2023 Electric
Integrated Resource Plan

Progress Report

January 3, 2023

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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2023 Electric IRP
Executive Summary

Avista has tradition of innovation and a commitment to providing safe, reliable, low-cost, clean energy to our customers. We meet this commitment through a diverse mix of generation and demand side resources.

The 2023 Integrated Resource Plan (IRP) Progress Report updates Avista's load forecast, energy efficiency and demand response assessment, supply-side resource costs, and the load-resource position. It includes only a Placeholder Resource Strategy until the full 2023 IRP is available and filed with state commissions on June 1, 2023.

This Progress Report includes new supply contracts signed since the 2021 IRP such as additional slices of the Chelan PUD's Rock Island and Rocky Reach contracts, Columbia Basin Hydro Power's irrigation generation facilities, and planned upgrades to Avista's Kettle Falls and Post Falls generation facilities. Additional resources will be added from 2022 All-Source Request for Proposals (RFP) and will be included in the final 2023 IRP.

Progress Report Highlights

Major changes from the 2021 IRP includes:

- Reporting on progress of the newly implemented Clean Energy Implementation Plan's Customer Benefit Indicators especially those relevant to and included in resource modeling. A forecast of new projects funded by the Named Community Investment Fund is also included.
- Higher load forecast from increased expectations of transportation and building electrification.
- Reduced Energy Efficiency targets due to lower avoided costs and lower potential opportunities.
- Updated plan utilizing future hydro and temperature conditions based on the RCP 4.5 forecast.

IRP Process

Each IRP is a thoroughly researched using a robust data-driven approach to identify a Resource Strategy to meet customer needs while balancing costs and risk measures with environmental goals and mandates. The process to date includes eight public meetings with Avista's Technical Advisory Committee (TAC), where Avista presents assumptions, methodologies, and results of planning analyses for public review and comment. The participants in the public process include customers, academics, environmental organizations, government agencies, consultants, utilities, elected officials, state utility commission stakeholders, and other interested parties.

Stakeholder involvement is encouraged and interested parties may contact John Lyons at (509) 495-8515 or irp@avistacorp.com for more information on participating in Avista's IRP process.

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1. Introduction

The Clean Energy Transformation Act (CETA) aims to fundamentally change the trajectory of the adoption of clean, non-carbon emitting electric generation by setting a series of targets and changing the way Integrated Resource Plans (IRP) are developed in Washington State. These requirements change how resource planning is approached, the modeling techniques and assumptions being used, and requires the careful consideration of many new issues going well beyond the traditional utility planning requirement of safety, reliability, and reasonable cost. These three pillars of resource planning have not gone away and still need to be met along with the new requirements and aspirations. Some of these new requirements will take several iterations to plan for them in an efficient manner.

There are now more incentives for clean energy use and development, additional emphasis on health and equity issues, more diverse participation in the planning process, and disincentives for greenhouse gas emitting resources. These disincentives include the end of coal-fired plants serving Washington customers by 2026 and the tapering down the use of natural gas-fired plants as CETA gets closer to its 100 percent clean energy goal in 2045. The Clean Energy Implementation Plan (CEIP) is another big change for readers of the IRP, as well as Washington now requiring a full IRP due every four years, instead of every two years, with a Progress Report due two years after the full IRP is published. Avista is still required to produce a full IRP for Idaho every two years.

Actual development of new resources often strays from the idealized world of modeling. This 2023 Progress Report is no exception as the new projects from the 2022 All-Source Request for Proposals (RFP) conclude with the signing of contracts. This Progress Report is a snapshot of what Avista's resource plan looks like based on the data the Company had available at the end of 2022. A draft version of the full 2023 IRP is scheduled to be released on March 31, 2023, for review and comment by the Washington and Idaho Commissions and the Technical Advisory Committee (TAC). The final 2023 IRP is scheduled for release on June 1, 2023 and will include all the new long-term resources.

This chapter discusses the Progress Report requirements, the process used to develop it, CEIP coordination and conditions, changes from the 2021 IRP, how the 2022 All-Source RFP will be included in the 2023 IRP and concludes with an overview of the chapters included.

Progress Report Requirements

The Progress Report defined in WAC 480-100-625 is due two years after each utility files its IRP starting with this first January 2023 Progress Report. The Report must cover four major areas plus any necessary updates as identified and described below from WAC 480-100-625(4)a – c include:

1. “Load forecast;
2. Demand-side resource assessment including a new conservation potential assessment;
3. Resource costs; and,
4. The portfolio analysis and preferred portfolio.”

Plus any “… other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces.” As well as “… update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.”

Progress Report Process

The process used to create this Progress Report looks very similar to the process used to create an IRP. This includes a series of public meetings with a mix of the traditional technical experts, such as utility commission staff, regional utility professionals, project developers, advocacy, and environmental groups, concerned state agencies, and both commercial and residential customers. Table 1.1 lists the dates and topics covered for each of the public meetings covering assumptions and concepts used in the creation of this Progress Report. The meetings include discussions about:

- how the loads are served between now and through 2045 and the resources already in place to serve those needs,
- the operating and environmental costs and benefits of new resources,
- the costs and benefits of energy efficiency measures and demand response,
- different types of energy storage,
- the expected future and alternate futures, and
- the non-energy impacts of resource decisions.

All these issues combined with the assumptions made about them and how each are included in the analysis are discussed. The subsequent results of the modeling provide an expectation of future prices for different resources, energy efficiency, demand response and storage options can be evaluated against. Avista develops a preferred portfolio of resources[1] to serve future needs. Besides the technical meetings, there are also public meetings for customers and others to hear about the plan and share their views on it.

[1] For the Progress Report, the traditional Preferred Resource Strategy is replaced with the “Placeholder” Resource Strategy until the 2022 RFP resource acquisition process is complete.

Table 1.1: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – December 8, 2021	• TAC Meeting Expectations and IRP Process Review • 2021 Action Item Review • Summer 2021 Heat Event – Resource Adequacy and Feeder Outages • Northwest Power Pool Resource Adequacy Program • Resource Adequacy Program Impact to IRP • IRP resource adequacy/resiliency planning • TAC Survey Results and Discussion • Washington State Customer Benefit Indicators • 2023 Draft IRP Workplan
TAC 2 – February 8, 2022	• Process Update • Demand and Economic Forecast • Load and Resource Balance Update
TAC 3 – March 9, 2022	• Existing Resource Overview • Resource Requirements • Non-Energy Impact Study • Natural Gas Market Overview and Price Forecast • Wholesale Electric Price Forecast
TAC 4 – August 10, 2022	• Electric Conservation Potential Assessment • Electric Demand Response Study • Clean Energy Survey
TAC 5 – September 7, 2022	• IRP Generation Option Transmission Planning Studies • Distribution System Planning with the IRP • Social Cost of Greenhouse Gas for Energy Efficiency – WA Only • Avoided Cost Rate Methodology
TAC 6 – September 28, 2022	• Supply Side Resource Cost Assumptions • Variable Energy Resource Integration Study Update • All-Source RPF Update • Global Climate Change Studies – Impacts to Avista Loads and Resources
TAC 7 – October 11, 2022	• DER Potential Study Scope • Load Forecast Update • Load & Resource Balance – Resource Need • Natural Gas Market Dynamics • Wholesale Electric Price Forecast • Western Resource Adequacy Program Update • CEIP Update and CBI's Use in the IRP • Portfolio and Market Scenario Options
Technical Modeling Workshop – October 20, 2022	• PRiSM Model Overview • Risk Assessment Overview • Washington Use of Electricity Modeling
TAC 8 Washington Progress Report Workshop – December 15, 2022	• Resource Acquisitions • Placeholder Resource Strategy – Energy Efficiency, Demand Response, Resource Selection and Avoided Cost. • CBI Forecast • Progress Report Outline • Next Steps

Virtual Public Meeting – Natural Gas and Electric IRPs	• Recorded Presentation • Daytime Comment and Question Session • Evening Comment and Question Session
TAC 9 – March 15, 2023	• All-Source RFP Update • Wholesale Market Scenario Results • Final Preferred Resource Strategy • Market Risk Assessment • Portfolio Scenario Analysis • Final Report Overview and Comment Plan • Action Items

Avista greatly appreciates the valuable contributions and time commitments made by each of its TAC members and wishes to acknowledge and thank the organizations and members who participated in the development of this Progress Report. Table 1.2 lists organizations participating in the 2023 IRP and Progress Report TAC processes.

