2021 Natural Gas Integrated Resource Plan

Safe Harbor Statement

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

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New 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.

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Executive Summary

Avista's 2021 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio to meet customer demand requirements over the next 20 years. Price volatility, or uncertainty, in the Pacific Northwest region, due to fully subscribed transportation has increased in recent years. As weather events throughout the United States have continued to rise, the risk to energy providers, utilities and consumers to these unknown events are also on the rise. Some recent examples include freezing temperatures in Texas and wildfire risk in California. Both events created the loss of a supply source and potentially dangerous circumstances for its customers. This IRP's primary focus is to meet our customers' needs under peak weather conditions, while evaluating our 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.

Benefits of Natural Gas

For Customers: Natural gas is affordable, resilient, and reliable.

For Society: Natural gas is an abundant energy resource produced in North America, which helps lessen our dependency on foreign oil.

For Innovation: Natural gas can play a supporting role in expanding the use of renewable energy sources.

For Environment: Natural gas is the cleanest burning fossil fuel, so it helps reduce smog and greenhouse gas emissions.

For Economy: Natural gas provides nearly a fourth of North America's energy today.

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 ample supplies for many decades because of continuing technological advancements in extraction. The use of natural gas in liquefied natural gas (LNG) exports, power generation and exports to Mexico will continue to add demand for natural gas. In addition to fossil fuel natural gas, renewable natural gas and hydrogen are considered vital toward any carbon reduction goal, but currently not as readily available. All future scenarios carry risk based on unknown prices and expected resources. To account for risk associated with these uncertainties, we model various sensitivities and scenarios to account for the risks in 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, Medford and Idaho service territories include areas served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN), and by both pipelines.

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, 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

2021 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Carbon Reduction

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
2021	95,126	363,586	349,210
2040	102,054	407,216	388,615

Annual Average Daily Demand

Expected average day, system-wide core demand increases from an average of 95,126 dekatherms per day (Dth/day) in 2021 to 102,054 Dth/day in 2040. These numbers are 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 28th of each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20th of 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 363,586 Dth/day in 2021 to 407,216 Dth/day in 2040. Forecasted non-coincidental peak day demand, or the sum of demand from the highest single day including all forecasted territories, peaks at 349,210 Dth/day in 2021 and increases to 388,615 Dth/day in 2040. This is also net of projected conservation savings from DSM programs.

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

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

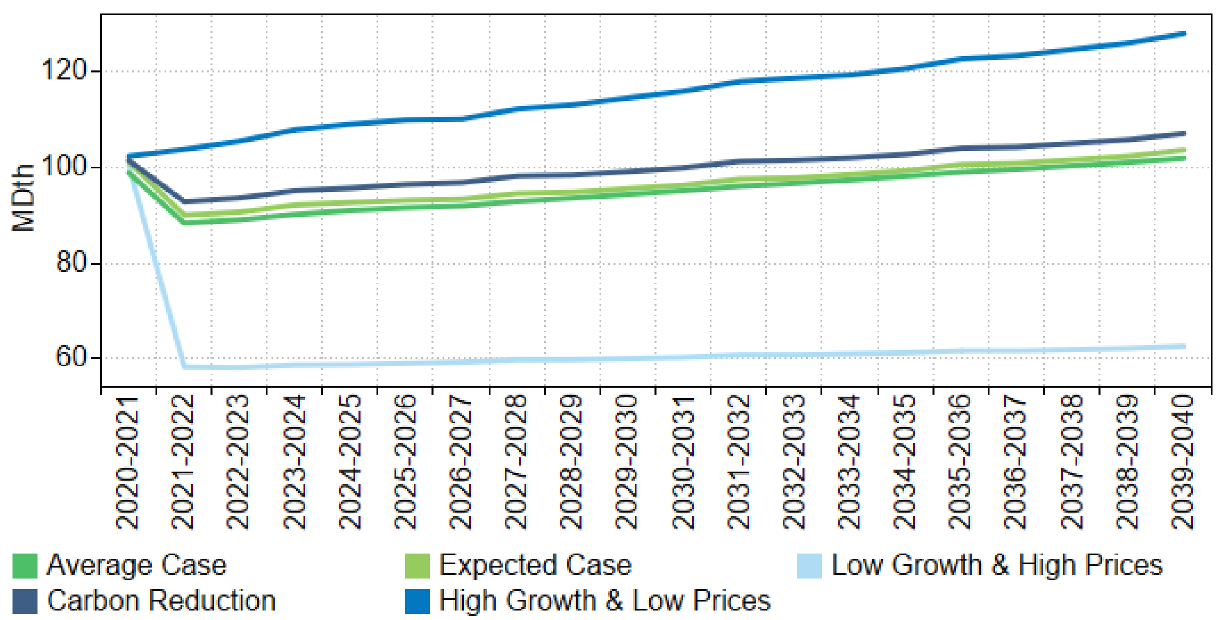
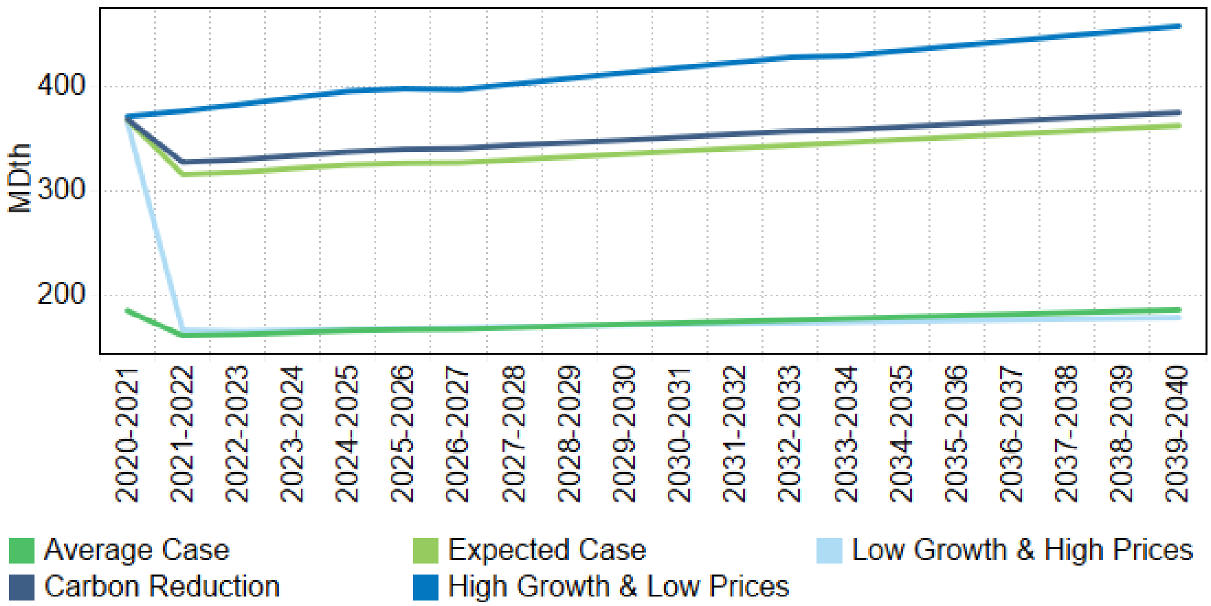


Figure 2 shows forecasted system-wide peak day demand for the five demand scenarios modeled over the IRP planning horizon.

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



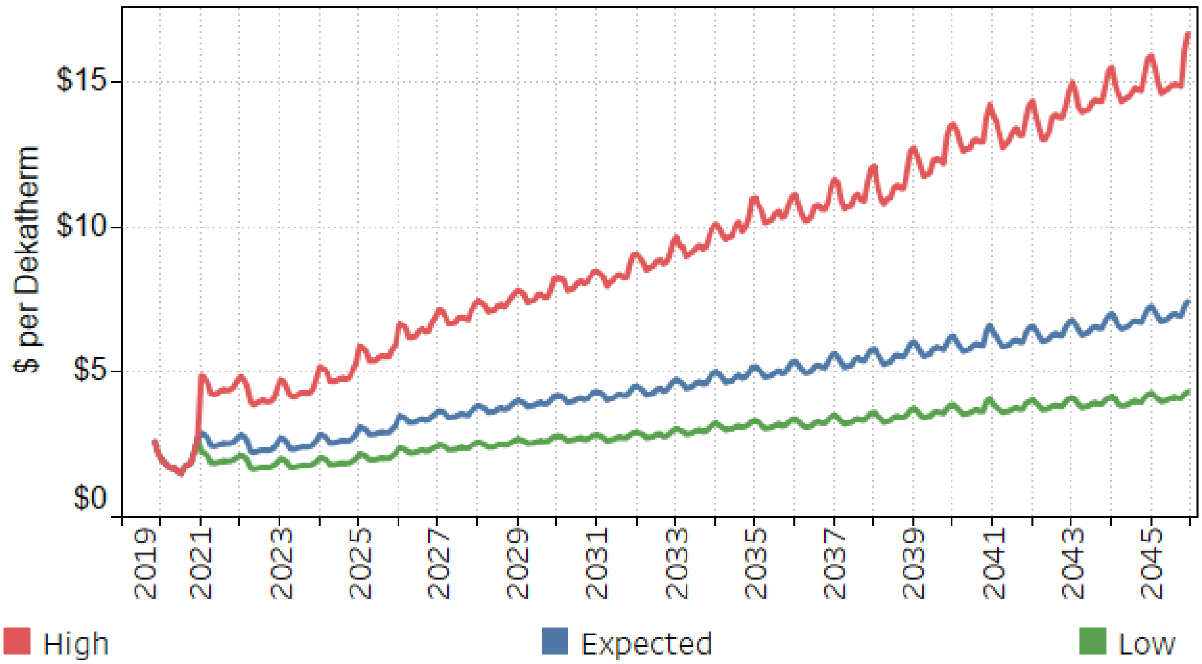
Natural Gas Price Forecasts

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.

Avista expects carbon legislation at the state level through a cap and reduce (Oregon) or social cost of carbon 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. These sensitivities were applied to all jurisdictions.

Avista combined forward prices with three fundamental price forecasts including a futures pricing strip in the near term to develop an expected price strip at the Henry Hub. A set of high and low price strips were developed based on the 95th and 25th percentile results of 1,000 simulated prices. 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 -0.081 for every 10% of price movement, as found in our Medford/Roseburg service territory, and applied it under various scenarios and sensitivities. As this price response continues to have a near muted response, Avista will look for additional studies and methodologies to account for elasticity in future resource plans where applicable.

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, renewable natural gas, storage options, hydrogen, distribution enhancements, and various forms of LNG storage or service. Avista models aggregated conservation potential that reduces demand if the conservation programs are cost-effective over the planning horizon. The identification and incorporation of conservation savings into the SENDOUT® model 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 both the High Growth and Low-price and the Carbon Reduction scenarios a resource deficiency was observed. The High Growth and Low-Price scenario observed an energy shortage, or it requires additional assets of any kind to supply more energy. The Carbon Reduction scenario does not have an energy shortage, but rather a need for carbon neutral or carbon reducing resources in order to reduce the carbon intensity of its supply stream. Avista is not resource deficient within the Expected Case for the 20-year planning horizon. As further information on goals and legislation come into focus, Avista will integrate these guideposts into our Expected Case.

Figures 4 through 7 illustrate Avista's peak day demand by service territory for both the current and prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show the timing and extent of resource deficiencies, if any, for the Expected Case. Based on this information, Avista has time to carefully monitor, plan and analyze 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 4: Expected Case – WA & ID Existing Resources vs. Peak Day Demand (Net of DSM)

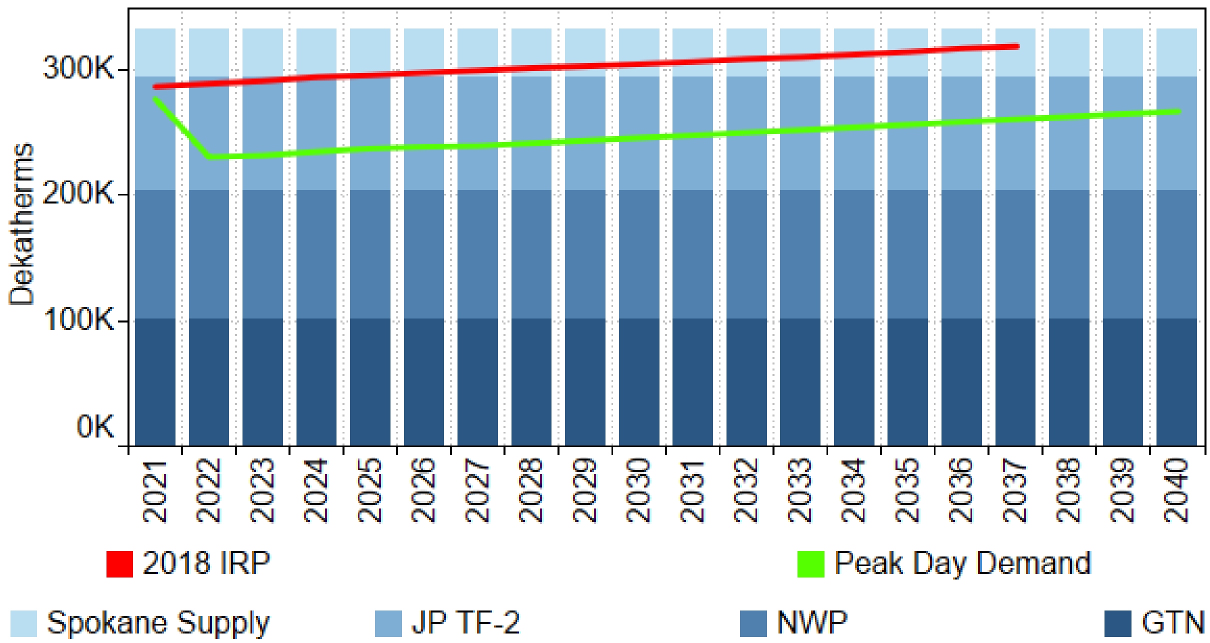


Figure 5: Expected Case – Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)

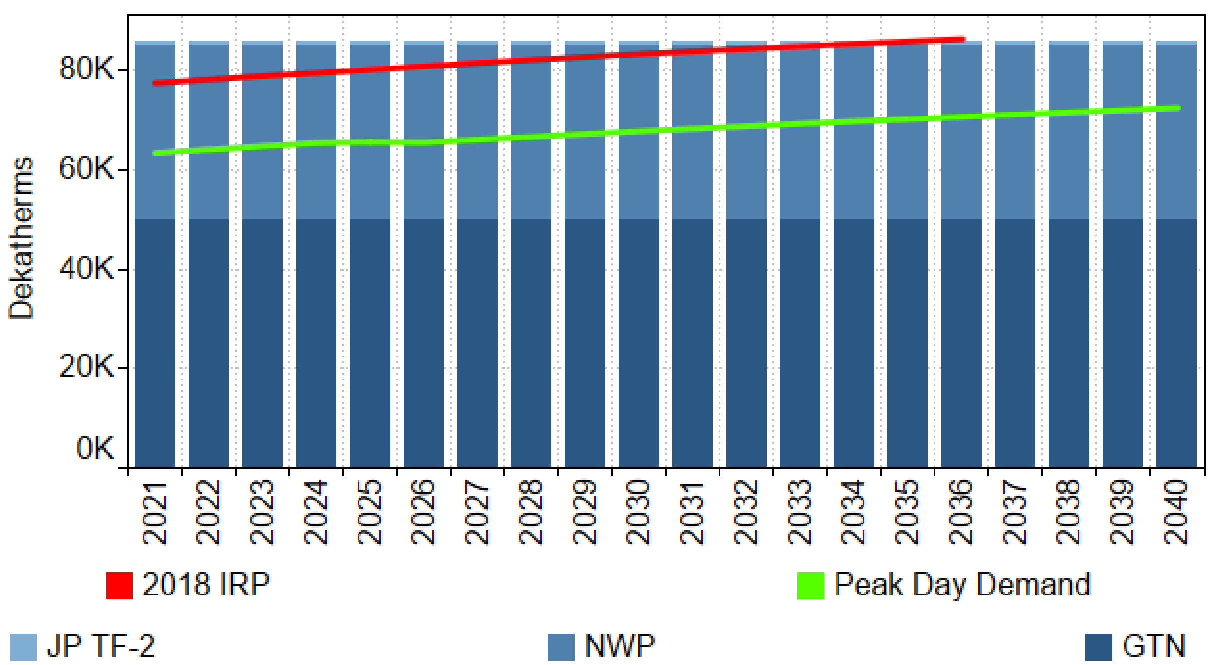


Figure 6: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)

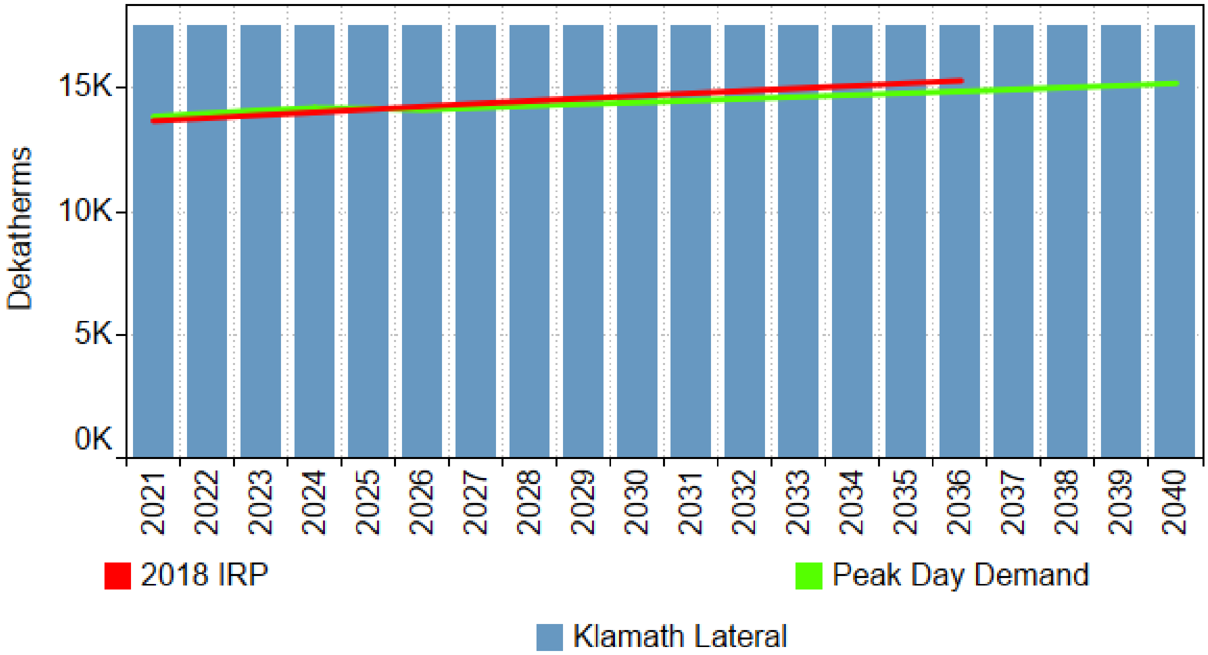


Figure 7: Expected Case – La Grande Existing Resources vs. Peak Day Demand (Net of DSM)

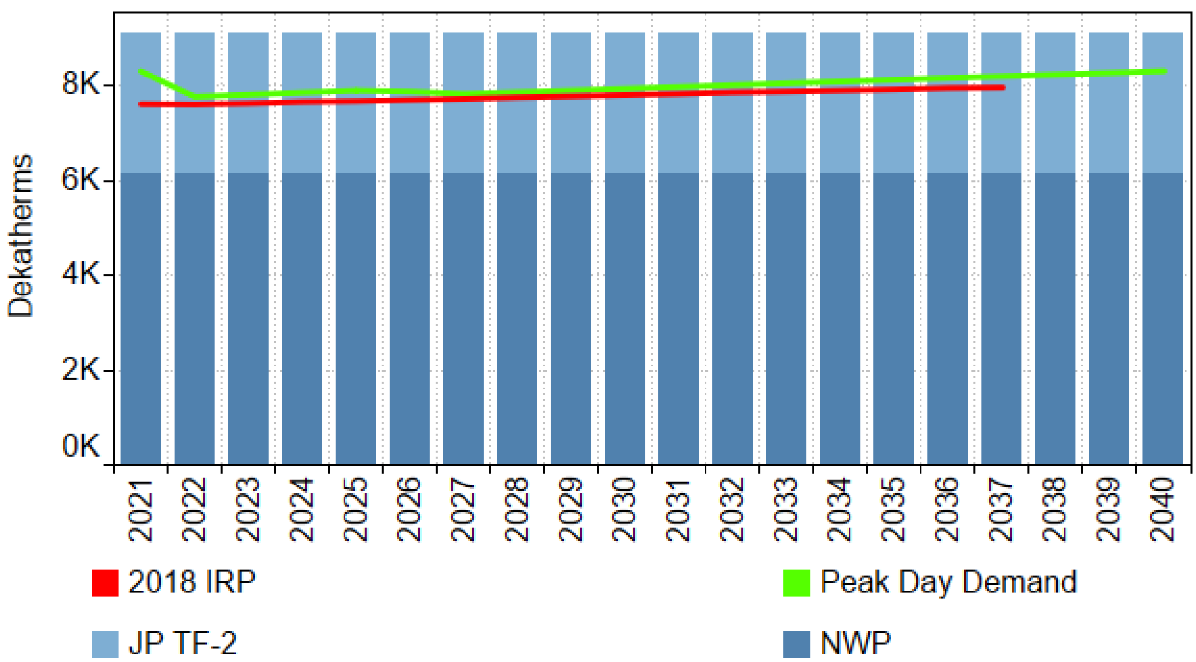
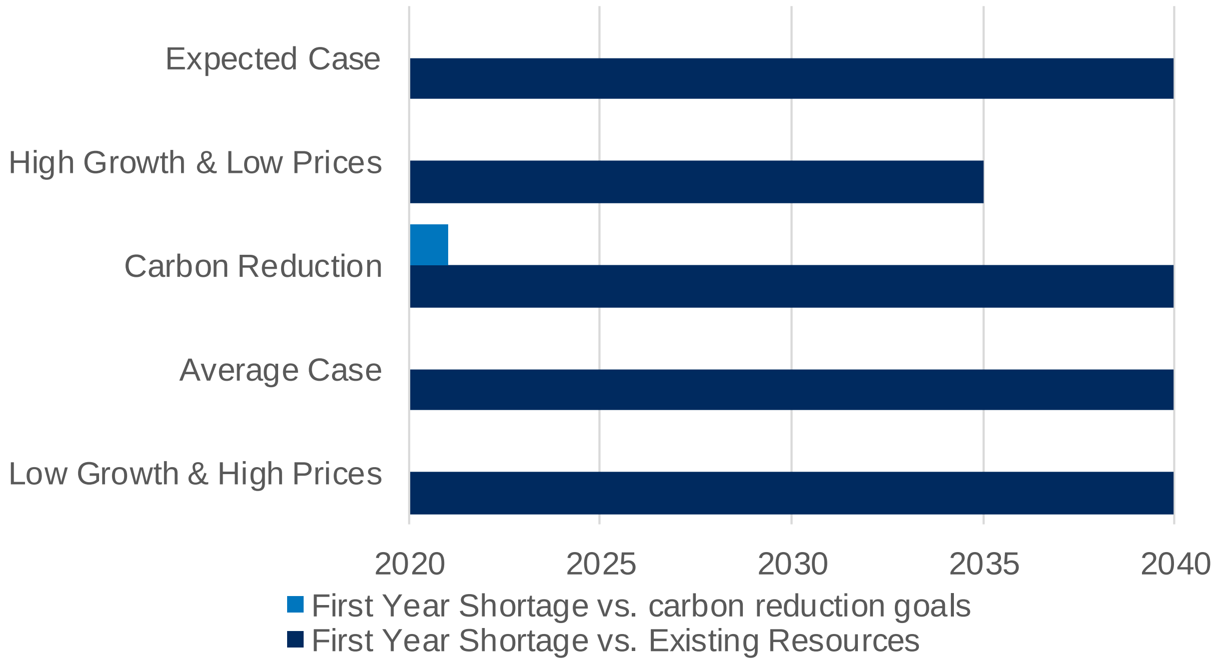
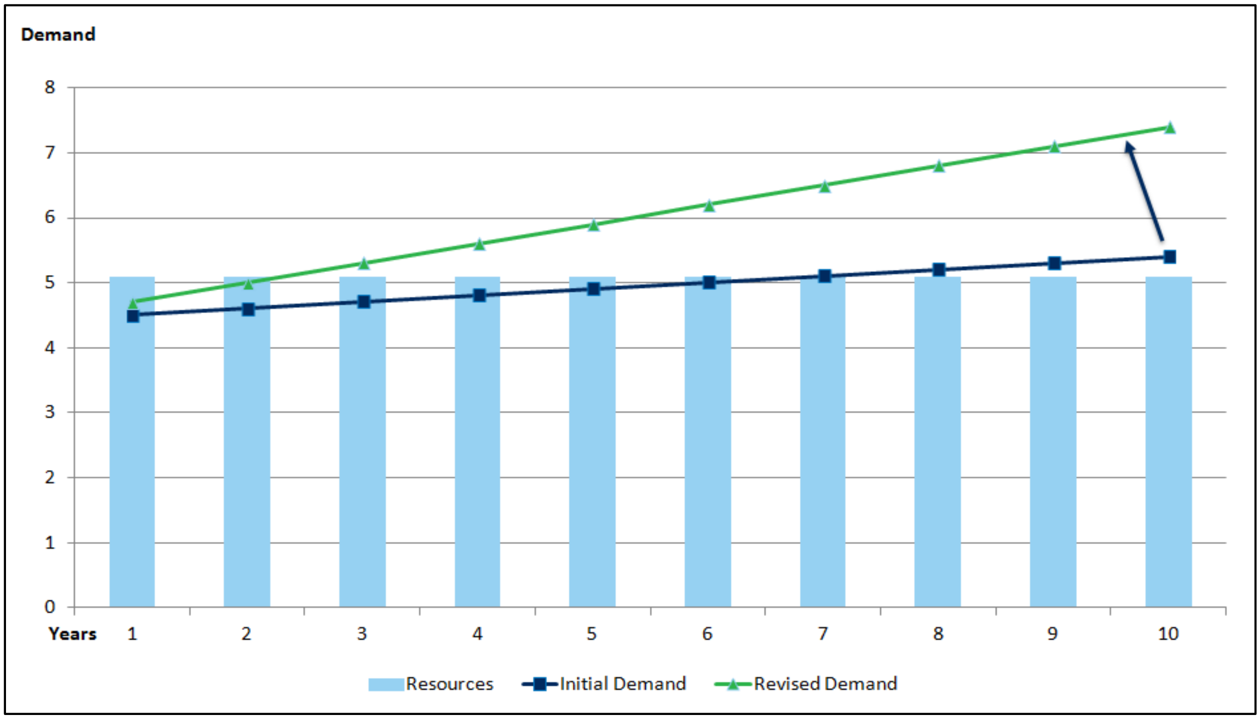


Figure 8: Scenario Comparisons of First Year Peak Demand Not Met with Existing Resources



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



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 decreased compared to the 2018 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 robust supply forecast and continued 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. In terms of North American demand, exports of LNG could consume 20 Bcf per day by 2030 and more than 30 Bcf per day by 2040. Although smaller in size, Mexico exports could increase from 5 Bcf per day in 2020 to over 8 Bcf per day in 2040. 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. which benefits Northwest consumers as the prices for Canadian gas have deep discounts as compared to the Henry Hub.

Action Plan

Avista's 2021-2022 Action Plan outlines activities for study, development and preparation for the 2023 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. Further model carbon reduction
2. Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout
3. Model all requirements as directed in Executive Order 20-04
4. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
5. Explore the feasibility of using projected future weather conditions in its design day methodology, rather than relying exclusively on historic data.
6. 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 require 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

A slightly lower customer growth level combined with an updated peak weather planning standard combine to create a lower overall peak day demand. Prices have a lower levelized price as compared to the 2018 IRP creating a slightly reduced amount of DSM. When combined, the need for additional supply side resources is pushed well into the future. By managing these assets through releases and optimization, Avista can help offset these costs while managing peak day demand need. A changing dynamic related to carbon emissions will continue to evolve future planning environments and any need for supply side resources. Regardless of policy, prices or demand, Avista will continue to properly plan to continue delivering safe, reliable, and economic natural gas service to our customers.

1: Introduction

Avista is an investor-owned utility 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 361,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon. Figure 1.2 shows the number of firm natural gas customers by state.

Figure 1.1: Avista's Natural Gas Service Territory

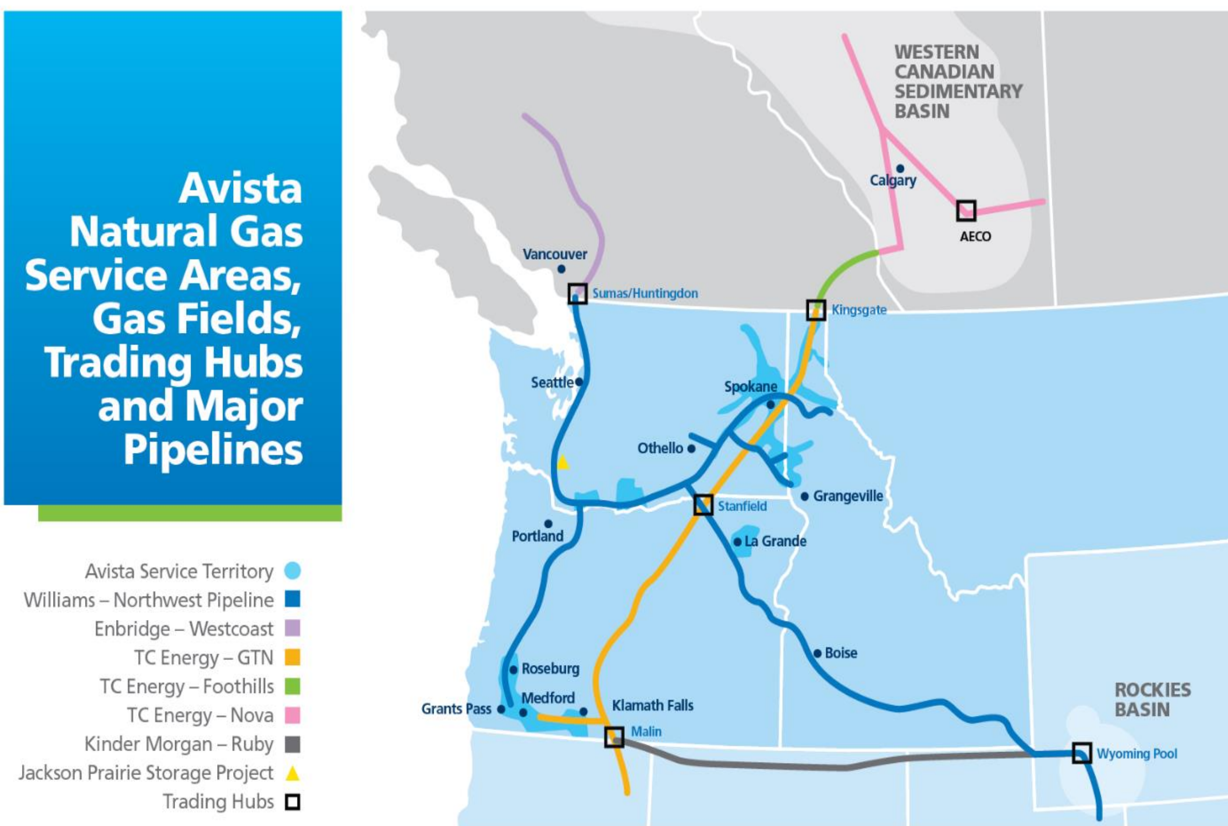
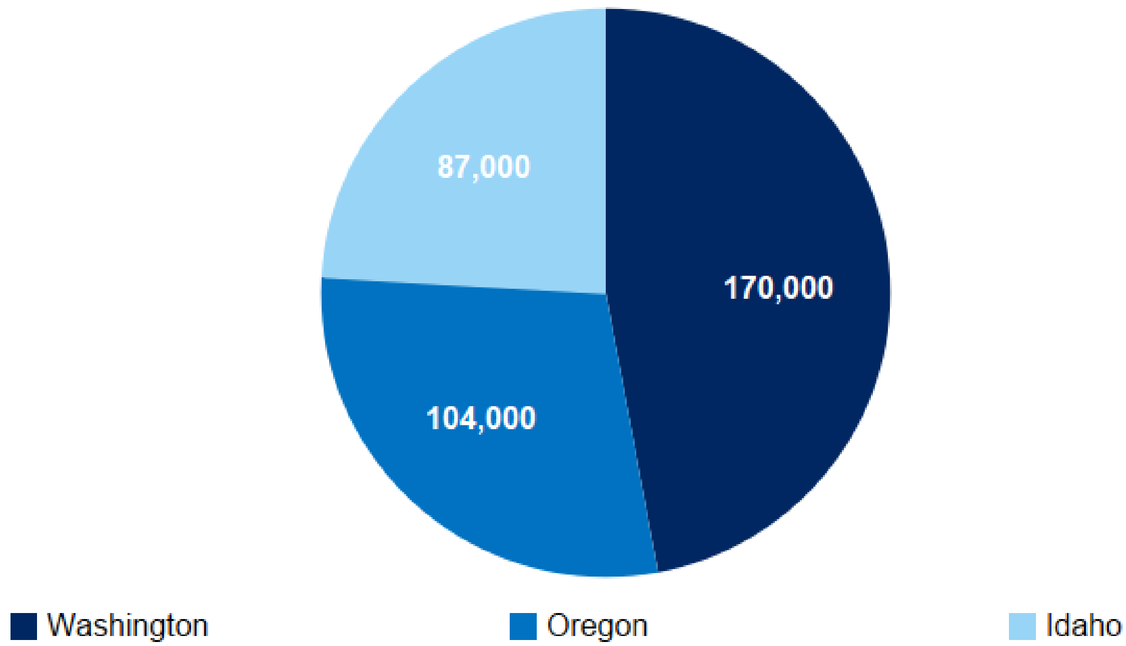


Figure 1.2: Avista's Natural Gas Customer Counts



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 1,000,000 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 523,000 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 5,800 miles in the distribution system in Washington and 3,300 miles in Idaho. The North Division receives natural gas at more than 40 points along interstate pipelines for distribution to over 257,000 customers.
- The South Division serves four counties in southern Oregon and one county in eastern Oregon. The combined population of these areas is over 514,000 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 308,000. The South Division consists of about 15 miles of natural gas transmission main and 3,700 miles of distribution pipelines. Avista receives natural gas at more than 20 points along interstate pipelines and distributes it to more than 104,000 customers.

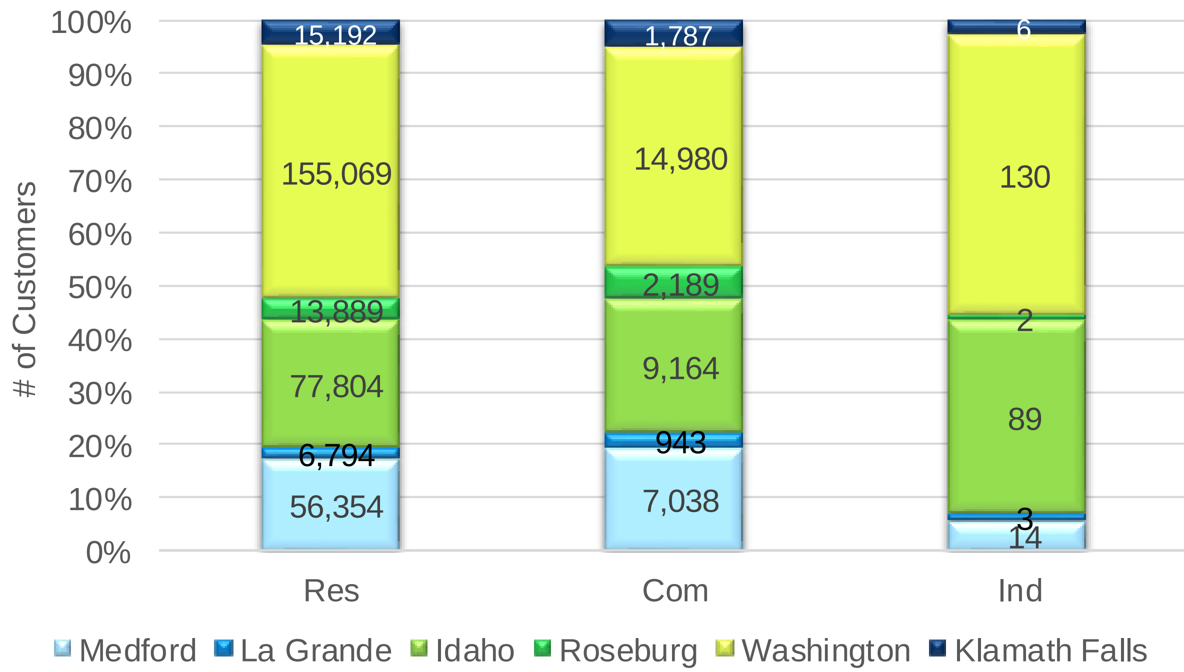
Customers

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.

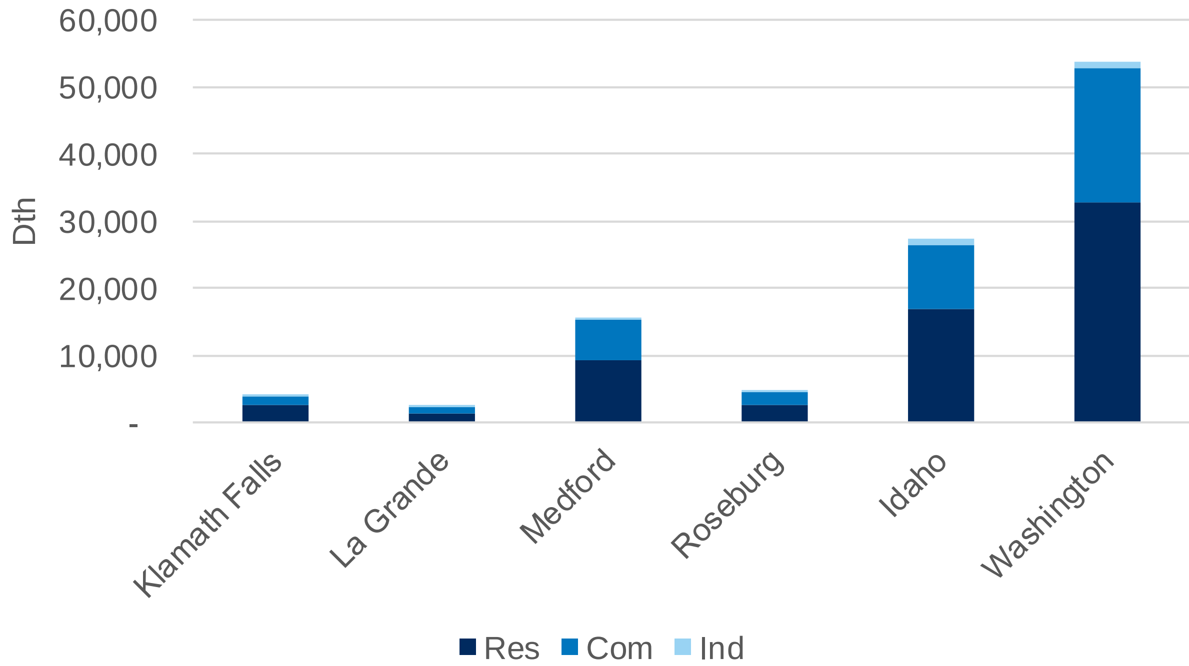
Avista's core or retail customers include residential, commercial and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

Figure 1.3: Firm Customer Mix



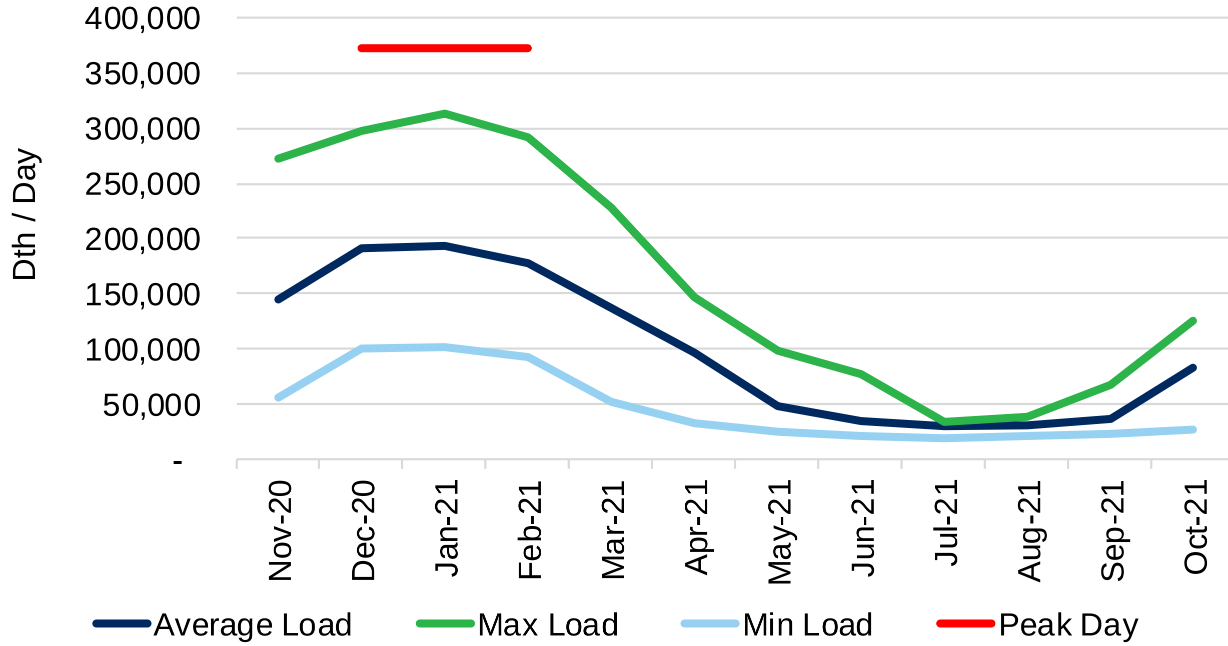
The customer mix is found mostly in the residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.

