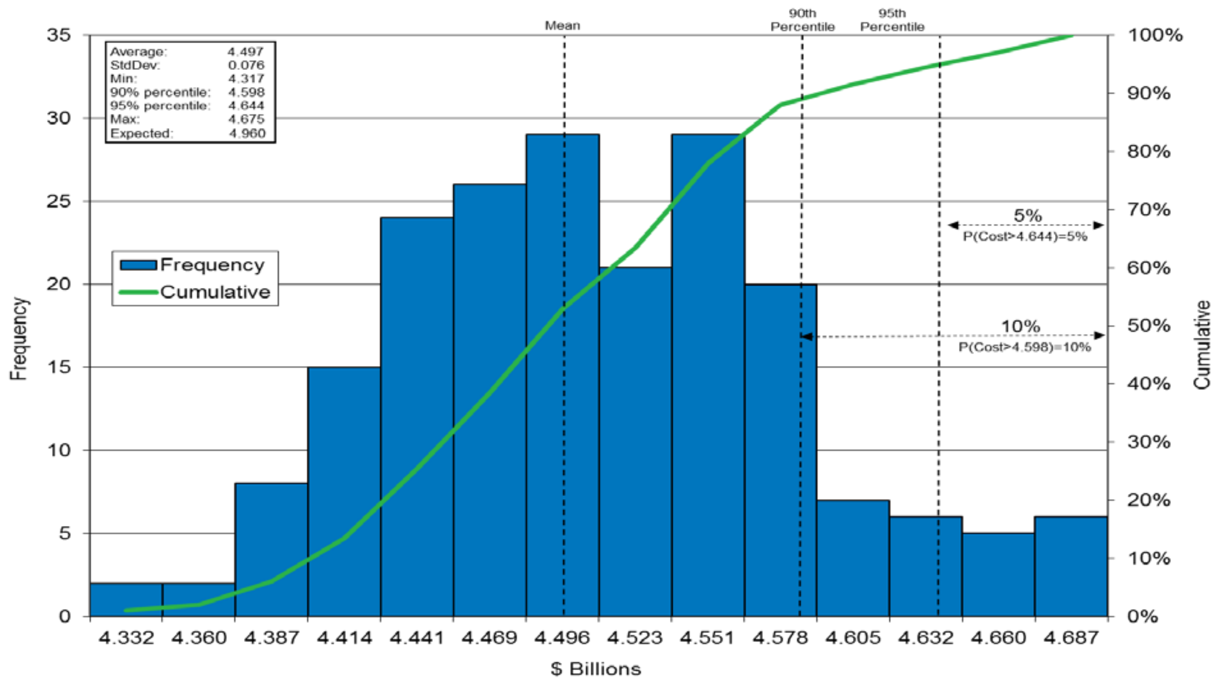


Price

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 7.9: 2018 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 confidence in the conclusions and stress tests the robustness of the selected portfolio of resources, thereby mitigating analytical risks.

Solving Unserved Demand

The components, methods and topics covered in this and previous chapters will now help to solve unserved demand in The High Growth & Low Price scenario. 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, deterministic analysis shows resource shortages do not occur until late in the planning horizon.

- 2032 in Washington/Idaho
- 2031 in Medford/Roseburg
- 2032 in La Grande

We begin to solve for unserved demand by adding additional resources as supply side options. The resources Avista modeled for the current IRP include 5 types of renewable natural gas, hydrogen, and an upsized compressor on the Medford lateral, additional GTN capacity and Plymouth LNG as seen in Table 7.2. All costs are entered by location with the associated daily, pipeline quality, volume available to inform the model. A deterministic resource mix is performed allowing the model to solve the demand based on the optimal least cost solution for the system as a whole. Avista performed this selection process both deterministically and stochastically. In Figure 7.10, the deterministic resource add by supply type is shown by cost and risk.