CEIP Coordination

The Progress Report, in accordance with WAC 480-100-625 (4)(c), updates any elements in the utility's current CEIP as described in WAC 480-100-640. Avista's 2021 CEIP was approved with Conditions in June 2022. The Company has included the inputs used and approved in the development of the 2021 Clean Energy Action Plan filed with the 2021 IRP. In addition, Conditions agreed to as part of the approval of the 2021 CEIP in Docket UE-210628 are included in the modeling informing this Progress Report. The following assumptions were used to develop the clean energy requirements for 2030 and 2045 CETA requirements.[2]

- Qualifying clean energy is determined by procurement and delivery of clean energy to Avista's system for all years.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary programs.
- Customer voluntary REC programs do not qualify toward the CETA standard.
- Primary and alternative compliance generation includes:
    - Washington's share of legacy hydro generation operating or contracted before 2022,
    - All wind, solar, and biomass generation. Nonpower attributes associated with Idaho's share will be purchased by Washington,
    - Newly acquired or contracted non-emitting generation including hydro, wind, solar, or biomass.
- Avista may transfer qualifying non-hydro clean energy generated for Idaho loads to Washington by compensating Idaho at market REC prices.

[2] *Avista paraphrase of Avista 2021 CEIP approved conditions list, the Company believes the action addresses.*

- Avista is not planning to use Idaho's share of existing hydro prior to 2030 for compliance. After 2030, these resources are planned to be available for Alternative Compliance.

Table 1.2: External Technical Advisory Committee Participating Organizations

Organization	
4Sight Energy Group	Myno Carbon
350.Org Spokane	National Grid
AEG	New Sun Energy
Biomethane, LLC	NW Energy Coalition
Bonneville Power Administration	Northwest Power and Conservation Council
Building Industry Association of Washington	Northwest Renewables
Carbon WA	Pacific NW Utilities Conference Committee
Chelan PUD	Pera Inc
City of Spokane	Perennial Power Holdings
Clenera	Phil Jones Consulting
Clear Result	Pivotal Investments
Clearwater Paper	Puget Sound Energy
Climate Solutions	Pullman City Council
Creative Renewable Solutions	Renewable Northwest
Cyprus Creek Renewables	Residential and Small Commercial Customers
Direct Energy	Shasta
Energy Keepers Inc.	Sierra Club
GE Energy	Sovereign Power
Heelstone Renewable Energy	Spokane Tribe of Indians
Huntwood	SpokEnergy
Idaho Conservation League	Strata Solar
Idaho Department of Environmental Quality	Tesla
Idaho Office of Energy and Mineral Resources	The Energy Authority
Idaho Power	Tollhouse Energy
Idaho Public Utilities Commission	Tyr Energy
Inland Empire Paper	Wartsila
Inland Power & Light	Washington State Department of Community, Trade and Economic Development
Innovari	Washington State Office of the Attorney General
Kiemle Hagood	Washington State Department of Enterprise Services
McKinstry	Washington Utilities and Transportation Commission
Measure Meant	Water Planet
Mitsubishi Power Americas, Inc	Western Grid Group
MRW Associates	Whitman County Commission

Conditions For IRP Progress Report from CEIP

Several of the Washington Utilities and Transportation Commission's (WUTC) approved conditions for the Company's CEIP were required to be included in this Progress Report. The following six conditions, listed by their original number issued in Order 01 from the WUTC, are covered in this Progress Report.

(2) Avista will apply Non-Energy Impacts (NEIs) and Customer Benefit Indicators (CBIs) to all resource and program selections in determining its Washington resource strategy, in its 2023 Integrated Resource Plan (IRP) Progress Report and will incorporate any guidance given by the Commission on how to best utilize CBIs in CEIP planning and evaluation. Avista agrees to engage and consult with its applicable advisory groups (IRP Technical Advisory Committee (TAC) and Energy Efficiency Advisory Group (EEAG)) regarding an appropriate methodology for including NEIs and CBIs in its resource selection. (Per Order 01: Avista will consult with its EAG after the development of this methodology to ensure the methodology does not result in inequitable results.)

> *Avista discussed with the TAC and EEAG on Oct 11, 2022 its approach to using both NEI and CBIs with the progress report, The EAG was also consulted during its meetings held on November 16th and 18th, 2022. Members did not voice concerns pertaining to inequities in the Company's approach.*

(8) Avista in its IRP resource selection model for the 2023 IRP Progress Report will give the model the option to meet CETA goals with a choice between an Idaho allocated existing renewable resource at market price (limited to Kettle Falls, Palouse Wind, Rattle Snake Flats Chelan PUD purchase contracts 2 & 3) or acquiring a new 100% allocated Washington renewable resource for primary compliance. Further, the model will have the option to acquire new 100% allocated resource, market REC, or Idaho allocated REC (at market prices) to meet alternative compliance.

> *Avista included logic in the PRiSM model to choose how it solves to meet primary and alternative compliance requirements either by using existing resources or by acquiring new resources.*

(14) Avista will include a Distributed Energy Resources (DERs) potential assessment for each distribution feeder no later than its 2025 electric IRP. Avista will develop a scope of work for this project no later than the end of 2022, including input from the IRP TAC, EEAG, and DPAG. The assessment will include a low-income DER potential assessment. Avista will document its DER potential assessment work in the Company's 2023 IRP Progress Report in the form of a project plan, including project schedule, interim milestones, and explanations of how these efforts address WAC 480-100-620(3)(b)(iii) and (iv).

The potential assessment for this study was discussed at both the TAC and Energy Efficiency Advisory Group (EAG) meetings in October 2022, the project plan and schedule is described in Chapter 5 and the proposed scope of work is in Appendix G.

(34) For its 2023 IRP Progress Report, Avista commits to reevaluate its resource need given acquisitions the Company has made since its 2021 IRP (e.g., Chelan PUD hydro slice contracts) and include those proposed changes in its 2023 Biennial CEIP Update.

Avista has included within its resource energy need all long-term resources currently under contract including the Chelan PUD slice agreements and the Columbia Basin Hydro agreement. Further, it includes planned upgrades to both Kettle Falls and Post Falls.

(35) Avista recognizes that not all CBIs will be relevant to resource selection (for example, some CBIs pertain to program implementation). For its 2023 IRP Progress Report, and future IRPs and progress reports, Avista should discuss each CBI and where the CBI is not relevant to resource selection, explain why.

Chapter 10 outlines how each CBI is either not relevant to resource selection or studied within the resource planning process. For those CBIs with a relation to resource selection, a forecast of their impact on the plan is included.

(36) For its 2023 IRP Progress Report, Avista will:

A. At the September 28, 2022, Electric IRP TAC meeting, present draft supply side resource cost assumptions, including DERs. The Company commits to revising said cost assumptions if TAC stakeholder feedback warrants changes. Avista will update its 2023 Electric IRP Work Plan (UE-200301) to reflect the date of this TAC meeting.
B. Use the Qualifying Capacity Credit (QCC) for renewable and storage resources from the Western Power Pool's Western Regional Adequacy Program (WRAP), if available, or explain why the WRAP's QCCs are inappropriate for use.
C. Update its load forecast to include the baseline zero emission vehicle (ZEV) scenario from its Transportation Electrification Plan.

Avista presented and provided TAC members with a complete supply resource assumptions at the September 2022 meeting. The resource assumptions are discussed in Chapter 6 of this Progress Report, along with associated technical documentation in Appendix F. Avista also uses QCC values where applicable from the WRAP, these are discussed in Chapter 3 for existing resources, Chapter 5 for DERs, and Chapter 6 for utility scale resources. Within Chapter 2 is a discussion of the associated loads included using the Transportation Electrification Plan.

Summary of Changes from the 2021 IRP

Avista made several material changes to the methodology of the analysis since the 2021 IRP for this Progress Report. The major changes are the capacity and energy position methodology, updated energy efficiency and demand response potential, updates to supply-side resource options and costs, refreshed wholesale market analysis and additional methods for the portfolio optimization analysis, each are described below.

Capacity and Energy Position, Including Load Forecasting

- The Western Power Pool's WRAP methodology is used for capacity planning. Avista will not use the WRAP planning reserve margin for planning until the program is binding but will utilize the QCC methodology and accounting metrics.
- The energy risk metric for energy planning now includes risks from load, hydro, and Variable Energy Resources (VERs).
- Load and hydro forecasts use the RCP 4.5[3] temperature forecast for future years rather than historical averages.
- A forecast for medium duty electric vehicles is included in the electric load forecast and the light duty vehicle forecast matches the Transportation Electrification Plan.
- New resource acquisitions are included in this forecast from Chelan PUD, Columbia Basin Hydro, and upgrades to Kettle Falls and Post Falls.

Energy Efficiency and Demand Response

- Non-Energy Impacts are included on an individual measure basis rather than a single value for all programs.
- The Named Community Investment Fund (NCIF) sets a threshold for additional low-income energy efficiency targets beyond cost effective measures.
- Peak time rebate and electric vehicle time of use are added to the list of demand response options.

Supply-Side Resource Options

- Resource options include new distribution level storage resource options including roof-top solar, community solar, and customer owned storage.
- New energy storage options include iron-oxide storage and ammonia turbines.
- The Inflation Reduction Act tax incentives are reflected in resource cost.
- A non-energy impact study for new resources is reflected in the resource selection.
- WRAP QCCs are used for new resource selection but discounted over time[4] to reflect changes in regional generation mix.