Figure 1.4: 2019 Daily Demand by Area and Class



The seasonal nature of weather in the Pacific Northwest can drastically alter the amount of energy demanded from the natural gas system (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: Total System Average Daily Load



Integrated Resource Planning

Avista's IRP involves a comprehensive analytical process to ensure that core firm customers receive long-term reliable natural gas service in extreme weather. 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 2021 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 2021 IRP. The first meeting convened on June 17, 2020 and the last meeting occurred on November 18, 2020. All meetings were held virtually, via web meetings, due to the restrictions and guidelines around the COVID-19 pandemic. 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 January 4, 2021 for their review. Avista appreciates 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 Energy Coalition	Oregon Public Utility Commission
Fortis	Northwest Natural Gas	Idaho Conservation League
Idaho Public Utilities Commission	Biomethane, LLC	Washington State Office of the Attorney General
Northwest Gas Association	Washington Utilities and Transportation Commission	Citizens Utility Board of Oregon
Washington State Department of Commerce	Northwest Power and Conservation Council	Energy Trust of Oregon
Intermountain Gas Company	Alliance of Western Energy Consumers	

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 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 methodologies and processes for the evaluation of 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 incorporate weather and price uncertainty. 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 as well as 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-Carbon Reduction. 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 2018 IRP (Table 1.2).

Table 1.2: Summary of Changes from the 2018 IRP

Chapter	Issue	2021 Natural Gas IRP	2018 Natural Gas IRP
Demand	Expected Customer Growth	Expected Case – system wide – growth is slightly lower at 1.0%.	Expected Case – system wide – growth at 1.2%.
	Weather Planning Standard	99% probability of a temperature occurring based on the coldest temperature each year for the past 30 years	Coldest on record
DSM	CPA potential	A lower price curve and slightly less conservation potential Cumulative Savings over 20 years: ID: 21.4 Million Therms OR: 14.8Million Therms WA: 37.7 Million Therms	Cumulative Savings over 20 years: ID: 21.1 Million Therms OR: 17.2 Million Therms WA: 41.4 Million Therms
Environmental Issues	Carbon Dioxide Emission (Carbon)	ID: No federal or State initiatives ($0) OR: Cap and Reduce ($15.83 – $97.90) WA – Social Cost of Carbon @ 2.5% discount rate ($79.86 - $158.06) *Prices are in nominal dollars per MTCO2e	ID: No federal or State initiatives ($0) OR: HB 4001 & SB 1507 ($17.86 – $51.58) WA – SSB 6203 ($10 - $30) *Prices are in nominal dollars per MTCO2e
Prices	Price Curve	A lower price curve at $3.73 levelized cost in real 2019 US $	A levelized price at the Henry Hub of $3.99 in 2017 real US $

Supply Side Resources	Supply Side Scenarios	There are two cases where resource deficiencies occur, the High Growth/Low Price scenario and the Carbon Reduction scenario. The High Growth/Low Price scenario is solved by adding RNG landfill within the city gate. The Carbon Reduction scenario is looking to reduce emissions and Dairy RNG provides the greatest amount of carbon intensity/carbon capture of RNG sources.	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.

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, forecasting will always have uncertainties regardless of methodology and data integrity. This IRP mitigates the uncertainty by considering a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

Demand Areas

Avista defined eleven demand areas, structured around the pipeline transportation resources ability to 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
+
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
+
of customers x daily Dth weather sensitive usage / customer x # of daily degree days

Customer Forecasts

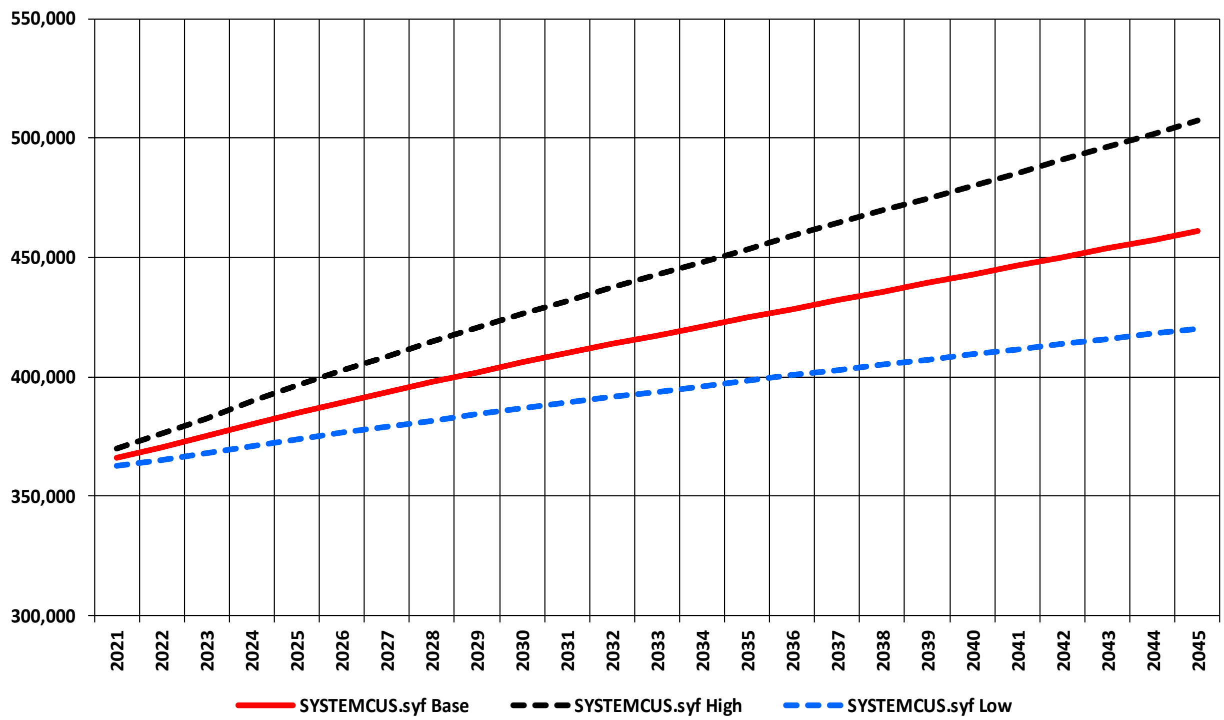
Avista's customer base includes firm residential, commercial and industrial categories. For each of the customer categories, Avista develops customer forecasts incorporating national economic forecasts and then drilling down into regional economies. U.S. GDP growth, national and regional employment growth, 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 lower 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 2018 IRP, the base forecast for customer growth decreases by nearly 1,400 new customers.

Figure 2.1: Customer Growth Scenarios

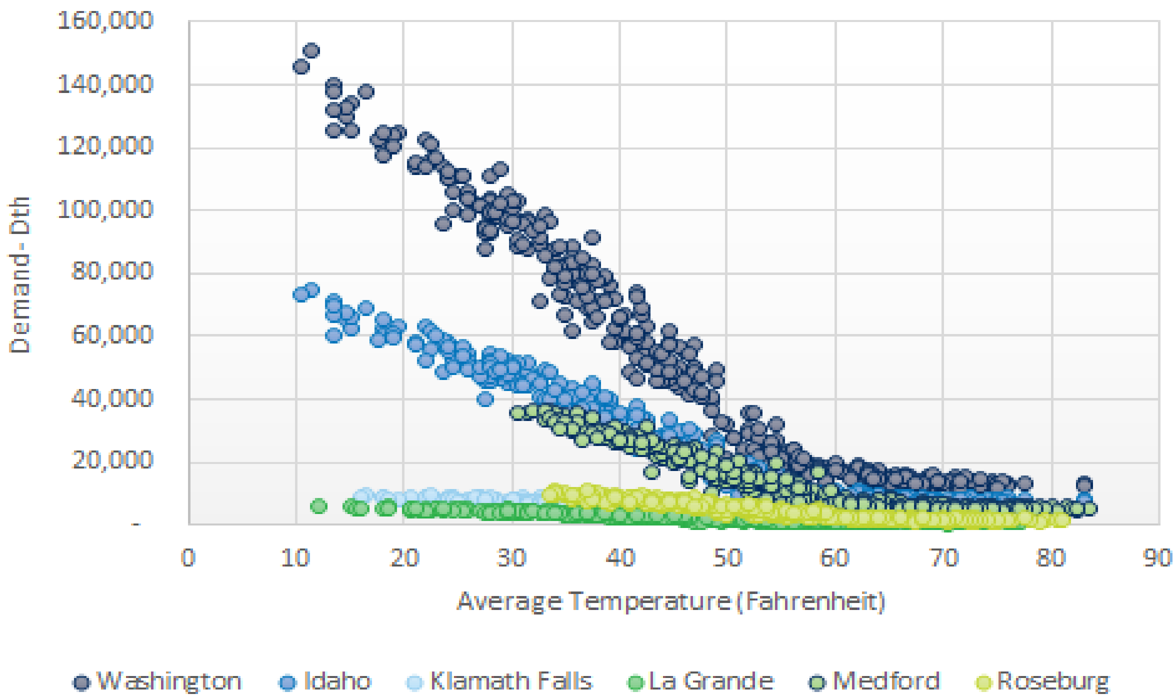


Variable	Low Growth	Base Growth	High Growth
Customers	0.6%	1.0%	1.3%
Population	0.4%	0.8%	1.1%

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. Temperature – 2019



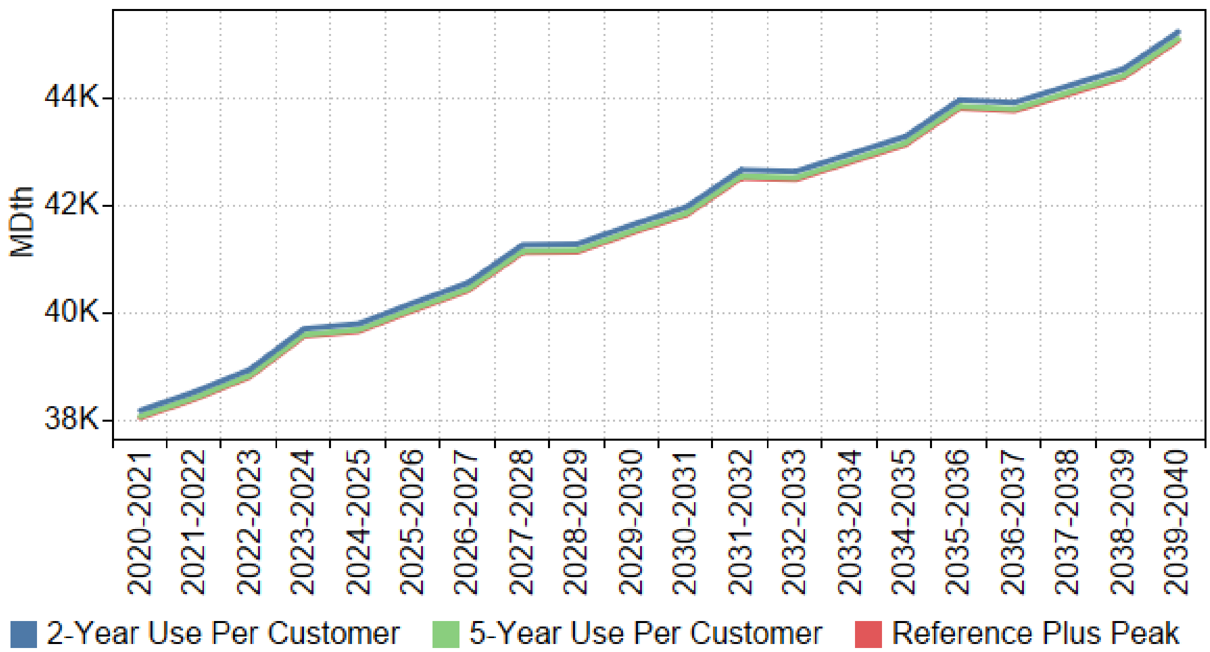
The first step in developing demand coefficients was gathering daily historical gas flow data for Avista city gates. The use of city gate data over revenue data is due to the tight correlation between weather and demand. The revenue system does not capture data daily and, therefore, makes a statistical 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 relatively stable in recent history. The two-year use-per-customer was much more pronounced for demand, likely based on a shorter timeframe for weather to impact the overall use-per-customer.

The three-year coefficient most closely aligns with economic expectations and use within Avista's territories in the short-term forecast. 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.

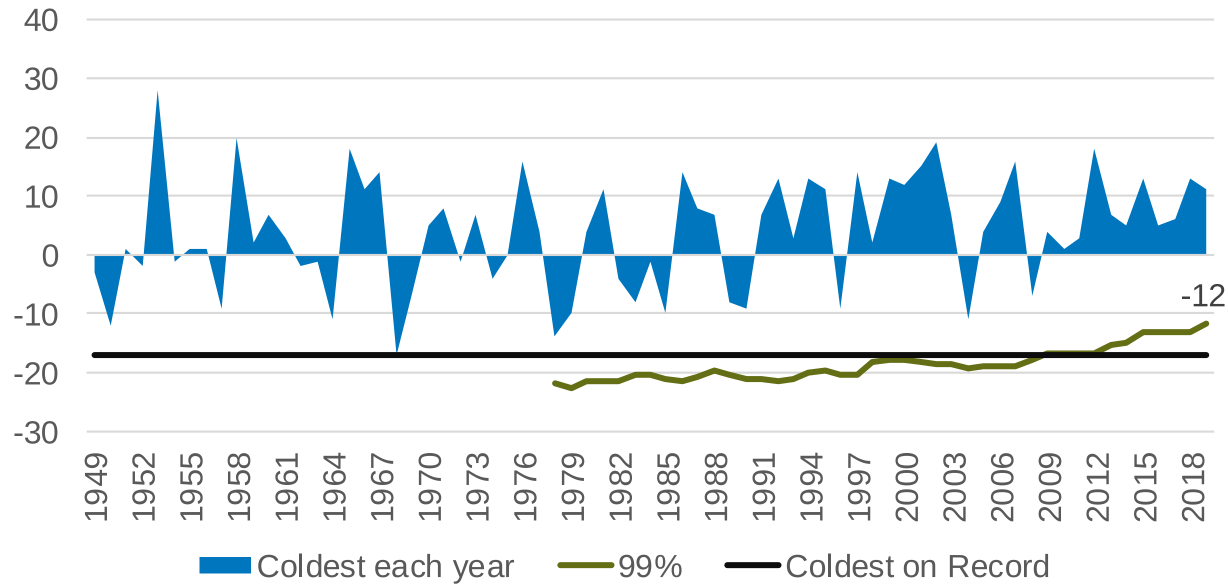
Weather Forecast

The last input in the demand modeling equation is weather. 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. The weather history for the Avista territories modeled within this IRP goes back 70 years and contains minimum, maximum and average weather data. The program utilizes the historic weather data patterns to simulate realistic weather data algorithms when running stochastic simulations.

The weather planning standard is an important piece of system planning for resources in an IRP. In prior IRP's a coldest on record approach was considered the planning standard. With the complexities of changing weather and maintaining a reliable and affordable system, finding a statistical methodology to weigh weather risk and cost risk led to the development of a new weather planning standard methodology. The expected weather planning standard will utilize a coldest average temperature each year for the past thirty years, by planning area, and combine these temperatures with a 99% probability of a weather occurrence. As shown in Figure 2.4. the coldest on record temperature in Washington and Idaho has remained static, ignoring any weather trends. With the updated methodology the 99% will adjust with changing trends in climate. This will ensure capital is not being invested where an event is statistically unlikely to occur. In the planning areas of La Grande and Klamath Falls, OR this peak weather standard has become colder due to the large amount of peak or near peak events in the recent 30-year weather history. This new standard will enhance Avista's ability to plan for peak weather events and paired with stochastic analysis will introduce more rigor and risk analysis into the planning process and climate uncertainty.

Figure 2.4: Spokane Weather Station – Weather Planning Standard Comparison



Utilizing a five-day cold weather event with the new weather planning standard will occur by service territory while adjusting the two days on either side of the planning standard to temperatures colder than average. For the Washington, Idaho and La Grande service territories, the model assumes this event on and around February 28 each year. As discussed in TAC 1, moving the peak day from February 15th to February 28th will allow for availability of resources to serve customers in these late season cold weather events. With supply side resources in the Pacific Northwest growing further constrained, managing supply along with the ability to serve cold days is paramount. 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 a comparison of prior IRP planning standard vs. The updated methodology (Table 2.4).

Table 2.4: Weather Planning Standard

Area	Coldest on Record (Prior IRP's)	99% Probability Avg. Temp
La Grande	-10	-11
Klamath Falls	-7	-9
Medford	4	11
Roseburg	10	14
Spokane	-17	-12

Warming trends are beginning to emerge in Roseburg and Medford, though the volatility surrounding the peak is still present as seen in Figures 2.6 and 2.9. 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 for the months of December, January and February.

Figure 2.5: Spokane

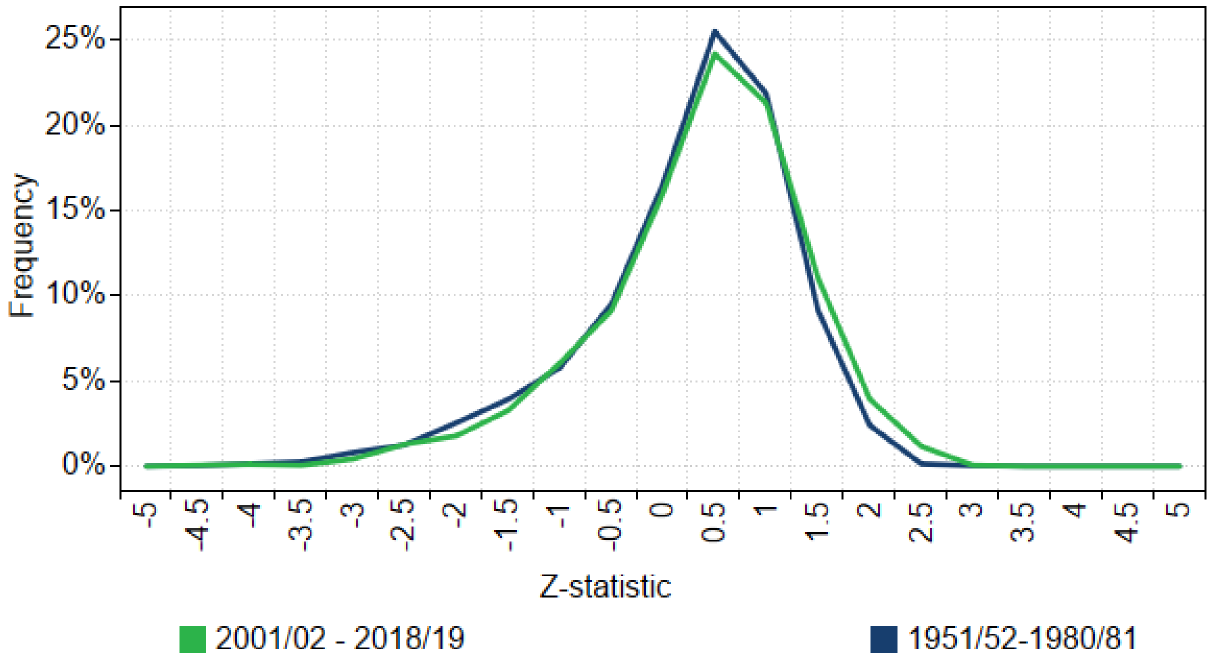


Figure 2.6: Medford

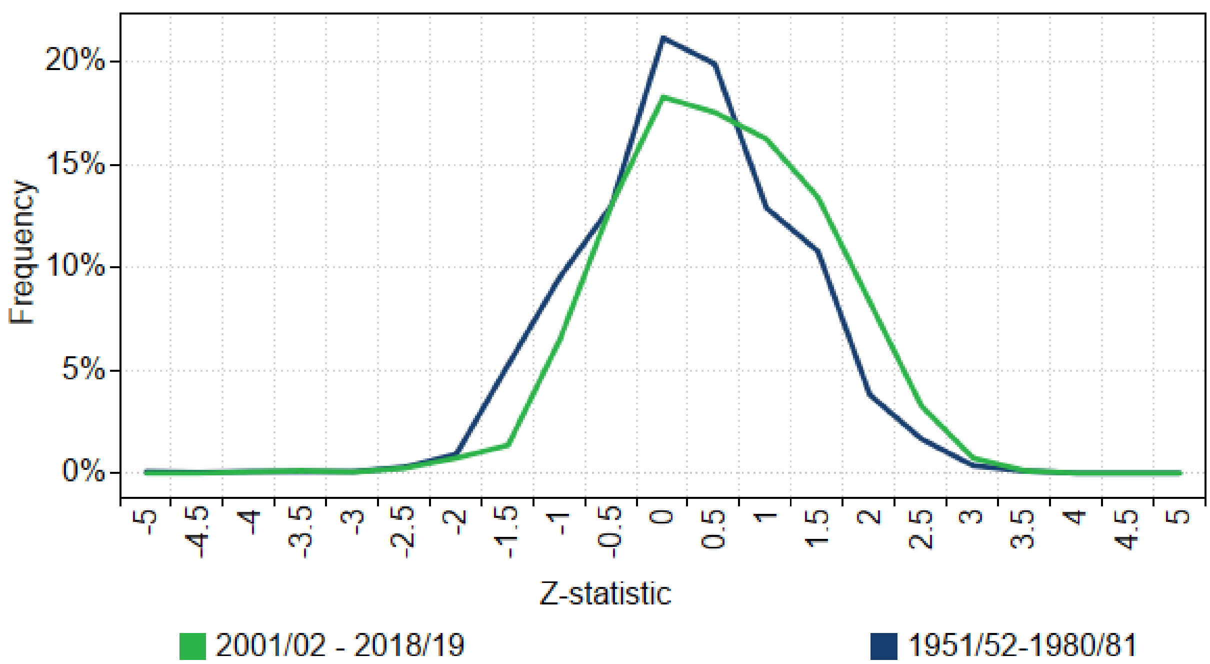


Figure 2.7: La Grande

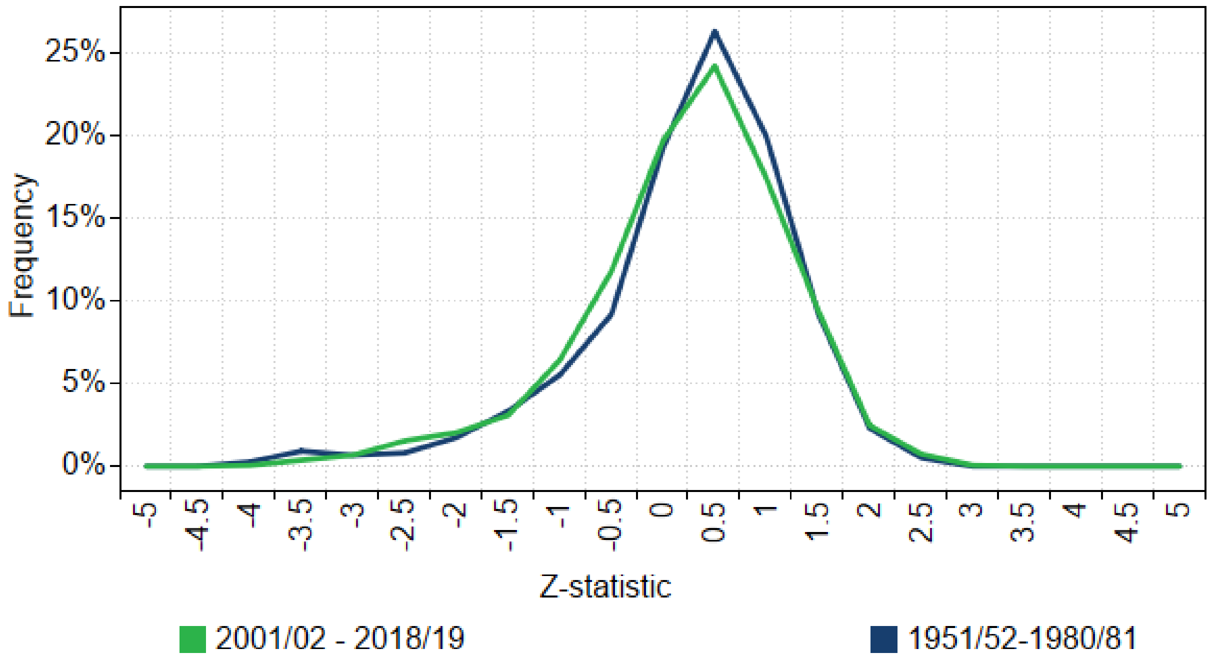


Figure 2.8: Klamath Falls

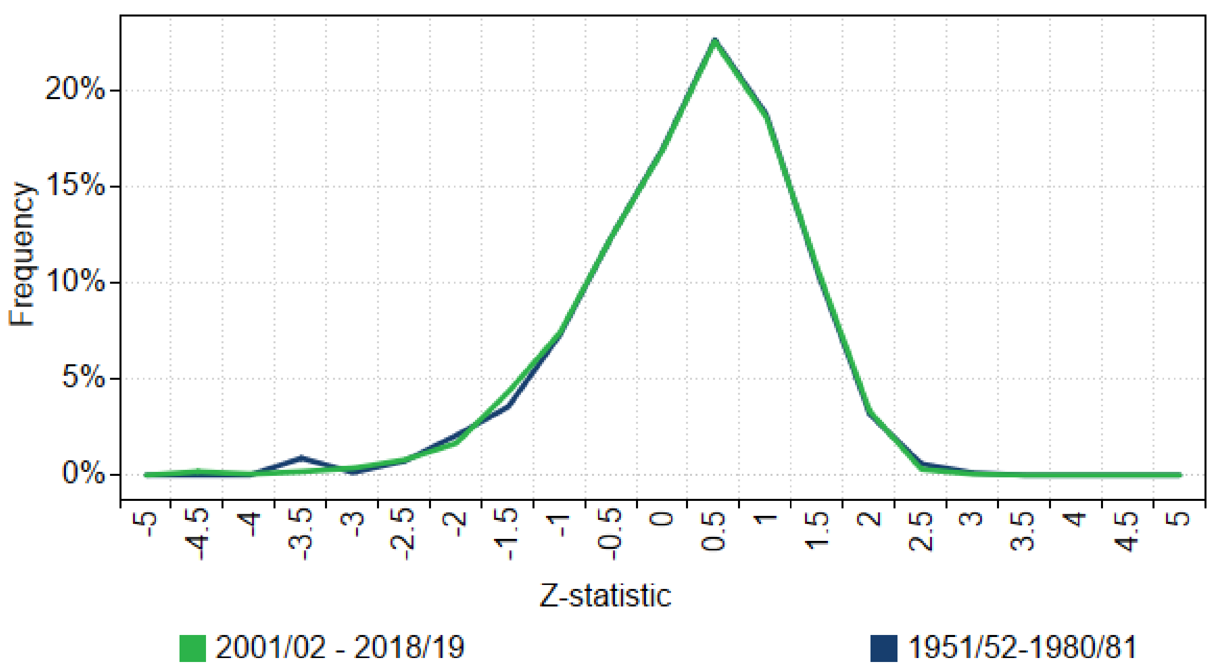
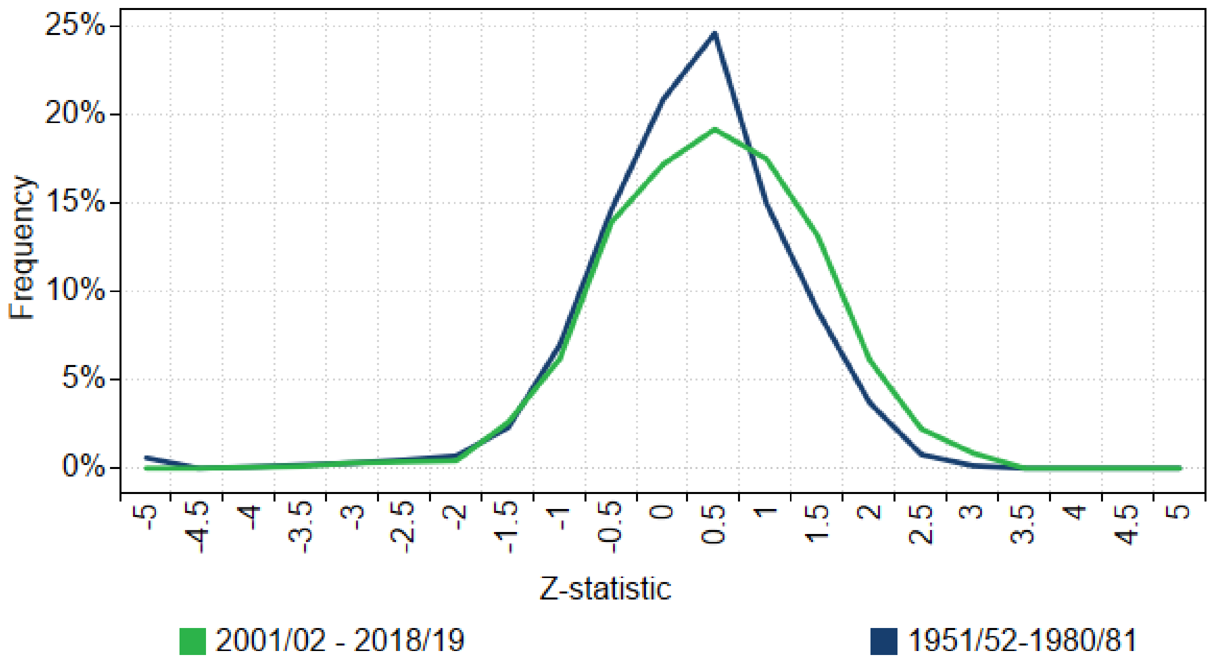


Figure 2.9: Roseburg



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 2.10. This case is only a starting point to compare other cases.

Figure 2.10: Reference Case Assumptions

1. **Customer Compound Annual Growth Rates**

Area	Residential	Commercial	Industrial
Idaho	1.4%	0.4%	-1.0%
Oregon	0.7%	0.6%	0.0%
Washington	1.0%	0.4%	-0.08%
System	**1.0%**	**0.5%**	**-0.8%**

2. **Use-Per-Customer Coefficients**

   Mostly Flat Across All Classes

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

3. **Weather**

   20-year Normal – NOAA (2000-2019)

4. **Elasticity**

   None

5. Conservation

None

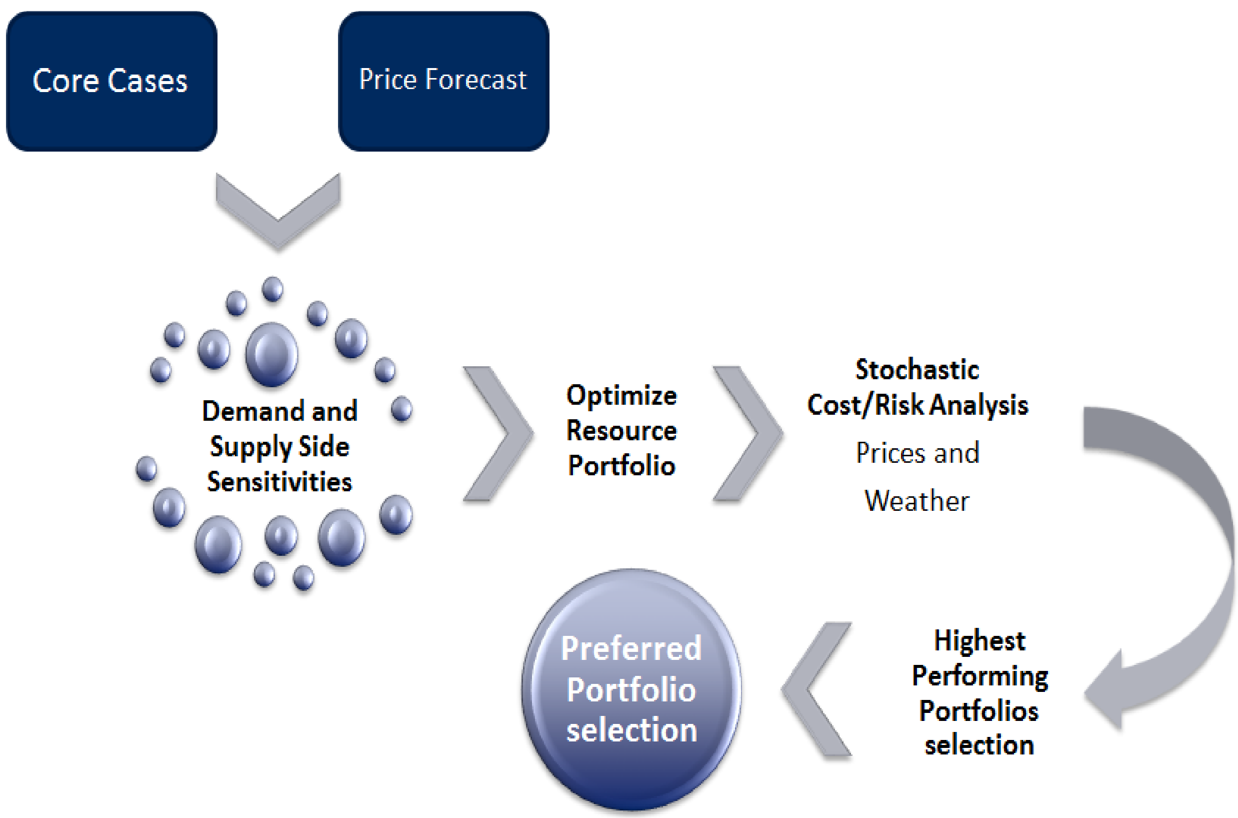
Dynamic Demand Methodology

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

Figure 2.11: Sensitivities and Preferred Portfolio Selection



Sensitivity Analysis

In analyzing demand drivers, Avista grouped them into three 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.
- Emissions Influencing Factors directly influencing the volume of gas and the price elasticity response.

After identifying demand, price, and emissions 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.

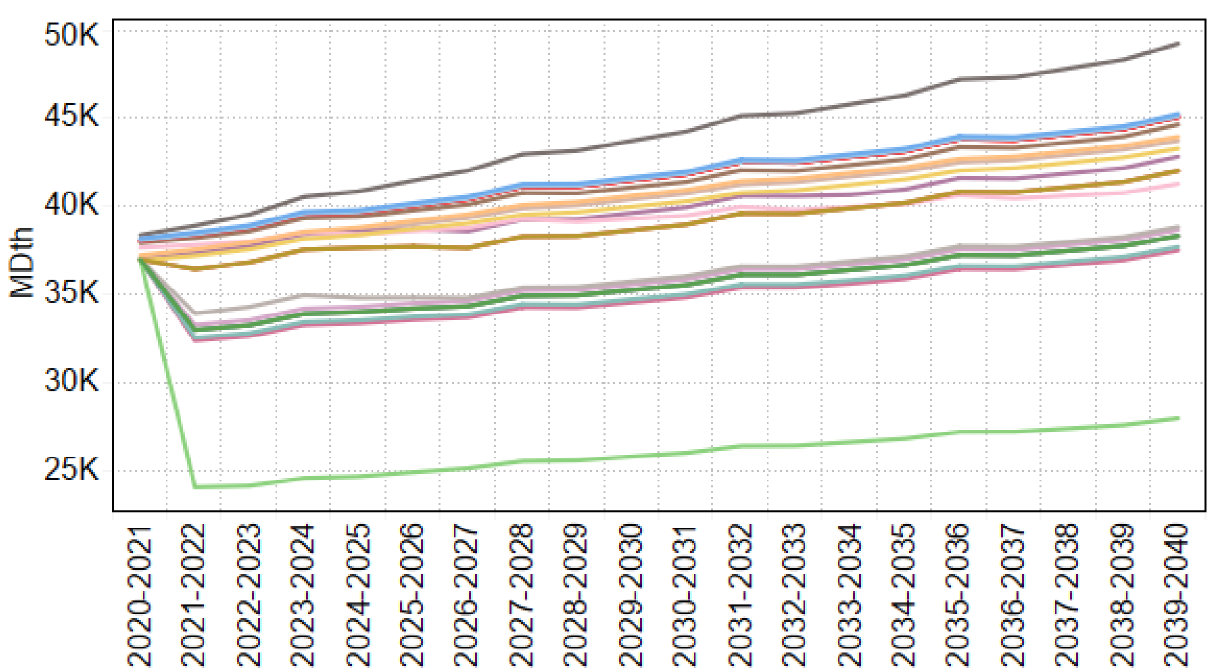
Sensitivity assumptions reflect incremental adjustments not captured in the underlying Reference Case forecast. Avista analyzed 33 demand sensitivities to determine the results relative to the Reference Case. Table 2.5 lists these sensitivities. Detailed information about these sensitivities is in Appendix 2.5 – Demand Forecast Sensitivities and Scenarios Descriptions.

Table 2.5: Demand Sensitivities

Influence Type	Chart Color	Sensitivity	Customer Growth Rate	Use per Customer	Weather	Demand Side Management	Prices	Elasticity	First Year System Unserved	Location Unserved
DEMAND INFLUENCING - DIRECT		Reference	Reference	3 Year Historical	20 Year Average	None	Expected	None	-	
		Reference Plus Peak			Planning Standard				2035	Washington
		Low Cust	Low Growth						-	
		High Cust	High Growth						2029	Washington
		Alternate Weather Standard	Reference		Coldest in 20yrs				2035	Washington
		DSM			20 Year Average	Expected			-	
		Peak plus DSM			Planning Standard				2036	Washington
		80% below 1990 emissions				None			2035	Washington
		2 Year use per customer Alternate		2 Year Historical					2035	Washington
		5 Year use per customer Alternate		5 Year Historical					2035	Washington
		JP Outage Only (0% capacity)		3 Year Historical					2021	Washington
		AECO Outage Only (0% capacity)							2020	WA, ID
		Sumas Outage Only (0% capacity)							2020	Medford
		Rockies Outage Only (0% capacity)							2020	La Grande
		JP Outage Only (50% capacity)							2021	Washington
		AECO Outage Only (50% capacity)							2026	Washington
		Sumas Outage Only (50% capacity)							2025	Washington
		Rockies Outage Only (50% capacity)							2025	La Grande
		NWP Outage (0% capacity)							2020	WA, ID, La Grande
		GTN Outage (0% capacity)							2020	WA, ID, Klamath Falls
		NWP Outage (50% capacity)							2020	WA, La Grande
		GTN Outage (50% capacity)							2026	Washington
PRICE INFLUENCING - INDIRECT		Expected Prices						Expected	-	
		Low Prices					Low		-	
		High Prices					High		-	
		Carbon Cost - High (SCC 95% at 3%)					Expected		-	
		Carbon Cost - Expected (SCC 2.5% (WA) & Cap&Red (OR))							-	
		Carbon Cost - Low $0							-	
EMISSIONS INFLUENCING		High Upstream Emissions 2.47% leakage (EDF study)							-	
		Expected Upstream Emissions (0.79% leakage)							-	
		No Upstream Emissions							-	
		Expected Global Warming Potential (20 Years)							-	
		Expected Global Warming Potential (100 Years)							-	

Figure 2.12 shows the annual demand from each of the sensitivities modeled for this IRP with the associated legend colors in Table 2.5.