Figure 7.10: Deterministic analysis by resource

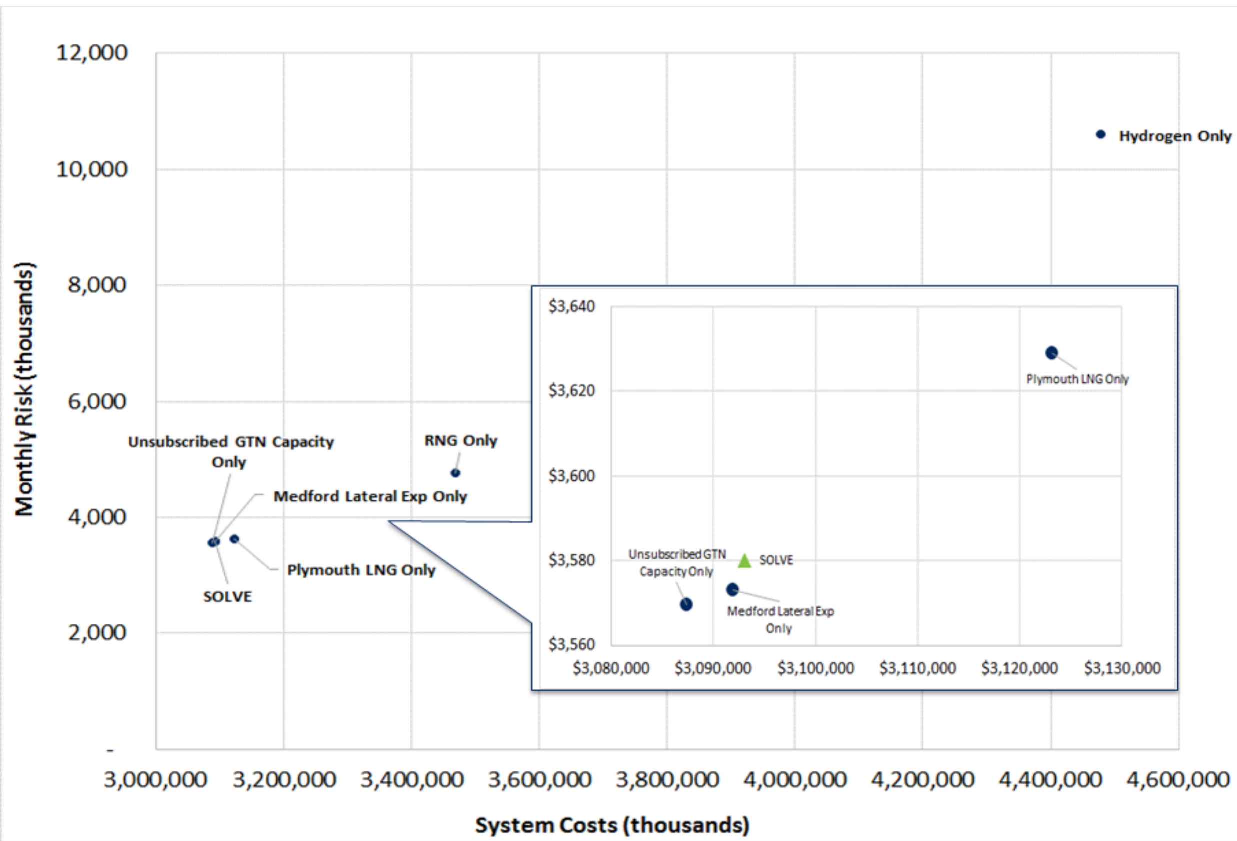


Table 7.6 demonstrates, by new supply resource or type from the deterministic runs:

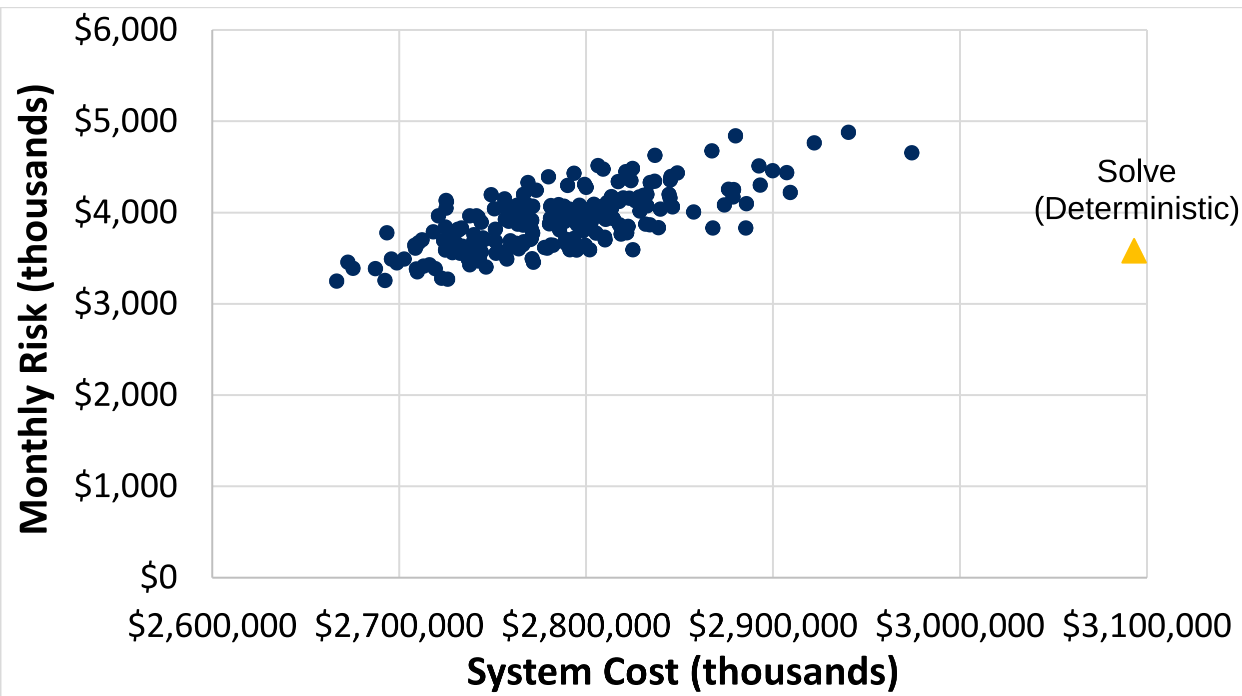
1. the twenty year system cost of only the specific resource
2. the average monthly risk or standard deviation of the system cost and
3. if resource would solve system unserved demand.