Market Analysis

- Natural gas prices and new regional resource forecast is updated to reflect best available information utilizing Energy Exemplar's latest WECC database.

[3] RCP 4.5 is defined in Chapter 4.
[4] For wind, solar, energy storage and demand response.

- The Climate Commitment Act (CCA) is reflected in the market forecast using Ecology's price estimate for imported power and power plants without free allowances.
- The stochastic price forecast was reduced from 500 hourly 8760-hour simulations to 300 bi-weekly hourly simulations due to enhanced modeling logic for storage resources increasing run times.

Portfolio Optimization Analysis

- Monthly level energy positions rather than annual and includes a constraint to satisfy all monthly energy positions with resources capable of delivery energy in each period.
- Monthly level capacity positions rather than summer and winter peak position are used for solved resource needs.
- Avista assumes CETA compliance on a monthly level where controlled renewables will count towards primary compliance if generated within the month up to the monthly retail load. Any renewable generation greater than monthly retail load is assumed to count toward alternative compliance.
- Applicable Customer Benefit Indicators results are included within the PRiSM model.
- The NCIF creates thresholds distributed energy resources to address state policy choices.

Full 2023 IRP

Avista is a multijurisdictional utility serving electric customers in Washington and Idaho. Both states have rules and regulation regarding filing dates, content, and methods used to develop electric integrated resource plans. Avista endeavors to consolidate state requirements into one plan filed every other year. Unfortunately, this plan was not achievable as Avista is in the process of completing its resource acquisitions from an All-Source Request for Proposal released in early 2022. These acquisitions will substantially reduce resource needs through the end of the decade. Avista was able to adjust its filing date for its 2023 Electric IRP in Idaho to June 2023, but Washington's regulations did not allow for a delay in its filing. Therefore, this Progress Report will not include all resources acquired from the RFP and will be subject to revision as the full electric IRP is updated in June 2023. In addition to updating the resource strategy, Avista will consider multiple updates to the plan assumptions including:

1. Reflect resource acquisitions from the 2022 All-Source RFP.
2. Update the load forecast due to changing requirements for natural gas usage in new residential buildings.
3. Include any available information regarding the functionality of Washington's Climate Commitment Act.
4. Include stakeholder feedback for improvement in the analysis or the report.
5. Conduct scenario analysis.

2023 Progress Report Outline

The 2023 Progress Report consists of 10 chapters.

Chapter 1: Introduction

This chapter introduces the Progress Report, covers requirements and details public participation and involvement in the process used to develop it.

Chapter 2: Economic and Load Forecast

This chapter covers regional economic conditions, Avista's energy and the peak load forecasts.

Chapter 3: Existing Supply Resources

This chapter provides an overview of Avista-owned generating resources and its contractual resources and obligations and environmental considerations.

Chapter 4: Long-Term Position

This chapter reviews Avista reliability planning and reserve margins, risk planning, resource requirements and provides an assessment of its reserves and resource flexibility. This chapter also covers the RCP 4.5 temperature and hydrology forecast.

Chapter 5: Distributed Energy Resources

This chapter discusses customer focused resources such as energy efficiency programs, demand response and distributed generation and energy storage. It provides an overview of the conservation potential assessment and demand response potential assessment, and the customer owned or other distributed generation resources.

Chapter 6: Supply-Side Resource Options

This chapter covers the cost and operating characteristics of utility scale supply side resource options modeled for the IRP.

Chapter 7: Transmission & Distribution Planning

This chapter discusses Avista distribution and transmission systems, as well as regional transmission planning issues. It includes details on transmission cost studies used in IRP modeling and summarizes Avista's 10-year Transmission Plan. The chapter concludes with a discussion of distribution planning, including storage benefits to the distribution system.

Chapter 8: Market Analysis

This chapter details Avista IRP modeling and its analyses of the wholesale electric and natural gas markets.

Chapter 9: Placeholder Resource Strategy

This chapter details the placeholder resource selection process used to develop the 2023 PRS and resulting avoided costs. This strategy will be updated for the 2023 IRP which will include the results of the 2022 All-Source RFP described earlier.

Chapter 10: Customer Impacts

This chapter includes an assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long- and short-term public health and environmental benefits, costs, and risks; and energy security risk. It also covers the inclusion of metrics related to NEIs and CBIs where applicable as well as which ones are quantifiable and included in resource modeling. It also estimates the degree to which benefits will be equitably distributed and/or burdened over the planning horizon.

2. Economic & Load Forecast

Avista's loads and resources are an integral component of the IRP Progress Report. This chapter summarizes customer and load projections; including adjustments to assumptions for customer-owned solar generation, electric vehicles, natural gas restrictions, and changing temperatures, as well as recent enhancements to load and customer forecasting models and processes.

Chapter Highlights

- The energy forecast grows 0.74 percent per year, higher than the 0.24 percent annual growth rate in the 2021 IRP. Higher growth largely reflects higher residential and commercial electric vehicles (EV) forecasts.
- Avista expects a 146 aMW increase in total load from residential and commercial EVs and a net decrease of 21 aMW from residential and commercial solar by 2045.
- Peak load growth is 1.02 percent in the winter and 1.25 percent in the summer.

Economic Characteristics of Avista's Service Territory

Avista's core electric service area includes more than a half million people residing in Eastern Washington and Northern Idaho. Three metropolitan statistical areas (MSAs) dominate its service area: the Spokane-Spokane Valley, Washington MSA (Spokane-Stevens counties); the Coeur d'Alene, Idaho MSA (Kootenai County); and the Lewiston-Clarkson Idaho-Washington, MSA (Nez Perce-Asotin counties). These three MSAs account for over 70 percent of both Avista's customers (i.e., meters) and load. The remaining 30 percent are in low-density rural areas in both states. Washington accounts for approximately two-thirds of customers and Idaho the remaining one-third.

Population

Population growth is increasingly a result of net migration within Avista's service area as more people move here. Net migration is strongly associated with both service area and national employment growth through the business cycle. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national trends.[1] Econometric analysis shows when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration and the reverse holds true. Figure 2.1 shows annual population growth since 1971 and highlights the recessions in yellow. During all deep economic downturns since the mid-1970s, reduced population growth rates in Avista's service territory led to lower load growth.[2] The Great Recession reduced population growth from nearly 2 percent in

[1] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.

[2] Data Source: Bureau of Economic Development, U.S. Census, and National Bureau of Economic Research.

2007 to less than 1 percent from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth above 1 percent after 2014.