Figure 2.12: 2021 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 2.6 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 Carbon Reduction 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 level. 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.

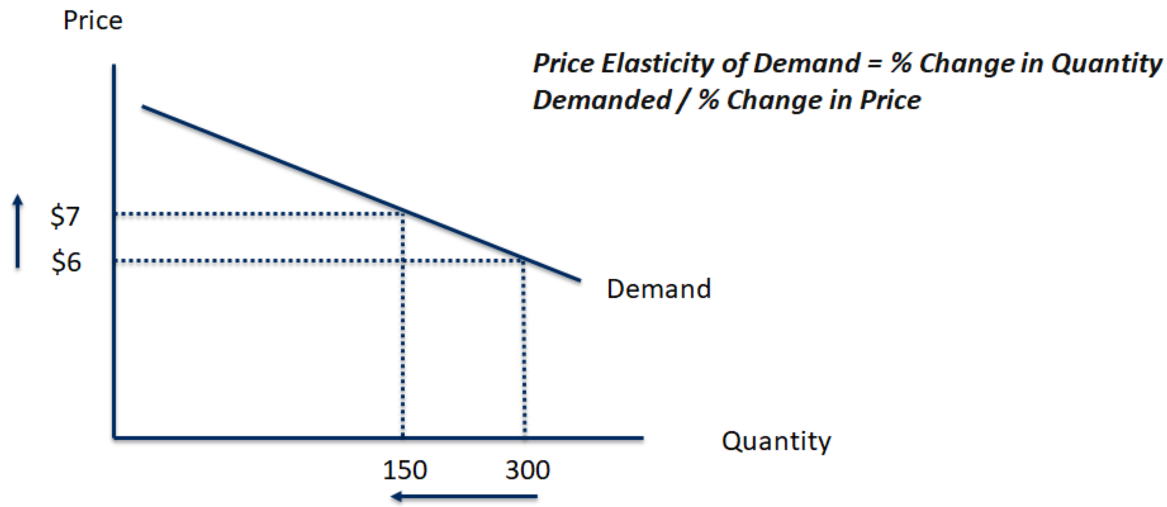
Table 2.6: Demand Scenarios

2021 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Carbon Reduction

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 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. An example of price elasticity is depicted in Figure 2.13:

Figure 2.13: Price Elasticity Example



Complex regulatory pricing mechanisms shield customers from price volatility, thereby dampening price signals and affecting price elastic responses. For example, comfort level 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.[1] 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 -0.081 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

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

including increased investments in energy DSM measures, building code improvements, behavioral changes, and heightened focus of consumers' household budgets.

Results

During 2021, the Average Case demand forecast indicates Avista will serve an average of 366,157 core natural gas customers with 34,720,917 Dth of natural gas. By 2040, Avista projects 442,863 core natural gas customers with an annual demand of over 37,351,708 Dth. In Washington/Idaho, the projected number of customers increases at an average annual rate of 1.11 percent, with demand growing at a compounded average annual rate of 0.33 percent. In Oregon, the projected number of customers increases at an average annual rate of 0.75 percent, with demand growing 0.54 percent per year.

The Expected Case demand forecast indicates Avista will serve an average of 366,157 core natural gas customers with 35,440,513 Dth of natural gas in 2021. By 2040, Avista projects 442,863 core natural gas customers with an annual demand of 37,987,712 Dth.

Figure 2.14 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[2]

Figure 2.14: Average Daily Demand – 2021 IRP Scenarios

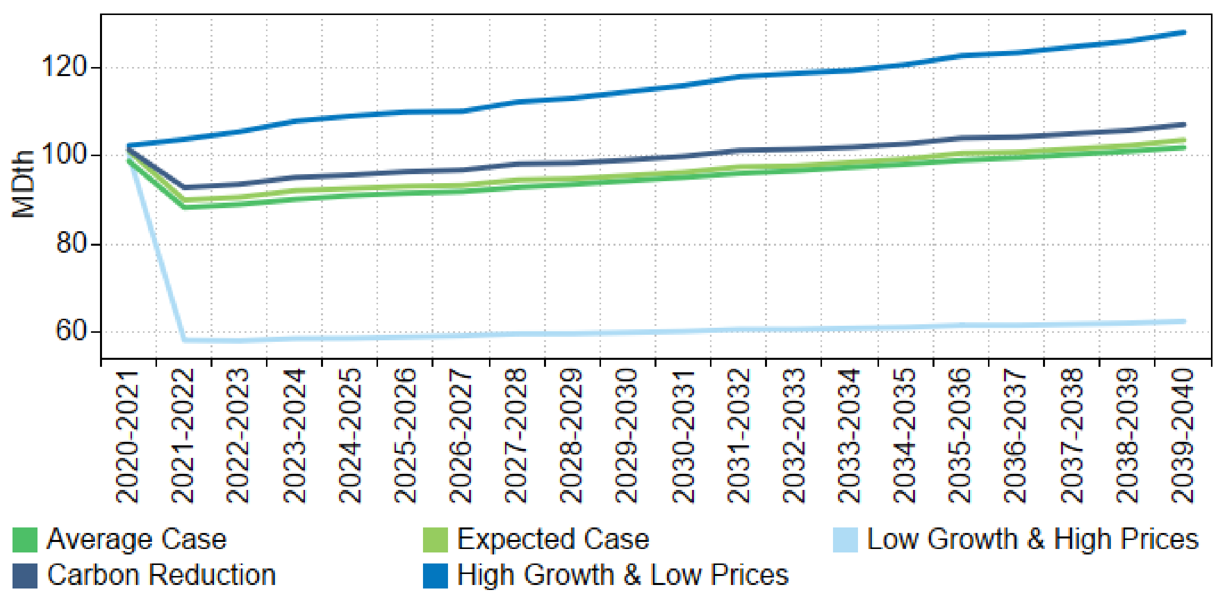
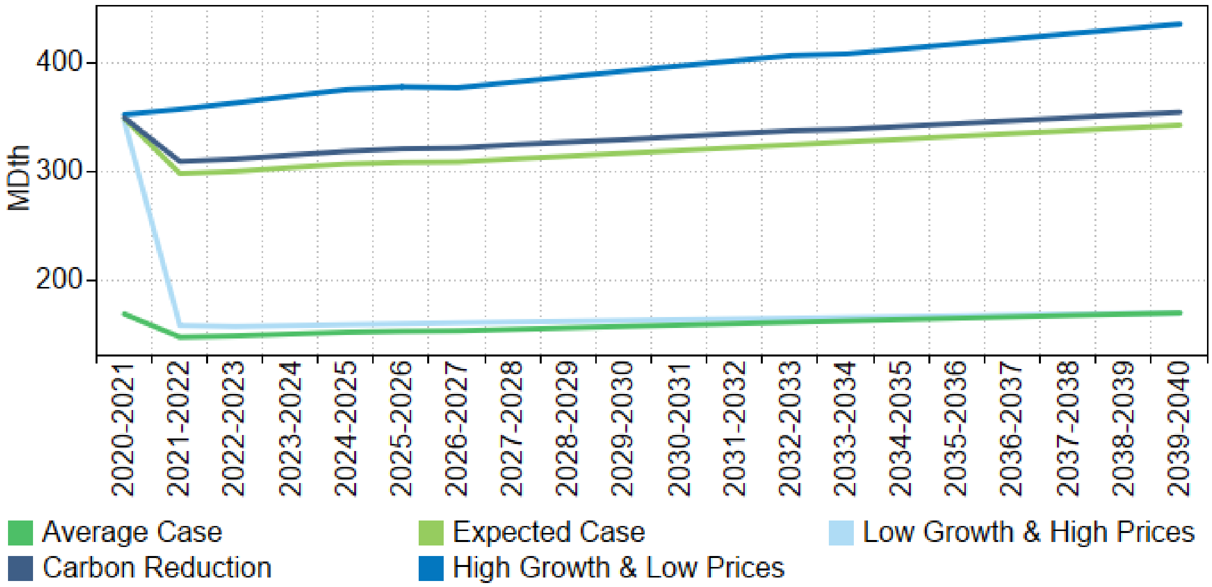


Figure 2.15 shows system forecasted demand for the Expected, High and Low Demand cases on a peak day basis for each year relative to the Average Case average daily winter

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

demand. Detailed data for all demand scenarios is in Appendix 2.8 – Demand Before and After DSM.

Figure 2.15: February 28th – Peak Day – 2021 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 while allowing 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 in some areas.

This reduced demand pushes the need for resources beyond the planning horizon, which means no new investment in resources is necessary from an energy standpoint. However, as discussed in Chapter 5 – Carbon Reduction, policy may change the resource demand for fossil fuels based on carbon reduction goals where new carbon reducing resources will be required to help meet these targets. Monitoring both growth and policy changes is key to managing assets needed to serve customers energy demand in all types of weather.

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 decade. 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 decreased by nearly 1,400 customers, as compared to Avista's 2018 IRP. With the inclusion 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: Demand Side Resources

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 aid 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.

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].

Avista issued an RFP and chose Applied Energy Group (AEG) to perform an external independent evaluation of Avista's conservation potential in Idaho and Washington while ETO continues to evaluate and manage DSM in Oregon. Included with these evaluations was the technical, economic and achievable conservation potential for each state over a 20-year planning horizon (2021-2040).

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

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 and ETO to use in selecting cost-effective potential within Avista's service territories.

Applied Energy Group (AEG): Idaho and Washington - CPA

Avista Early in 2020, Avista Utilities (Avista) contracted with Applied Energy Group (AEG) to conduct this Conservation Potential Assessment (CPA) in support of their conservation and resource planning activities. This report documents this effort and provides estimates of the potential reductions in annual energy usage for natural gas customers in Avista's Washington and Idaho service territories from energy conservation efforts in the time period of 2021 to 2040. To produce a reliable and transparent estimate of energy efficiency (EE) resource potential, the AEG team performed the following tasks to meet Avista's key objectives:

- Used information and data from Avista, as well as secondary data sources, to describe how customers currently use gas by sector, segment, end use and technology.
- Developed a baseline projection of how customers are likely to use gas in absence of future EE programs. This defines the metric against which future program savings are measured. This projection used up-to-date technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation that will impact energy EE potential.
- Estimated the technical, achievable technical, and achievable economic potential at the measure level for energy efficiency within Avista's service territory over the 2021 to 2040 planning horizon.
- Delivered a fully configured end-use conservation planning model, LoadMAP, for Avista to use in future potential and resource planning initiatives
- In summary, the potential study provided a solid foundation for the development of Avista's energy savings targets.

Table ES-1 summarizes the results for Avista's Washington territory at a high level. AEG analyzed potential for the residential, commercial, and industrial market sectors. First-year utility cost test (UCT) achievable economic potential in Washington is 75,820 dekatherms. This increases to a cumulative total of 173,838 dekatherms in the second year and 1,386,479 dekatherms by the tenth year (2030).

Table ES-1: Washington Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	19,118,293	19,289,575	19,805,020	20,612,516	21,619,876
Cumulative Savings (Dth)					
UCT Achievable Economic	75,820	173,838	457,423	1,386,479	3,560,512
Achievable Technical	41,871	416,584	1,221,810	3,183,398	6,309,826
Technical	187,983	897,098	2,314,334	5,084,999	8,908,493
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.3%	6.7%	16.5%
Achievable Technical Potential	0.2%	2.2%	6.2%	15.4%	29.2%
Technical Potential	1.0%	4.7%	11.7%	24.7%	41.2%

Table ES-2 summarizes the results for Avista's Idaho territory at a high level. First-year utility cost test (UCT) achievable economic potential in Idaho is 35,816 dekatherms. This increases to a cumulative total of 87,995 dekatherms in the second year and 737,710 dekatherms by the tenth year (2030).

Table ES-2: Idaho Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	10,019,377	10,144,894	10,520,169	11,004,568	12,006,819
Cumulative Savings (Dth)					
UCT Achievable Economic	35,816	87,995	229,283	737,710	2,025,410
Achievable Technical	26,220	226,613	657,997	1,722,830	3,544,048
Technical	102,031	490,826	1,273,202	2,777,509	5,013,697
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.2%	6.7%	16.9%
Achievable Technical Potential	0.3%	2.2%	6.3%	15.7%	29.5%
Technical Potential	1.0%	4.8%	12.1%	25.2%	41.8%

As part of this study, we also estimated total resource cost (TRC) potential, with the focus of fully balancing non-energy impacts. This includes the use of full measure costs as well as quantified and monetizable non-energy impacts and non-gas fuel impacts (e.g. electric cooling or wood secondary heating) consistent with methodology within the 2021 Northwest Conservation and Electric Power Plan (2021 Plan). We explore this potential in more detail throughout the report.

The entire CPA report including the methodology can be found in Appendix 3.1.

Energy Trust of Oregon - CPA

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.[2]

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 as a single entity across the five overlapping service territories of Oregon's investor-owned gas and electric utilities has experienced a great deal of success. Since its inception, Energy Trust has saved more than 783 aMW of electricity and 71 million annual therms. This equates to more than 32.7 million tons of CO_2 emissions avoided and is a significant factor contributing to the relatively flat or lower energy sales observed by both gas and electric utilities from 2009 to 2018, as shown in OPUC utility statistic books.[3]

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. In 2019, Energy Trust's programs achieved savings of 384,000 therms—equivalent to 107% of the established savings goal of 360,000 therms, as shown in Figure 3.1.

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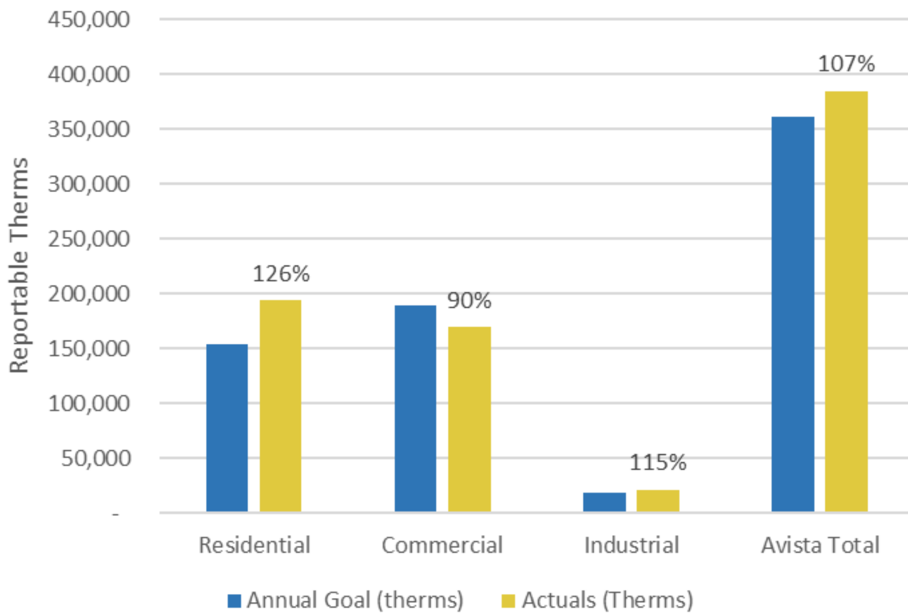
[2] In 2007, Oregon's Renewable Energy Act (SB 838) allowed the electric utilities to capture additional, cost-effective electric efficiency above what could be obtained through the 3 percent charge, thereby avoiding the need to purchase more expensive electricity. This new supplemental funding, combined with revenues from natural gas utility customers, increased Energy Trust revenues from about $30 million in 2002 to $182 million in 2020.

[3] OPUC 2018 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2018-Oregon-Utility-Statistics-Book.pdf

Figure 3.1: 2019 Achieved Savings vs. Goals for Avista Service Territory



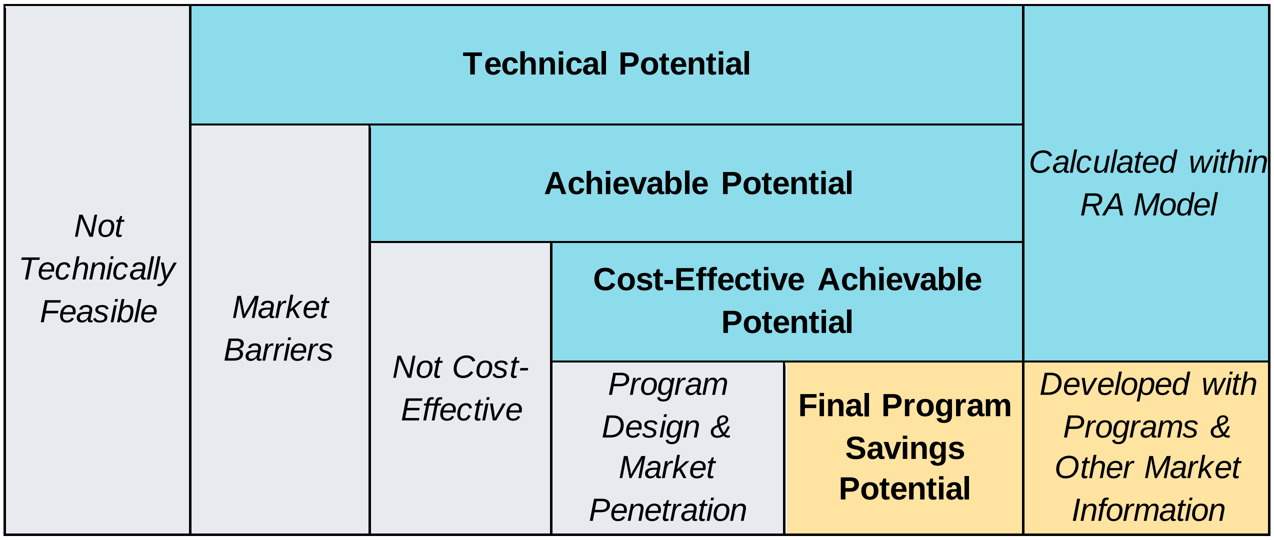
In addition to administering energy efficiency programs on behalf of the utilities, Energy Trust also provides each utility with a 20-year forecast of cost-effective energy efficiency savings potential expected to be achieved by Energy Trust. The results are used by Avista and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential in their territory that can be used to meet their customers' projected load.

Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a DSM resource forecast for Avista using its resource assessment modeling tool (hereinafter the "RA Model") to identify the total 20-year cost-effective modeled savings potential. This potential is subsequently 'deployed' exogenously of the model to estimate the final savings forecast for each of the 20 years. There are four types of potential that are calculated to develop the final savings potential estimate. These are shown in Figure 3.2 and discussed in greater detail in the sections below.

Figure 3.2: Types of Potential Calculated in 20-Year Forecast Determination



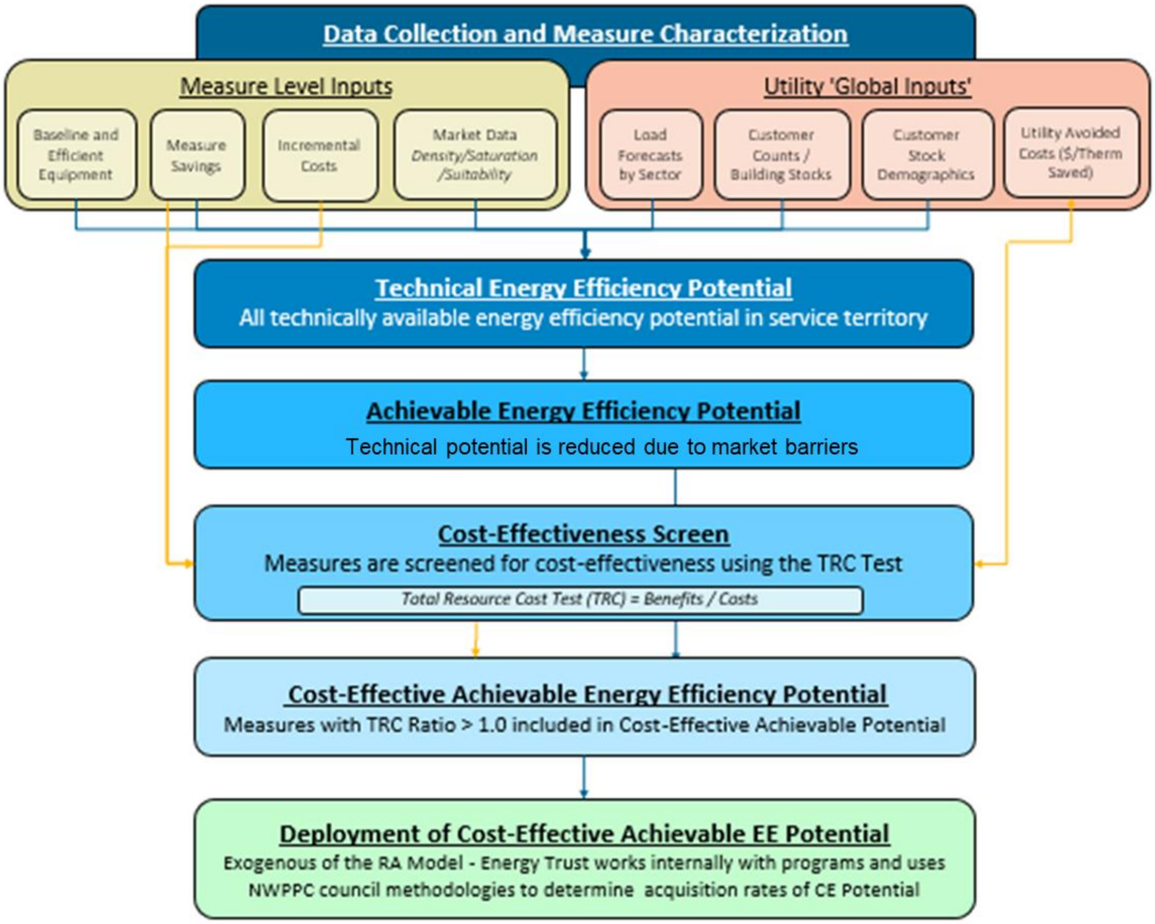
The RA Model utilizes the modeling platform Analytica®[4], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, 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 3.3. 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 on each of the steps shown below.

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

Figure 3.3: 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.[5] In addition to identifying and characterizing applicable measures, Energy Trust collects necessary data to scale the measure level savings to a given service territory (known as 'global inputs').

[5] 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.

- ***Measure Level Inputs:***
  Once the measures have been identified for inclusion in the model, 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[6], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are organized 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% AFUE furnace replacing an 80% AFUE baseline furnace). A measure's replacement type is also determined in this step – retrofit, replace on burnout, or new construction.
  2. ***Measure Savings****:* natural gas 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 retrofit measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a replace on burnout or new construction measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline equipment.
  4. ***Market Data****:* Market data of a measure includes the density, saturation, and suitability of a measure. The density is the number of measure units that can be installed per scaling basis (e.g., the average number of showers per home for showerhead measures). Saturation is the share of equipment that is already efficient (e.g., 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage that represents the percent of installation opportunities where the measure can actually be installed. For example, a duct sealing measure would need to reflect the share of homes that actually have ducted heating systems. These data inputs are generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments.
- ***Utility Global Inputs:***
  The RA Model requires several utility-level inputs to create the DSM forecast. These inputs include:

[6] 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)

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 ‘per home’ scaling basis, so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that Avista has forecasted 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 customer building stock that utilize different fuels for space and water heating. The RA Model uses these inputs to segment the total stock to the portion that is applicable to a measure (e.g., gas 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 savings. Energy Trust calculates these values based on inputs provided by Avista. The avoided cost 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 energy savings potential of a measure that could be achieved regardless of cost or market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units of 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*

This savings potential does <u>not</u> consider the various cost and market barriers that will limit the adoption of efficiency measures.

3. **Calculate Achievable Energy Efficiency Potential**
   Achievable potential is simply a reduction of the technical potential to account for market barriers that prevent the adoption of the measures identified in the technical potential. This is done by applying a factor to reflect the maximum achievability for each measure. For Avista's 2020 IRP, Energy Trust updated its methodology to reflect the maximum achievability estimated by the Northwest Power and Conservation Council for the 2021 Power Plan. While in past power plans a universal assumption of 85% was used, these factors now typically range from 85% to 95%.[7]

Achievable Potential =	*Technical Potential * Maximum Achievability Factor*

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. This test evaluates the total present value of all benefits attributable to the measure divided by the total present value of all costs. A TRC test value greater than or equal to 1.0 means the value of benefits is equal to or exceeds the costs and the measure is 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 or operations and maintenance cost reductions from advanced controls).

Where the *Present Value of Costs* includes:

a) Incentives paid to the participant; and

[7] For details on this, see https://www.nwcouncil.org/sites/default/files/2019_0813_p5.pdf.

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

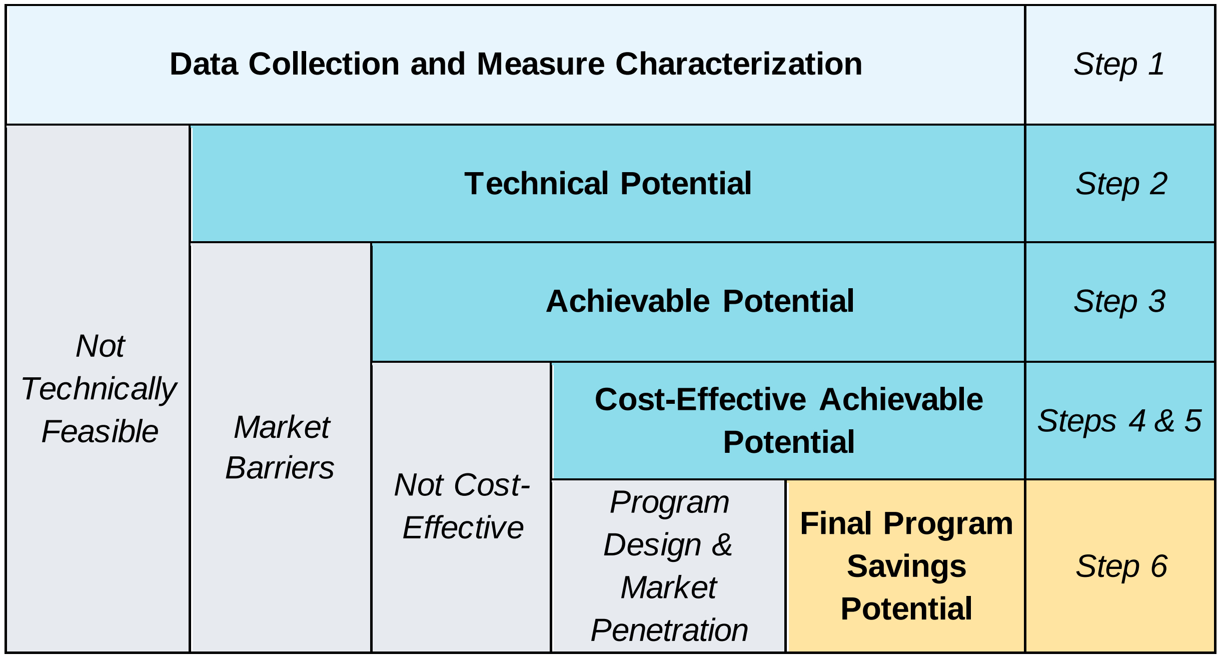
The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures unless an exception has been granted by the OPUC.

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 the achievable savings from a measure is included in this potential. If the measure does not pass the TRC test above, the measure's potential 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 is not 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 savings from very large projects that are not characterized in Energy Trust's RA Model but 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.

Figure 3.4 below reiterates the types of potential shown in Figure 3.2, and how the steps described above and in the flow chart fit together.

Figure 3.4: The Progression to Program Savings Projections



Forecast Results

The results of Energy Trust's forecast are shown below.

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. These results do not include the application of ramp rates applied in Step 6 described above.

Forecasted Savings by Sector

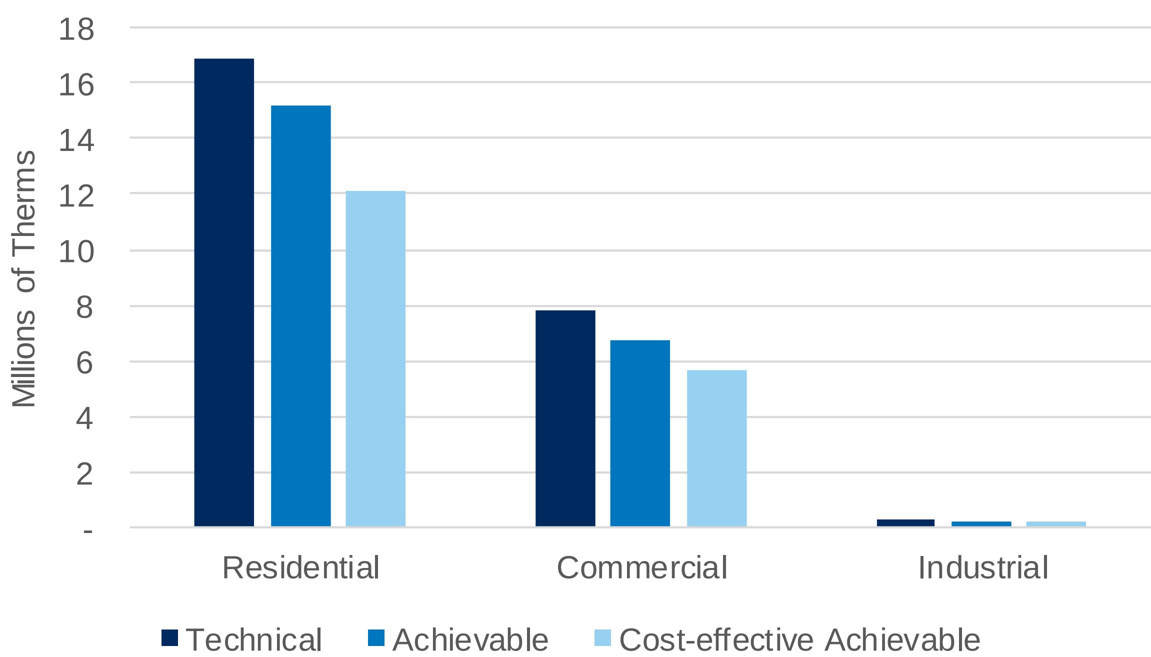
Table 3.3 summarizes the technical, achievable, and cost-effective potential for Avista's system in Oregon. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Figure 3.4 above. Modeled savings represent the full spectrum 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 3.3: Summary of Cumulative Modeled Savings Potential - 2021–2040

Sector	Technical Potential (Million Therms)	Achievable Potential (Million Therms)	Cost-Effective Achievable Potential (Million Therms)
Residential	16.9	15.2	12.1
Commercial	7.8	6.8	5.7
Industrial	0.3	0.2	0.2
Total	**24.9**	**22.2**	**18.0**

Figure 3.5 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 small 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. 85% of the industrial technical potential is cost-effective, while in the residential and commercial sectors, cost-effective achievable potential is 72% and 73% of technical potential, respectively.

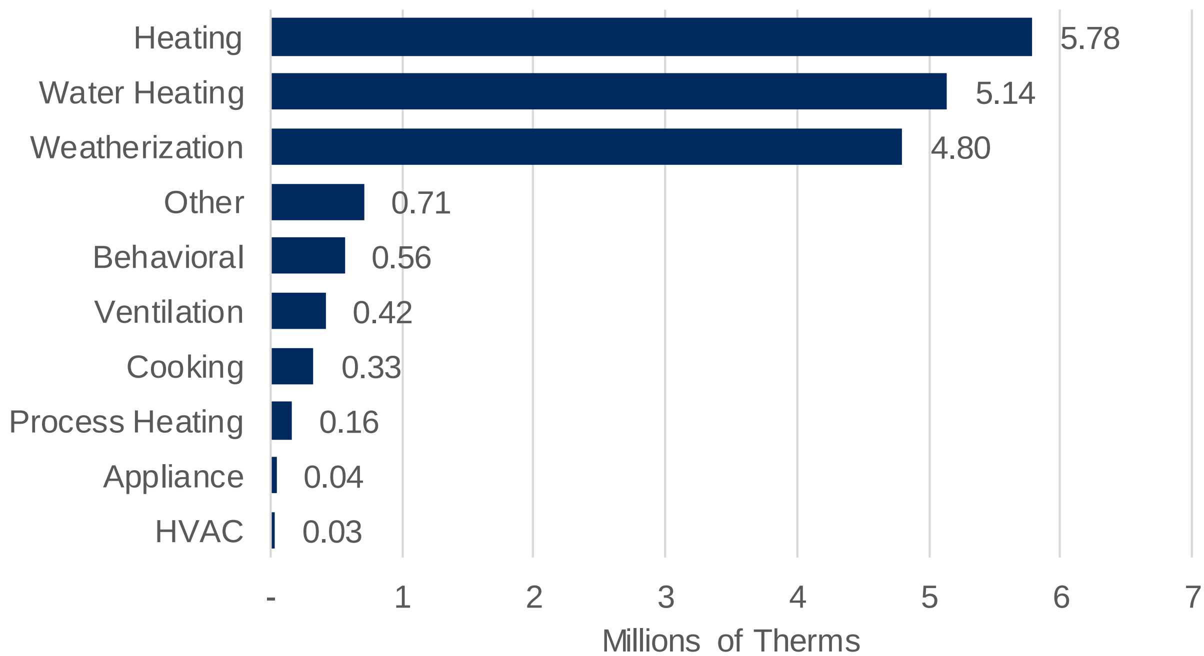
Figure 3.5: Savings Potential by Sector and Type – Cumulative 2021–2040 (Millions of Therms)



Cost-Effective Achievable Savings by End-Use

Figure 3.6 below provides a breakdown of Avista's 20-year cost-effective savings potential by end use.

Figure 3.6: 20-Year Cost-Effective Cumulative Potential by End Use



As is typical for a gas utility, the top saving end uses are heating, water heating, 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 New Homes pathways offered through Energy Trust's residential programs. The New Home pathways are packages of measures in new construction homes with savings that span several end-uses. Energy Trust assigns an end-use to each of the New Homes pathways based on the end-use that achieves the most significant savings in 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. Heating, weatherization, and HVAC end uses represent the savings associated with space heating equipment, retrofit add-ons, and new construction packages. The behavioral end use consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training and support 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 in its model. The emerging technologies included in the model are listed in Table 3.4.

Table 3.4: Emerging Technologies Included in the Model

Residential	Commercial	Industrial
• Path 5 Emerging Super-Efficient Whole Home • Window Replacement (U<.20) • Absorption Gas Heat Pump Water Heaters • Advanced Insulation	• DOAS/HRV • Gas-fired Heat Pump Hot Water • Gas-fired Heat Pump, Heating • Advanced Windows	• Gas-fired Heat Pump Water Heater • Wall Insulation-Vacuum Insulated Panel, R0-R35

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

- Market risk
- Technical risk
- Data source risk

The framework for assigning the risk factor is shown in Table 3.5. Each emerging technology was assessed within each risk category and then a total weighted score was then calculated. Well-established and well-studied technologies have lower risk factors and nascent, unevaluated technologies (e.g., gas absorption heat pump water heaters) have higher risk factors. This risk factor is then applied as a multiplier to reduce the incremental savings potential of the measure.

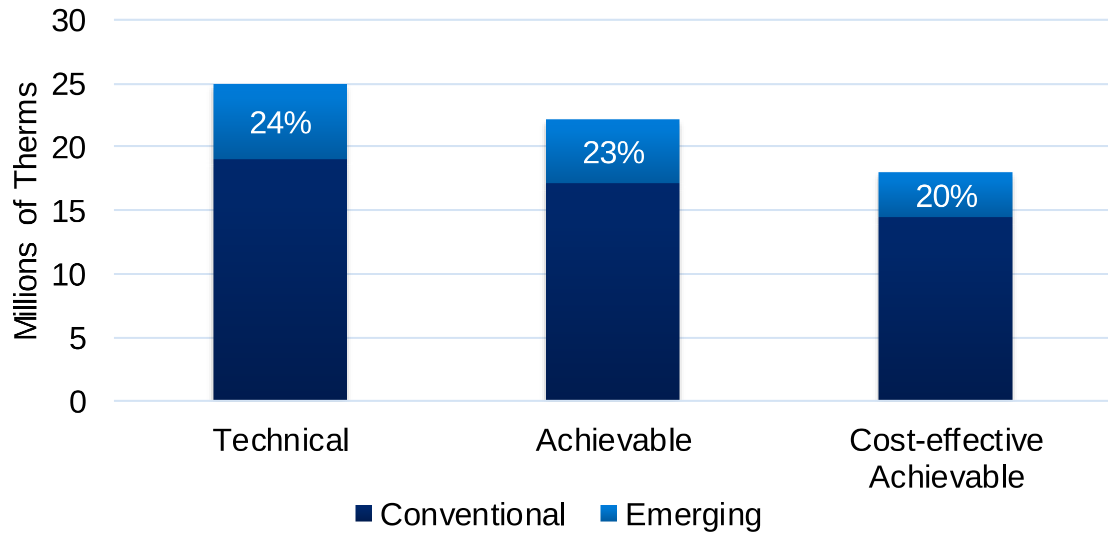
Table 3.5: Emerging Technology Risk Factor Score Card

	Emerging Technology 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 3.7 shows the amount of emerging technology savings within each type of 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 to 20% of total cost-effective achievable potential. This is because some 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 where applicable, some are not cost-effective at any point over the planning horizon.

Figure 3.7: Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 3.6 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 is not 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 3.6: Cumulative Cost-Effective Potential (2021-2040) due to Cost-Effectiveness Override (Millions of therms)

Sector	With Cost Effectiveness Override	Without Cost Effectiveness Override	Difference
Residential	12.1	10.9	(1.2)
Commercial	5.7	5.7	-
Industrial	0.2	0.2	-
Total	**18.0**	**16.8**	**(1.2)**

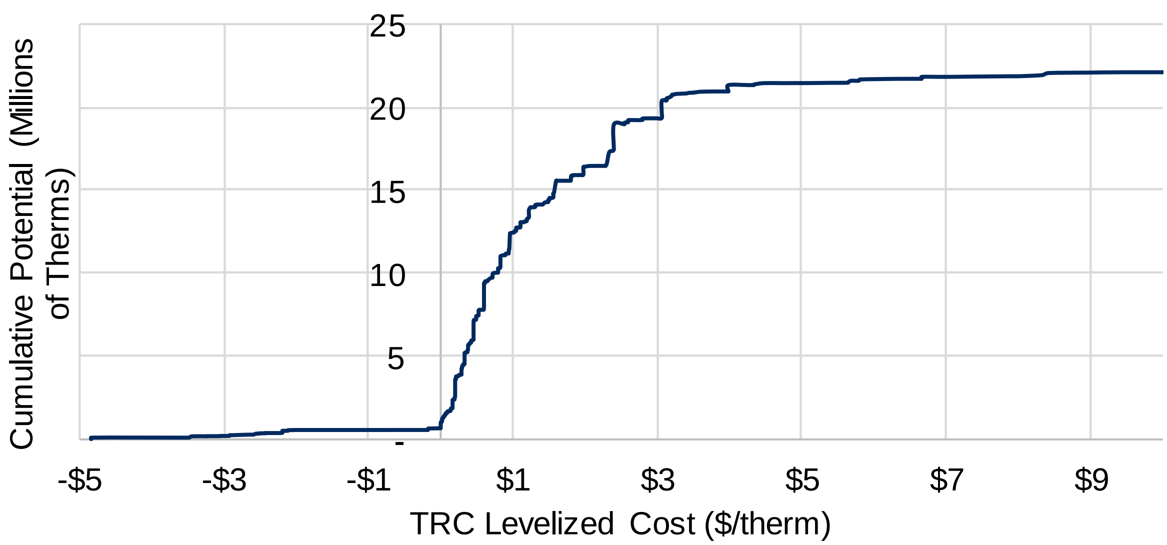
In this IRP, approximately 7% of the cost-effective potential identified by the model is due to the use of the cost-effective override. The measures that had this option applied to them included residential attic, floor, and wall insulation, clothes dryers, certain new homes packages, and clothes washers in the commercial 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 that could be saved at various costs. The levelized cost provides a consistent basis for comparing efficiency measures and other resources with different lifetimes. The levelized cost calculation starts with the incremental cost of a given measure. The total cost is amortized over the estimated measure lifetime using the Avista's discount rate. The annualized measure cost is then divided by the annual natural gas savings. Some measures have negative levelized costs because these measures have non-energy benefits that are greater than the total cost of the measure over the same period.