Table 7.6 – System cost, standard deviation and outcome of adding resource to system:

Scenario	System Cost (thousands) (PVRR)	Std Dev (thousands)	Unserved Demand
High Growth, Low Price - Unsubscribed GTN Capacity Only	$3,087,370	$3,570	2030
High Growth, Low Price - Medford Lateral Exp Only	$3,091,928	$3,573	2032
High Growth, Low Price	**$3,093,097**	**$3,580**	**None**
High Growth, Low Price - Plymouth LNG Only	$3,123,163	$3,629	2030
High Growth, Low Price - RNG Only	$3,469,219	$4,763	None
High Growth, Low Price - Hydrogen Only	$4,477,137	$10,599	2034

Once an optimal resource is found deterministically a stochastic analysis takes place to measure risk. Figure 7.11 depicts a stochastic simulation with all options available in order to solve the unserved system demand in a least cost solution.

The optimal solution Figure 7.11: High Growth and Low Price Cost vs. Risk (200 Draws)



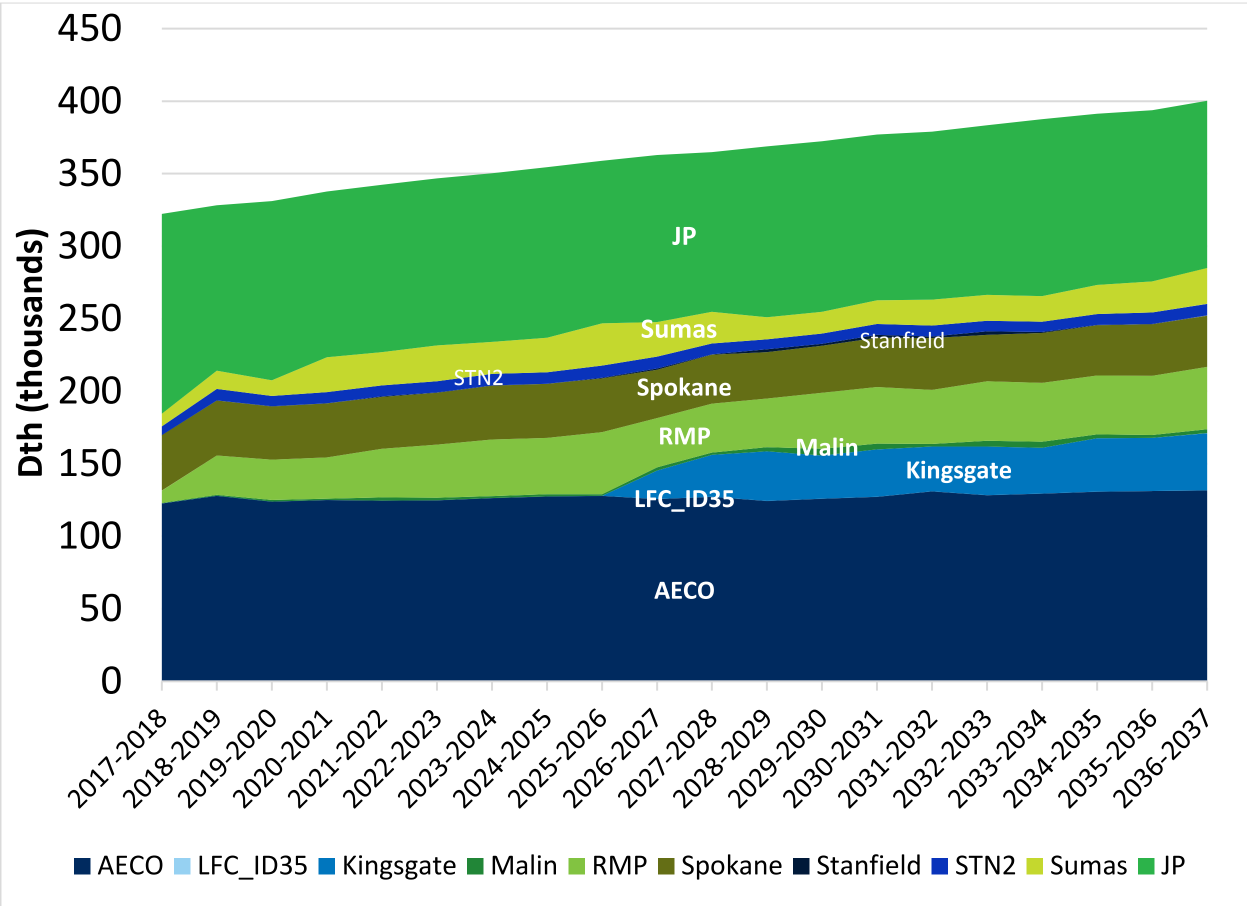
Stochastically, the model solved the unserved demand by selecting the following supply sources, below, and can be seen in Figure 7.12:

1. Additional capacity from Kingsgate to Spokane in 2026

2. Centralized landfill gas in Idaho (LFC_ID35) in 2035

3. Upsized compressor on Medford lateral in 2026

Figure 7.12: High Growth and Low Price - Average Supply by Source and Area on February 15th (200 Draws)



The stochastic analysis shows a supply resource need in the 2026 timeframe. In a stochastic analysis, variability and randomness based on historical information is utilized to measure risk and unknown elements (price and weather). An example of this lies within our expected coldest on record weather assumption. Within the deterministic model this value is equal to exactly 82 HDD in Avista's Washington and Idaho service territories, but in a single random draw, this value is slightly higher at 82.18 HDD affecting the overall demand. A slight increase in weather expectations can alter the unserved timeframe, especially in areas with higher populations or those nearing their current resource limits. Of the 200 – 20 year futures, less than 10 observe an unserved demand earlier than those in the deterministic analysis. Randomly simulated future prices provide the model with the ability to select from a variety of potential supply side resources over a range of 200 – 20 year future draws. When looking for the lowest cost and least risk portfolio, the model will look to solve unserved demand in each 20 year scenario with the lowest cost resources based on the values simulated (weather and price) and provided costs(transportation costs, storage costs, etc.) Additional detailed information on this and other scenarios is included in the following appendices:

1. Demand and Existing Resources graph by service territory (High Growth Case only) – Appendix 7.1
2. Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.2

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 – IRP Guideline Compliance Summaries 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 analytical processes. 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 15 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 conservation savings for evaluation.

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

Conclusion

In planning, a reasonable set of criteria is necessary to help measure the inherent risk of the unknown in future events. In prior years the "Low Growth and High Prices" scenario was considered our lower band of risk. In the 2018 IRP, Avista has added a new risk in the scenario referred to as "80% below 1990 emissions" due to a continued policy shift toward a reduced role of natural gas as a fuel choice. In all but one scenario, High Growth and Low Prices, the firm customer demand is served with existing resources. Simulating random future events by case with unserved demand provides a better idea of the risk and costs involved in each resource. This will allow Avista to monitor customer growth and demand while maintaining a watchful eye on policy and new resources.

8: Distribution Planning

> **Chapter Highlights**
> - Avista maintains its distribution system based on economics, safety and reliability
> - Avista maintains a total of 12,800 miles of distribution in three jurisdictions

Overview

Avista's IRP evaluates the 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 Avista's city gates become secondary issues if distribution system growth behind the city gates increases faster than expected and the system becomes severely constrained. Important parts of the distribution 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 integrated resource planning.

Avista's natural gas distribution system consists of approximately 3,300 miles of distribution main and services pipelines in Idaho, 3,700 miles in Oregon and 5,800 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. Distribution network pipelines and regulating stations operate and maintain system pressure solely from the pressure provided by the interstate transportation pipelines.

Distribution System Planning

Avista conducts two primary types of evaluations in its distribution system planning efforts: capacity requirements and integrity assessments.

Capacity requirements include 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 reinforcements and expansions 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, new service requests, field personnel discussion, and inquiries from major developers.