Figure 2.1: MSA Population Growth and U.S. Recessions, 1971-2021

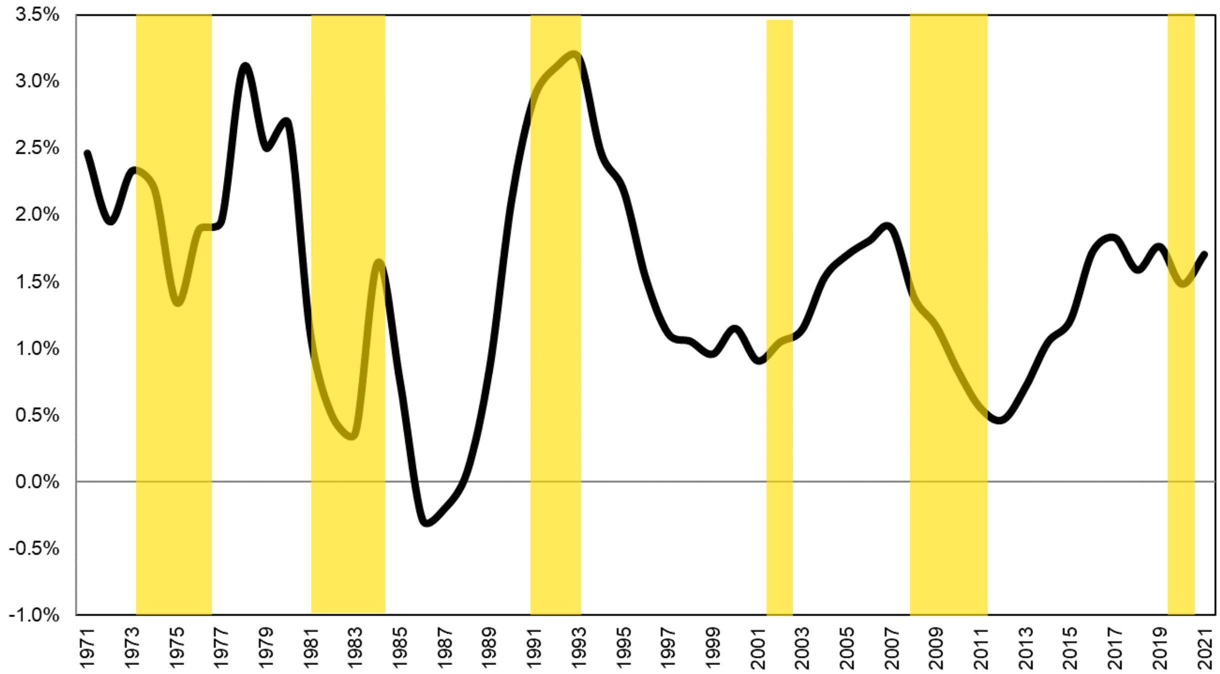
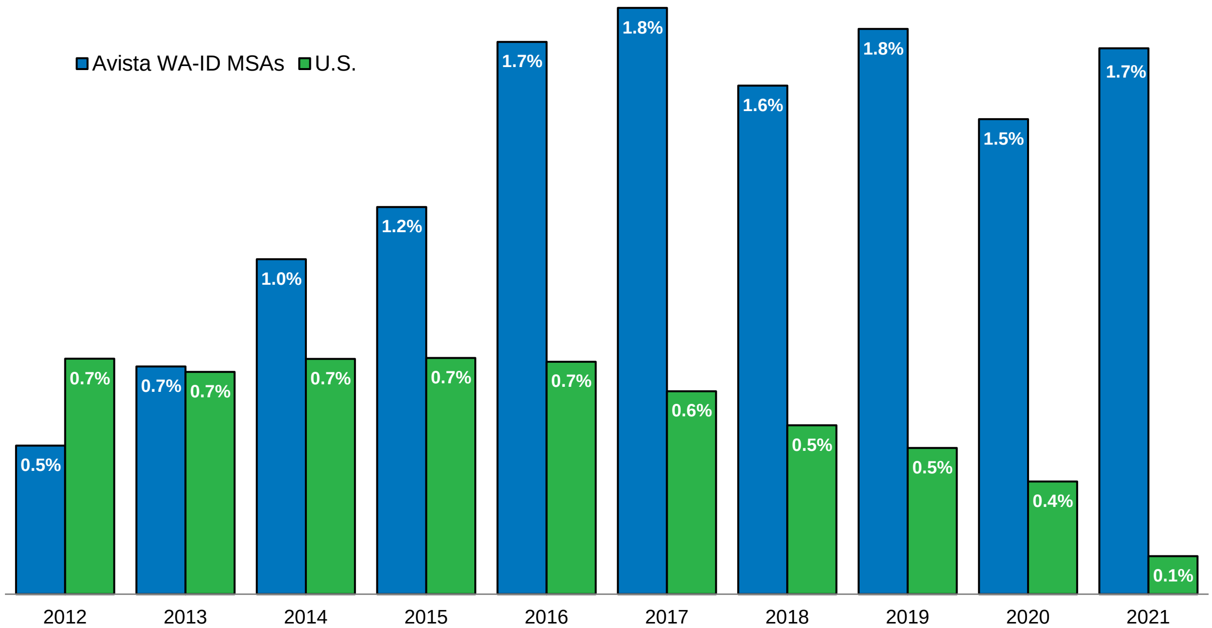


Figure 2.2 shows population growth since the start of the Great Recession in 2007.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; however, it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. population growth. The association of employment growth to population growth has a one-year lag. The relative strength of service area employment growth in year “y” is positively associated with service area population growth in year “y+1”. Econometric estimates using historical data show when holding the U.S. employment-growth constant, every 1 percent increase in service area employment growth is associated with a 0.4 percent increase in population growth in the next year.

[3] Data Source: Bureau of Economic Analysis, U.S. Census, and Washington State Office of Financial Management.

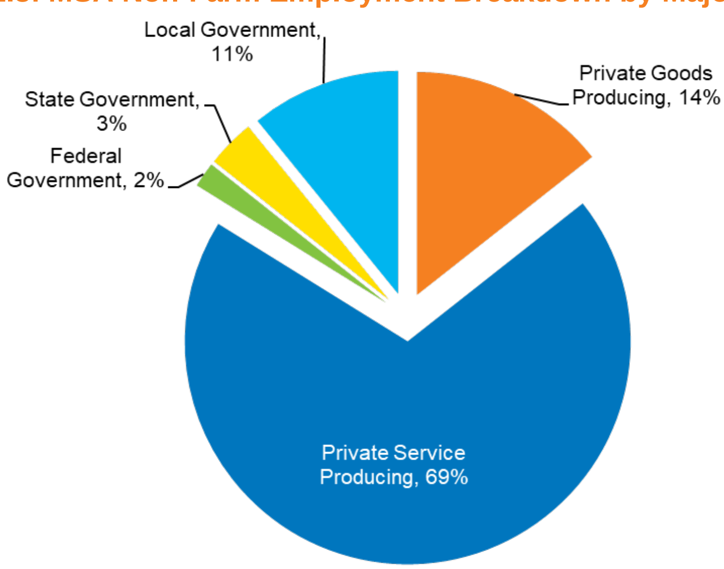
Figure 2.2: Avista and U.S. MSA Population Growth, 2007-2021



Employment

Given the correlation between population and employment growth, it is useful to examine the distribution of employment and employment performance since 2012. The Inland Northwest is a services-based economy rather than its former natural resources-based manufacturing economy. Figure 2.3 shows the breakdown of non-farm employment for all three-service area MSAs from the Bureau of Labor and Statistics. Almost 70 percent of employment in the three MSAs is in private services, followed by government (16 percent) and private goods-producing sectors (14 percent). Farming accounts for 1 percent of total employment. Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest.

Figure 2.3: MSA Non-Farm Employment Breakdown by Major Sector, 2021



Following the Great Recession, regional employment recovery did not materialize until 2013, when services employment started to grow.[4] Service area employment growth began to match or exceed U.S. growth rates by the fourth quarter 2014. Since the COVID-19 induced recession in 2020, service area employment has more than recovered from the losses resulting from the nationwide shutdowns. Figure 2.4 compares Avista and the U.S MSA non-farm employment growth for 2010 to 2021.

Figure 2.4: Avista and U.S. MSA Non-Farm Employment Growth, 2010-2021

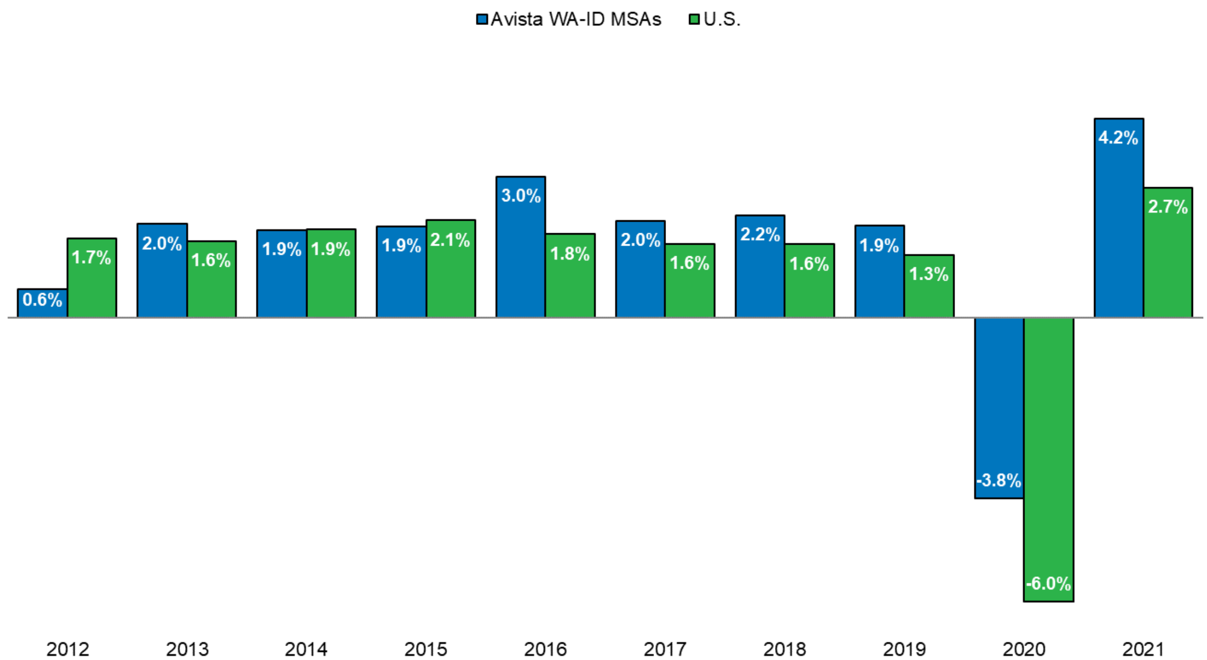


Figure 2.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[5] Regular income includes net earnings from employment, and investment income in the form of dividends, interest, and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare, and Medicaid.