Figure 3.8 below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The cost-effective potential identified in this assessment is approximately 18 million therms, which translates to approximately $2.40/therm on this graph. This is not a precise point, however, since measures around this point will save natural gas at different times in relation to Avista's peak periods and therefore have varying capacity values that function to make them more or less cost-effective. Consequently, measures on either side of this point may or may not be cost effective. Finally, after approximately $3/therm, additional potential comes at rapidly increasing cost increments.

Figure 3.8: Natural Gas Supply Curve



Deployed Results – Final Savings Projection

The results of the final savings projection show that Energy Trust can achieve 2.1 million annual therm savings across Avista's system in Oregon from 2021 to 2025 and nearly 14.8 million therms by the end of 2040. This represents a 14.4 percent cumulative load reduction by 2040 and is an average of just under a 0.8 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 3.7, which compares the technical, achievable, and cost –effective achievable potential for comparison.

Table 3.7: 20-Year Cumulative Savings Potential by Type (Millions of Therms)

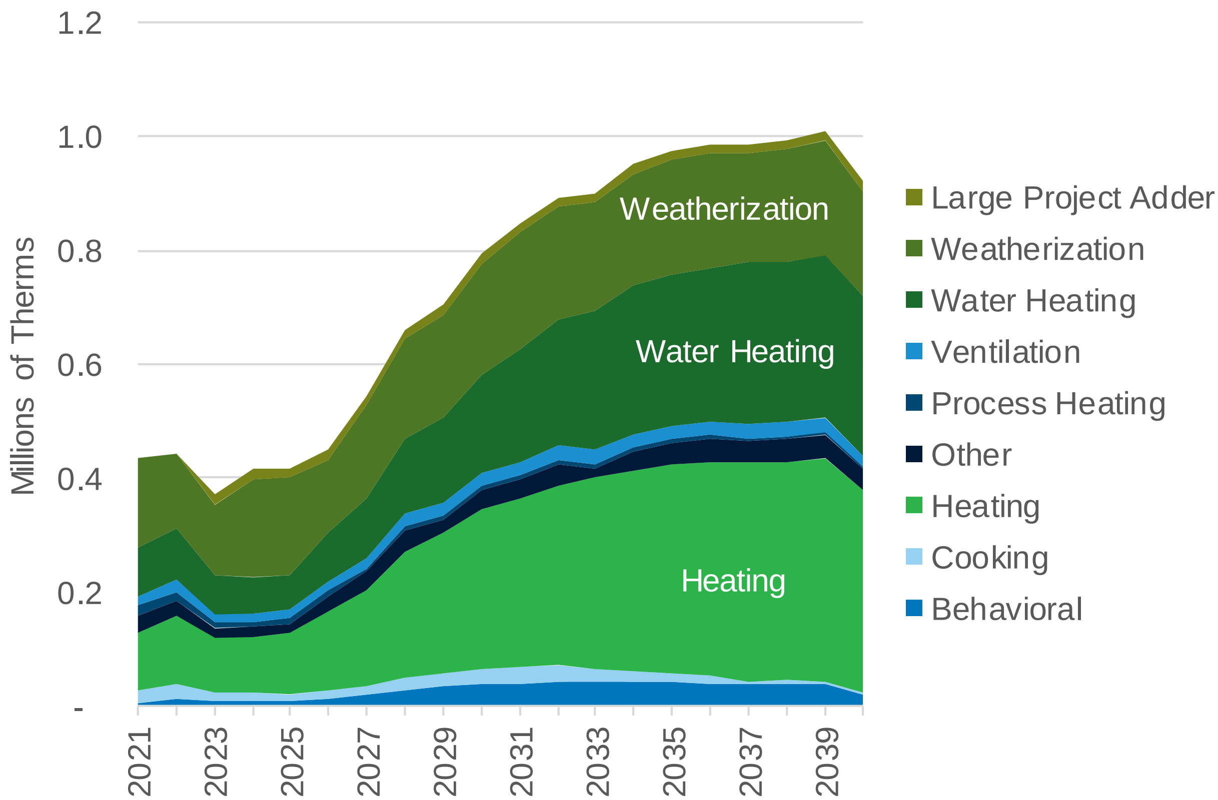
	Technical Potential	Achievable Potential	Achievable Cost-Effective Potential	Energy Trust Deployed Savings Projection
Residential	16.9	15.2	12.1	8.2
Commercial	7.8	6.8	5.7	6.1
Industrial	0.3	0.2	0.2	0.5
Total	**24.9**	**22.2**	**18.0**	**14.8**

The final deployed savings projection is less than the modeled cost-effective achievable potential. The primary reason for this additional step down in savings is lost opportunity measures. These measures are meant to replace failed equipment or be installed in new construction. They are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment 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 the efficient equipment is not installed, then the opportunity is lost until the equipment fails again. Energy Trust assumes that most lost opportunity measures have gradually increasing annual adoption rates as time passes due to increasing program influence and increasing codes and standards.

However, in the commercial and industrial sectors, the final Energy Trust savings projection is higher than the model-identified cost-effective potential. In the commercial sector, new construction savings are difficult to adequately represent in the model and program forecasts exceed the available potential quantified in the RA model. The industrial sector projection is higher because it includes an adder for large projects that are not forecast by the RA model but are nonetheless expected to be acquired over time.

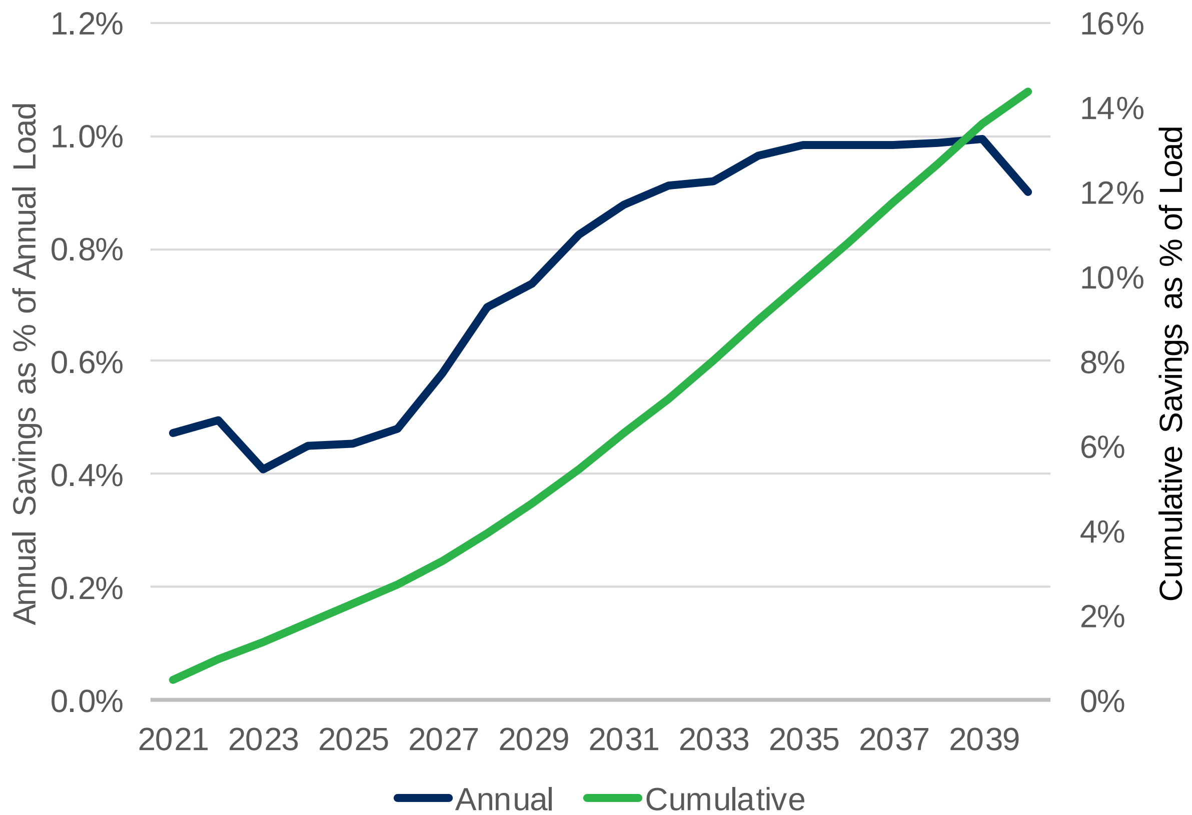
Figure 3.9 below shows the annual savings projection by end use. The savings acquisitions in the initial years are fairly flat due to expected market conditions. After this point, expected program savings ramp up over the forecast period, to achieve as much cost-effective potential as possible.

Figure 3.9: Annual Deployed Final Savings Potential by End Use



Finally, Figure 3.10 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 0.4% at its lowest to just under 1% at its highest, as represented on the left axis and the blue line. Cumulatively, the savings as a percentage of load builds to 14.4% by 2040, as shown on the right axis and the gold line.

Figure 3.10: Annual and Cumulated Forecasted Savings as a Percentage of Avista Load Forecast



Deployed Results – Peak Day Results

In the state of Oregon and around the region, there is an increased focus on the peak 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. 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 and are shown in Table 3.8 below. Avista is still reviewing this methodology and for the purpose of this analysis, Energy Trust utilized the peak day factors that are used in the avoided costs used to screen measure for cost-effectiveness to determine the cost-effective achievable resource per the description above. These include residential and commercial space heating factors developed by NW Natural in and hot water, process load (flat), and clothes washer factors sourced from load shapes developed by 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 3.8: 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 3.11 below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast developed for this IRP. 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 207,427 therms, or 1.4% of the total deployed savings potential in Avista's Oregon service territory over the 20-year forecast, as shown below.

Figure 3.11: Annual Deployed Peak Day DSM Savings Contribution by Sector

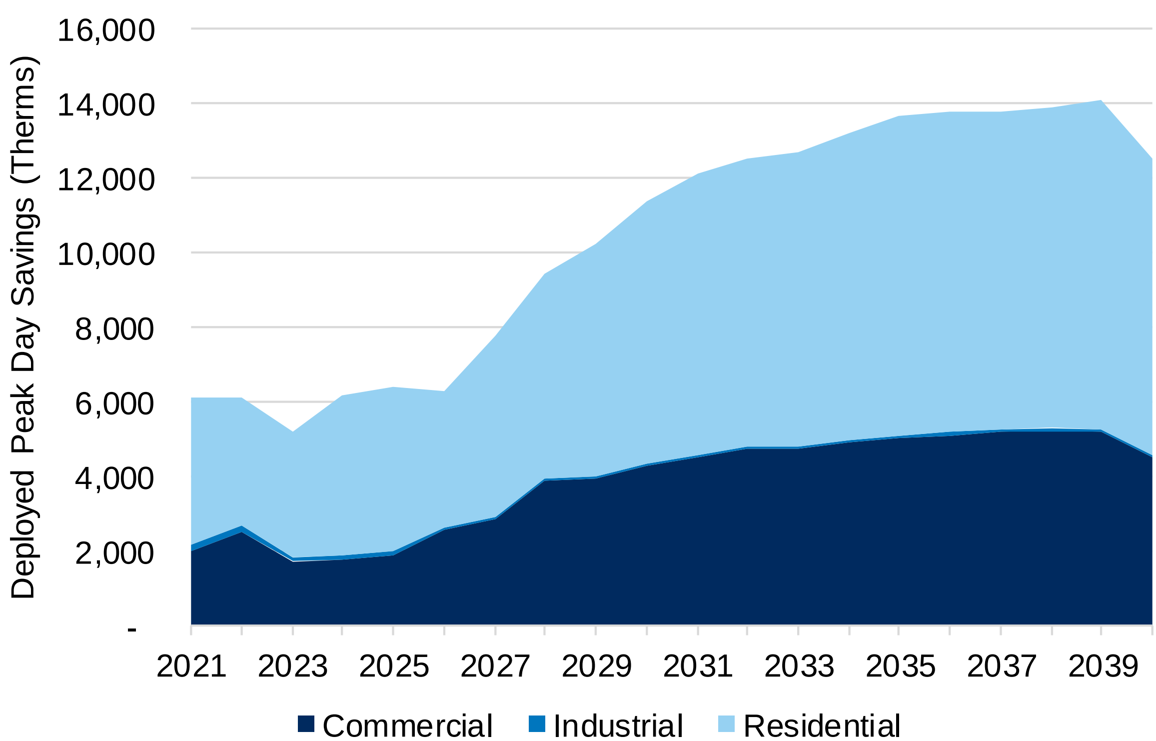


Table 3.9: Cumulative Deployed Peak Day DSM Savings Contribution by Sector (Therms)

Sector	Cumulative Peak Day Savings (Therms)	% of Overall Sector Savings
Commercial	76,529	1.3%
Residential	129,245	1.6%
Industrial	1,653	0.3%
Total	**207,427**	**1.4%**

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.

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 energy demand. Avista's objective is to provide reliable service at reasonable prices. To help 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.

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. Carbon reducing supplies, such as renewable natural gas (RNG) and hydrogen (H2) 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 the production in areas of the Northeast and Southern United States. 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. High Canadian production paired with limited options for flowing gas into demand areas has created a, generally, discounted commodity in the Northwest when compared to the Henry Hub. Although stalled due to an oil price collapse in 2020, associated gas from oil wells is still providing a large amount of the natural gas supply. 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. These LNG plants will be a large demand addition to North American supply. There are a few LNG export facilities in the Western half of North America. The first is Jordan Cove and although approved by FERC, it is not expected to be built in the long-term outlook from Wood Mackenzie. The second is Canadian project known LNG Canada and is in Kitimat B.C. This facility is one of the largest investments in Canadian history and is currently under construction. 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 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 to over 5 Bcf per day.

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 many decades 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 primary Canadian exporter of natural gas to the U.S. and historically produces 90 percent of Canada's natural gas.
- **Rockies** – This pricing point represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain natural gas-producing areas clustered in areas of Colorado, Utah, 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

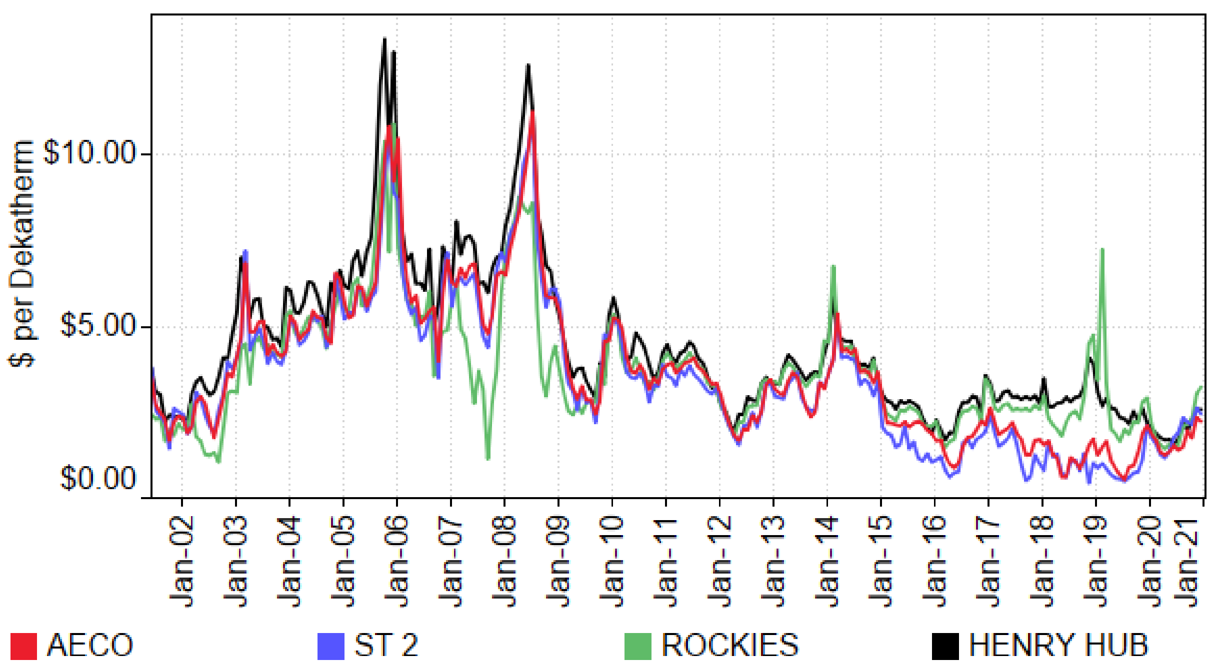
Enbridge's Westcoast Pipeline and predominantly markets Canadian natural gas from Northern British Columbia.

- **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 an alteration in flows of natural gas specifically coming from Western Canada.

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:

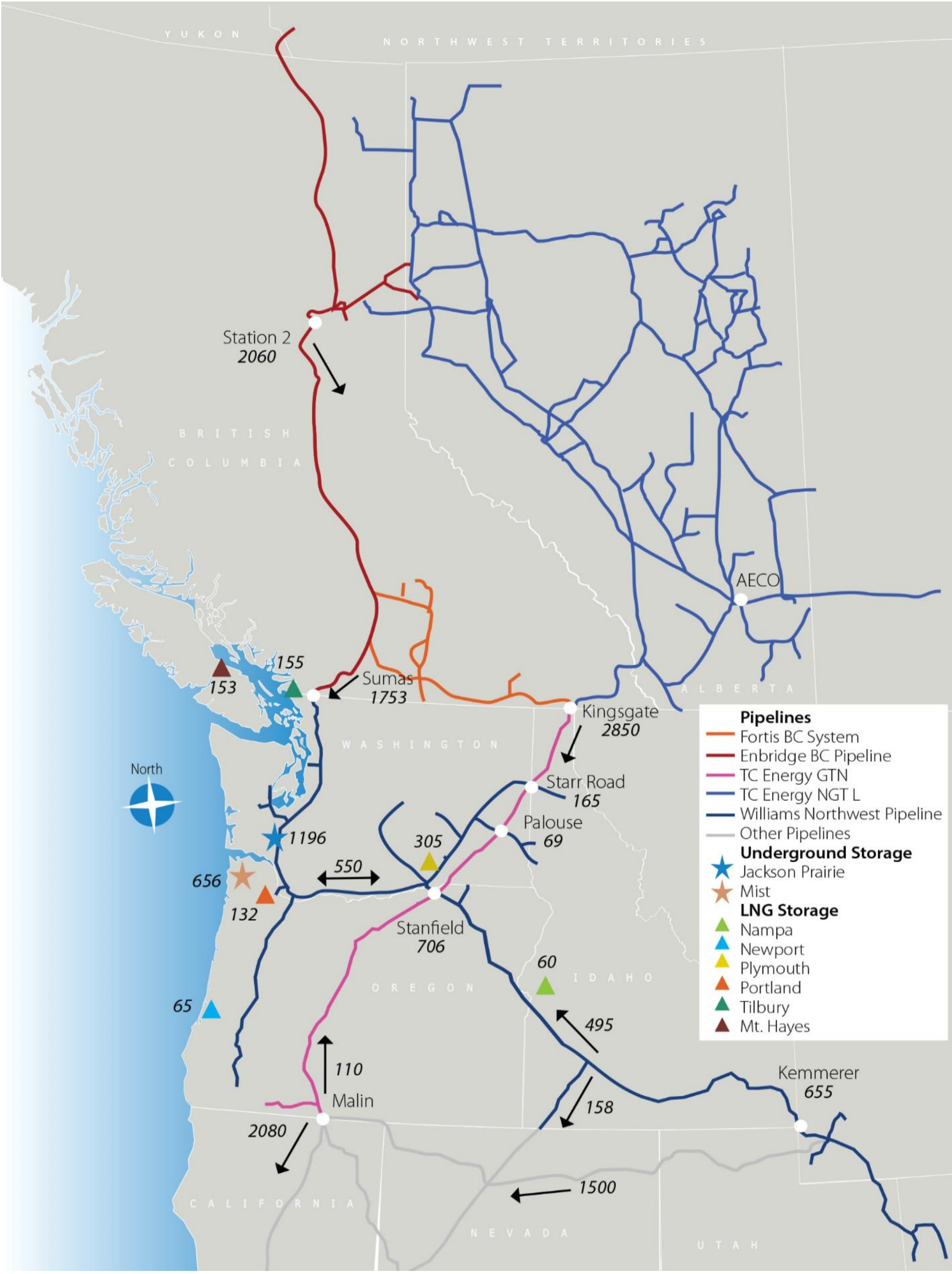
- **Firm vs. Non-Firm:** Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.
- **Fixed vs. Floating Pricing:** The agreed-upon price for 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. The regional map, from the Northwest Gas Association (NWGA), shows the relative capacity of the pipelines and storage capacity (Figure 4.2)

Figure 4.2: Regional Pipeline and Storage Capacity



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)

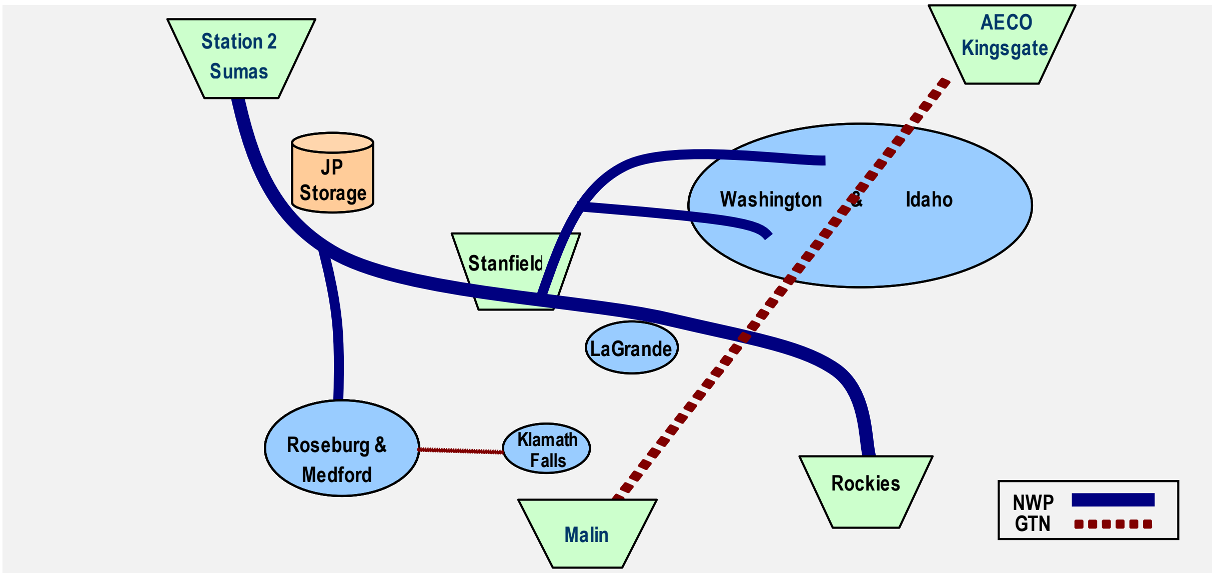
	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie	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 4.3 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[1]

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

Figure 4.3: 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 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 pipeline. Except for 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, also fully contracted, 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.

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, keeps Avista’s portfolio flexible while minimizing costs to customers. 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 or selling between different forward months. Since forward months have risks or premiums built into the price the result is Avista locking in a given spread. Storage optimization takes place all while maintaining the peak day deliverability, at a not to exceed level, to plan for this cost-effective resource to serve customer needs. All optimization of assets directly reduce customers 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. As previously discussed, both GTN and NWP are fully subscribed, but GTN currently maintains 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.

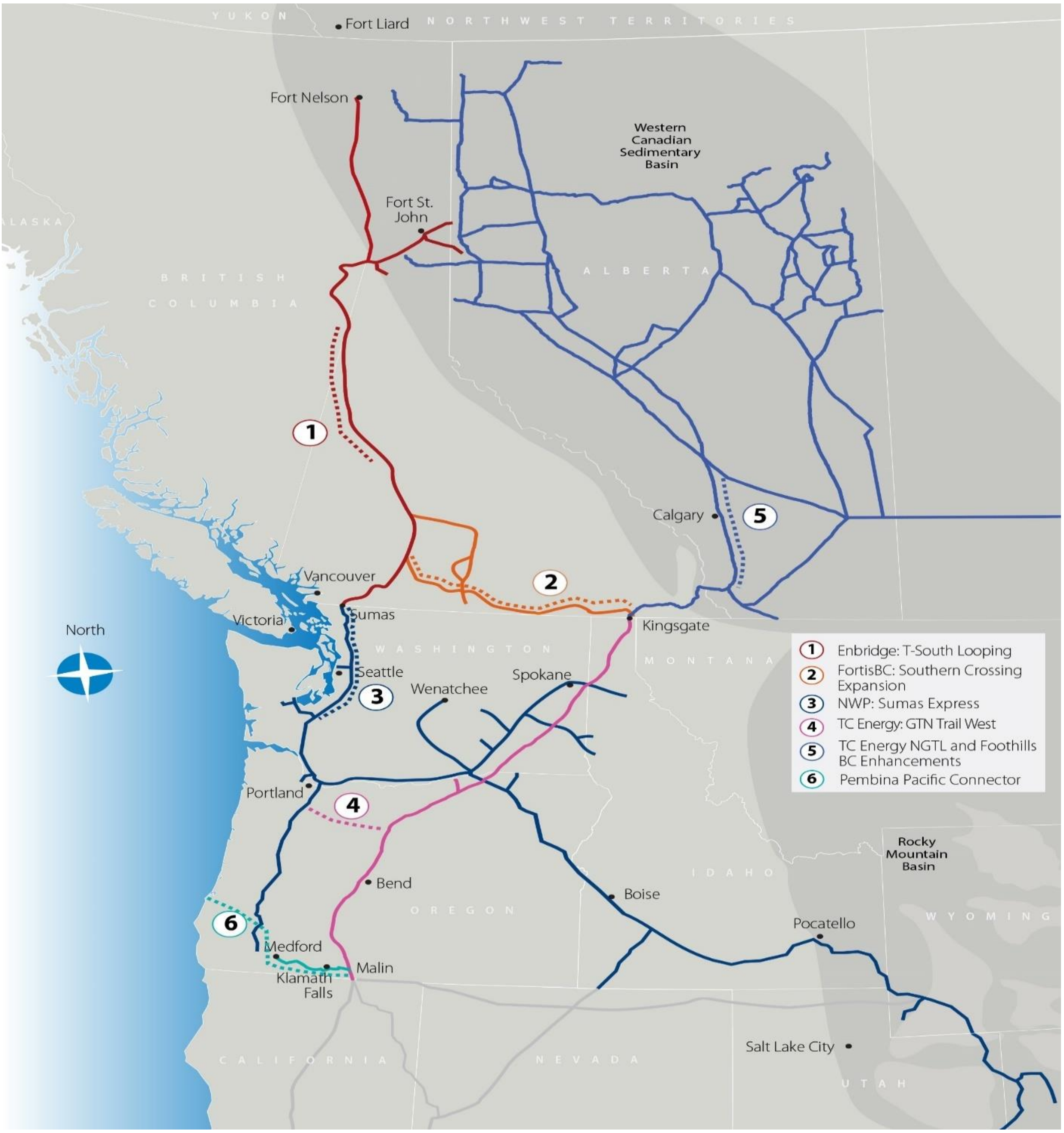
New Pipeline Transportation

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. No new pipelines were considered in the current IRP as resource options due to the exceedingly difficult legal path in getting approval for their construction. If one of these pipeline projects were to come forward as a viable option Avista would consider the costs and risks in a future IRP.

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 4.4 illustrates their location.

Figure 4.4: Proposed Pipeline Locations



1. **Enbridge T-South System Looping**

FortisBC and Enbridge are system enhancement on the T-South pipeline. Removing constraints will allow expansion of Enbridge'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 Huntingdon/Sumas market through looping and compressor station upgrades along the system.

2. **FortisBC Southern Crossing Expansion:**

   The Southern Crossing pipeline system is a bidirectional pipeline connecting Westcoast T South system at Kingsvale, BC and TransCanada's Alberta/BC border. 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.

3. **NWP - 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 demand.

4. **TC Energy GTN Trail West**

   The pipeline taking natural gas off of GTN and onto NWP hub near Molalla is referred to as Trail West. 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.

5. **TC Energy NGTL and Foothills BC Enhancements**

   In order to meet existing aggregate demand in southern AB and incremental long-term delivery commitments at the A/BC border, NGTL is ongoing and expected to have an in-service date of 2022. This project will increase the delivery point capacity at the A/BC border by 288,000 GJ per day and will operationally true-up capacity differences between NGTL and Foothills and provide additional export capacity into the US.

6. **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.

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, it would require combining them with additional capacity on existing pipeline resources.

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 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 South Korea, Japan and Spain. 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 additional demand to nearly 9 Bcf per day. This massive buildout of LNG exports has led to the U.S. becoming the third largest exporter of LNG in the world.

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.

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. Due to the changing direction in policy and fossil fuels, Avista did not model this resource in the current IRP.

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 to quantify methane saved by its capture as methane has been found to have a multiplier effect on global warming of 34[2] 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.

[2] https://www.ipcc.ch/

Table 4.2: Carbon Intensity[3]

Source	Current Carbon Intensity (g CO2e/MJ)	Estimated % of Carbon reduction as compared to natural gas	lbs. per Dth
Natural Gas	78.37		128.27
Landfill	46.42	41%	75.98
Dairy	-276.24	-452%	(580.40)
WWT	19.34	75%	31.65
Solid Waste	-22.93	-129%	(165.80)

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 and 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. For more information about RNG and its potential uses in energy policy within Avista territories please see Chapter 5 - Carbon Reduction.

Avista's Natural Gas Procurement Plan

Avista's foundational purpose/goal of the natural gas procurement plan is to provide a diversified portfolio of reliable supply while at the same time managing the volatility and cost of that supply. Avista manages the procurement plan by layering in hedges over a period of time based on average system load per month. Avista does not measure the success of this plan based on a certain cost or loss risk, rather it is considered successful when we have secured firm load at a reasonable price while addressing risk inherent

[3] California Air Resources Board

within these markets. The measurable objectives monitored toward this goal include a daily financial position of the overall portfolio, tracking of all new and previously transacted hedges, and the tracking of remaining hedges yet to be purchased based on a percentage of forecasted load as specified in the procurement plan.

No company can accurately predict future natural gas prices, however, market conditions and experience help shape Avista's overall approach to natural gas procurement. The Avista procurement plan seeks to acquire natural gas supplies while reducing exposure to short-term price and load volatility. This is done by utilizing a combination of strategies to reduce the impacts of changing natural gas prices in a volatile market. A portion of hedges will be focused on the concentration risk of fixed-price natural gas purchases by utilizing Hedge Windows, and another portion of hedges will target reducing risk in a volatile market by utilizing Risk Responsive methods. This allows Avista to set a risk level to help reduce exposure to events outside of our control such as the Energy Crisis in the early 2000's or the Enbridge pipeline rupture in 2018 or most recently the COVID-19 pandemic and the oil price collapse.

Hedge transactions may be executed for a period of one-month through thirty-six months prior to delivery period and are for the Local Distribution Customer (LDC) only. Due to Avista's geographic location, transactions may be executed at different supply basins in order reduce our overall portfolio risk. This procurement plan is disciplined, yet flexible, allowing for modifications due to changing market conditions, demand, resource availability, or other opportunities. Should economic or other factors warrant, any material changes are communicated to senior management and Staff.

In addition to hedges, the Company's procurement plan includes storage utilization and daily/monthly index purchases. It is diversified through time, location, and counterparty in accordance with Risk Management credit terms.

Market-Related Risks and Risk Management

There are several types of risk and approaches to risk management. The 2021 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.

Strategic Initiatives

Strategic Initiatives are generally defined as the means through which a vision is translated into practice. These initiatives are a group of projects and programs that are outside of the organizations daily operational activities and help an organization achieve a targeted performance.

The two primary roles of the Energy Resources Department (including Natural Gas Supply) is two-fold:

1. Serve Load – Assure adequate and reliable energy supplies for Avista Utilities natural gas customers.

2. Manage Resources – Exercise prudent stewardship of Avista Utilities energy supply facilities and related Company resources.

Through the use of fixed-priced hedges, daily balancing transactions and storage injections and withdrawals the Company can meet its obligation to serve load. In addition, through our Dynamic Window Hedges and Risk Responsive Hedges, we are also able to provide a level of price certainty in volatile commodity markets and reduce cost risk exposure. Related to managing our resources, we have secured firm natural gas transportation capacity in order to ensure we are able to reliably deliver the commodity to our customers. Finally, we have secured a level of storage (through ownership at Jackson Prairie) providing Avista with an additional level of firm supply and associated transportation contracts.

It is part of Avista's culture to be good stewards of our customer's resources. While there is no "targeted performance level", success is measured by the ability to capture benefit from our existing resources to the best of our ability, which results in either lower overall expenses for our customers or a higher level of price certainty. As such, we are continuously monitoring the procurement plan, evolving market conditions, new supply opportunities, and regulatory conditions.

Accordingly, effective in 2015 the Company implemented a new Storage Optimization Model which meets the definition of "Strategic Initiative" as described above. Prior to the implementation of the model, Storage had been utilized in the standard way – to purchase natural gas in the spring and summer when prices are historically low, inject into Storage, and withdraw in the winter when prices are historically high. Through the use of this model, we are able to still provide reliability of supply for our customers, but also capture benefits of price spreads between time periods. The model is governed by a storage management program that sets boundaries on injections and withdrawals as well as tracks real time market data to guide the purchase and sale of natural gas storage transactions with favorable spreads. Through this model, the Company can purchase natural gas in one period and sell into a higher priced market, effectively locking in a benefit for our customers.

The program enforces storage constraints and requirements such as the storage fill schedule, peak day load requirements, transportation capacity limits, and deliverability constraints.

The Company also has mechanisms in place which allow us to optimize the value of our existing pipeline and storage assets in order to reduce costs for customers until such resources are required to meet demand. Should there be transportation capacity that is not required to serve load, we may be able to optimize this capacity by purchasing natural gas, transporting it, and selling it into a higher priced market. Commodity purchases and sales are carefully tracked and allocated, or directly assigned, jurisdictionally based on the unique characteristics of each individual pipeline capacity.[4] Avista may also be able to release a portion of this unutilized firm transportation capacity to third parties, further reducing customer's firm transportation expense.

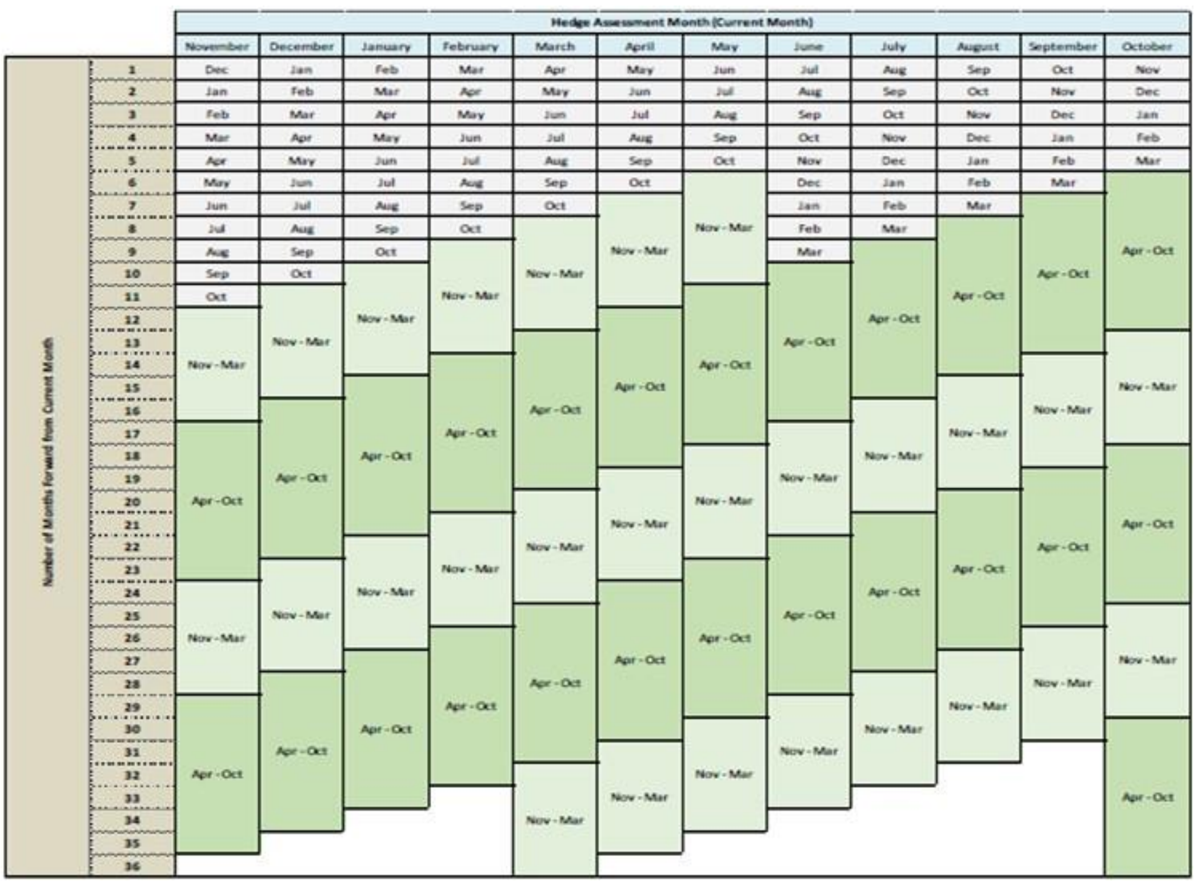
[4] Allocation between Washington and Idaho for Commodity purchases and sales is based on actual calendar load for each respective month.

Dynamic Window Hedges (DWH)

The DWH portion of the plan secures a pre-determined, minimum hedge portion for LDC load with fixed priced purchases. These transactions are diversified in terms of time, location and delivery period. The target delivery periods, development, procures, and execution are described below. Dynamic Window Hedging reduces the cost risk and increases the loss risk.[5]

The target delivery periods for the DWH portion of the Plan is for a period of 30 to 36 months depending on market availability of the hedging period (Figure 4.5).

Figure 4.5: Dynamic Window Hedging Plan



DWH Development

A DWH is defined by its set-price (SP), an upper control limit (UCL), a lower control limit (LCL) and an expiration date. The SP is the closing price of the day prior to the window

[5] Loss risk is the potential to pay more than the daily gas price with a forward hedge. Cost risk is the potential for daily prices to rise above the hedge price.

opening. The UCL and LCL are developed using quantitative mathematics to define boundaries in relation to the SP. Expiration dates are determined based on the remaining volumes to be hedged and remaining time to expiration. Each DWH's SP is based upon the closing price, of the selected supply basin for the delivery period. The supply basin for each hedge window will be selected from available term markets, based on whichever market has the highest volatility.

Hedge windows remain "open" as long as the previous day's forward delivery period price remains between the UCL and the LCL, and the window has not reached its time expiration. The selected basin closing price will be the determining benchmark of the forward delivery period price. Hedge window status is examined each business day. If the hedge window's current rate moved outside the UCL or LCL, a hedge transaction is triggered, subject to execution provisions described later in this report. If a SP does not move outside the UCL or LCL prior to time expiration, then the window's hedge transaction is executed on the expiration date.