Avista regularly conducts integrity assessments of its distribution systems. Ongoing system evaluation can 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.

Gas Engineering planning models are also compared with capacity limitations at each city gate station. Referred to as city gate analysis, the design day hourly demand generated from planning analyses must not exceed the actual physical limitation of the city gate station. A capacity deficiency found at a city gate station establishes a potential need to rebuild or add a new city gate station.

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. As natural gas exits the pipeline network, it causes a pressure drop due to its movement and friction. As customer demand increases, pressure losses increase, reducing the pressure differential across the pipeline network. If the pressure differential is too small, flow stalls and the network could run out of pressure.

It is important to design a distribution network such 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 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. These equations have been refined through years of research to the point where modeling solutions closely resemble actual system behavior.

Avista conducts network load studies using GL Noble Denton's Synergi software. This modeling tool allows users to analyze and interpret solutions graphically.

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 most distribution systems operate through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations. Line pack is the difference between the natural gas contents of the pipeline under packed (fully pressurized) and unpacked (depressurized) conditions. Line pack is negligible in Avista's distribution system due to the smaller diameter pipes and lower pressures. In transmission and inter-state pipelines, line-pack contributes to the overall capacity due to the larger diameter pipes and higher operating pressures.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and 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]

Distribution System Enhancements

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification and corresponding optimum combinations 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 two broad categories of distribution enhancement solutions are pipelines and regulators.

[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.

Pipelines

Pipeline solutions consist of looping, upsizing and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. Looping 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 connecting previously unconnected mains. The feasibility of looping a pipeline depends upon the location where the pipeline will be constructed. Installing natural gas pipelines through private easements, residential areas, existing paved surfaces, and steep or rocky terrain can 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 where 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 the 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 pipeline 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 natural 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 regulator 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 natural 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 into the future.

Compressors can be a cost effective option to resolving system constraints; however, regulatory and environmental approvals to install a compressor 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

The evaluation of distribution system constraints includes 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 the longer-term, targeted conservation programs may provide a cumulative benefit that could offset potential constraint areas and may be an effective strategy.

Distribution Scenario Decision-Making Process

After achieving a working load study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur.

Avista's design HDD for distribution system modeling is determined using the coldest day on record for each given service area. This practice is consistent with the peak day demand forecast utilized in other sections of Avista's natural gas IRP.

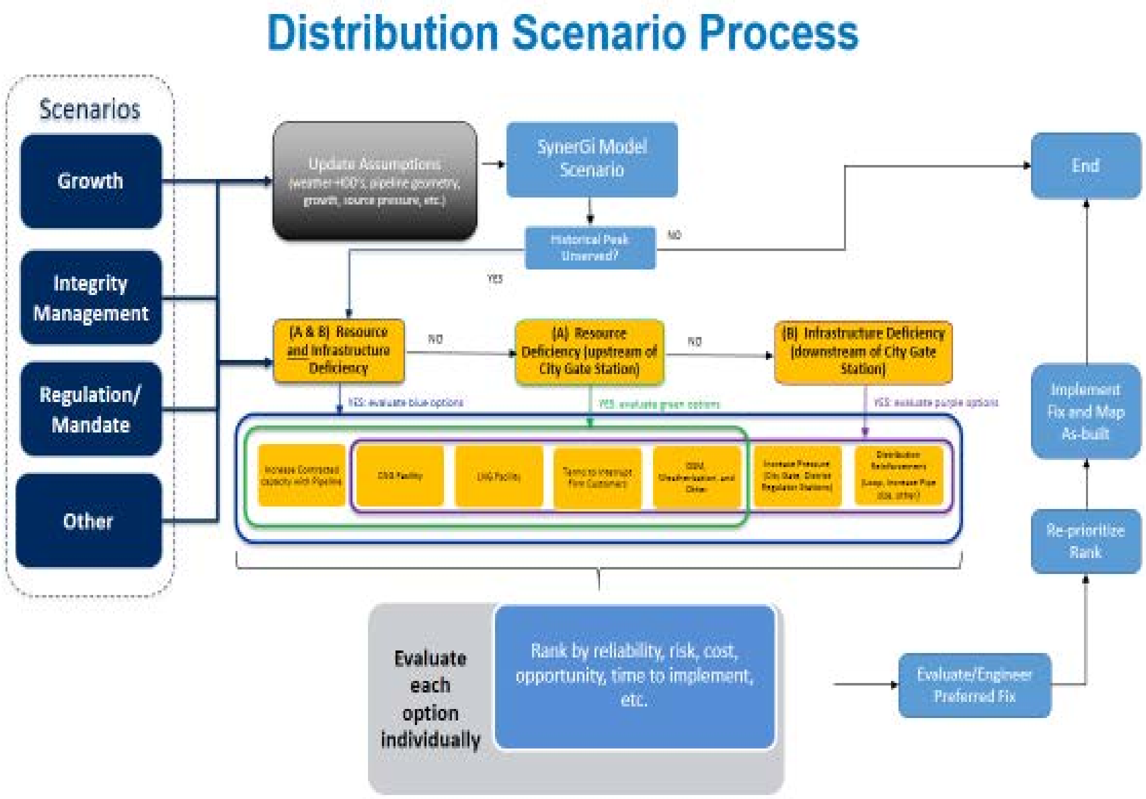
Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given a temperature experienced rarely, or only once. Given the potential impacts of an extreme weather event on customers' personal safety and property damage to customer appliances and Avista's infrastructure, it is a prudent regionally accepted planning standard.