Transfer payments in Avista's service area in 1970 accounted for 12 percent of the local economy. The income share of transfer payments has nearly doubled over the last 40 years to 27 percent. Although 56 percent of personal income is from net earnings, transfer payments still account for more than one in every five dollars of personal income. Recent years have seen transfer payments become the fastest growing component of regional personal income. This growth in regional transfer payments reflects an aging regional population, a surge of military veterans, and the lingering impacts of the COVID-19 transfer payments to households, including enhanced unemployment benefits.

[4] Data Source: Bureau of Labor and Statistics.
[5] Data Source: Bureau of Economic Analysis.

Figure 2.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Note that in the 1980 – 1990 period, the service area experienced significantly lower income growth compared to the U.S. because of the back-to-back recessions of the early 1980s according to the Bureau of Economic Analysis. The impacts of these recessions were more negative in the service area compared to the U.S., so the ratio of service area per capita income to U.S. per capita income fell from 93 percent in the 1970s to around 85 percent by the mid-1990s. The income ratio has not recovered.

Figure 2.5: MSA Personal Income Breakdown by Major Source, 2021

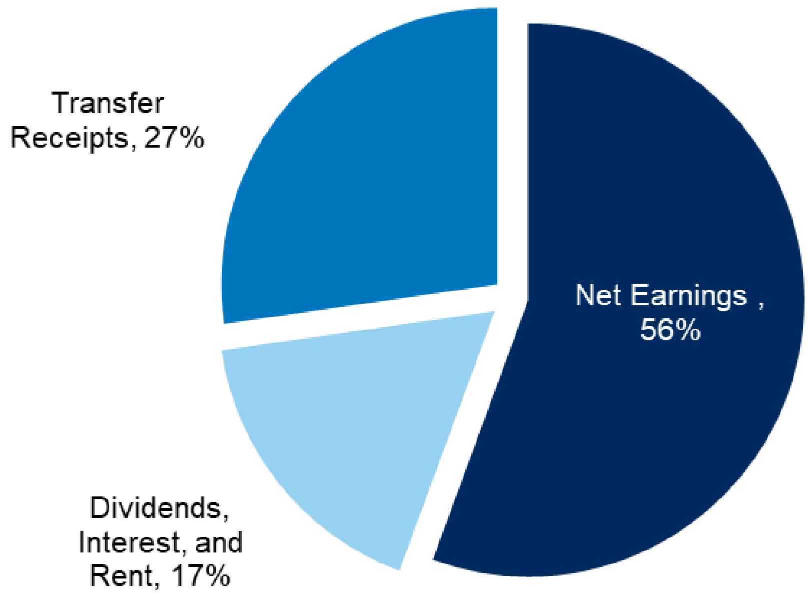
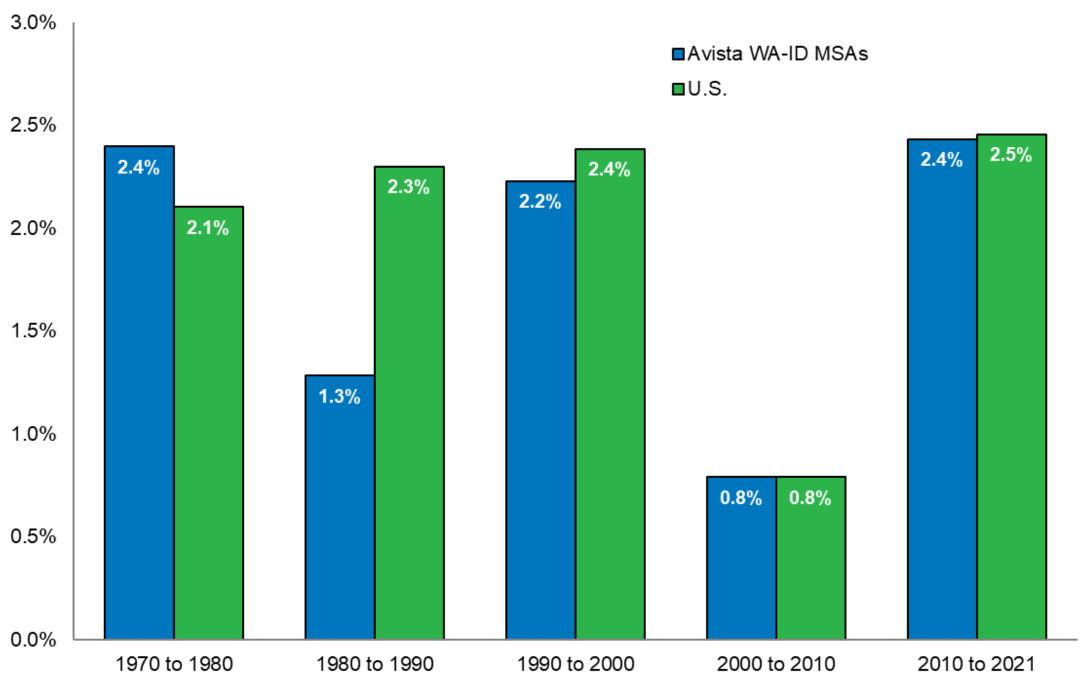


Figure 2.6: Avista and U.S. MSA Real Personal Income Growth by Decade, 1970-2021



Overview of the Medium-Term Retail Load Forecast

The retail load forecast is a two-step process. The first step is a detailed medium-term forecast to 2026. The second step bootstraps off the medium-term forecast to generate a forecast for years 2027 to 2045 by applying the long-run growth assumptions discussed later in this chapter.

There is a monthly use per customer (UPC) forecast and a monthly customer forecast for each customer class in most rate schedules.[6] The load forecast multiplies the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 2.1.

Equation 2.1: Generating Schedule Total Load

$$F(kWh_{t,y_c+j,s}) = F(kWh/C_{t,y_c+j,s}) \times F(C_{t,y_c+j,s})$$

Where:

- $F(kWh_{t,y_c+j,s})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $F(kWh/C_{t,y_c+j,s})$ = the UPC forecast.
- $F(C_{t,y_c+j,s})$ = the customer forecast.

UPC Forecast Methodology

The econometric modeling for UPC is a variation of the "fully integrated" approach expressed by Faruqui (2000) in the following equation:[7]

Equation 2.2: Use Per Customer Regression Equation

$$kWh/C_{t,y,s} = \alpha W_{t,y} + \beta Z_{t,y} + \epsilon_{t,y}$$

The model uses actual historical weather, UPC and non-weather drivers to estimate the regression in Equation 2.2. To develop the forecast, normal weather replaces actual weather (W) along with the forecasted values for the Z variables (Faruqui, pp. 6-7). Here, W is a vector of heating degree day (HDD) and cooling degree day (CDD) variables; Z is a vector of non-weather variables; and $\varepsilon_{t,y}$ is an uncorrelated N(0,σ) error term. For non-weather sensitive schedules, W = 0.

The W variables will be HDDs and CDDs. Depending on the schedule, the Z variables may include real average energy price (RAP); the U.S. Federal Reserve industrial production index (IP); residential natural gas penetration (GAS); non-weather seasonal dummy variables (SD); trend functions (T); and dummy variables for outliers (OL) and periods of structural change (SC). RAP is measured as the average annual price (schedule total revenue divided by schedule total usage) divided by the consumer price

[6] For schedules representing a single customer, where there is no customer count and for street lighting, Avista forecasts total load directly without first forecasting UPC.

[7] Faruqui, Ahmad (2000). *Making Forecasts and Weather Normalization Work Together*, Electric Power Research Institute, Publication No. 1000546, Tech Review, March 2000.

index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC, and OL. See Table 2.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 2.2 can be improved by converting it into an autoregressive integrated moving average (ARIMA) “transfer function” model such that $\epsilon_{t,y} = ARIMA\epsilon_{t,y}(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the moving average (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values relate to “k,” or the frequency of the data, with the current monthly data set, k = 12.

Certain schedules, such as lighting, use simpler regression and smoothing methods because they offer the best fit for irregular usage without seasonal or weather-related behavior, is in a long-run steady decline, or is seasonal and unrelated to weather. Over the 2023-2026 period, Avista defines normal weather for the load forecast as a 20-year moving average of degree-days taken from the National Oceanic and Atmospheric Administration’s Spokane International Airport data. Normal weather updates only occur when a full year of new data is available. For example, normal weather for 2018 is the 20-year average of degree-days for the 1998 to 2017 period; and 2019 is the average of the 1999 to 2018 period. This forecast uses the 20-year average from the 2002 to 2021 period to develop the 2023 to 2026 forecast.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, climate research from the National Aeronautics and Space Administration’s (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting almost 30 years ago. The GISS research finds summer temperatures in the Northern Hemisphere increased one degree Fahrenheit above the 1951-1980 reference period; the increase started roughly 30 years ago in the 1981-1991 period.[8] An in-house analysis of temperature in Avista’s Spokane-Kootenai service area, using the same 1951-1980 reference period, also showed an upward shift in temperature starting about 30-years ago. A detailed discussion of this analysis is provided in the peak-load forecast section of this chapter.