Figure 4.6 shows a hedge which was executed for the Summer of 2022 (April – October) time period and the associated limits.

Figure 4.6: Dynamic Window Hedge (April 2022 – October 2022)

Risk Responsive Hedging Tool (RRHT)

In 2018, Gas Supply incorporated a Risk Responsive Hedging Tool in addition to the Dynamic Window Hedges discussed above. The RRHT helps to manage the Value at Risk (VaR) of Avista's LDC natural gas portfolio's open position on a daily basis. The forward gas prices are the basis for the VaR analysis. The analysis utilizes a confidence level and historic volatility to calculate a portfolio VaR, and combines it with the current mark-to-market portfolio price to develop a price risk metric that is compared to a predetermined threshold value (Operative Boundary). If the price metric exceeds the Operative Boundary, then one or more hedges will be executed to bring the price metric back within the Operative Boundary. In any case, hedge volumes should not exceed the Maximum Hedge Ratio. Upon trigger, Gas Supply will begin to transact to bring the price metric back within the Operative Boundary.

The Dynamic Window Hedging will continue to systematically hedge to a certain minimum hedge level through the use of time limits and UCL/LCL. RRHT will monitor the market financially and call for additional hedging if pre-determined risk tolerance limits are triggered.

The RRHT includes all utility purchase and sales transactions, estimated customer load, and storage injections and withdrawals to derive open positions (by basin) that are marked to forward market prices. These monthly financial positions, along with market volatility, are then used to calculate the Value at Risk (VaR) by basin, which in turn is used to evaluate recommended hedging actions.

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 4.7. Figure 4.8 shows the continued increase in efficiency of production compared to just a year ago as shown by the EIA's Drilling Productivity Report 4.9[6].

Figure 4.7: Seven Major Drilling Regions in the United States

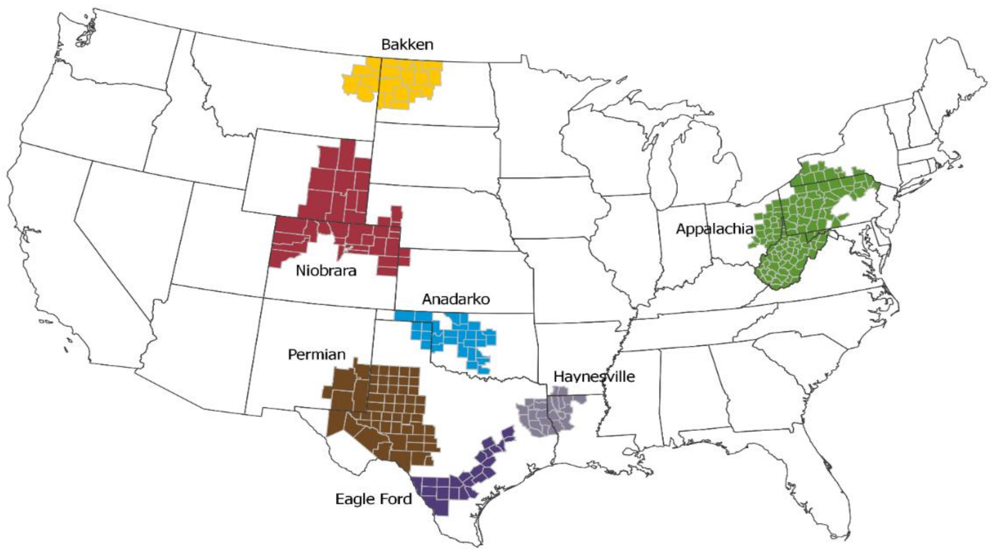
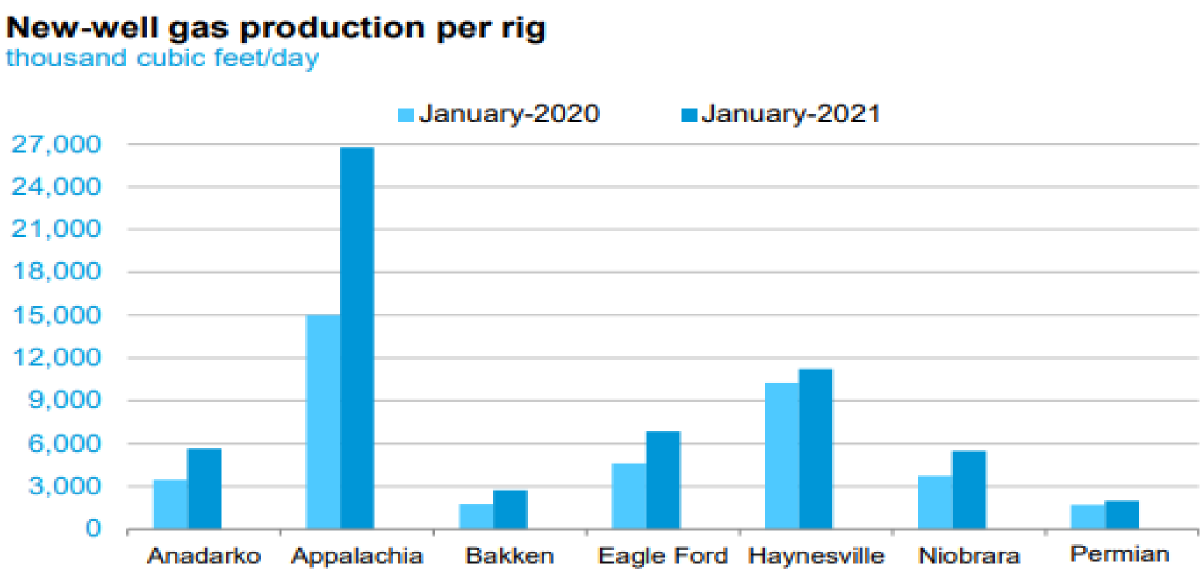


Figure 4.8: December 2020 Drilling Productivity Report, EIA[7]



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

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

[7] www.eia.gov

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. 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.[8] Additionally, wastewater injections are used for all well types, 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[9] 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.

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.

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

[9] https://fracfocus.org/

- 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.
- Monitor renewable supply resource options, availability and pricing trends.

Conclusion

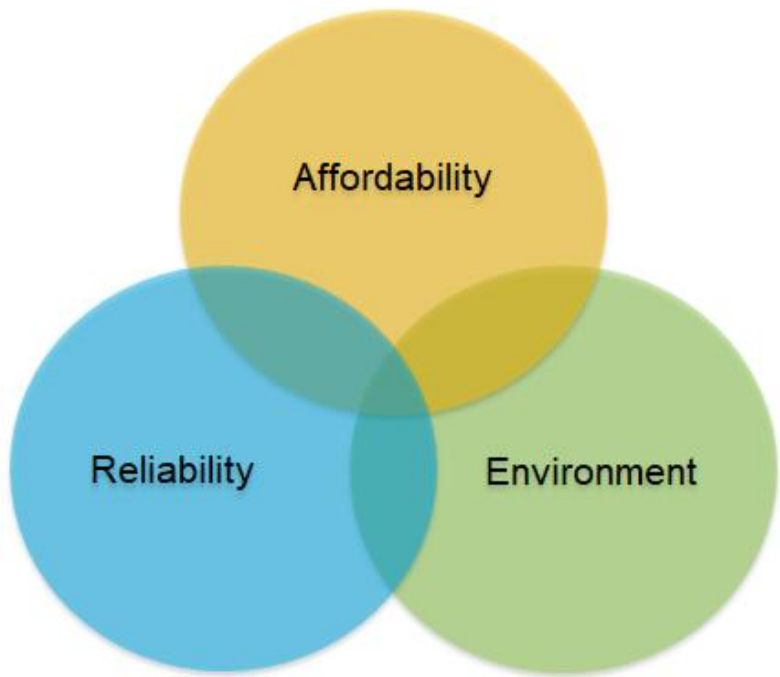
North American fossil natural gas supply continues to show its robustness in spite of challenges it faces. Regional supply constraints are beginning to increase in their likelihood causing prices to act in a more volatile fashion. This volatility in pricing paired with supply side resource availability has made Avista’s procurement plan an increasingly important piece to manage customer rates, diversity of supply and peak day demand. Without new supply side resources, the region will face some difficult decisions in the coming decades. 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: Carbon Reduction

Regulatory environments regarding energy topics such as renewable energy, carbon reduction, carbon intensity 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 reduction of carbon in the natural gas stream.

Avista and Carbon Reduction:

Focus on solutions that balance carbon reduction, affordability, and reliability.



Avista's Environmental Objective

Avista has always been on the forefront of clean energy and innovation. Founded on clean, renewable hydro power on the banks of the Spokane River, Avista has maintained a generation portfolio that is already more than half renewable, while continuously making investments in new renewable energy, advancing the efficient use of electricity and natural gas, and driving technology innovation that has enabled and will continue to become the platform and gateway to a clean energy future.

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. 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.

Natural Gas System Emissions

Upstream emissions include any emission found upstream of the point of combustion and includes production, processing, transmission and equipment. To fully account for emissions in the natural gas stream the upstream emissions are now included in the totals as measured in pounds of carbon dioxide equivalent. This becomes important when placing a tax or cost of emissions on the price per Mmbtu. The emissions are measured at the standard 100-year Global Warming Potential (GWP) meaning a 34 multiplier of the heat that would be absorbed by the same mass of carbon dioxide. The levels of upstream gas are determined by production region, specifically in Canada and the Rockies in the United States and multiplied by the associated emissions estimate. Over the past five years, nearly 90 percent of Avista's natural gas was sourced from Canadian production leaving roughly 10 percent of estimated upstream emissions to the Rockies region. When combined with a 0.77 percent of Canadian production attributed to upstream emissions, as calculated in a study for the Tacoma LNG project, the majority of Avista's fossil fuel natural gas is less intensive as compared to the fossil natural gas emissions from the Rockies region of 1.0 percent as calculated in the EIA sinks and emissions estimates. This estimate[1] from the EIA is updated on a yearly basis and will show gains and losses as they occur as compared to a point in time study.

The final upstream emissions from CH4 in carbon equivalent add nearly 10.66 pounds per MMBtu as shown in Table 5.1:

Table 5.1: Avista Specific LDC Natural Gas Emissions

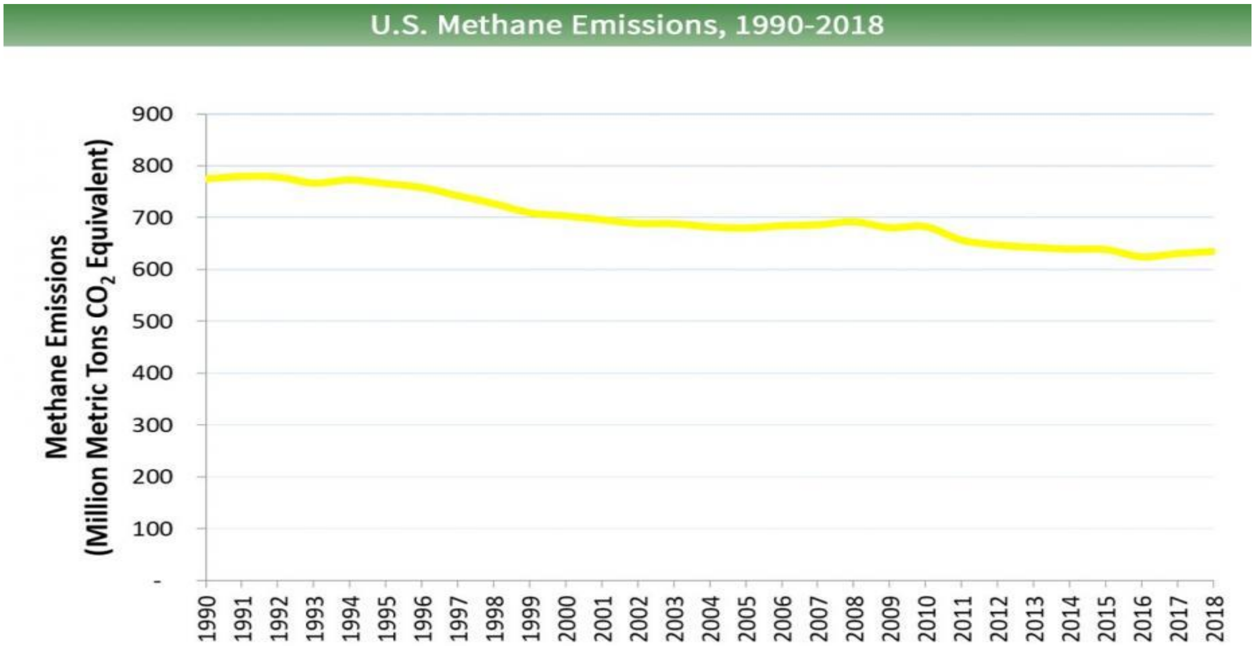
	Avista Specific Natural Gas	
Combustion	**Lbs. GHG/MMBtu**	**Lbs. CO2e/MMBtu**
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.313406851	10.66
Total		128.27

At a national level, overall methane emissions in the U.S. have been on the decline for many decades. As illustrated in Figure 5.1, the EPA has estimated methane emissions as decreasing by nearly 20 percent as compared to 1990. As coal fired plants have

[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks | Greenhouse Gas (GHG) Emissions | US EPA

retired, production of electricity natural gas generation has dramatically increased to cover this demand. Interestingly, during this reference period, production from natural gas has more than doubled while total electric production increased 35 percent during this same timeframe.

Figure 5.1: United States Methane Emissions



Carbon dioxide equivalent (CO2e) is the most common unit to measure climate warming. In order to understand how different greenhouse gasses such as methane (CH4) and nitrous oxide (N20) affect the earths warming a conversion must occur. As illustrated in Table 5.2 below, the Intergovernmental Panel on Climate Change released their 5th assessment study to help define these impacts to global warming in units of CO2e.

Table 5.2: Global Warming Potential (GWP) in CO2 Equivalent

5th Assessment of the Intergovernmental Panel on Climate Change		
Greenhouse Gas	**GWP – 100 Year**	**GWP – 20 Year**
CO_2	1	1
CH_4	34	86
N_2O	298	268

Local Distribution Pipeline Emissions - Methane Study

In a study led by Washington State University (WSU), and sponsored by the Environmental Defense Fund (EDF) and others, an estimate of utility pipeline distribution systems leakage found that overall levels of leakage were around 0.1 percent to 0.2 percent of methane delivered nationwide. The study goes on to state that the Eastern regions of the United States contribute much more methane to the total, as compared to the Western regions, which were found to account for only 5 percent of these emissions overall. The study theorizes that older infrastructure and material types are the likely culprit, but also goes on to attribute regulations and better infrastructure and monitoring by utilities for these decreased emissions. It found that "out of 230 measurements, three large leaks accounted for 50 percent of the total measured emissions from pipelines leaks. In these types of emission studies, a few leaks accounting for a large fraction of total emissions are not unusual."[2]

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 cap and reduce system, and a carbon tax. Comprehensive climate change policy can include multiple components, such as renewable portfolio standards, DSM standards, and emission performance standards. 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

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

Oregon Policy Considerations

The State of Oregon has a history of greenhouse gas emissions and renewable portfolio standards legislation. In March of 2020, Governor Brown signed into law Executive Order (EO) 20-04 requiring the reduction of greenhouse gas emissions to at least 45 percent below 1990 levels by 2035 and 80 percent below 1990 levels by 2050. This EO requires the reductions statewide by all carbon emitting sources and managed by the respective emissions sources governing agencies. State agencies are directed to exercise any and all authority to achieve GHG emissions reduction goals expeditiously. Many specifics of

[2] https://methane.wsu.edu

this EO will be taking shape in the upcoming year including systems, carbon costs, programs such as to a cap and reduce program to buy or sell offsets and many other complexities of an endeavor of this magnitude.

Oregon SB 334

In Oregon, Senate Bill 334[3] was passed in 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. In September 2018 the Oregon Department of Energy issued the report to the Oregon legislature titled "Biogas and Renewable Natural Gas Inventory."

Oregon SB 844

Senate bill 844 passed in 2013 with rulemaking following under AR 580, placed into effect in December of 2014. This bill directed the OPUC to establish a voluntary emission reduction program and criteria for the purpose of incentivizing public natural gas utilities to invest in emission reducing projects providing benefits to their respective customers. The public utility, without the emission reduction program, would not invest in the project in the ordinary course of business.

To date, this legislation has not yielded any emission reducing projects. Avista is aware that Governor Brown's Executive Order 20-04 has the OPUC reconsidering the usefulness of SB844.

Oregon SB 98 & AR 632 Rule Making

Oregon Senate Bill 98 passed during the 2019 regular session and mandates the Oregon Public Utility Commission (PUC) "to adopt by rule a renewable natural gas program for natural gas utilities to recover prudently incurred qualified investments in meeting certain targets for including renewable natural gas purchases for distribution to retail natural gas customers."

The Oregon PUC initiated the AR 632 rulemaking process in late 2019 with a series of public workshops. This collaborative process with various stakeholder involvement and input concluded in the spring of 2020. Final rules were made effective on July 17, 2020. The rule allows investment recovery. In order to participate in Oregon's SB 98 RNG Program, a petition to participate is required. Small utilities desiring to participate are required to define their respective percent of revenue requirement per year needed to support potential project investment costs. The bill allows investment in gas conditioning equipment without RFP process. Per AR 632 the RNG attributes will be tracked by the

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

M-RETS system as renewable thermal certificates (RTC) in which (1) RTC = (1) Dekatherm of RNG.

Washington

Washington State Policy Considerations[4]

In December 2020 a State Energy Strategy was released as a roadmap that commits Washington to reducing greenhouse gas emissions:

- By 2030 a 45% reduction below 1990 levels
- By 2040 a 70% reduction below 1990 levels
- By 2050 a 95% reduction below 1990 levels and net-zero emissions

Washington HB 2580

Washington State House Bill 2580[5] 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.

Washington HB 1257

The bill passed during the 2019 Regular Session, coined the "Building Energy Efficiency" bill, mandates that each gas company must offer by tariff a voluntary renewable natural gas service. The bill also allows for LDCs to create an RNG program to supply a portion of the natural gas to customers. This program is subject to review and approval by the UTC. With regard to natural gas distribution companies, this bill was designed for the purpose of establishing *"efficiency performance requirements for natural gas distribution companies, recognizing the significant contribution of natural gas to the state's greenhouse gas emissions, the role that natural gas plays in heating buildings and powering equipment within buildings across the state, and the greenhouse gas reduction benefits associated with substituting renewable natural gas for fossil fuels*."

Section 12 of the bill "finds and declares that:

[4] 2021 State Energy Strategy - Washington State Department of Commerce
[5] http://apps2.leg.wa.gov/billsummary?Year=2017&BillNumber=2580&Year=2017&BillNumber=2580

a) Renewable natural gas provides benefits to natural gas utility customers and to the public;

b) The development of RNG resources should be encouraged to support a smooth transition to a low carbon energy economy in Washington;

c) It is the policy of the state to provide clear and reliable guidelines for gas companies that opt to supply RNG resources to serve their customers and that ensure robust ratepayer protections."

Section 13 of the bill allows LDC's to propose an RNG program under which the company would supply RNG for a portion of the natural gas sold or delivered to its retail customers.

Section 14 of the bill states that LDC's must offer by tariff a voluntary RNG service available to all customers to replace any portions of the natural gas that would otherwise be provided by the gas company.

HB 1257 provided limited direction and the necessary details to advance RNG programs and projects. As such, there has been an effort on behalf of the impacted utilities to provide the commission with feedback and clarity with respect to gas quality and cost treatment. More specifically, the Northwest Gas Association (NWGA) has collaborated with Washington LDC's to develop a common Gas Quality Standard Framework, and proposed language defining the treatment of RNG program costs.

On December 16, 2020, the Washington UTC issued a Policy Statement to provide guidance with respect to the following elements of HB 1257 as follows; General Program Design, RNG Program cost cap, Voluntary Program cost treatment, gas quality standards, and pipeline safety, environmental attributes and carbon intensity, renewable thermal credit (RTC) tracking, banking and verification.

RNG at Avista

Avista has been preparing for RNG. A new RNG Program, RNG Manager, and a cross-functional working team has been assembled and includes representatives from Gas Engineering, Gas Supply, Legal, Governmental Affairs, Regulatory Affairs, Products & Services, Business Development & Strategy, Corporate Communications, and Environmental. This team meets on a routine basis for program and project updates and coordination purposes. Additionally, internal efforts to prepare for and advance RNG include but are not limited to; draft charter document, draft business cases for use in Capital Budget Planning process, internal communications, gas quality, interconnection requirements, and business development efforts in pursuit of potential RNG projects.

Program Considerations

As Avista prepares to move forward with RNG, some of the primary considerations given are as follows:

- Evaluate available RNG procurement options
- Pursue potential RNG development opportunities from local RNG feedstock resources under new legislation (Washington HB 1257 & Oregon SB 98)
- Develop an understanding of RNG development cost, cost recovery impacts to customers, resulting supply volumes and RNG costs
- Evaluate potential RNG customer market demands vs. supply
- Participation in rule making and policy:
- Participation in HB 1257 Policy development
- Participation in SB 98 Policy Rulemaking via AR 632 informal and formal
- Cost recovery proposal led by NWGA with input from all four Washington LDC's
- Collaborative RNG Gas Quality Framework established across four Washington LDC's

Pipeline Safety & Interconnection Requirements

Avista's Gas Engineering Department has researched and learned about gas quality, testing, and interconnection requirements from those at the forefront of the RNG industry. Additionally, through a collaborative effort coordinated by the Northwest West Gas Association (NWGA), all four Washington LDC's have developed a common Gas Quality Framework which is now that basis for Avista's Gas Quality Specification. The development of Interconnection requirements and draft contractual language has also been developed and has taken form as an Interconnection Agreement template. Other procedural documents such as an Interconnection Study Agreement and RNG Interconnection Request Form have been developed.

RNG workshops and rulemaking

In addition to participating in RNG industry workshops and conferences to learn how others are implementing RNG projects and programs, Avista has actively participated in Oregon SB 98 informal and formal rulemaking, and Washington HB 1257 workshops including collaborative efforts with the NWGA to develop a common Gas Quality Framework, and proposed cost cap language.

Utility RNG Projects

RNG projects require feedstocks that are not always readily available and feedstock owners who are willing to partner with an LDC. Even with potential willing feedstock partners, Avista recognizes many practical complexities associated with developing RNG projects as well as the many benefits. The following examples are based on what we have learned during our business development efforts;

- New legislation allows LDC's to invest in RNG infrastructure projects with feedstock partners
- LDC's are credit worthy partners offering long term off-take contracts to feedstock owners
- Each RNG project is unique with respect to capital development costs & resulting RNG costs
- Each RNG project will vary in size, location, and distance to interconnection pipeline, feedstock type, gas conditioning equipment and requirements, and operating costs
- Economies of scale – Low volume biogas opportunities face economic challenges
- The utility cost of service model is typically a foreign concept to feedstock owners, requiring an educational process to get them comfortable
- Feedstock owners over-valuing their biogas can degrade project economics
- New RNG Projects can take 3-4 years to develop given myriad factors. A new RNG project is a multi-year endeavor involving the usual phases expected for major capital construction projects, coupled with many first ever discussions between the utility and the feedstock owner, a new regulatory process and program requirements, the identification of customer cost impacts, environmental benefits, and tracking process just to name a few
- Customers have paid for a vast pipeline infrastructure that can be utilized for a cleaner future by transitioning the fuel and keeping the pipe

Project Evaluation - Build or Buy

Avista recognizes the two primary options to procure RNG; build RNG project(s) or buy RNG. In the build scenario, new RNG facilities are developed, and the costs are recovered the through AAC or GRC. Avista can also buy RNG from other RNG producers and pass the costs through the GPA.

Build

Both Oregon SB 98 and Washington HB 1257 are both focused on decarbonization for the greater good of society and both pieces of legislation clearly support the development of new RNG infrastructure and RNG resources by allowing utility companies (LDC's) to build and deliver RNG on a utility cost-of-service model for utility customer building heat usage. Both allow the recovery of investments through an AAC or GRC. Avista believes the "build" option best meets the intent of the legislation as it affords a higher level of cost control through the elimination of for-profit intermediary burdens, delivering RNG to customers at the true cost. Further, local projects contribute to improved local air quality, and support the local economy during construction and during annual operations.

Naturally, feedstock biogas royalties are expected to be a key factor in project economics, as will operating costs including power, conditioning equipment type, interconnection pipeline distance and cost. Since utility companies are institutional credit worthy partners that can offer long term off-take contracts for biogas, it is expected that these types of arrangements will be desirable with feedstock owners, and that long-term arrangements will temper biogas royalty pricing. Ultimately the utility customer benefits from this scenario.

Buy

The new legislation in Oregon and Washington is an intentional shift away from the transportation market and opens the door for a new renewable thermal credit (RTC) market which is not intended to compete with the existing heavily subsidized transportation markets, federal and state alike. In the short term, and since the transportation and utility markets are in conflict with respect to RNG values, the procurement of RNG for utility use is an inherent challenge for utility use.

At Avista, we expect our voluntary RNG program demands to be limited volumes, and short-term in nature in the initial years. Since a short-term, low-volume off-take purchase scenario is not likely to be attractive to producers that typically seek long-term off-take agreements, the expectation is higher RNG costs. Given the nature of this temporary interim situation, a short-term voluntary pilot program in which off-take volumes may be procured from a local producer with excess supply, at a negotiated price may be advantageous.

This strategy will allow Avista to ramp-up and learn more about our new first ever voluntary RNG program and minimize risk until at a point in time in which Avista can supply RNG from new RNG infrastructure investment projects.

Voluntary RNG Programs

Avista's Products and Services Department will be developing Avista's first ever voluntary RNG product. To date the following market studies and observations have been completed:

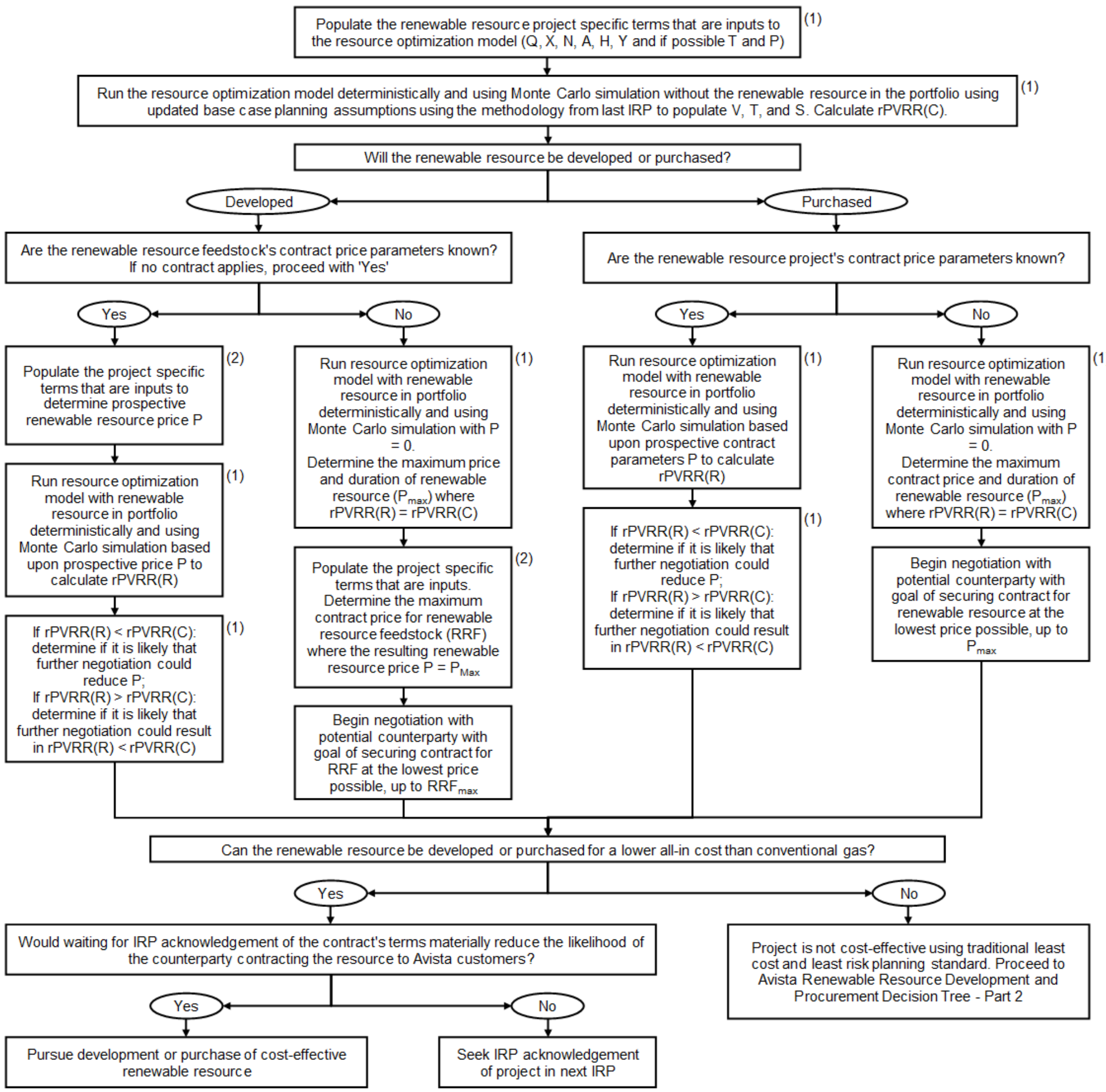
- RNG Commercial Market Study completed in 2019
- RNG Residential Market Survey concluded in September 2020
- Customers lack understanding of RNG since it is a new concept
- Customers like the environmental aspects of RNG
- Customers like to choose their level of participation to manage costs predictably

The voluntary customer RNG program design will advance based on the studies above. Estimated voluntary customer program demands are yet to be defined, however volumes are expected to be very small initially. Eventually, Avista is looking forward to adding RNG to Avista's renewables portfolio.

Cost Effective Evaluation Methodology

At Avista, developing a methodology has been a work in process. To date, the methodology shown is derived from OPUC UM2030, also referenced in the OPUC SB 98 AR 632 Rulemaking. The evaluation method shown herein is subject to input, refinement and reconsideration (Figure 5.2).

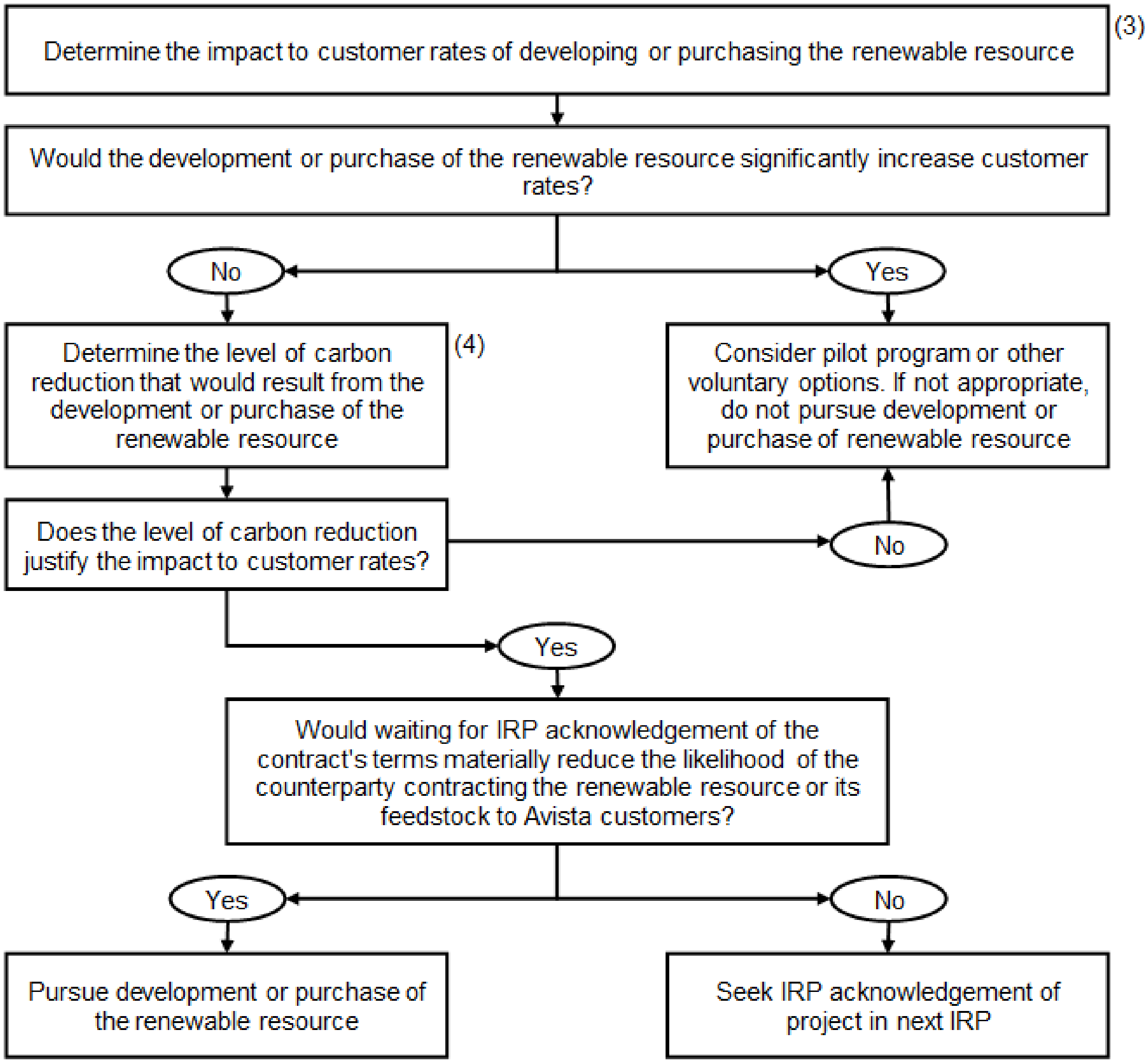
Figure 5.2: Avista Renewable Resource Development and Procurement Decision Tree – Part 1[6]



(1) Avista Renewable Resource Least Cost/Least Risk Evaluation Criteria and Calculations
(2) Avista Renewable Resource Project Revenue Requirement Model

[6] The Avista Renewable Resource Development and Procurement Decision Tree described above is a work in progress and is subject to change at any time.

Figure 5.3: Avista Renewable Resource Development and Procurement Decision Tree – Part 2



(3) Avista Renewable Resource Project Rate Impact Analysis
(4) Avista Renewable Resource Project Carbon Reduction Calculation

In-depth descriptions of the calculations and components used in the Avista Renewable Resource Development and Procurement Decision Tree are in Appendix 5.

Environmental Attribute Tracking

Oregon SB 98 specifies M-RETS as the third-party entity designated to manage environmental attribute tracking and banking. M-RETS will utilize a proprietary transparent electronic certificate tracking system in which (1) renewable thermal certificate (RTC) is equal to (1) dekatherm (Dth) of RNG per the OPUC.

Given the Oregon requirement, and in lieu of contracting with another vendor for the tracking and banking of Washington environmental attributes, Avista will likely use M-RETS for Washington RNG attributes.

The California RNG market will continue to be a major draw for renewable resources due to the low carbon fuel standard (LCFS) in addition to the federal RIN market. These incentives can bring the value of these specific renewable resource attributes to many multiples of conventional natural gas prices. While the market has volatility based on demand, the primary issue of bringing additional projects into the market are based on the unknowns as related to the market itself. There are currently no forward prices for these renewable credits and the environmental attribute value for local markets is unidentified. These are just a few of the major obstacles potential producers run into when looking for financing of their projects.

A potential solution to some of these unknowns in the market are through utility RNG projects. These feedstock owners would now be able to partner with LDC's to cultivate new RNG projects. The obstacle of financing becomes less of an issue as most LDC's are credit worthy and can provide a measure of certainty with long term offtake agreements. This concept would test the project owner's willingness to partner with the utility's cost of service model, which is a foreign concept when seeking the highest value for their biogas.

Developing a generic cost for RNG based on feedstock will require several assumptions as each specific RNG project will have its own capital development costs. Each RNG project will vary in size, location and distance to interconnection pipeline, feedstock type, gas conditioning equipment and requirements and operating costs. In general terms, new RNG projects can take 2-3 years to develop depending on size and scope.

Hydrogen

Hydrogen is a fuel source with a long history and a great potential to help solve future energy needs. Its energy factor, as measured in a kilogram (kg) of low heating value (LHV), is roughly equivalent to a gallon of gasoline. While hydrogen can be made from any energy source including nuclear (pink H2) and electric renewables (green H2), most is currently made by reforming natural gas, also known as grey H2. The high cost of this energy has been the primary barrier to an accelerated use and adoption. With expanding renewable electricity production, the ability to create green H2 with excess renewable electricity is moving from concept to market throughout the world. While it is assumed hydrogen can only be mixed and stored in a natural gas distribution pipeline system as a small percentage of the total volume of gas in the pipe, it can be combined with a carbon dioxide source first to produce methane, referred to as methanation, and then injected in a natural gas pipe without limits on the percent in the gas stream. This process of using power to separate water into hydrogen and oxygen is known as power to gas. This process can provide seasonal energy storage needs while providing a useful product based on when renewable electricity is being produced.

Conclusion

Avista views RNG and low carbon fuels as an important component of its corporate environmental strategy and decarbonization goals. By utilizing waste streams to create green fuel, RNG and H2 both support Avista's environmental strategy and will provide Avista's customers with a new environmentally friendly, low carbon fuel choice, delivered seamlessly via Avista's existing natural gas system.

6: Integrated Resource Portfolio

Overview

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

The foundation for integrated resource planning is the criteria used for developing demand forecasts. The weather planning standard has been updated in the current IRP cycle. The new planning standard has Avista moving away from coldest on record and into a 99 percent probability of a daily temperature occurring. 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 months (April and October) and summer demand. The modeling process includes an optimization for every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system 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 the weather planning standard, a blended price curve of three studies 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. This fuel is used to move the gas from point A on the pipeline to point B or the delivery point. The FERC and National Energy Board approved tariffs govern the percentage of required additional fuel supply.

SENDOUT® Planning Model

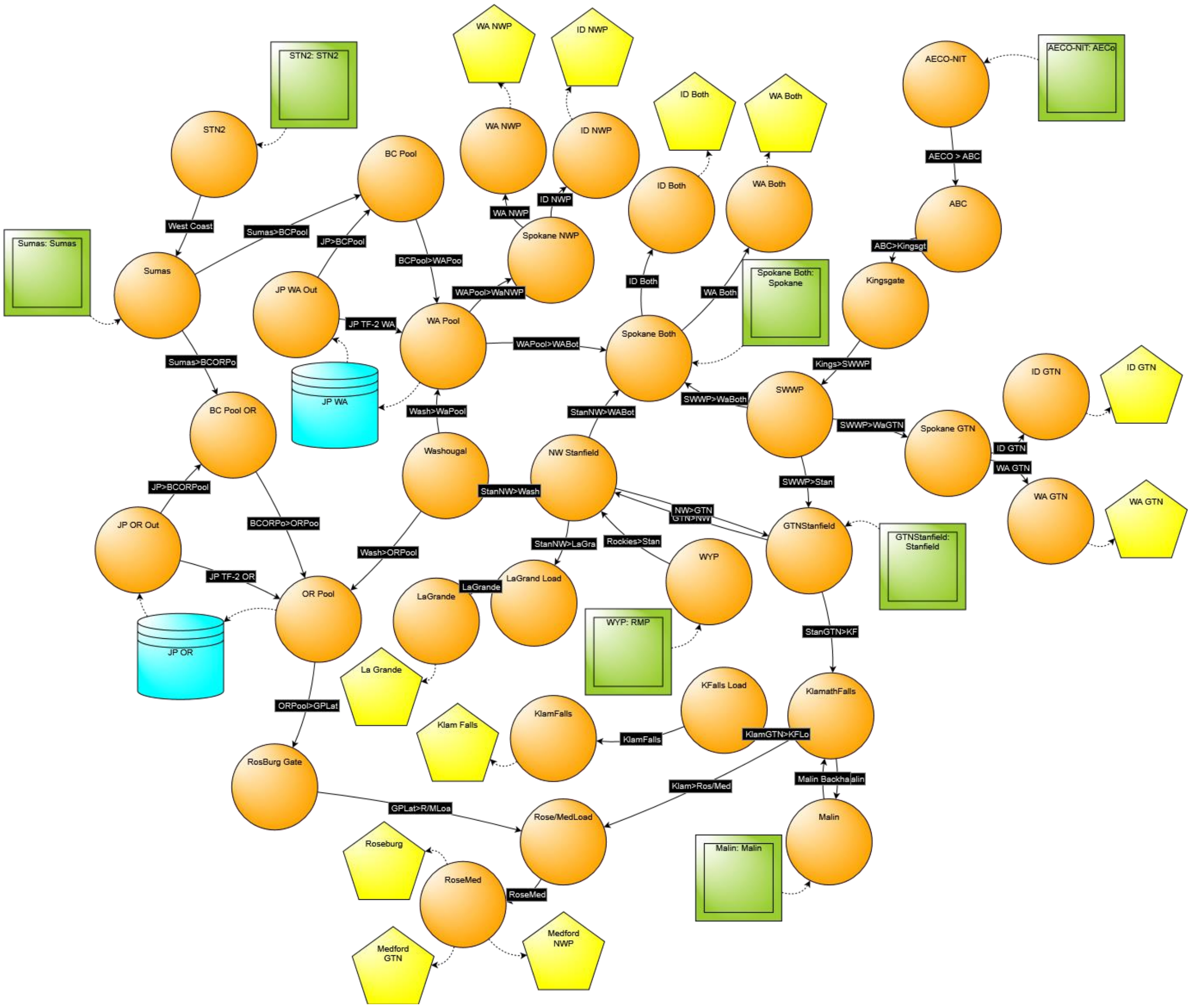
SENDOUT® is a linear programming model used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique to solve minimization/maximization problems. SENDOUT® analyzes the complete problem at one time within the study horizon, while accounting for physical 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 LDC's across the U.S., however it is becoming increasingly outdated for the current regulatory environment when it comes to carbon reduction. Because of this enhanced need for modeling software, Avista is planning on replacing SENDOUT® as stated in Chapter 9 – Action Plan.