These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient part of the distribution system.
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights or traffic issues.
- Minimal to no water, railroad, major highway crossings, etc.
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, the design engineer or construction project coordinator begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of the above project/reinforcement selection criteria. Figure 7.1 provides a schematic representation of the distribution scenario process.

Figure 8.1: Distribution Scenario Process



An example of the distribution scenario decision making process is from the Medford high pressure loop reinforcement where the analysis resulted in multiple paths or pipeline routes. The initial path was based on quantitative factors, specifically the shortest length and least cost route. However, as field investigations and coordination with local city and county governments began, alternative routes had to be determined to minimize future conflicts, environmental considerations, and field and community disruptions. The final path was based on several qualitative factors that including:

- Available right-of-way along city streets;
- Availability of private easements from property owners;
- Restrictions due to City of Medford future planned growth with limited planning information; and
- Potential to avoid conflict with other utilities including a large electric substation along the initial route.

Planning Results

Table 8.1 summarizes the cost and timing, as of the publication date of this IRP, of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of expenditures.

The Distribution Planning Capital Projects criteria includes:

- Prioritized need for system reliability (necessary to maintain reliable service);
- Scale of project (large in magnitude and will require significant engineering and design support); and
- Budget approval (will require approval for capital funding).

These projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of distribution system enhancement projects generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment and timing of planned completion may change based on the aforementioned ongoing reassessment of information.

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

Coeur d'Alene High Pressure Reinforcement – Post Falls Phase: The last phase of this project will reinforce the Post Falls distribution system, where the current distribution pipe has not been able to meet growing customer demand. Additionally, during cold weather conditions, supply resources have been constrained. Approximately 14,600 feet of high pressure steel gas main was designed in 2017 and construction began in 2018.

Cheney High Pressure Reinforcement: This project will reinforce the Cheney distribution system, whose customer demands have exceeded the capacity of the high pressure feeder constructed in 1957. During cold weather conditions, Avista periodically asks some large customers to reduce their nature gas usage in order to serve core customer demand. Approximately 27,700 feet of high pressure steel gas main will be designed in 2018 and construction is expected to begin in 2019.

Schweitzer Mountain Road and Warden High Pressure Reinforcements: The Schweitzer Mountain Road and Warden high pressure reinforcements are necessary to serve either new or increased industrial customer demand. At this time, both industrial customers, whose projected demands necessitated reinforcements, have either cancelled expansion plans or are considering alternative locations. In anticipation of similar industrial loads in the future, Avista will continue to list each project, but defer construction until distribution constraints materialize.

Table 8.1 Distribution Planning Capital Projects

Location	2018	2019	2020+
Coeur d'Alene High Pressure Reinforcement; Post Falls Phase	$4,000,000		
Cheney High Pressure Reinforcement		$4,900,000	$4,100,000
Schweitzer Mountain Rd High Pressure Reinforcement			$1,500,000
Warden High Pressure Reinforcement			$6,000,000

Table 8.2 shows city gate stations identified as over utilized or under capacity. Estimated cost, year and the plan to remediate the capacity concern are shown.

These projects are preliminary estimates of timing and costs of city gate station upgrades. The scope and needs of each project generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment.

The Post Falls City Gate Station will be reconfigured to accommodate a new high pressure feeder. The supplying pipeline has not been able to meet the increase in customer growth and demand in this area. An increase in flow and capacity will be achieved by the new high pressure feeder directing gas from Rathdrum to Post Falls, the third phase of the Coeur d'Alene High Pressure Reinforcement.