The second factor in using a 20-year moving average is the volatility of the moving average as a function of the years used to calculate the average. Moving averages of 10 and 15 years showed considerably more year-to-year volatility than the 20-year moving average. This volatility can obscure longer-term trends and leads to overly sharp changes in forecasted loads when applying the updated definition of normal weather each year. These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As will be discussed below and in Chapter 4, after 2026, temperature is assumed to increase using weather forecasts from global climate models based on using the RCP 4.5 forecast. In other words, the 20-year moving average of weather is used until 2026.

[8] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html.

Starting in 2027, changing HDDs and CDDs are built in using the RCP 4.5 forecast. The RCP 4.5 forecast predicts a steady decline in HDDs and increase in CDDs over the 2027-2045 period.

As noted earlier, if non-weather drivers appear in Equation 2.2, then they must also be in the five-year forecast used to generate the UPC forecast. The assumption in the five-year forecast is for RAP to be constant through 2027; increase at 1 percent from 2027 to 2029; and then increase 1.5 percent until 2045. RAP no longer appears explicitly in the regression equations for the five-year forecast. The coefficient estimates for RAP have become unstable and statistically insignificant. Therefore, this forecast assumes residential and commercial own-price elasticity to be -0.3 percent, based on long-run estimates from academic literature.[9] This forecast generates IP forecasts from a regression using the GDP growth forecasts (GGDP). Figure 2.7 describes this process.

Table 2.1: UPC Models Using Non-Weather Driver Variables

Schedule	Variables	Comment
Washington:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in WA to electric residential schedule 1 customers in WA.
Industrial Schedules 11, 21, and 25	IP	
Idaho:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in ID to electric residential schedule 1 customers in ID.
Industrial Schedules 11 and 21	IP	

The forecasts for GDP reflect the average of forecasts from multiple sources including the Bloomberg survey of forecasts, the Philadelphia Federal Reserve survey of forecasters, the Wall Street Journal survey of forecasters and other sources. Averaging forecasts reduces the systematic errors of a single-source forecast. This approach assumes macroeconomic factors flow through UPC in the industrial rate schedules. This reflects the relative stability of industrial customer growth over the business cycle. Figure 2.8 shows the historical relationship between the IP and industrial load for electricity.[10,11] The load values have been seasonally adjusted using the Census X11 procedure. The historical relationship is positive for both loads. The relationship is very strong for electricity with the peaks and troughs in load occurring in the same periods as the business cycle peaks and troughs.

[9] Avista is unable to produce reliable elasticity estimates using its own UPC data. It is difficult to obtain reliable elasticity estimates using data for an individual utility, so the Company relies on academic estimates using multiple regions and estimation methods. As theory predicts, the literature indicates that short-term elasticity is lower (less price sensitive) than long-term elasticity. Avista assumes the low end of the long-term range of academic elasticity estimates.
[10] Data Source: U.S. Federal Reserve and Avista records.
[11] Figure 2.8 excludes one large industrial customer with significant load volatility.

Figure 2.7: Forecasting IP Growth

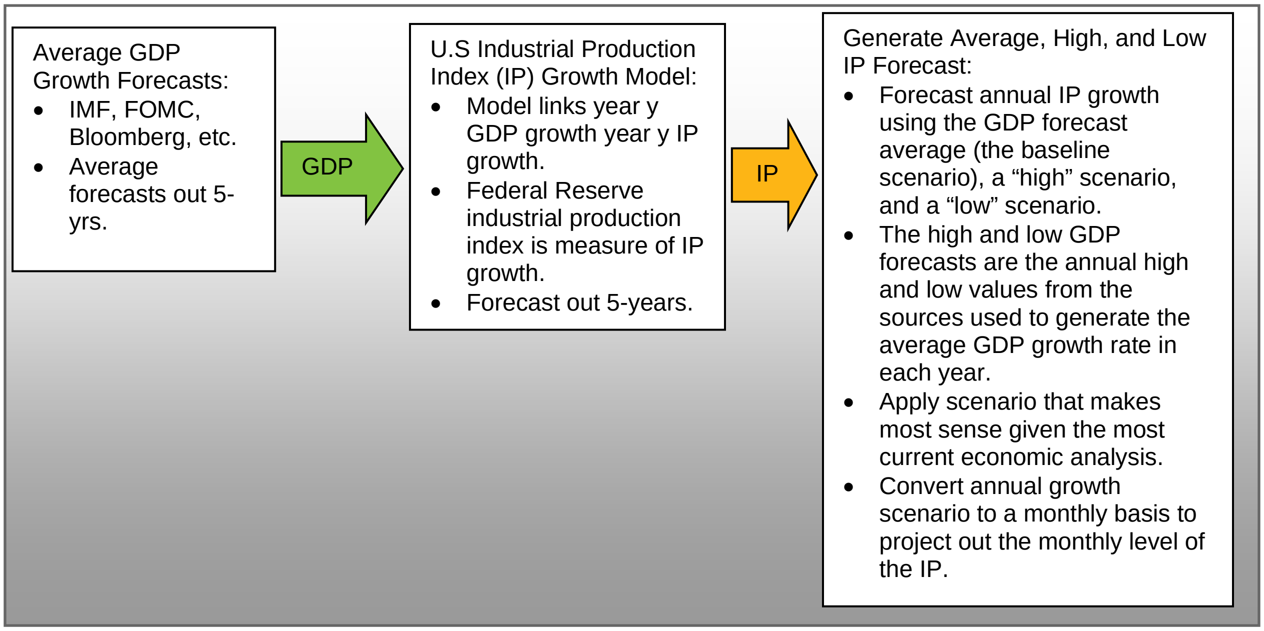
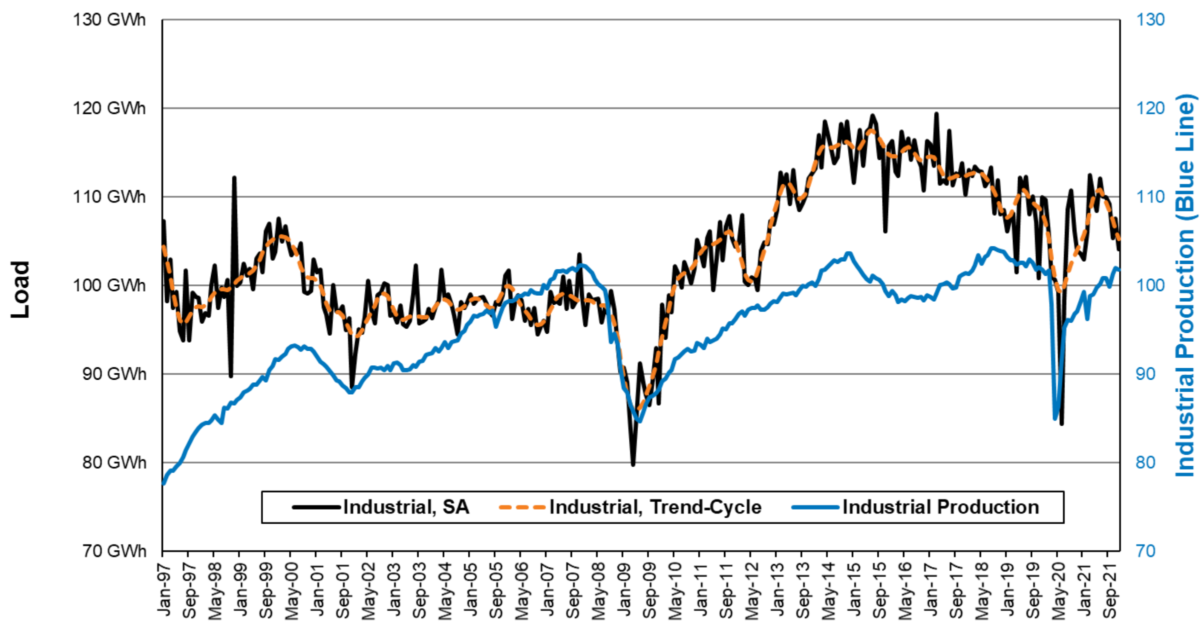


Figure 2.8: Industrial Load and Industrial (IP) Index



Customer Forecast Methodology

The econometric modeling for the customer models ranges from simple smoothing models to more complex ARIMA models. In some cases, a pure ARIMA model without any structural independent variables is used. For example, the independent variables are only the past values of the rate schedule customer counts, which is also the dependent variable. Because the customer counts in most rate schedules are either flat or growing in a stable fashion, complex econometric models are generally unnecessary for generating reliable forecasts. Only in the case of certain residential and commercial schedules is more complex modeling required.