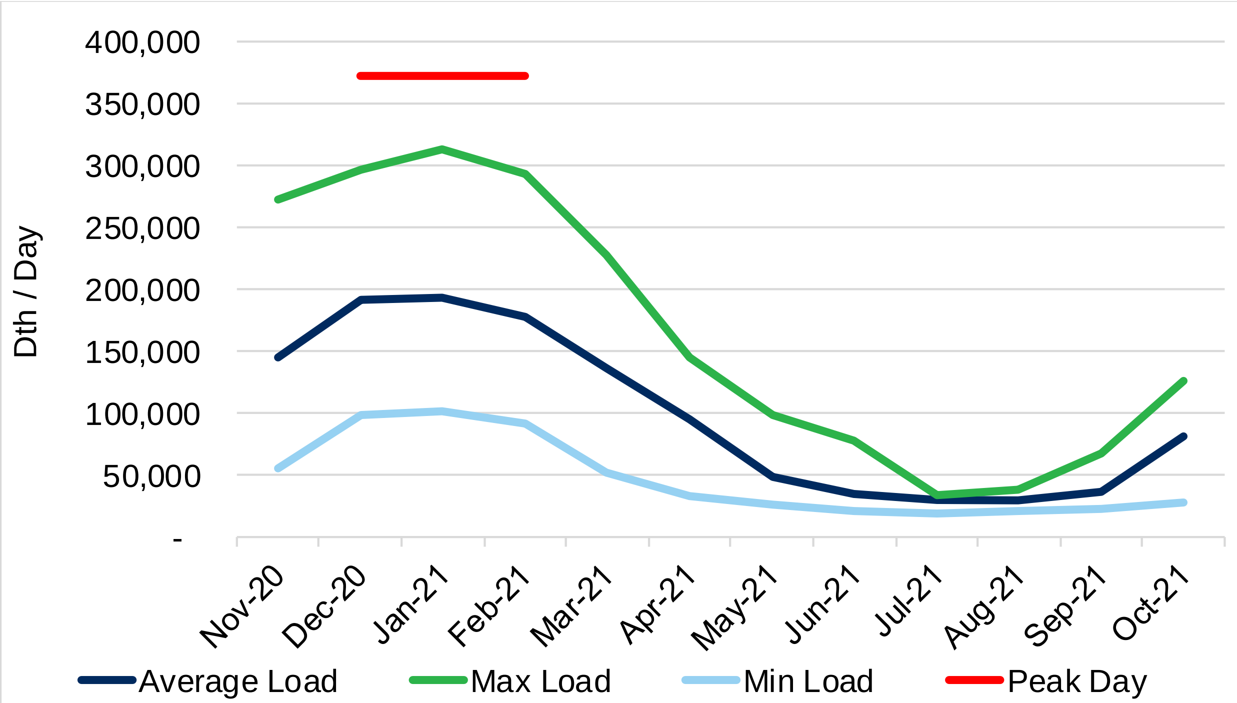
Resource Integration

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. 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 and the ability to physically deliver gas to an area); 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 firm customer classes are residential, commercial and 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

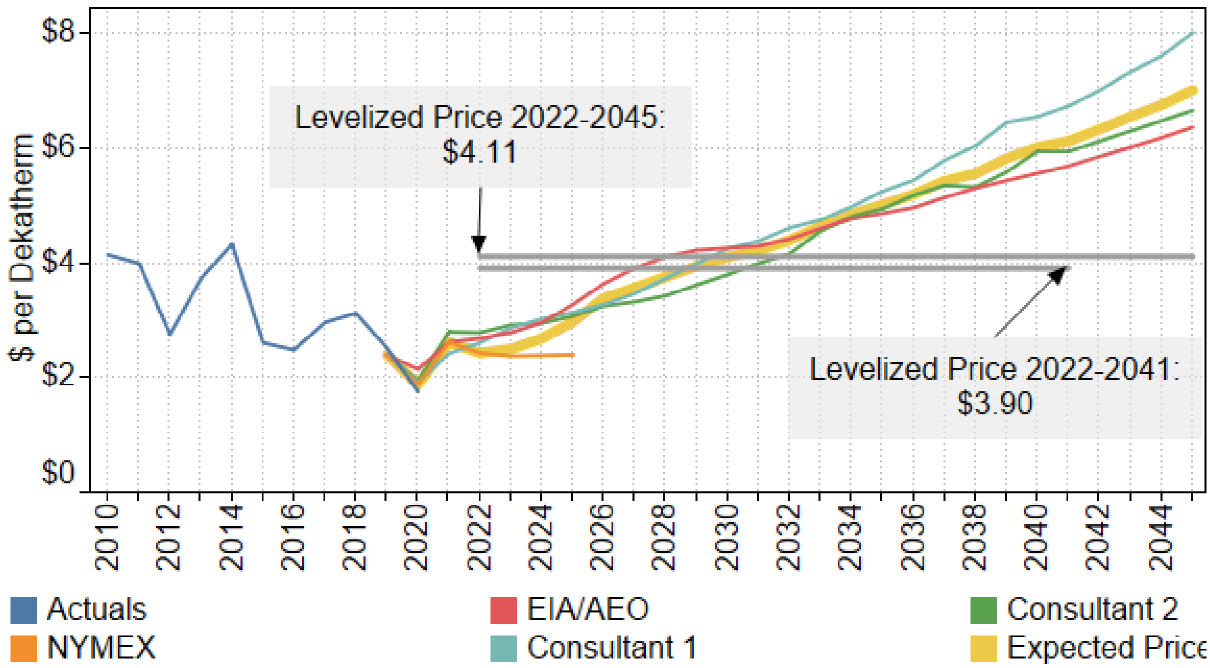
Natural gas prices play an integral role in the development of the IRP. It is the most significant variable in determining the cost-effectiveness of DSM measures and of procuring new resources. The price of natural gas also influences consumption through price elasticity, which affects demand in Avista's natural gas service territories.

The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry, including improved drilling methods and technology used in oil and natural gas production, increasing exports to Mexico, and LNG. These factors, in addition to more stringent renewable energy standards and increased need for natural gas-fired generation to back up such resources, are contributing to the rapidly changing natural gas environment. The uncertainty in predicting future events and trends requires modeling a range of forecasts.

Many additional factors influence natural gas pricing and volatility, such as regional supply and demand issues, weather conditions, storage levels, natural gas-fired generation, infrastructure disruptions, and infrastructure additions, such as new pipelines and LNG terminals. Estimates of these supply resource additions vary between studies as does the study date and ultimately drive the primary differences between sources in pricing expectations.

Although Avista closely monitors these factors, we cannot accurately predict future prices across the 20-year horizon of this IRP. As a result, several price forecasts from credible industry experts were used in developing the price forecasts considered in this IRP. Figure 6.3 depicts the annual average prices of these forecasts in nominal dollars and includes the expected price resulting from a blending technique.

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



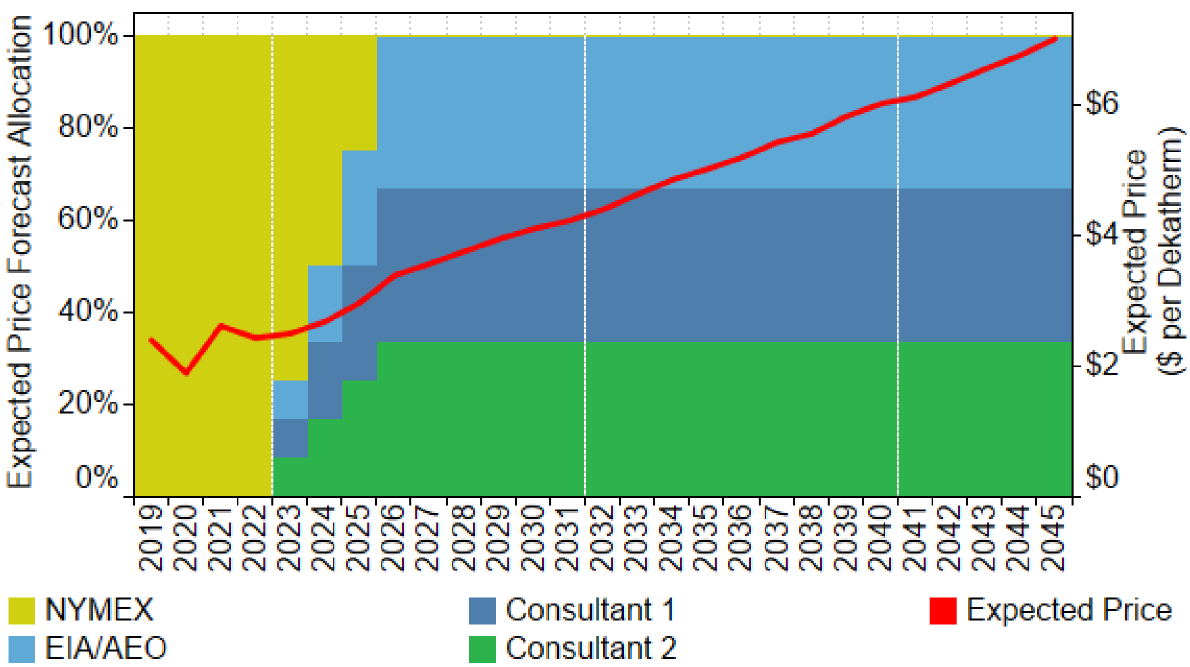
Expected prices at Henry Hub were derived through a blend of forecasts from four sources, including the New York Mercantile Exchange (NYMEX) forward strip on June 30, 2020, the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO), and two reputable market consultants. Combining an ensemble of forecasts improves the accuracy of our model based on the premise that the aggregate market knows more than any single entity or model.

The weightings applied to each source vary throughout the twenty-year forecasting horizon. Due to the high volume of market transactions, expected prices align completely with those of the NYMEX forward strip in the first two years. From 2023 through 2025, market activity and speculation on the NYMEX deteriorate significantly, so forecasts from the other three sources, proportionally, are applied incrementally more weighting. By the year 2026, and through the end of our forecasting horizon, the expected price is the result of an equally weighted blend of forecasts from the EIA's AEO and our two market consultants. The specific weightings applied are described in Table 6.1 and the resulting annual average expected price at Henry Hub is depicted in Figure 6.4 below.

Table 6.1: Price Blend Methodology

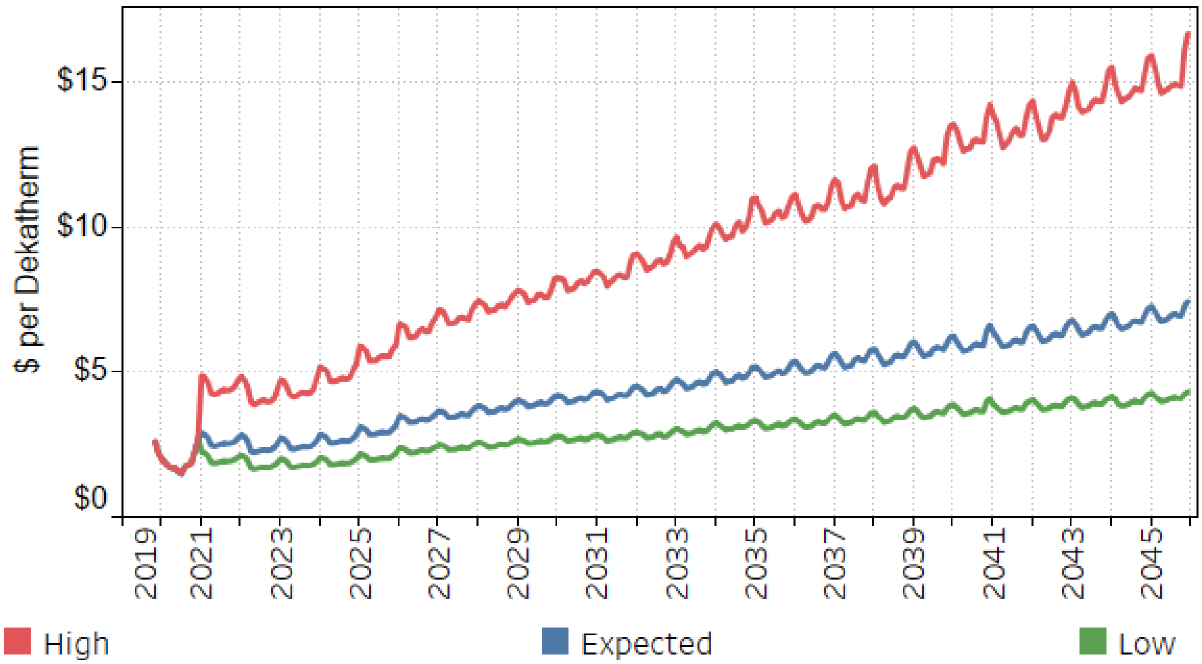
Years	Price Blend Methodology
2021 & 2022	forward price only
2023	forward price / 25% average consultant forecasts
2024	50% forward price / 50% average consultant forecasts
2025	25% forward price / 75% average consultant forecasts
2026 - 2040	100% average consultant forecasts

Figure 6.4: Expected Price with Allocated Price Forecast



To accommodate for the likelihood that the expected prices at Henry Hub do not perfectly reflect future natural gas prices and to help measure price risk in resource planning, a stochastic analysis of 1,000 possible futures were modeled based on the expected price forecast. Each future contains unique monthly price movements throughout the twenty-year forecasting horizon. With the assistance of the TAC, Avista selected the 95th and 25th highest prices in each month from the stochastic results to determine high and low price curves, respectively. The high, expected, and low price curves in nominal dollars are illustrated in Figure 6.5 below.

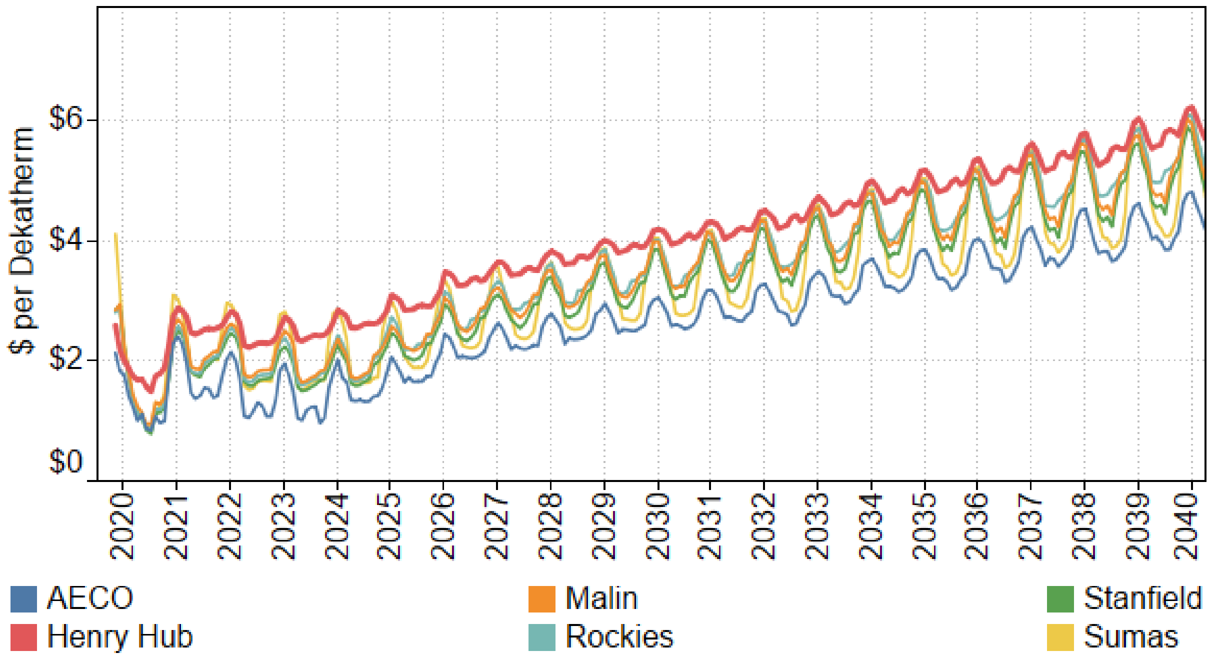
Figure 6.5: Henry Hub Forecasts for IRP Low/ Expected/ High Forecasted Price – Nominal $/Dth



Henry Hub is located in southeastern Louisiana, near the Gulf of Mexico. It is recognized as the most important pricing point in the U.S. due to its proximity to a large portion of U.S. natural gas production and the sheer volume traded in the daily, or spot, market and forward markets via the NYMEX futures contracts. Consequently, prices at other trading points tend to follow the Henry Hub with a positive or negative basis differential. Of the two market consultants Avista uses, only one forecasts basis pricing at the gas hubs modeled throughout the twenty-year horizon.

The natural gas hubs 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 largest natural gas basins in North America (Western Canada and the Rockies). Figure 6.6 below shows the resulting regional prices as compared to the Henry Hub.

Figure 6.6: Regional Price as a compared to the Henry Hub Price



Carbon Policy Resource Utilization Summary

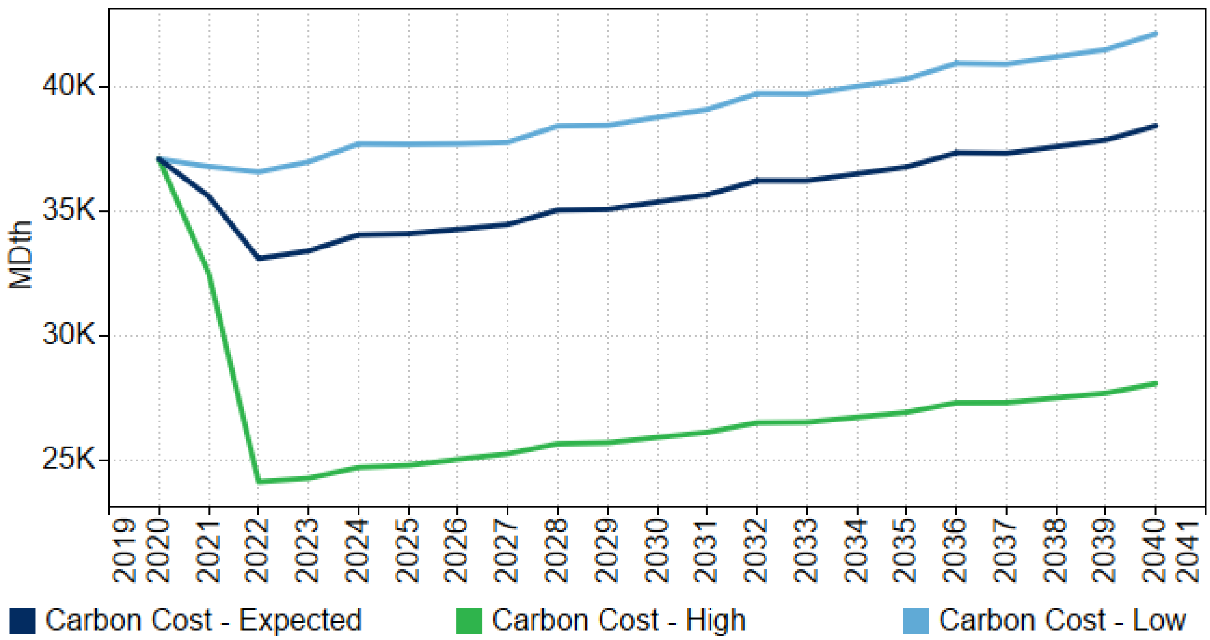
Avista uses an estimated carbon price as an incremental adder to address any potential policy. Carbon adders increase the price of a dekatherm of natural gas and impact resource selections and demand through expected elasticity (Chapter 2 – Demand Forecasts, Price Elasticity). Oregon was assumed to have a cap and reduce market as estimated by Wood Mackenzie, through a cap and trade estimate, and presented to the TAC on September 30, 2020. In this price estimate, the initial level starts low per MTCO2e at around $15.83, rising to $97.90 by 2040. The cap and reduce market discussed in Oregon's EO 20-04[1] is still under development at the time of this filing making modeling of a market price difficult. Washington State was modeled at $79.86 per MTCO2e starting in 2021 and rising to $158.06 per MTCO2e by 2040. These carbon tax figures are based on the requirement to utilize SCC at 2.5% discount estimates from the EPA as required by RCW 80.28.395. 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 to account for risk including a lower and higher than expected price of carbon and are applied to all three jurisdictions. The low carbon price is assumed at $0, or no cost, of carbon to help measure the risk of a continued stalemate

[1] https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf

with carbon pricing. 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 a much higher cost of carbon beginning in 2021 at $151.01 and increasing to $219.33 per $MTCO_2e$ by 2040. 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 6.7.

Figure 6.7: 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 6.8 and 6.9.

Figure 6.8: Existing Firm Transportation Resources – Washington & Idaho

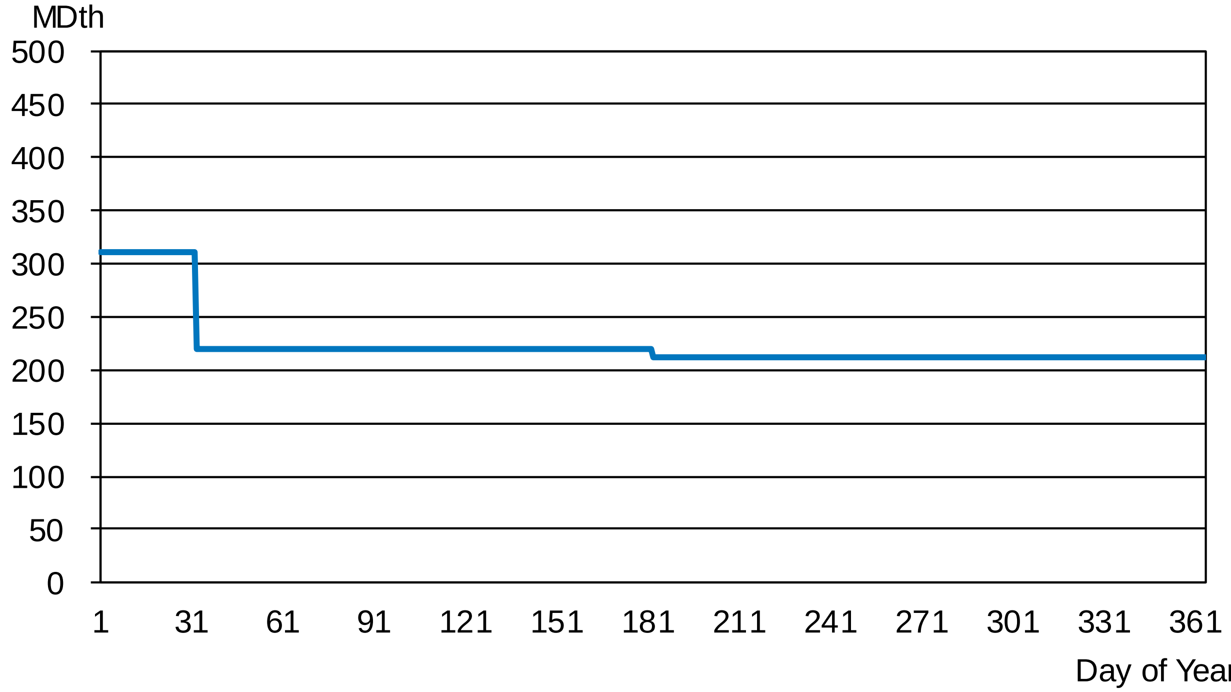
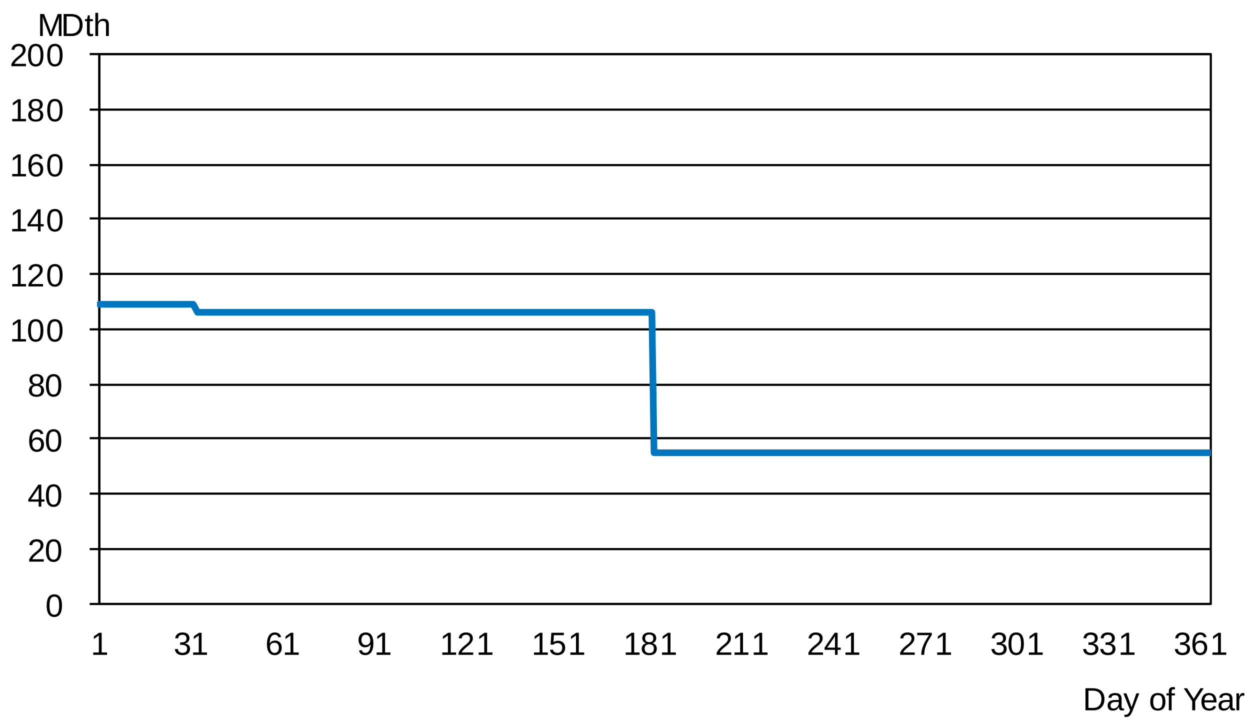


Figure 6.9: Existing Firm Transportation Resources – Oregon



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.

Demand 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 6.10 through 6.13 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 6.10: Average Case – Washington/Idaho Existing Resources vs. Average Demand – February 28th

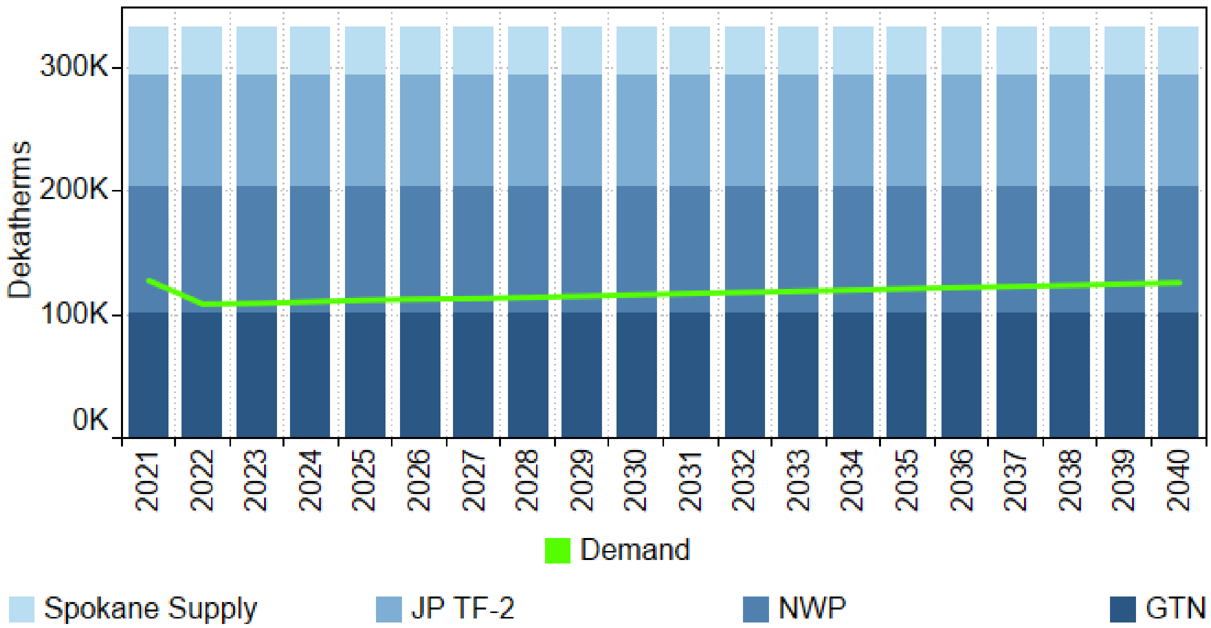


Figure 6.11: Average Case – Medford / Roseburg Existing Resources vs. Average Demand – December 20th

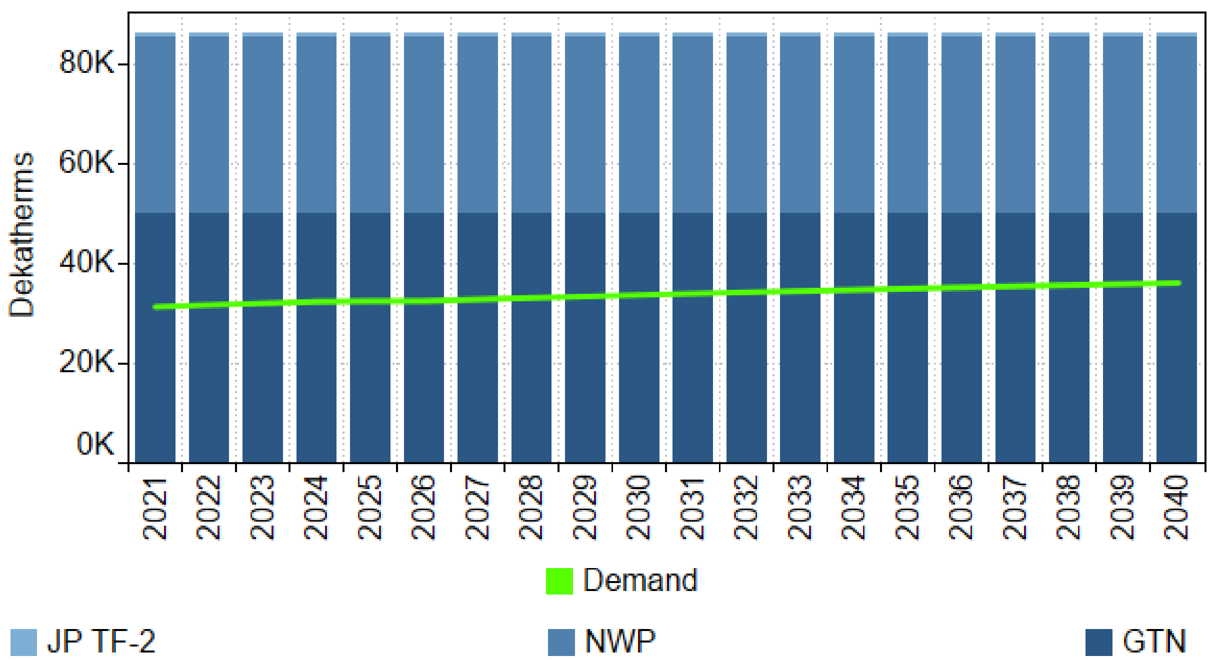


Figure 6.12: Average Case – Klamath Falls Existing Resources vs. Average Demand – December 20th

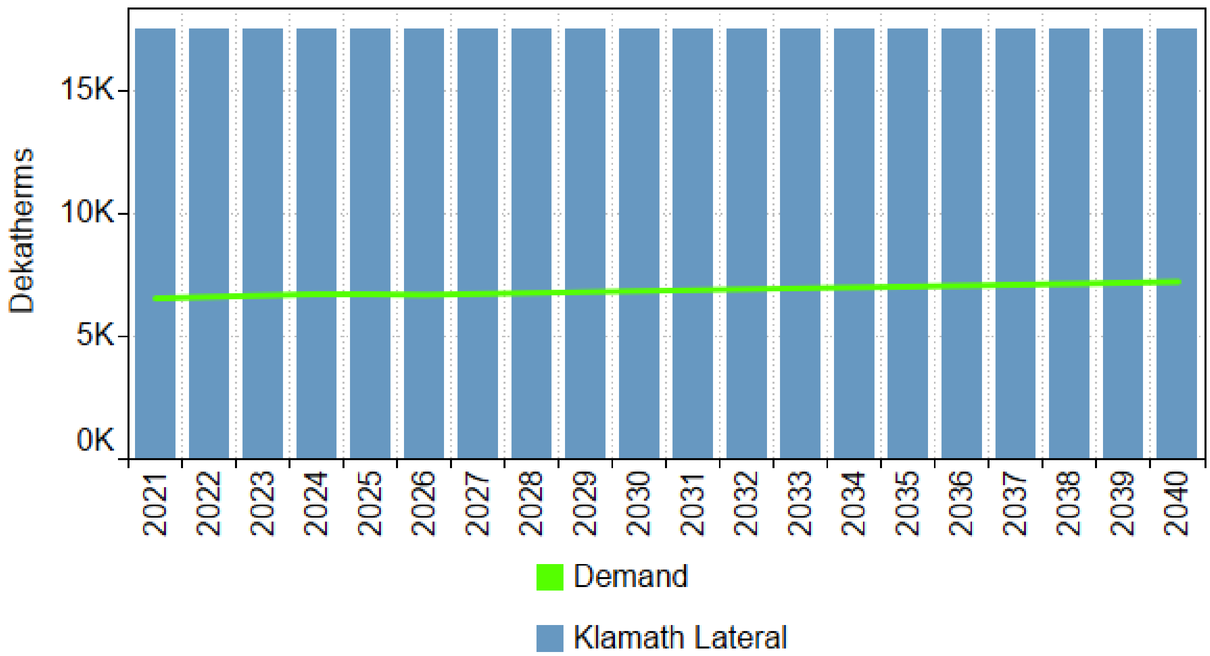
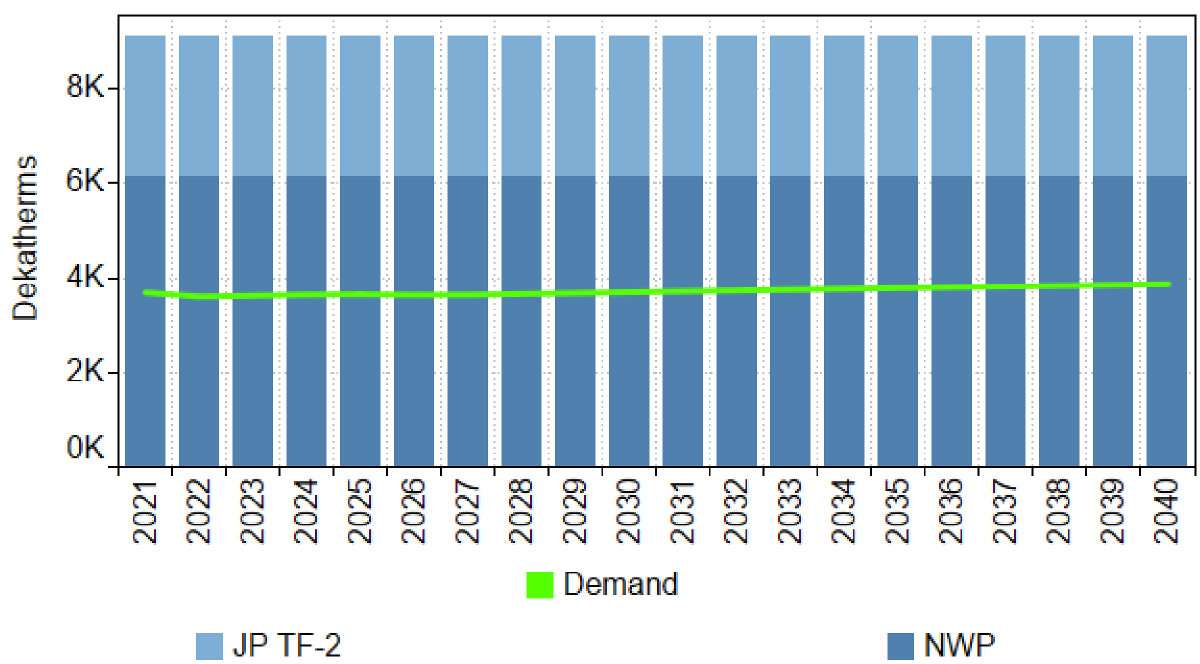


Figure 6.13: Average Case – La Grande Existing Resources vs. Average Demand February 28th



Figures 6.14 through 6.17 summarize Expected Case peak day demand compared to existing resources, as well as demand comparisons to the 2018 IRP. This demand is net of conservation savings. Based on this information Avista has time to carefully monitor, plan and analyze 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 6.14: Expected Case – Washington & Idaho Existing Resources vs. Peak Day Demand – February 28th