The remaining city gate station projects in Table 8.2 have relatively small capacity constraints, and thus will be periodically reevaluated to determine if upgrades need to be accelerated or deferred. Under current planning considerations, these projects will be tentatively scheduled for 2020 or later.

Table 8.2 City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
Post Falls, ID	Post Falls #215	Reconfigure	Included in Table 7.1	2018
CDA (East), ID	CDA East #221	TBD	-	2020+
Athol, ID	Athol #219	TBD	-	2020+
Bonners Ferry, ID	Bonners Ferry #208	TBD	-	2020+
Colton, WA	Colton #316	TBD	-	2020+
Genesee, ID	Genesee #320	TBD	-	2020+
Klamath Falls, OR	Klamath Falls #2703	TBD	-	2022+
Mead, WA	Mead #1	TBD		2020+
Mica, WA	Mica #15	TBD	-	2020+
Pullman, WA	Pullman #350	TBD	-	2020+
Sprague, WA	Sprague #117	TBD	-	2020+
Sutherlin, OR	Sutherlin #2626	TBD	-	2022+

CONCLUSION

Avista's goal is to maintain its natural gas distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal relies on 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 natural gas delivery is enhanced through localized distribution planning, which enables coordinated targeting of distribution projects responsive to customer growth patterns.

9: Action Plan

The purpose of an action plan 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 natural gas industry trends Avista will monitor as a part of its planning processes.

2017-2018 Action Plan Review

- The price of natural gas has dropped significantly since the 2014 IRP. This is primarily due to the amount of economically extractable natural gas in shale formations, more efficient drilling techniques, and warmer than normal weather. Wells have been drilled, but left uncompleted due to the poor market economics. This is depressing natural gas prices and forcing many oil and natural gas companies into bankruptcy. Due to historically low prices Avista will research market opportunities including procuring a derivative based contract, 10-year forward strip, and natural gas reserves.
  - **Result:** After exploring the opportunity of some type of reserves ownership, it was determined the price as compared to risk of ownership was inappropriate to go forward with at this time. As an ongoing aspect of managing the business, Avista will continue to look for opportunities to help stabilize rates and/or reduce risk to our customers.
- Avista's 2018 IRP will contain a dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on Expected Case assumptions. In the 2018 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
  - **Result:** After attempting to get dynamic dsm into the Sendout model we determined an alternate method will be necessary. Some reasons for this are:
    - 1 – The total dsm measures has a maximum of 999 measures. If we were to model our areas as is combined with 400 measures by area we would come up with a total need of 4400 measures.
    - 2 – If we were able to group them by dollars or efficiency levels it takes away the desired approach of measure by measure.

        - 3 – We have every bit of data both ETO and AEG can provide and the model is not acting appropriately and cannot determine a stopping point for taking a single measure. This means it would take the maximum, if cheaper than gas, to fill the entire demand.
        - 4 – The output data from ETO and AEG is very different and we need to understand it better before modeling.

- Monitor actual demand for accelerated growth to address 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 at least bi-annually.
    - **<u>Result:</u>** actual demand was closely tracked and shared with Commissions in semi-annual or quarterly meetings and trended closely to the IRP forecast per customer. No new resources were necessary during this timeframe.
- In the 2018 IRP, include a section in the IRP that discusses the specific impacts of the new Clean Air Rule in Washington (WAC 173-441 and 173-442).
    - **<u>Result:</u>** Carbon Policy including the Clean Power Plan and Clean Air Rule were both reviewed and included in TAC 2 Meeting materials on 2/22/2018. An indicator of where Avista’s carbon reduction requirements under the CAR was also included. Since the CAR was invalidated on 12/15/2017 in Thurston County Superior Court this analysis is intended to meet the action item in addition to showing the potential impacts of similar policies.
- In the 2018 IRP, provide more detail on Avista’s natural gas hedging strategy, including information on upper and lower pricing points, transactions with counterparties, and how diversification of the portfolio is achieved.
    - **<u>Result:</u>** Avista’s natural gas hedging strategy was discussed during the TAC 2 Meeting on 2/22/2018. The upper and lower pricing points in Avista’s programmatic hedges is controlled by taking into consideration the volatility over the past year for the specific hedging period. This volatility is weighted toward the more recent volatility. The window length and quantity of windows is also a part of the equation. Avista transacts on ICE with counterparties meeting our credit rating criteria. The diversification of the portfolio is achieved through the following methods:
        - **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.