For the main residential and commercial rate schedules, the modeling approach needs to account for customer growth between these schedules having a high positive correlation over a 12-month period. This high customer correlation translates into a high correlation over the same 12-month period. Table 2.2 shows the correlation of customer growth between residential, commercial, and industrial consumers of Avista's electricity and natural gas. To assure this relationship in the customer and load forecasts, the models for the Washington and Idaho Commercial Schedules 11 use Washington and Idaho Residential Schedule 1 customers as a forecast driver. Historical and forecasted Residential Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

Table 2.2: Customer Growth Correlations, 1998 – 2021

Customer Class (annual growth)	Residential	Commercial	Industrial	Streetlights
Residential	1.00			
Commercial	0.74	1.00		
Industrial	-0.26	-0.0004	1.00	
Streetlights	-0.21	-0.07	-0.02	1.00

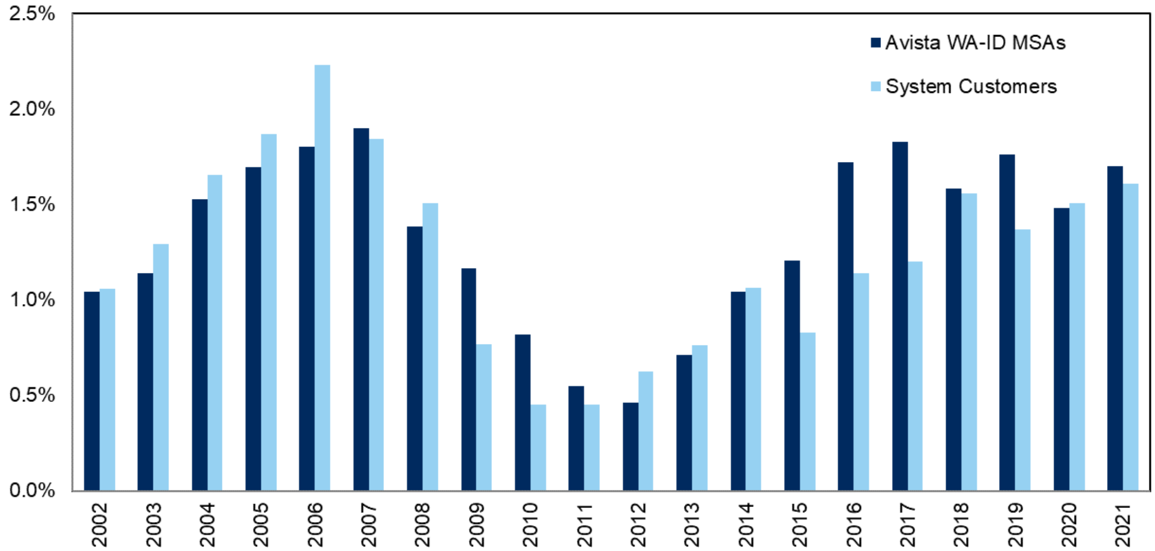
Figure 2.9 shows the relationship between annual population growth and year-over-year customer growth.[12] Customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs over the last 20 years. Population growth averaged 1.3 percent over the 2000-2021 period and customer growth averaged 1.3 percent annually.

Figure 2.9 demonstrates how population growth is the primary driver of customer growth. As a result, forecasted population is the primary driver of Residential Schedule 1 customers in Washington and Idaho. The forecast is made using an ARIMA times-series model for Schedule 1 customers in Washington and Idaho.

Forecasting population growth is a process that links U.S. GDP growth to service area employment growth and then links regional and national employment growth to service area population growth.

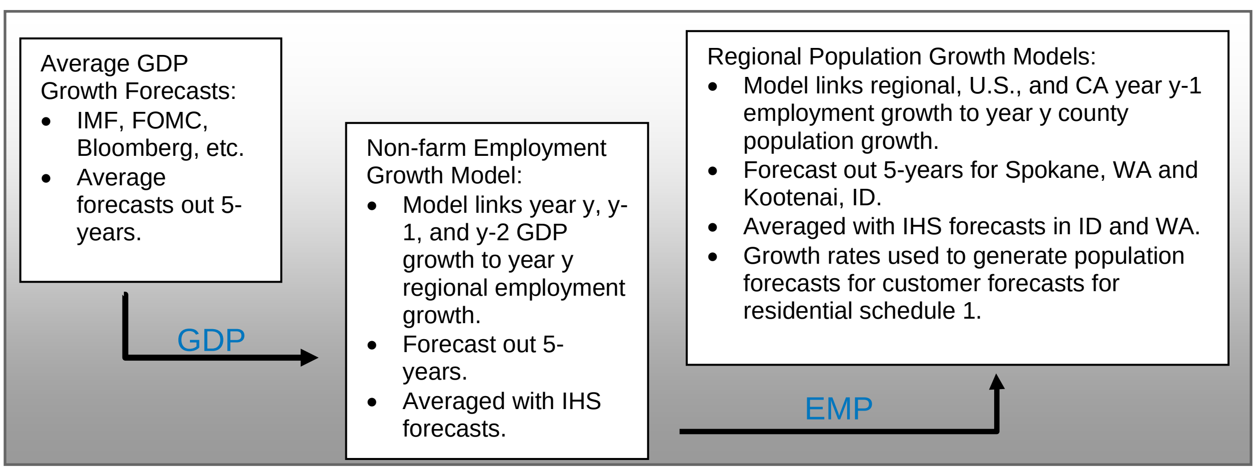
[12] Data Source: Bureau of Economic Analysis, U.S. Census, Washington State OFM, and Avista records.

Figure 2.9: Population Growth vs. Customer Growth, 2000-2021



The same average GDP growth forecasts used for the IP growth forecasts are inputs to the five-year employment growth forecast. Avista averages employment forecasts with IHS Connect's (formerly HIS Global Insight) forecasts for the same counties. Averaging reduces the systematic errors of a single-source forecast. The averaged employment forecasts become inputs to generate population growth forecasts. Figure 2.10 summarizes the forecasting process for population growth for use in estimating Residential Schedule 1 customers.

Figure 2.10: Forecasting Population Growth



The employment growth forecasts (average of Avista and IHS forecasts) become inputs used to generate the population growth forecasts. The Spokane and Kootenai forecast are averaged with IHS's forecasts for the same MSA. These averages produce the final population forecast for each MSA. These forecasts are then converted to monthly growth rates to forecast population levels over the next five years.

Long-Term Load Forecast

The Basic Model

The long-term load forecast extends the intermediate term projection out to 2045. It includes adjustments for electric vehicle (EV) fleet and residential rooftop photovoltaic (PV) solar growth. The long-run modeling approach starts with Equation 2.3.

Equation 2.3: Long-Run Forecast Relationship

$$\ell_y = c_y + u_y$$

Where:

- ℓ_y = class load growth in year y.
- c_y = class customer growth in year y.
- u_y = class UPC growth in year y.

Equation 2.3 sets annual residential load growth equal to annual customer growth plus the annual UPC growth.[13] C_y is not dependent on weather, so where u_y values are weather normalized, ℓ_y results are weather-normalized. Varying c_y and u_y generates different long-term forecast simulations. This forecast varies c_y for economic reasons and u_y for increased usage of PVs, EVs, and expected policy changes.

Expected Case Assumptions

The forecast makes the following assumptions about the long-run relationship between residential, commercial, and industrial classes.

1. As noted earlier, long-term residential and commercial customer growth rates are linked, with a positive correlation between the two (see Table 2.2). Figure 2.11 shows the time path of residential customer growth. The average annual growth rate from 2023 to 2045 is approximately 0.9 percent, with a gradual decline out to 2045. The growth rates to 2026 shown in Figure 2.11 uses Avista's own employment and population forecasts in conjunction with IHS's employment and population forecasts. After 2026, IHS's population forecasts alone drive the residential customer forecast. Starting in 2027, the model assumes annual commercial customers increase by approximately 11 customers for every 100 additional residential customers. This relationship is based on long-run annual regression relationships. The annual average growth rate of commercial customers over 2023-2045 is approximately 0.6 percent. Average annual industrial customer growth rate over 2023-2045 is -1.0 percent, which is equivalent to an annual decline of 11 industrial customers a year through 2045. This assumption reflects an ongoing long-term decline in industrial customers since 2005.