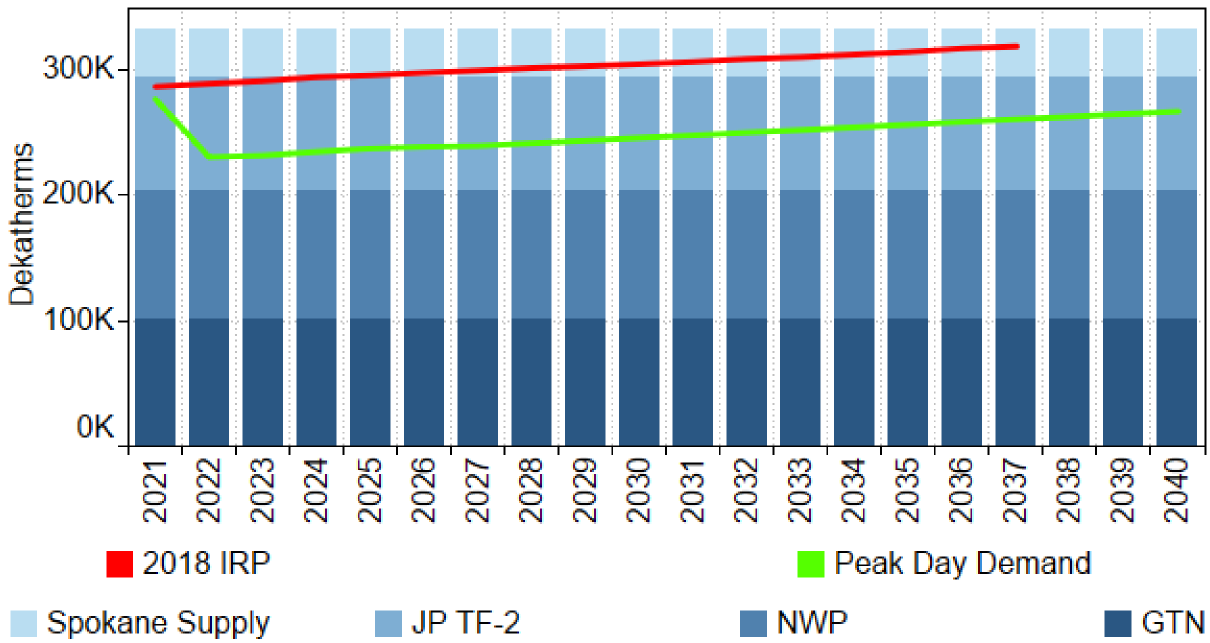


Figure 6.15: Expected Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

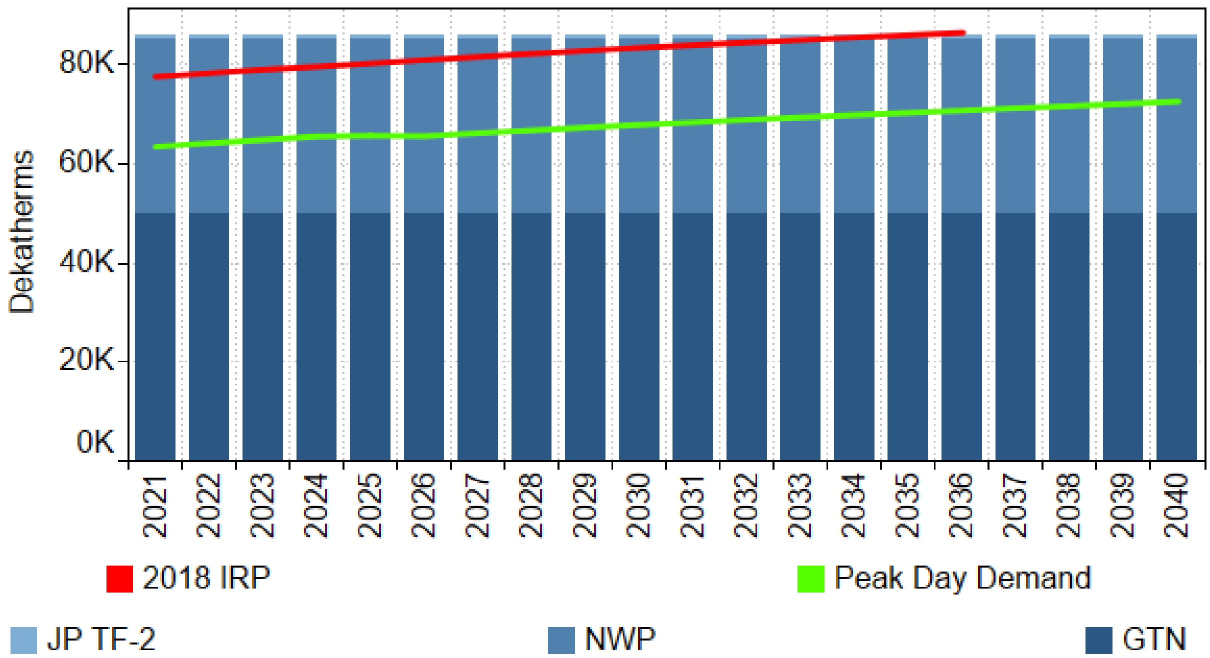


Figure 6.16: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

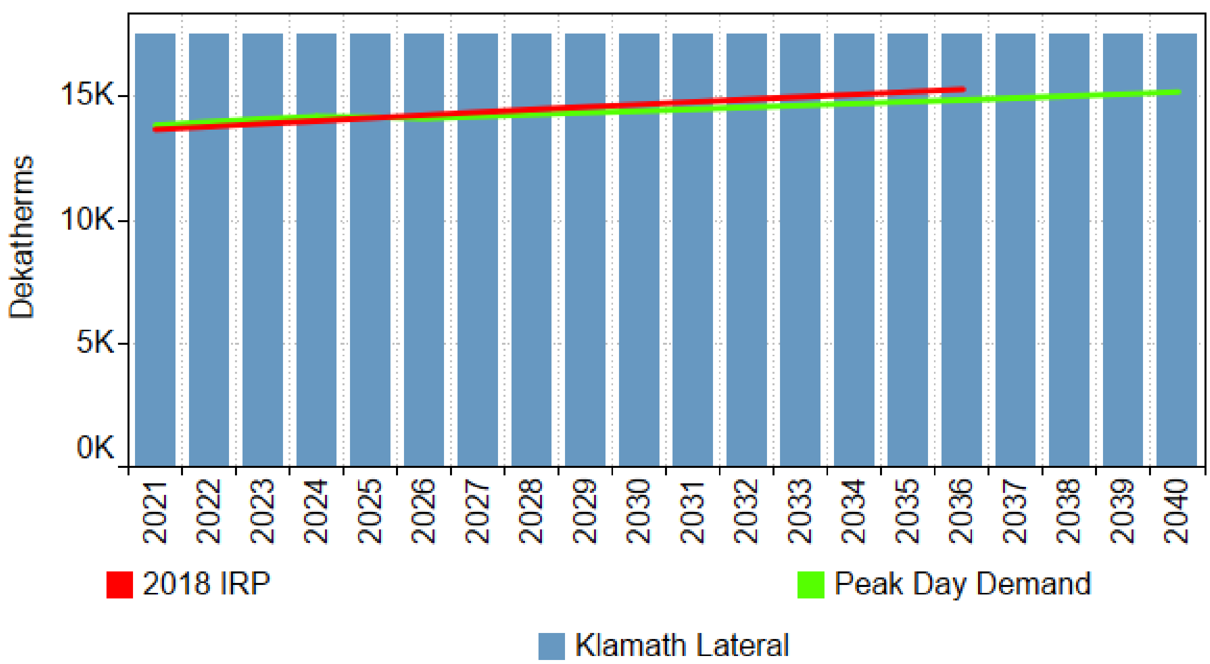
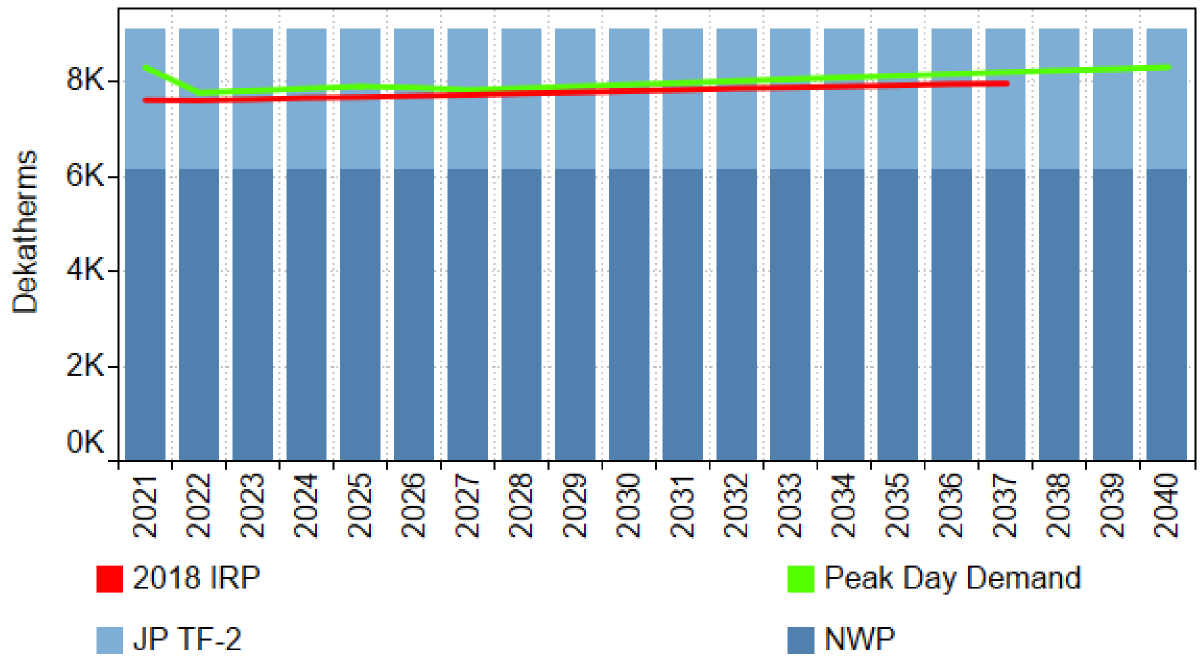


Figure 6.17: Expected Case – La Grande Existing Resources vs. Peak Day Demand – February 28th



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. The 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 6.2 quantifies the forecasted total demand net of conservation savings and unserved demand from the above charts.

Table 6.2: Peak Day Demand – Served and Unserved (MDth/day)

Case	Gas Year	LaGrande				Idaho				Washington			
		Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served
Expected Case	2020-2021	8.31	-	8.31	100%	96.37	-	96.37	100%	179.82	-	179.82	100%
Expected Case	2021-2022	7.78	-	7.78	100%	94.17	-	94.17	100%	135.76	-	135.76	100%
Expected Case	2022-2023	7.82	-	7.82	100%	95.36	-	95.36	100%	135.83	-	135.83	100%
Expected Case	2023-2024	7.87	-	7.87	100%	96.79	-	96.79	100%	137.38	-	137.38	100%
Expected Case	2024-2025	7.91	-	7.91	100%	98.06	-	98.06	100%	138.75	-	138.75	100%
Expected Case	2025-2026	7.89	-	7.89	100%	98.04	-	98.04	100%	140.11	-	140.11	100%
Expected Case	2026-2027	7.84	-	7.84	100%	97.40	-	97.40	100%	141.39	-	141.39	100%
Expected Case	2027-2028	7.87	-	7.87	100%	98.30	-	98.30	100%	142.67	-	142.67	100%
Expected Case	2028-2029	7.91	-	7.91	100%	99.16	-	99.16	100%	143.93	-	143.93	100%
Expected Case	2029-2030	7.95	-	7.95	100%	100.03	-	100.03	100%	145.21	-	145.21	100%
Expected Case	2030-2031	7.99	-	7.99	100%	100.94	-	100.94	100%	146.38	-	146.38	100%
Expected Case	2031-2032	8.02	-	8.02	100%	101.90	-	101.90	100%	147.55	-	147.55	100%
Expected Case	2032-2033	8.06	-	8.06	100%	102.82	-	102.82	100%	148.67	-	148.67	100%
Expected Case	2033-2034	8.10	-	8.10	100%	103.80	-	103.80	100%	149.83	-	149.83	100%
Expected Case	2034-2035	8.14	-	8.14	100%	104.81	-	104.81	100%	150.95	-	150.95	100%
Expected Case	2035-2036	8.17	-	8.17	100%	105.85	-	105.85	100%	152.10	-	152.10	100%
Expected Case	2036-2037	8.21	-	8.21	100%	106.86	-	106.86	100%	153.18	-	153.18	100%
Expected Case	2037-2038	8.24	-	8.24	100%	107.88	-	107.88	100%	154.24	-	154.24	100%
Expected Case	2038-2039	8.28	-	8.28	100%	108.93	-	108.93	100%	155.29	-	155.29	100%
Expected Case	2039-2040	8.32	-	8.32	100%	109.99	-	109.99	100%	156.35	-	156.35	100%

Case	Gas Year	Klamath Falls				Medford/Roseburg			
		Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served
Expected Case	2020-2021	14.87	-	14.87	100%	67.94	-	67.94	100%
Expected Case	2021-2022	13.85	-	13.85	100%	63.46	-	63.46	100%
Expected Case	2022-2023	13.98	-	13.98	100%	64.18	-	64.18	100%
Expected Case	2023-2024	14.10	-	14.10	100%	64.86	-	64.86	100%
Expected Case	2024-2025	14.21	-	14.21	100%	65.54	-	65.54	100%
Expected Case	2025-2026	14.19	-	14.19	100%	65.70	-	65.70	100%
Expected Case	2026-2027	14.12	-	14.12	100%	65.61	-	65.61	100%
Expected Case	2027-2028	14.20	-	14.20	100%	66.20	-	66.20	100%
Expected Case	2028-2029	14.27	-	14.27	100%	66.76	-	66.76	100%
Expected Case	2029-2030	14.35	-	14.35	100%	67.34	-	67.34	100%
Expected Case	2030-2031	14.42	-	14.42	100%	67.87	-	67.87	100%
Expected Case	2031-2032	14.50	-	14.50	100%	68.39	-	68.39	100%
Expected Case	2032-2033	14.57	-	14.57	100%	68.90	-	68.90	100%
Expected Case	2033-2034	14.65	-	14.65	100%	69.41	-	69.41	100%
Expected Case	2034-2035	14.72	-	14.72	100%	69.87	-	69.87	100%
Expected Case	2035-2036	14.80	-	14.80	100%	70.33	-	70.33	100%
Expected Case	2036-2037	14.87	-	14.87	100%	70.79	-	70.79	100%
Expected Case	2037-2038	14.95	-	14.95	100%	71.25	-	71.25	100%
Expected Case	2038-2039	15.03	-	15.03	100%	71.69	-	71.69	100%
Expected Case	2039-2040	15.11	-	15.11	100%	72.12	-	72.12	100%

New Resource Options

When existing resources are insufficient 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 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 along with carbon intensity. 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 other parties to secure firm resources for customers. RNG resources specifically will have an increased amount of competition as the drive for carbon reducing supplies increases with associated policy.

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).

Demand-Side Resources

Integration by Price

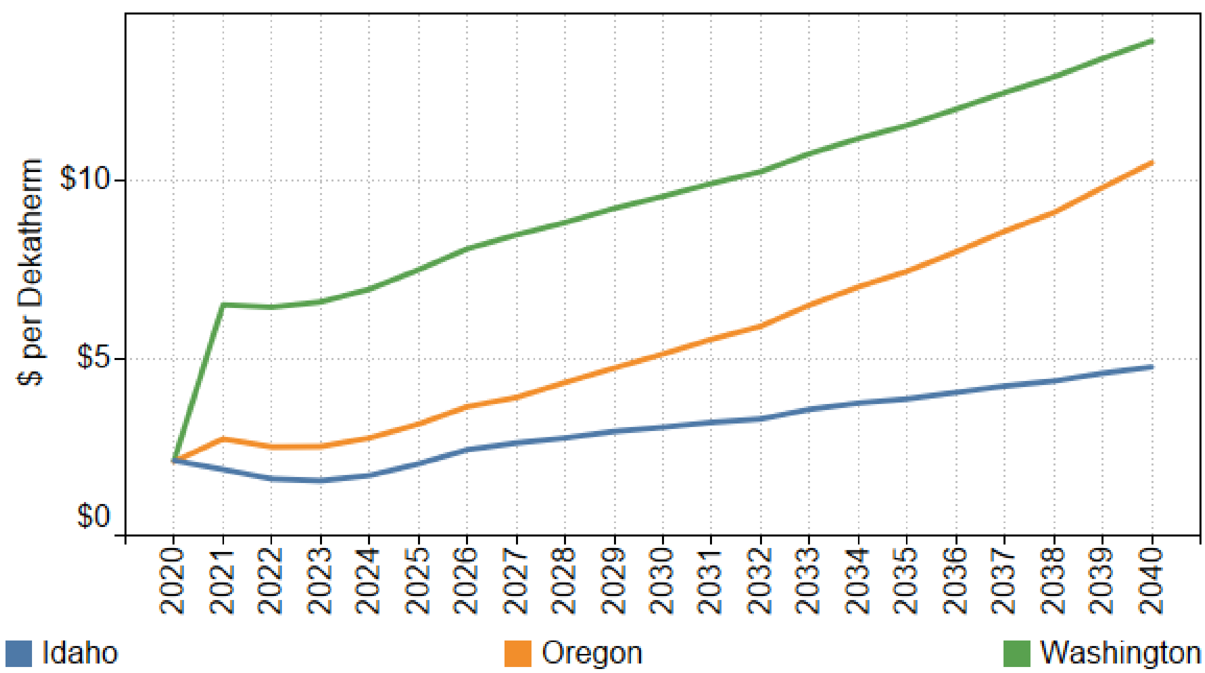
As described in Chapter 3 – Demand-Side Resources, the model runs without future DSM programs. This preliminary model run provides an avoided cost curve for both Applied Energy Group (AEG) and Energy Trust of Oregon (ETO) to evaluate the cost effectiveness of DSM programs against the initial avoided 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 (Oregon), or utility cost (for Idaho and 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 while reducing the risk of unserved demand in peak weather.

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 each jurisdictional area is in Figure 6.18. The detailed data is in Appendix 6.4 – Avoided Cost Details. Other than the carbon tax adder, avoided costs 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 6.18: Avoided Cost (by jurisdiction)



Conservation Potential

Using the avoided cost thresholds, AEG selected all potential cost-effective DSM programs for the Idaho and Washington service areas, while ETO performed the CPA study for Oregon. Table 6.3 shows potential DSM savings in each region from the selected conservation potential for the Expected Case.

Table 6.3: Annual and Average Daily Demand Served by Conservation

Case	Gas Year	Klamath Falls Annual DSM (MDth)	Klamath Falls Daily DSM (MDth/Day)	LaGrande Annual DSM (MDth)	LaGrande Daily DSM (MDth/Day)	Medford/Roseburg Annual DSM (MDth)	Medford/Roseburg Daily DSM (MDth/Day)	Oregon Annual DSM (MDth)	Oregon Daily DSM (MDth/Day)
Expected Case	2020-2021	4.51	0.01	3.45	0.01	22.73	0.06	30.69	0.08
Expected Case	2021-2022	6.50	0.02	4.92	0.01	33.07	0.09	44.49	0.12
Expected Case	2022-2023	5.81	0.02	4.79	0.01	28.93	0.08	39.52	0.11
Expected Case	2023-2024	5.99	0.02	4.86	0.01	29.40	0.08	40.25	0.11
Expected Case	2024-2025	6.26	0.02	4.99	0.01	30.59	0.08	41.84	0.11
Expected Case	2025-2026	6.55	0.02	5.18	0.01	32.68	0.09	44.41	0.12
Expected Case	2026-2027	7.66	0.02	5.74	0.02	38.45	0.11	51.85	0.14
Expected Case	2027-2028	9.29	0.03	6.67	0.02	46.90	0.13	62.86	0.17
Expected Case	2028-2029	10.34	0.03	7.25	0.02	52.02	0.14	69.61	0.19
Expected Case	2029-2030	11.49	0.03	7.89	0.02	57.66	0.16	77.04	0.21
Expected Case	2030-2031	12.51	0.03	8.46	0.02	62.70	0.17	83.68	0.23
Expected Case	2031-2032	13.24	0.04	8.88	0.02	66.38	0.18	88.50	0.24
Expected Case	2032-2033	13.57	0.04	9.04	0.02	67.77	0.19	90.38	0.25
Expected Case	2033-2034	14.12	0.04	9.35	0.03	70.45	0.19	93.92	0.26
Expected Case	2034-2035	14.63	0.04	9.61	0.03	72.78	0.20	97.02	0.27
Expected Case	2035-2036	14.89	0.04	9.74	0.03	74.05	0.20	98.67	0.27
Expected Case	2036-2037	14.96	0.04	9.75	0.03	74.34	0.20	99.05	0.27
Expected Case	2037-2038	15.03	0.04	9.77	0.03	74.67	0.20	99.47	0.27
Expected Case	2038-2039	15.23	0.04	9.87	0.03	75.62	0.21	100.71	0.28
Expected Case	2039-2040	14.43	0.04	9.37	0.03	71.48	0.20	95.28	0.26

Case	Gas Year	Washington Annual DSM (MDth)	Washington Daily DSM (MDth/Day)	Idaho Annual DSM (MDth)	Idaho Daily DSM (MDth/Day)	Total System Annual DSM (MDth)	Total System Daily DSM (MDth/Day)
Expected Case	2020-2021	52.69	0.14	24.83	0.07	108.21	0.30
Expected Case	2021-2022	91.95	0.25	47.52	0.13	183.96	0.50
Expected Case	2022-2023	114.86	0.31	60.30	0.17	214.68	0.59
Expected Case	2023-2024	118.33	0.32	61.90	0.17	220.48	0.60
Expected Case	2024-2025	128.52	0.35	67.15	0.18	237.50	0.65
Expected Case	2025-2026	146.36	0.40	76.80	0.21	267.57	0.73
Expected Case	2026-2027	168.03	0.46	91.28	0.25	311.17	0.85
Expected Case	2027-2028	190.26	0.52	104.33	0.29	357.44	0.98
Expected Case	2028-2029	207.19	0.57	113.78	0.31	390.58	1.07
Expected Case	2029-2030	219.84	0.60	121.78	0.33	418.66	1.15
Expected Case	2030-2031	229.45	0.63	127.88	0.35	441.01	1.21
Expected Case	2031-2032	238.49	0.65	132.89	0.36	459.88	1.26
Expected Case	2032-2033	243.14	0.67	138.05	0.38	471.56	1.29
Expected Case	2033-2034	239.15	0.66	137.80	0.38	470.87	1.29
Expected Case	2034-2035	233.38	0.64	135.32	0.37	465.72	1.28
Expected Case	2035-2036	227.09	0.62	133.12	0.36	458.89	1.25
Expected Case	2036-2037	220.49	0.60	131.07	0.36	450.60	1.23
Expected Case	2037-2038	218.81	0.60	132.68	0.36	450.96	1.24
Expected Case	2038-2039	214.36	0.59	132.59	0.36	447.66	1.23
Expected Case	2039-2040	211.27	0.58	132.79	0.36	439.33	1.20

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 most 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.

These strategies and plan is discussed in detail in Chapter 4 – Supply side resources. 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 in addition to contracted volumes of 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 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 multiple years, 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 daily).

Storage allows lower summer-priced natural gas to be stored and used in the winter during high demand or peak day events. Like 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 standard. To do this, Avista utilizes industry experts to help determine prices and a 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

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 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: 2021 IRP Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case	Average Case	Low Growth & High Prices	Carbon Reduction	High Growth & Low Prices
Customer Growth Rate	Reference Case Cust Growth Rates		Low Growth Rate	Reference Case Cust Growth Rates	High Growth Rate
Use per Customer	3 yr + Price Elasticity				
Demand Side Management	Expected Case CPA		High Prices DSM	Low Prices DSM	
Weather Planning Standard	99% probability of coldest in 30 years	20 year average	99% probability of coldest in 30 years		
GWP	100-Year GWP				
Prices Price curve	Expected		High	Low	
Carbon Legislation ($/Metric Ton)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID		Carbon Cost - High (SCC 95% at 3%)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID	$0

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.

Figure 7.1: Peak Day (Feb 28) – 2021 IRP Demand Scenarios

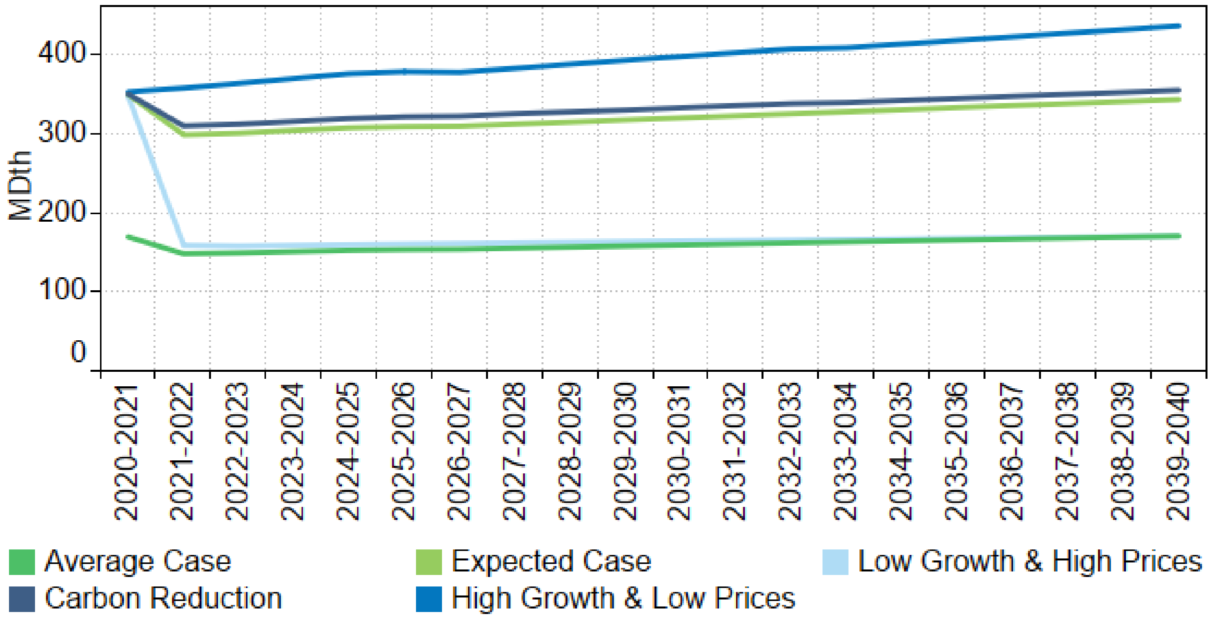
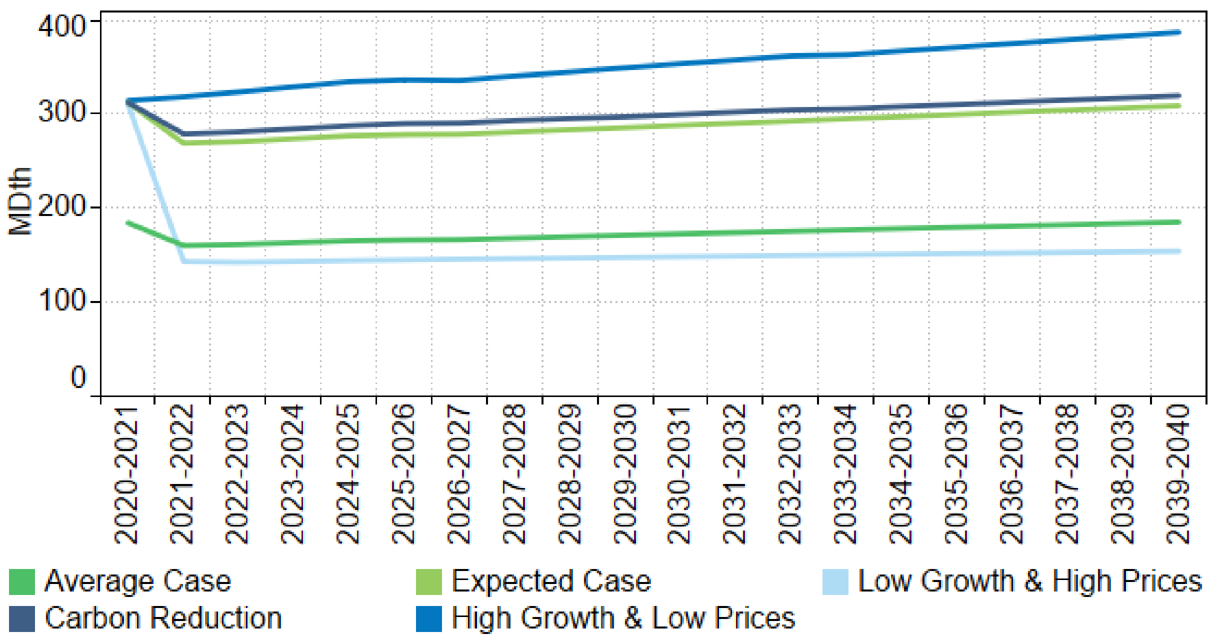
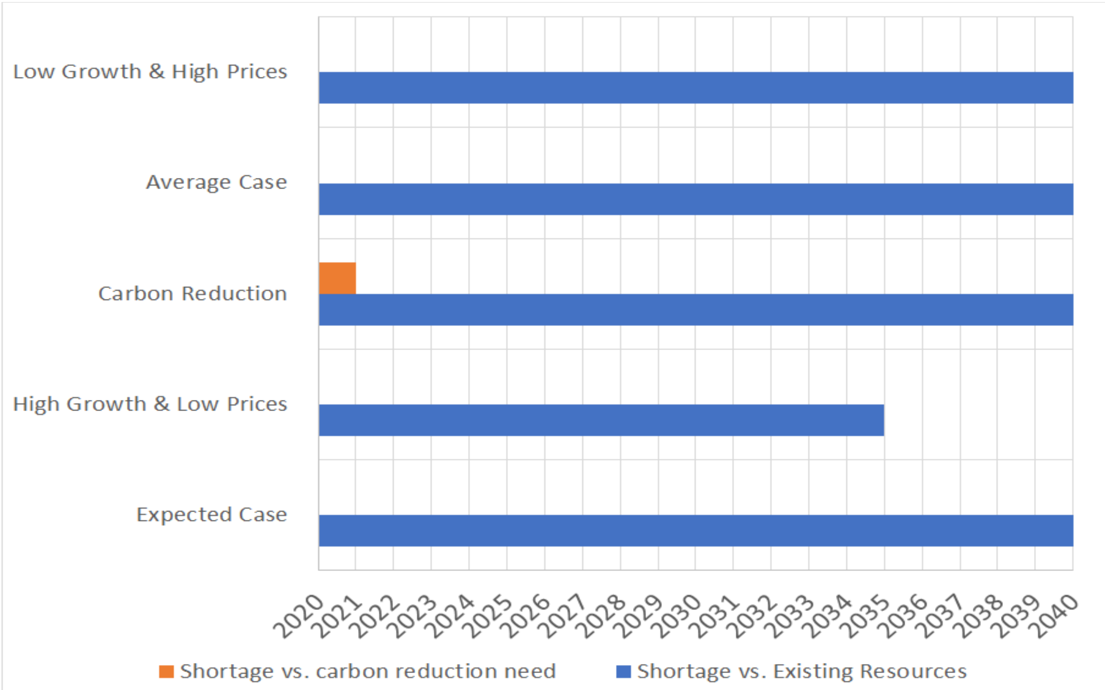


Figure 7.2: Peak Day (Dec 20) – 2021 IRP Demand Scenarios



As in the Expected Case, Avista used SENDOUT® to model the same resource integration and optimization process described in this section for each of the five demand scenarios (see Appendix 2.7 for a complete listing of portfolios considered). This 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. This could be a regional issue with utilities look toward carbon reduction with limited resources available. The likelihood of this scenario occurring is remote due to a yearly recurrence of the weather planning standard 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 renewable supply resources is displayed in Table 7.2 and fossil resources are included in Table 7.3.

Table 7.2: Levelized Cost of Renewable Resources

Resource	Dth per year	20-year Levelized Cost Per Dth (Year 1)	$ per kWh (retail)
Distributed Renewable Hydrogen Production	60,509	$47.25	$0.161
Distributed LFG to RNG Production	231,790	$15.90	$0.054
Centralized LFG to RNG Production	662,256	$14.11	$0.048
Dairy Manure to RNG Production	231,790	$14.30	$0.049
Wastewater Sludge to RNG Production	187,245	$23.34	$0.080
Food Waste to RNG Production	108,799	$33.14	$0.113

Table 7.3: Other Supply Resources

Additional Resource	Size	Cost/Rates	Availability	Notes
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate	2021	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Expansion	50,000 Dth / Day	$35M capital + GTN Rate	2022	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate	2021	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO’s to create firm transport

As discussed in Chapter 5 – Carbon Reduction, Hydrogen is beginning to emerge as a true potential as a clean fuel to help offset emissions in the natural gas system. Excess electricity from renewable resources can create green. Not only will this act as a type of storage desperately needed by the electric grid, it will capture excess green energy for future use. Some estimates have green hydrogen as a major fuel in the supply mix by 2050. 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 discussed in Chapter 5. The net effect of using this is the removal of carbon from the atmosphere. Finally, Renewable Identification Number (RIN) 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[1].

Many of the potential resources are not yet commercially available or well tested, technically making them speculative. Avista will continue to monitor all resources and assess their appropriateness for inclusion in future IRPs as described in Chapter 9 – Action Plan.

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 (Chapter 4 – Supply Side Resources) and conservation resources (Chapter 3 – Demand Side Management) are compared and selected on a least cost basis. Once new

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

resources are determined, a net present value of the revenue requirement (PVRR) is calculated. Results from each scenario can be found in Table 7.4.

Table 7.4: PVRR by Portfolio

Scenario	System Cost (PVRR) Billions of $
Expected Case	$6.88
High Growth & Low Prices	$2.68
Carbon Reduction*	$5.70
Average Case	$5.69
Low Growth & High Prices	$9.80

*Carbon Reduction Scenario does not have sufficient factors to stochastically represent alternative futures due to the unknown nature of the cost and availability of RNG and H2.

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 how each scenario will respond 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 unknown 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 1,000 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

The model considers five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. A new weather planning standard was introduced into the 2021 IRP, and Avista assessed the frequency of the weather planning standard peak day occurs in each area from the simulation data. The stochastic analysis shows that in over 1,000, 20-year simulations, peak day (or more) occurs with enough frequency to utilize the new planning standard for the current IRP. This topic remains a subject of continued analysis. For example, the Medford weather pattern over the 1,000 20-year draws (i.e, 20,000 years) HDDs at or above peak weather (49 HDDs) occur 1,926 times or once every 10 years.

See Figures 7.4 through 7.8 for the number of peak day occurrences by weather area. help explain why this can occur we look to the process itself. Monte Carlo simulations use historic data to obtain randomly generated weather events. Due to the change in planning standard, no peak days were simulated above the historic coldest on record temperature. Though due to the number of peak days occurring in the past 30 years, probability sees it is a higher likelihood of occurrence.