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- Carbon Policy including federal and state regulations specifically those surrounding the clean air rule and clean power plan.
    - **Result:** Carbon Policy including the Clean Power Plan and Clean Air Rule were both reviewed and included in TAC 2 Meeting materials on 2/22/2018. An indicator of where Avista's carbon reduction requirements under the CAR was also included. Since the CAR was invalidated on 12/15/2017 in Thurston County Superior Court this analysis is intended to meet the action item in addition to showing the potential impacts of similar policies.
- Weather analysis specific to Avista's service territories.
    - **Result:** A weather analysis was included and reviewed in TAC 2 meeting materials on 2/22/2018 and can be found in Chapter 2 Demand Forecasts.
- Stochastic Modeling and supply resources.
    - **Result:** This was shown in detail and with risk and cost in TAC 4 on 5/10/2018. Regional pipelines were discussed in TAC 2 meeting on 2/22/2018. Potential resources were 4 types of RNG, Plymouth LNG, additional Kingsgate to Spokane and an upsized compressor on GTN's Medford lateral. A list of these resources modeled can be found in Chapter 7 Alternate Scenarios Portfolios Stochastic Analysis along with the results.
- Updated DSM methodology including the integration of ETO.
    - **Result:** See chapter 3 Demand Side Resources and action item
- In the 2018 IRP, ensure that the entity performing the Conservation Potential Assessment (CPA) evaluates and includes the following information:
    - All conservation measures excluded from the CPA, including those excluded prior to technical potential determination;
        - **Result:** Very few measures were excluded from the current CPA prior to estimation of technical potential. Those explicitly excluded were highly custom commercial and industrial controls/process measures that were instead captured under a retrocommissioning or strategic energy management program.
    - Rationale for excluding any measure;

        - **Result:** Measures that did not pass the economic screen were still counted within achievable technical potential, allowing Avista to review for inclusion in programs if portfolio-level cost-effectiveness allows.
    - Description of Unit Energy Savings (UES) for each measure included in the CPA; specify how it was derived and the source of the data; and
        - **Result:** The measure list developed during the CPA includes descriptions of each measure included. AEG will provide this as an appendix to the final report. Source documentation for assumptions, including UES, lifetime, and costs (including NEIs) may be found in the "Measure Summary" spreadsheet delivered as an appendix to the final report. This will include the name of the source and version (if applicable)
    - Explain the efforts to create a fully-balanced TRC cost effectiveness metric within the planning horizon. Additionally, while evaluating the effort to eventually revert back to the TRC, Avista should consult the DSM Advisory Group and discuss appropriate non-energy benefits to include in the CPA.
        - **Result:** TRC potential was estimated alongside UCT for each measure analyzed. In this study, we expanded the scope of non-energy/non-gas impacts to include the following:
            - 10% Conservation Credit in Washington
            - Quantified and monetized non-energy impacts (e.g. water, detergent, wood)
            - Projected cost of carbon in Washington
            - Heating calibration credit for secondary fuels (12% for space heating, 6% for secondary heating)
            - Electric benefits for applicable measures (e.g. cooling savings for smart thermostats, lighting and refrigeration savings for retro-commissioning)
- Staff believes public participation could be further enhanced through "bill stuffers, public flyers, local media, individual invitations, and other methods."
    - **Result:** Avista utilized it's Regional Business Managers in addition to digital communications and newsletters in all states in order to try and gain more public participation in addition to an eCommunity newsletter was distributed January 15, 2018.

- o Avista forecast its number of customers using at least two different methods and to compare the accuracy of the different methods using actual data as a future task in its next IRP.
  - o **<u>Result:</u>** Avista analyzed the data, but there was nothing material discovered the come up with a meaningful forecast alternative.

2019-2020 Action Plan

Avista's 2019-2020 Action Plan outlines activities for study, development and preparation for the 2020 IRP.

New Activities for the 2020 IRP

1. Avista's 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
2. Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.
3. Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.
4. Revisit coldest on record planning standard and discuss with TAC for prudency.
5. Provide additional information on resource optimization benefits and analyze risk exposure.
6. DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.
7. Carbon Costs – consult Washington State Commission's *Acknowledgement Letter Attachment* in its 2017 Electric IRP (Docket UE-161036), where emissions price modeling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.
8. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.

9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:
   - Natural gas infrastructure investment not included as discrete projects in IRP
     - Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
       - Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
     - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely requires additional capital to comply
       - Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
     - Construction of gas infrastructure associated with growth
     - Other special contract projects not known at the time the IRP was published
   - Other non-IRP investments common to all jurisdictions that are ongoing, for example:
     - Enterprise technology projects & programs
     - Corporate facilities capital maintenance and improvements

Ongoing Activities

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, methanol plants, supply and market dynamics and pipeline and storage infrastructure availability.
- Monitor availability of 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.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.