Figure 7.4: Frequency of Peak Day Occurrences – Spokane

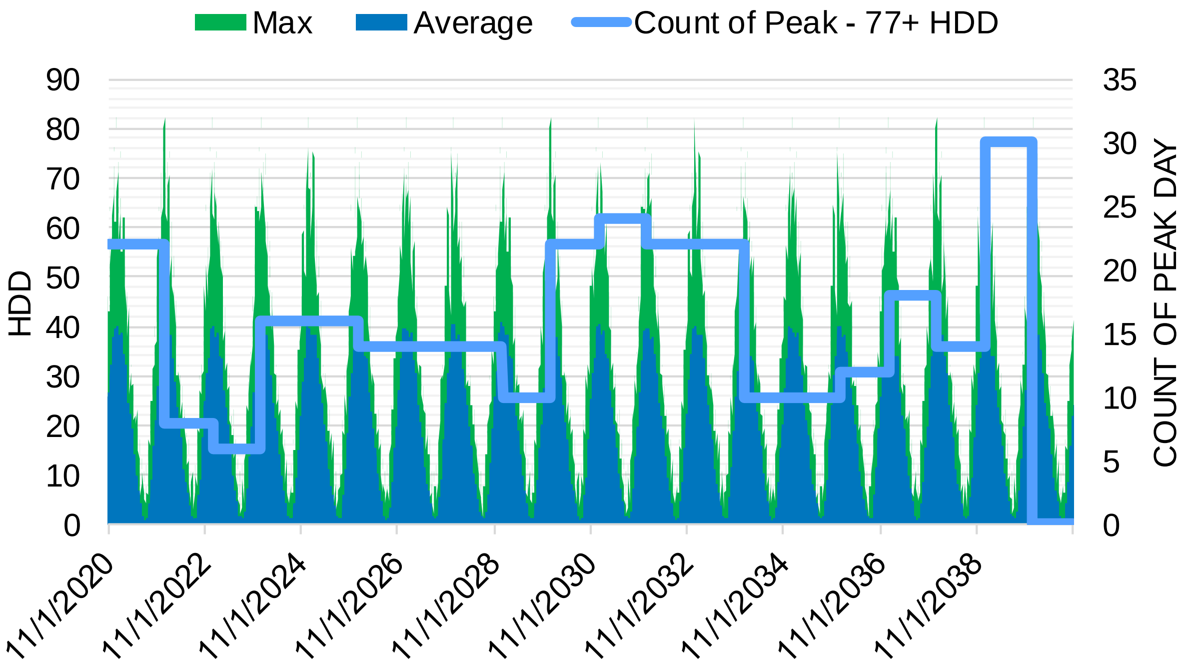


Figure 7.5: Frequency of Peak Day Occurrences – Medford

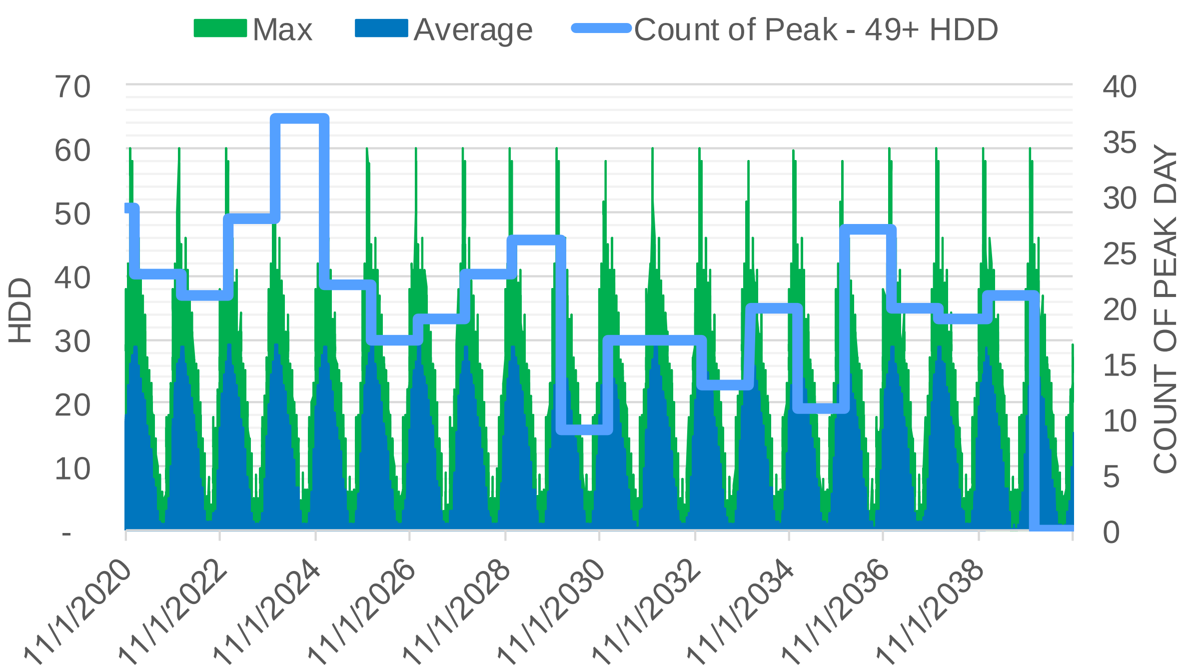


Figure 7.6: Frequency of Peak Day Occurrences – Roseburg

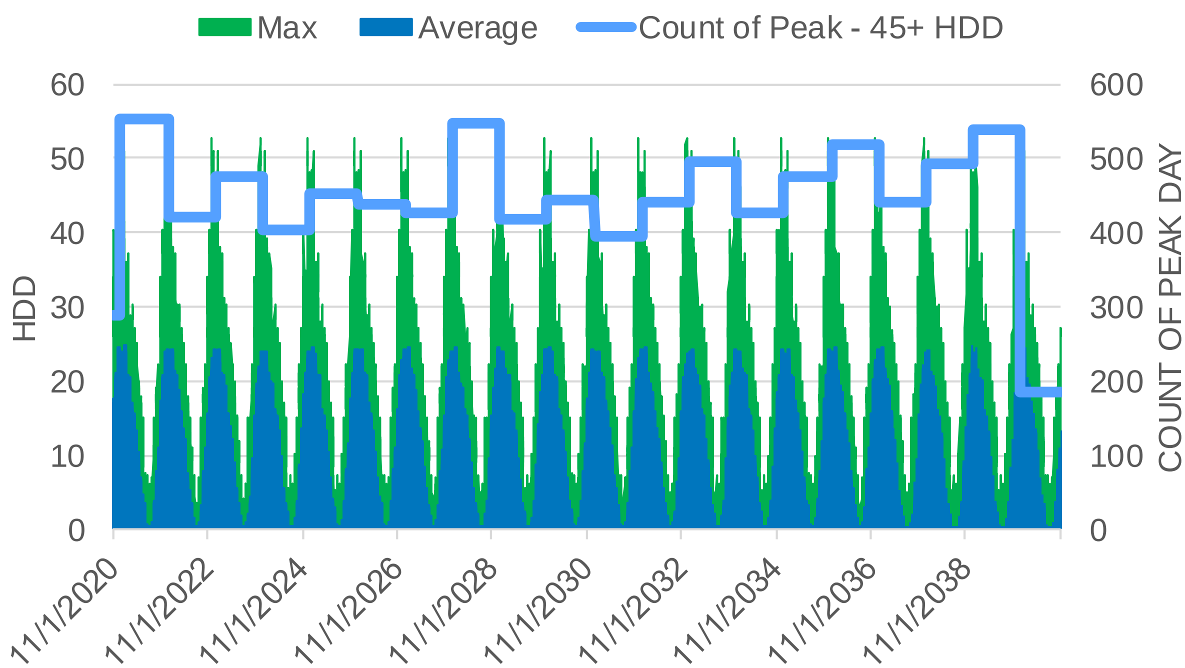


Figure 7.7: Frequency of near Peak Day Occurrences – Klamath Falls

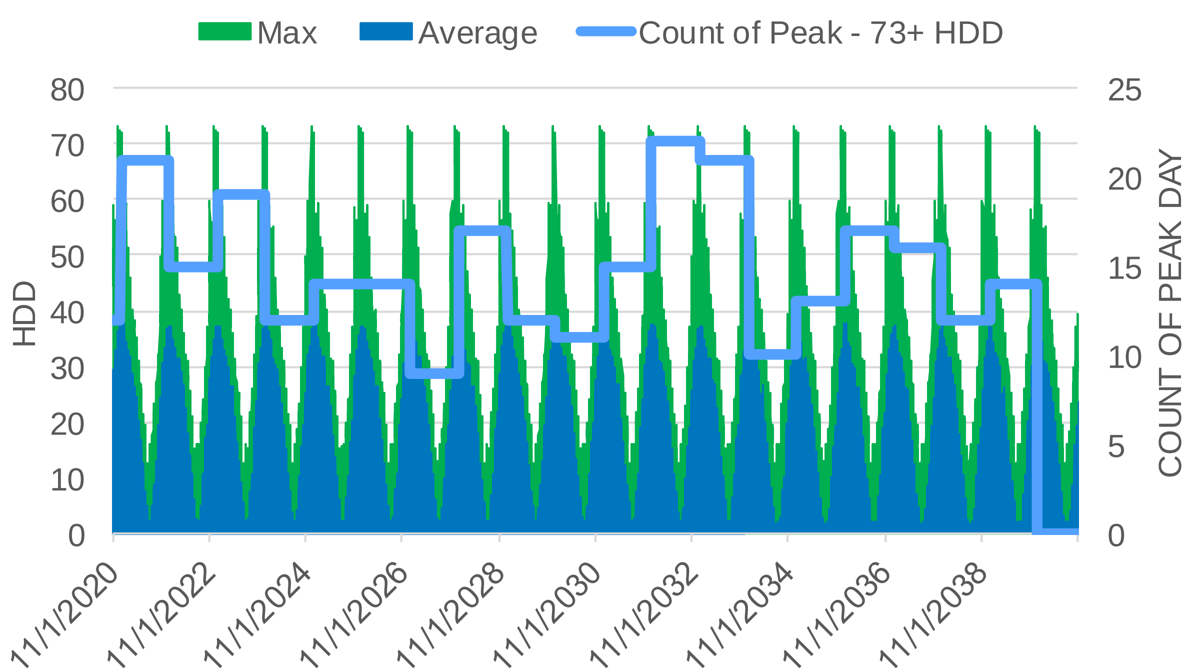
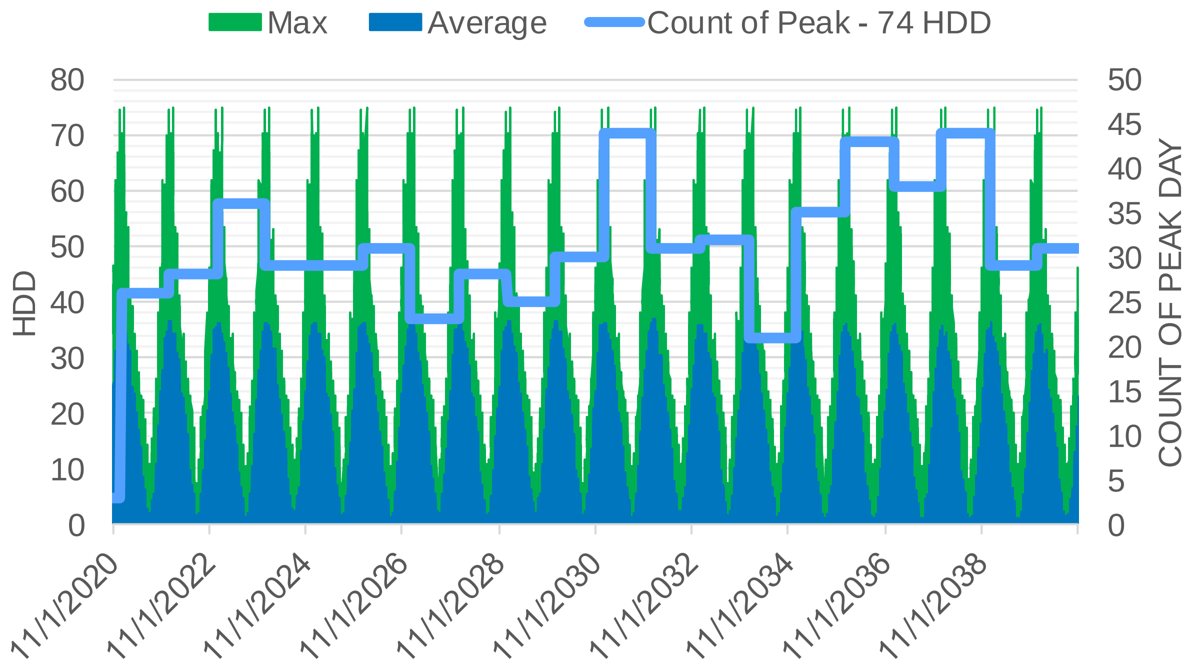


Figure 7.8: Frequency of near Peak Day Occurrences – La Grande

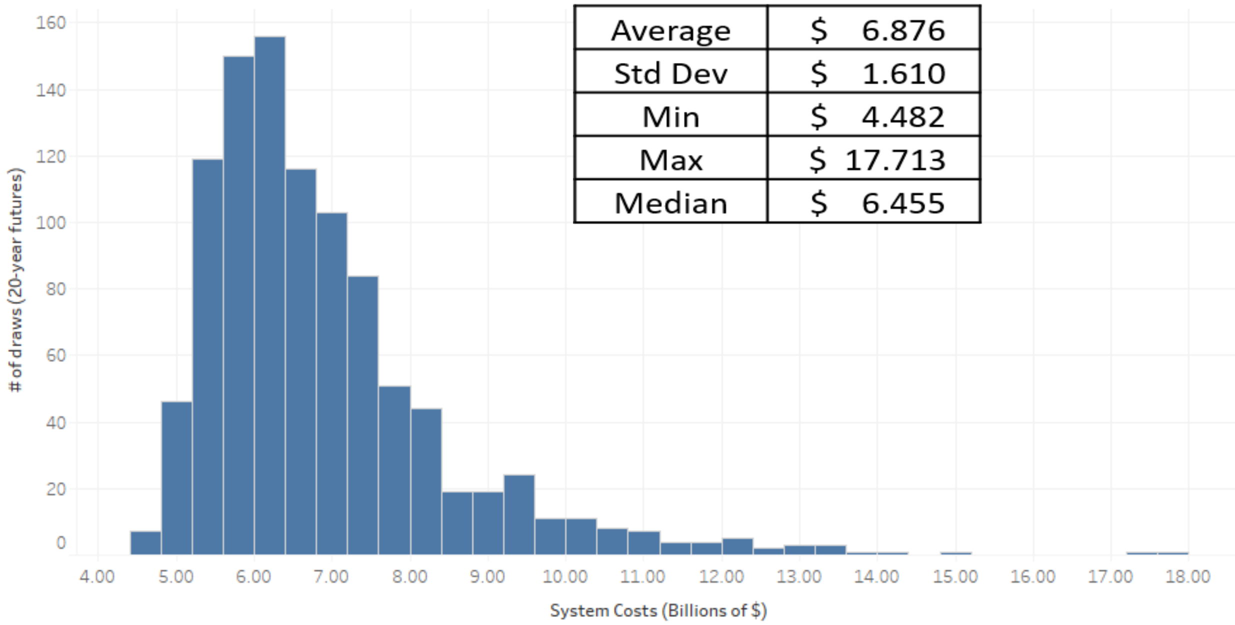


Price

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 1,000 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 1,000 draws, plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all of the draws, the mean of the draws, the standard deviation of the total costs, and the total costs from the Expected Case.

Figure 7.9: 2018 IRP Total 20-Year Cost (Billions of $)



Measuring risk in both weather and price is done through a statistical approach of shocking each of these measures to reflect the uncertain nature of a future outcome. Risk can be measured in the variation of cost outcome of resources in addition to unknown weather events and the ability to serve customer demand. 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

High Growth & Low Price

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.

- 2036 in Washington/Idaho
- 2040 in La Grande

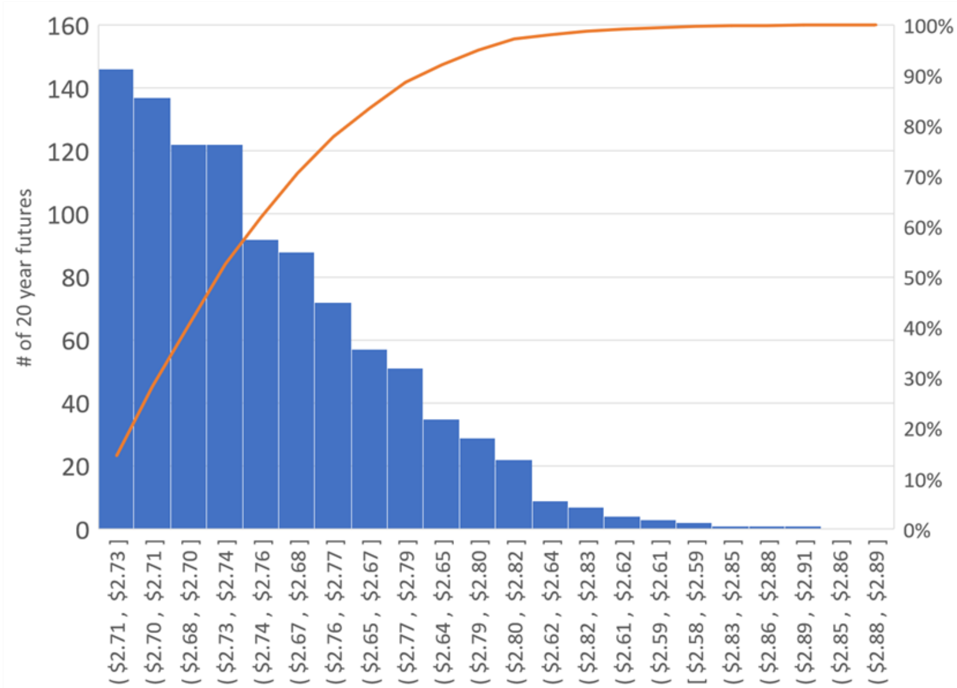
We begin to solve for unserved demand by adding additional resources as supply side options. The resources Avista modeled for the current IRP include 5 types of renewable natural gas, hydrogen, and an upsized compressor on the Medford lateral, additional GTN capacity and Plymouth LNG as seen in Table 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. Avista performed this selection process both deterministically and stochastically with the statistical measures shown for each resource option as illustrated in Table 7.6.

Table 7.6: System Cost, Standard Deviation and Outcome of Adding Resource to System

Solve – No Unserved	Average	Stdev	Median	Max	Min
RNG Resources Only	$2.683	$0.043	$2.681	$2.861	$2.542
Plymouth, RNG in La Grande	$2.721	$0.043	$2.719	$2.901	$2.580
GTN – RNG in La Grande	$2.734	$0.042	$2.675	$2.855	$2.540
Medford Lateral Expansion, RNG in La Grande	$2.734	$0.044	$2.731	$2.915	$2.600
*$ in Billions **1,000 draws each scenario					

Once an optimal resource is found deterministically a stochastic analysis takes place to measure risk. Figure 7.10 shows the frequency of occurrence from the solve (RNG Resources Only) by cost in addition to a running sum of overall percentage of the total number of future 20 year draws.

The Optimal Solution Figure 7.10: High Growth and Low Price Cost vs. Risk (1,000 Draws – Billions of $)

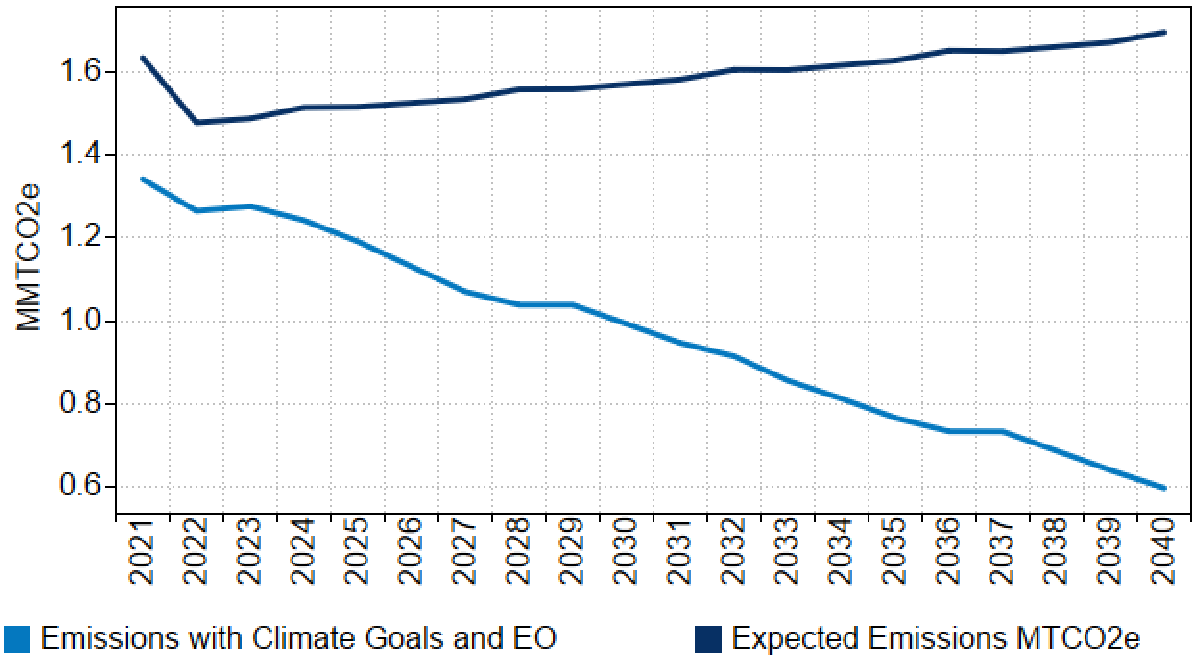


Carbon Reduction Scenario

As carbon policy continues to shift and evolve, mapping out potential supply options to meet these climate goals is increasingly important. Understanding the dynamic between serving the energy demand while reducing carbon emissions is a relatively new paradigm in the natural gas industry. Reducing carbon can take the form of alternate fuel choices either partially reducing, increased energy efficiency (DSM) or fully offsetting the carbon intensity of fossil natural gas. Some RNG sources, as mentioned in Chapter 5 – Carbon Reduction, will turn each unit of energy into a methodology to capture carbon rather than just fully offset the emissions of fossil fuel natural gas. These sources such as dairy or WWTP RNG will leave a deficit of energy for the number of emissions offsets provided. Pairing the right amount of energy with the necessary amount of emissions reduction is where this IRP will begin to discover solutions and provide answers.

Future IRP's will have the ability to solve for emissions and costs to meet a dual goal least cost and risk set of supply side resources. Emissions reduction goals can be measured to include various goals as a percentage based on a specific year or timeframe. In this scenario, we take the Expected case assumptions as inputs and combine them with an estimated 1990 emissions goal for Oregon and Washington. The emissions reduction for Oregon and Washington can be seen in Figure 7.11.

Figure 7.11: Expected Emissions vs. Emissions with Climate Goals (Net of DSM)



It is assumed the goal and reductions need to be met on a yearly basis based on the average emissions reduction needed to meet these major milestones. Carbon emissions offsets are not modeled in the current IRP as their costs are unknown as are the allowable quantity by timeframe for their use. The selling of carbon credits, like RINs, will need consideration in future resource plans. As the cost of carbon increases, the levelized cost of resources decreases especially those with the ability to capture carbon as opposed to just offsetting emissions. This places dairy RNG into the preferred supply side resource if the ability to obtain the quantity of projects and the respective output is available as displayed in Figure 7.12 along with each modeled scenario's carbon emissions (Figure 7.13).

Figure 7.12: Carbon Reduction Solve

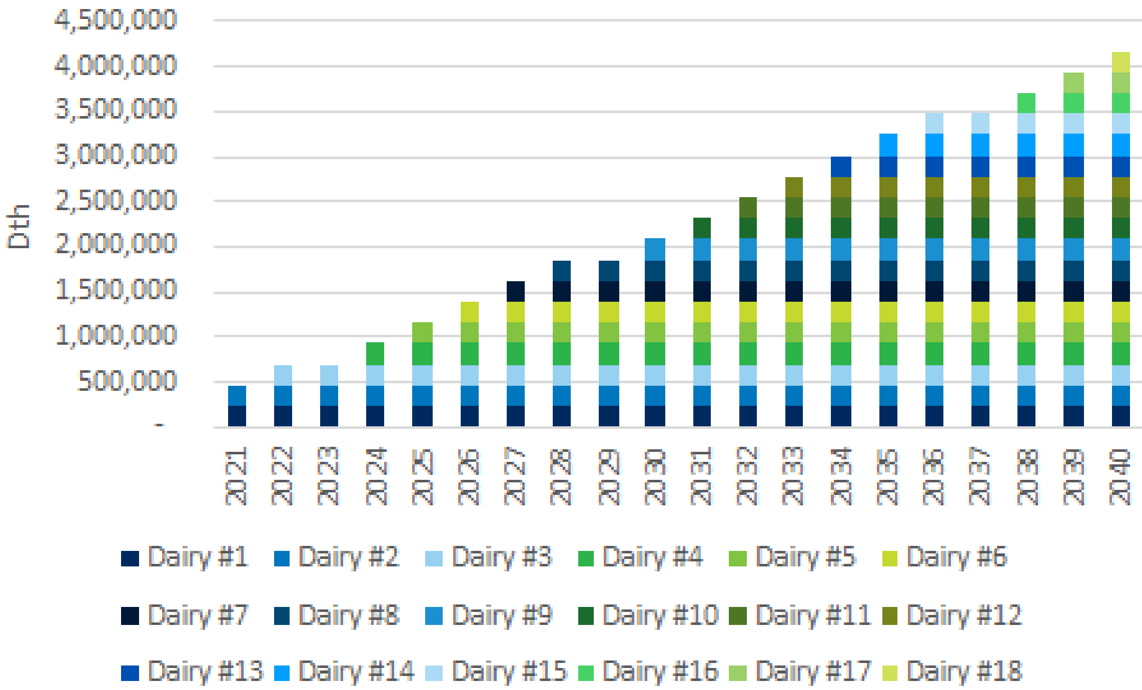
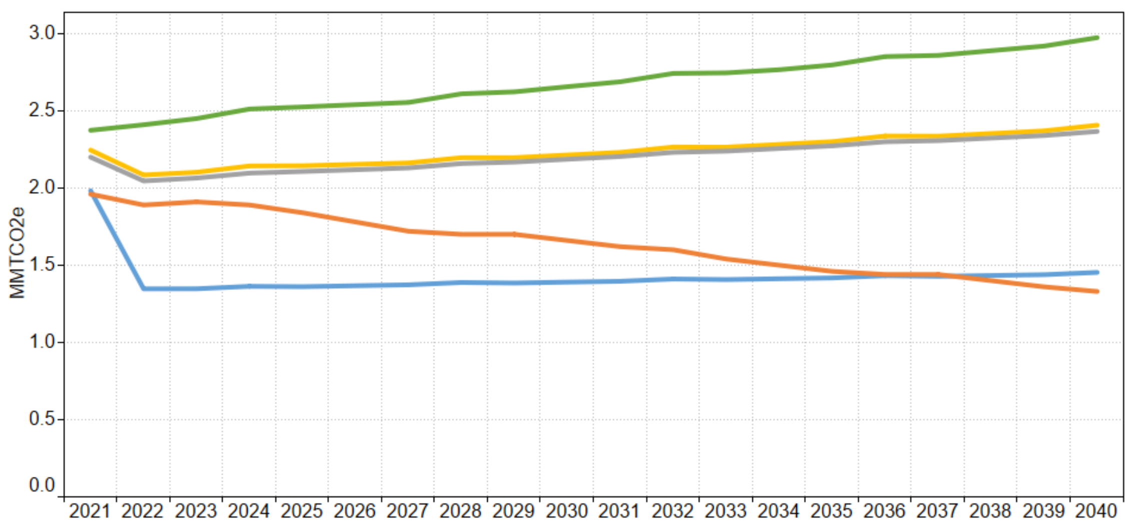


Figure 7.13: Depicts System Emissions for each Scenario



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Carbon Reduction	1.96	1.89	1.91	1.89	1.84	1.78	1.72	1.70	1.70	1.66	1.62	1.60	1.54	1.50	1.46	1.44	1.44	1.40	1.36	1.33
Average Case	2.20	2.05	2.06	2.10	2.11	2.12	2.13	2.16	2.17	2.19	2.20	2.23	2.24	2.26	2.27	2.30	2.31	2.32	2.34	2.37
Expected Case	2.25	2.08	2.10	2.14	2.14	2.15	2.16	2.20	2.20	2.21	2.23	2.27	2.26	2.28	2.30	2.34	2.34	2.35	2.37	2.41
Low Growth	1.98	1.35	1.35	1.36	1.36	1.37	1.37	1.39	1.38	1.39	1.40	1.41	1.41	1.41	1.42	1.43	1.43	1.43	1.44	1.45
High Growth	2.37	2.41	2.45	2.51	2.52	2.54	2.55	2.61	2.62	2.66	2.69	2.74	2.75	2.77	2.80	2.85	2.86	2.89	2.92	2.97

Electrification Scenarios

Avista uses three scenarios to identify impacts to the power system if space and water heating is electrified in the Washington service area[3], specifically for the residential and commercial customers. The first scenario of electrification uses current electric technology and efficiency. The second, continues to use the natural gas system for peak heating needs with non-peak electrified. Finally, the third scenario uses an assumption of high efficiency electric equipment. Each scenario uses the conversion from natural gas to electric assumes a 50 percent reduction in natural gas load by 2030 and an 80 percent reduction by 2045. Avista estimates 75 percent of the added electric load will be on Avista's system and the remaining load on other utilities.

Figure 7.14 below illustrates additional Avista load on the Avista electric system in Washington:

Figure 7.14: Additional Avista Load on Avista Electric System - Washington

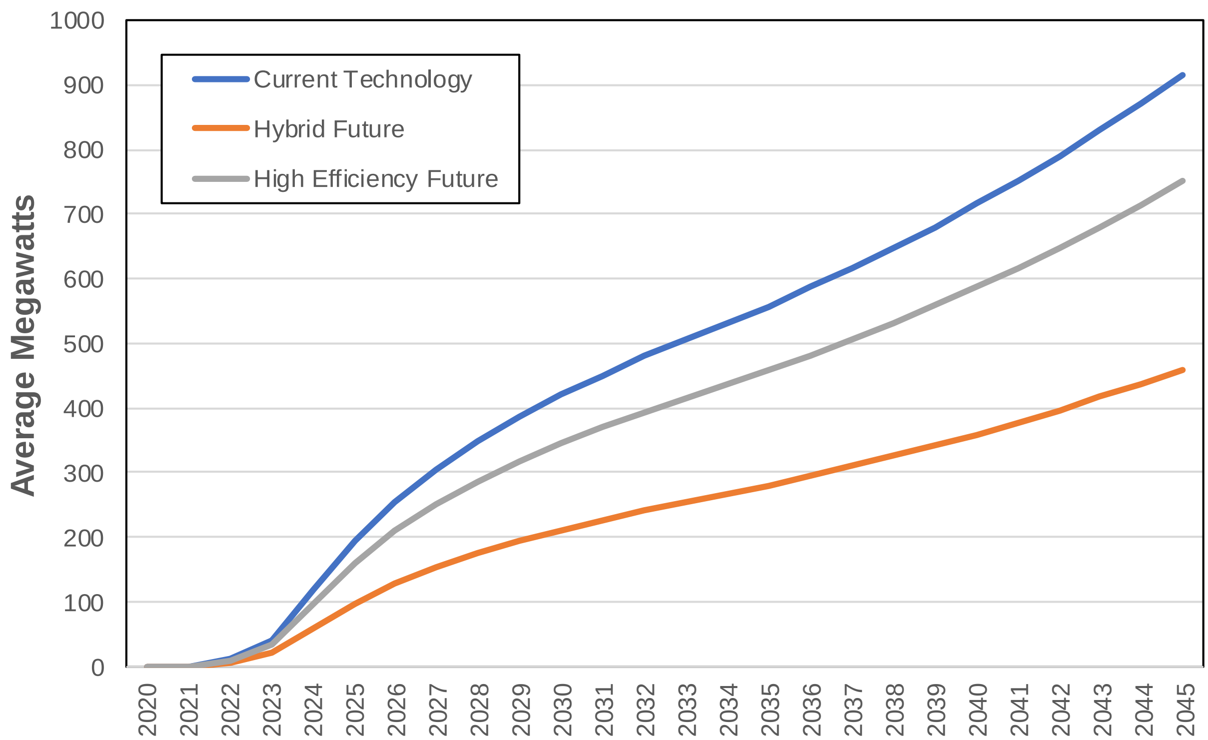
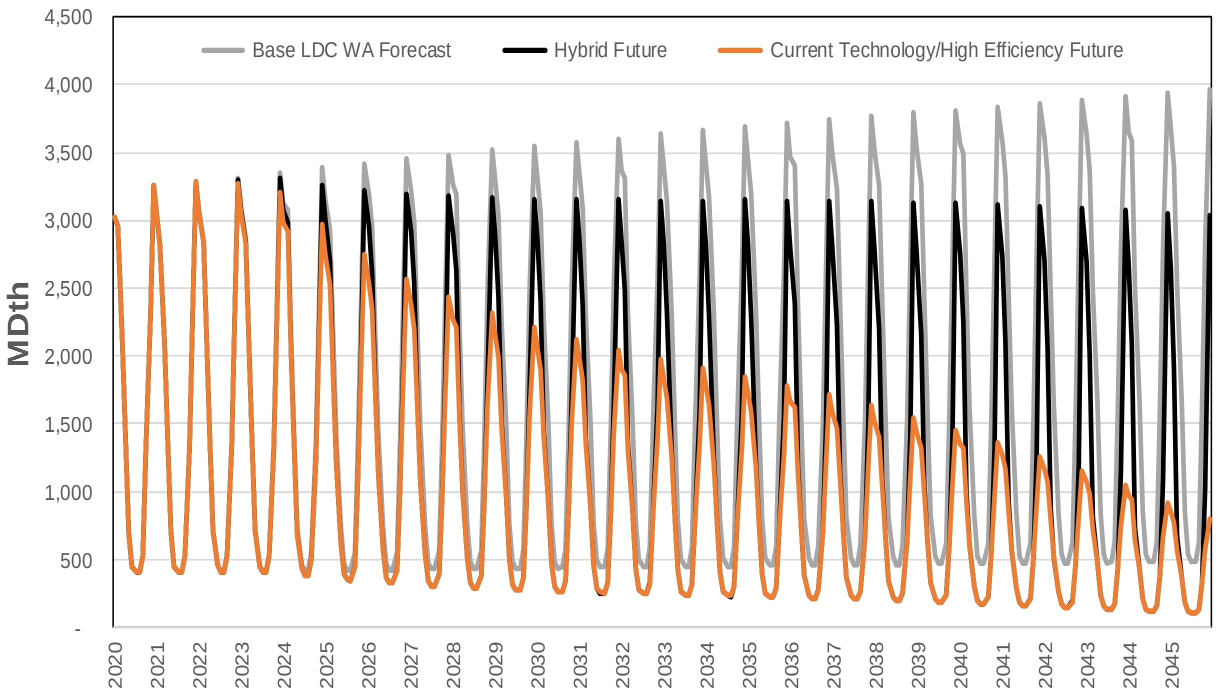


Figure 7.15 displays the natural gas supplied for each electrification scenario:

[3] The load conversion analysis also includes natural gas process conversion such as cooking, cloths drying, etc.

Figure 7.15: Natural Gas Supply by Electrification Scenario



While these scenarios have advanced our understanding of an electrification future, further studies are needed to fully understand the full impacts and costs of electrification. Some of these areas include:

- cost to homeowners to convert equipment;
- transmission or distribution grid impacts and costs;
- Avista has not re-studied the northwest electric market to account for pricing and resource availability impacts.

Given the large scope and impacts of this future scenario it may be best suited for a non-IRP analysis on a regional level. For additional detail on these scenarios, please refer to the Avista 2021 Electric IRP (Chapter 12-Portfolio Scenario Analysis).

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 multiple demand sensitivities and 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. With the inclusion of the Carbon Reduction scenario, Avista will continue to consider resources to solve the energy demand in combination with new policy, specifically those requiring carbon reductions. As policy continues to require green sources from the electric grid, the existing natural gas infrastructure should be used in the battle against climate change. Resources such as RNG and H2 can play an important part in these electric generation green resources, utilizing the excess energy while providing mitigation to outages and weather-related events that are far more common in the electric industry[4]. Energy security during the coldest of times is a pillar of resource planning and Avista will continue to consider all the environment, affordability and reliability of resources to meet our customer's needs.

[4] www.energy.gov

8: Distribution Planning

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 service 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 five 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 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.

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

[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.

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 a 99% statistical probability method 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 based on a statistical probability method of historical temperatures may seem aggressive since extreme temperatures are experienced rarely. 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.

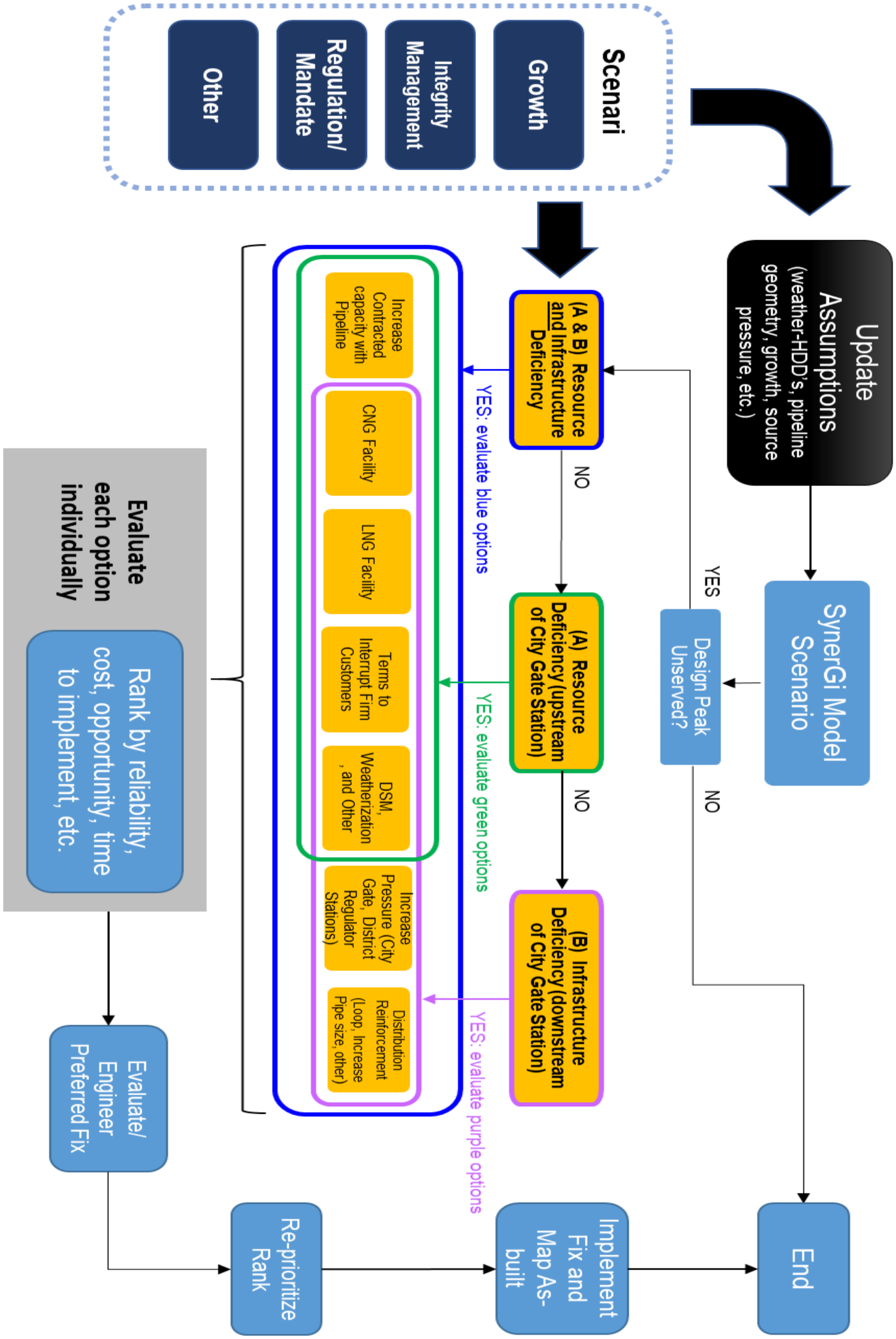
These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- 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 8.1 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 capacity (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 whose costs exceed $500,000 in any year. 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.

Airway Heights High Pressure Reinforcement, WA: The Airway Heights high pressure line has provided natural gas to one of the fasted growing regions in all of Avista's service territories. Recent rapid growth has included both residential and industrial customers, quickly depleting the available capacity of the high pressure line. This reinforcement will provide additional capacity and ensure reliable pressure at the end of the high pressure line, which supplies a major regulator station feeding the Downtown Spokane neighborhoods.

Cheney High Pressure Reinforcement, WA: This project will reinforce the Cheney distribution system, whose customer demands have exceeded the capacity of the high pressure line constructed in 1957. During cold weather conditions, Avista periodically asks some large firm customers to reduce their natural gas usage in order to serve core customer demand. Project began in 2020 and will continue in 2021.

Pullman High Pressure Reinforcement, WA: The Pullman high pressure reinforcement would connect both Moscow and Pullman's high pressure systems. This would bring Moscow gas to Pullman, avoiding the need to rebuild the Pullman City Gate Station which is currently exceeding its physical capacity. Additionally, this interconnection would increase reliability as both Moscow and Pullman would then have two sources of gas. Design is tentatively scheduled for 2024 and we continue to monitor existing customer demand. Construction timelines may change due to customer growth expectations.

Warden High Pressure Reinforcement, WA: The Warden high pressure reinforcement is necessary to serve either new or increased industrial customer demand. At this time, prospective 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 this project, but defer major construction until supply constraints subside.

Table 8.1 High Pressure - Distribution Planning Capital Projects

Location	2021	2022	2023	2024	2025+
Airway Heights High Pressure Reinforcement, WA	$3,000,000	$3,000,000	---	---	---
Cheney High Pressure Reinforcement, WA	$3,100,000	---	---	---	---
Pullman High Pressure Reinforcement, WA	---	---	---	$2,400,000	---
Warden High Pressure Reinforcement, WA	$100,000	$2,950,000	$2,950,000	---	---

Table 8.2 shows city gate stations identified as possibly 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 city gate station projects in Table 8.2 are periodically reevaluated to determine if upgrades need to be accelerated or delayed.

Those assigned a TBD year have relatively small capacity constraints, and thus will be monitored. There are no plans to rebuild or upgrade these city gate stations at this time.

Table 8.2 City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
Colton, WA	Colton #316	TBD	-	TBD
Medford, OR	Medford #2431	TBD		TBD
Pullman, WA	Pullman #350	TBD	-	TBD
Roseburg, OR	Melrose #2608	TBD	-	TBD
Sprague, WA	Sprague #117	TBD	-	TBD
Sutherlin, OR	Sutherlin #2626	TBD	-	TBD

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

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.

Result – Result- Avista discussed with Energy Trust of Oregon. It was decided that we will continue to use Energy Trust's current modeling protocols to run scenarios analyses for the Conversation Potential Assessment (CPA). This decision enables the greatest alignment between what Energy Trust expects they will be able to achieve under different policy scenarios. These scenarios may include modeling using differential assumptions such as: a) different avoided costs and b) accelerated and decelerated program uptake scenarios. This also allows Energy Trust to include measures in the CPA that are offered through Energy Trust programs under cost-effectiveness exceptions granted by the OPUC under UM-551 guidelines. These CPA practices coincide well with the capabilities of the software that Avista is using for other IRP modeling purposes. Consequently, Avista has chosen not to further investigate dynamic DSM program structure modeling in its analytics. Based on Avista's efforts with ETO, it was decided to forgo the ability to analyze DSM in Washington and Idaho due to any disparities that may occur from the separation of analysis types.

Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.

Result - Any large natural gas distribution system analysis will be included in all future IRP's against system resources where necessary.

Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.

Result – Distribution system costs are included in the avoided cost calculation and will be included in all future IRP documents.

Revisit coldest on record planning standard and discuss with TAC for prudency.

Result – Avista has changed its weather planning standard based on a probability of occurrence based on each weather planning location. The current methodology uses the most recent 30 years of weather and the coldest day of each year combined with a 99% probability of a weather event occurring.

Provide additional information on resource optimization benefits and analyze risk exposure.

Result – Chapter 4 – Supply Side Resources has been expanded to not only add in resource optimization benefits and risk exposure, but also includes additional details of Avista's natural gas hedging program

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.

Result – The integration of Avista's CPA providers is discussed in Chapter 3 – Demand Side Management.

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.

Result – The social cost of carbon is used in the Expected Scenario for the State of Washington.

Avista will ensure Energy Trust of Oregon (ETO) has sufficient funding to acquire therm savings of the amount identified and then approved by the OPUC and ETO Board.

Result – The ETO has received the necessary funding to acquire therm savings as identified and then approved by the OPUC and ETO Board.

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 require 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

An updated table 8.1 for those distribution projects in Oregon:

Location	Gate Station	Project to Remediate	Cost	Year
Klamath Falls, OR	Klamath Falls #2703	TBD	-	2023+
Sutherlin, OR	Sutherlin #2626	TBD	-	2023+

Result – Large High-pressure distribution and City Gas projects did not occur since the 2018 IRP. Quarterly updates will continue to occur with Oregon Staff to ensure any change in projects is known along with reasons for any major changes in expected capital expenditures.

Avista will work with members of the OPUC to determine an alternative stochastic approach to Monte Carlo analysis prior to Avista's 2020 IRP and share any recommendations with the TAC members.

Result – Avista and the OPUC agreed on a 1,000 draw minimum in all scenarios and were performed to this standard in all stochastic simulations in the current IRP.

2021-2022 Action Plan

New Activities for the 2023 IRP

1. Further model carbon reduction in Oregon and Washington
2. Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout
3. Model all requirements as directed in Executive Order 20-04
4. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
5. Explore the feasibility of using projected future weather conditions in its design day methodology.
6. 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 require 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.