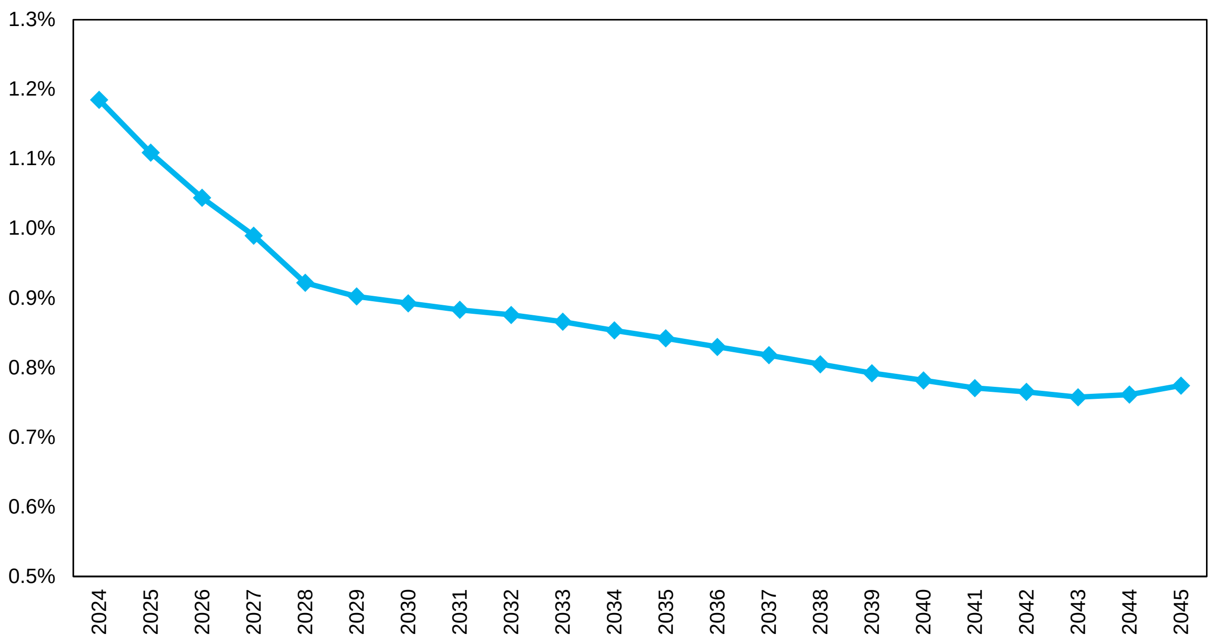
2. Consistent with historical behavior, industrial and streetlight load growth projections do not correlate with residential or commercial load. Average annual industrial load growth is -0.3 percent over the forecast horizon. This reflects the assumption that the annual -1.0 percent decline in industrial customer growth is not offset by UPC growth

[13] Since UPC = load/customers, calculus shows the annual percentage change UPC ≈ percentage change in load - percentage change in customers. Rearranging terms, the annual percentage change in load ≈ percentage change in customers + percentage change in UPC.

driven by long-run economic growth, as measured by GDP growth. The GDP growth assumption averages 1.8% after 2026, which is the long-run growth used by the Federal Reserve for their forward guidance. The streetlight load growth is zero percent over the forecast horizon to reflect the assumption of slow customer growth being offset by the impact of LED lighting.

3. As noted earlier, the assumption in the five-year forecast is for the RAP for residential and commercial load to be constant through 2026; increase 1 percent annually between 2026 and 2029; and then increase 1.5 percent yearly until 2045. RAP no longer appears explicitly in the regression equations for the medium-term forecast. The regression coefficient estimates for the RAP have become unstable and statistically insignificant. Therefore, the forecast assumes own-price elasticity to be -0.3 percent, based on long-term estimates from the academic literature (See also footnote 11).

Figure 2.11: Long-Term Annual Residential Customer Growth



4. Avista estimates approximately 3,900 residential light duty electric vehicles (LDEV) are currently within its service area. The forecasted rate of EV adoption over the 2023-2045 period assumes 342,000 LDEVs will be in the service area by 2045. Between 2024 and 2045, this is an average annual growth rate of 23 percent. To be consistent with Avista's current Transportation Electrification Plan, the forecast assumes each LDEV averages 3,153 kWh per year and will constitute 15 percent of all residential light-duty vehicle sales by 2030 and 38 percent by 2045. Based on the assumption of approximately two vehicles per residential customer (based on U.S. Census data for our service area), the LDEV penetration rate is forecasted to rise from 0.5 percent of residential customers in 2023 to just over 27 percent by 2045 for a total load of 123 aMW in 2045.

Avista estimates there are approximately 160 commercial medium duty electric vehicles (MDEV) currently operating in its service area. The forecasted rate of adoption over the 2024-2045 period assumes 25,000 MDEVs will be in the service area by 2045. Between 2024 and 2045, the implied average annual growth rate is 23 percent. The forecast assumes each MDEV averages 12,700 kWh per year and MDEVs will constitute 0.02 percent of all commercial light-duty vehicle sales by 2030 and 24 percent by 2045. The MDEV penetration rate is forecasted to rise from near zero percent of commercial vehicles in 2024 to just over 13 percent by 2045 for a total load of 23 aMW. The current data on commercial MDEV in our service area is limited, so the modeling assumptions described above will have to be carefully reviewed in future forecasts.

Figure 2.12 shows the net impact of EV load additions against PV load reductions for this forecast. There are three significant barriers to the rapid, near-term accumulation of all types of EVs. The first is consumer preferences related to model options and battery range. Although these barriers are slowly shrinking, the gap with traditional internal combustion vehicles is still notable. This is important in Avista's service area given the significant number of rural and suburban households and businesses. Second, there is consumer uncertainty about the evolution of the public charging infrastructure to support rapid adoption in the near term. Although improving, the public charging infrastructure remains significantly underdeveloped compared to traditional vehicles. Third is the willingness of consumers to rapidly abandon relatively new traditional vehicles for EVs with similar characteristics that may require a higher upfront cost. Third, there is evidence that production constraints (e.g., labor and rare earths) may hold back supply even as demand grows via preferences or policies outlawing internal combustion engines. Because of these barriers, as with previous forecasts, this forecast assumes rapid adoption in Avista's service area will not start until the early 2030s.

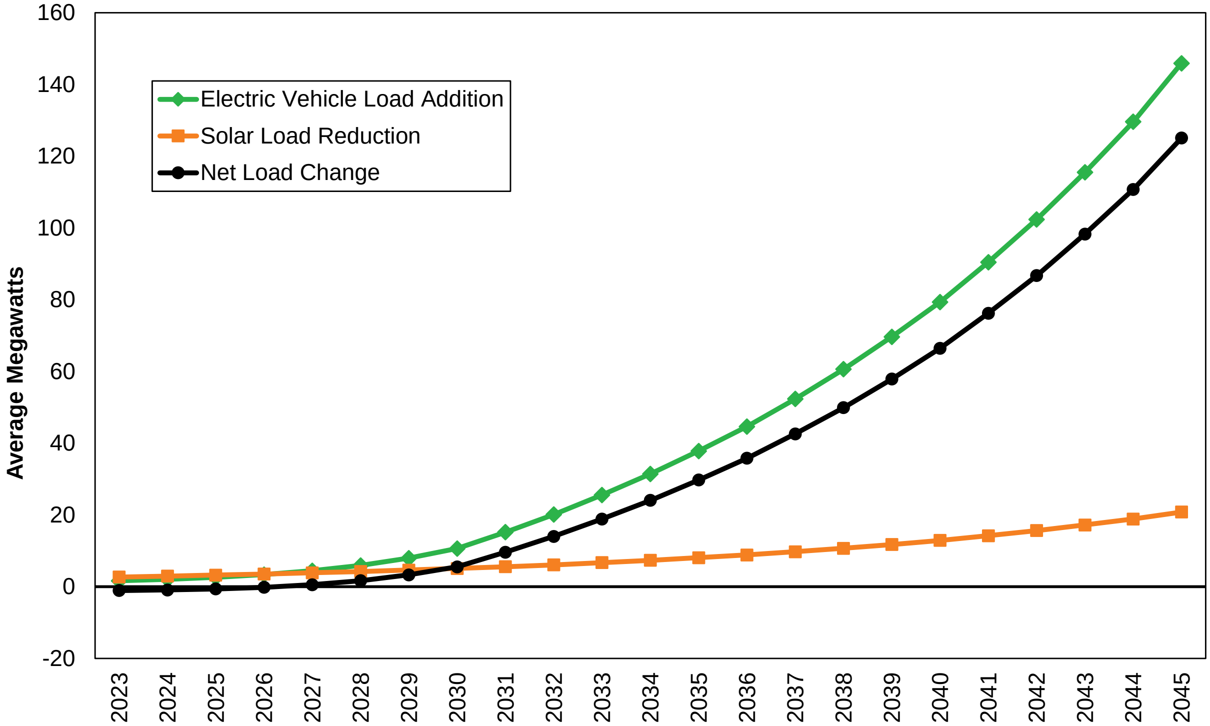
5. Residential rooftop solar penetration, measured as the share of residential solar customers to total residential customers, continues to grow at present levels in the forecast. The starting average PV system size is set at 7 kW (DC) with a 14 percent capacity factor, or about 8,500 kWh per year per customer. These values reflect current Company data on customer installation size and system efficiency. The forecast assumes the starting system size will increase 1 percent annually to about 10,900 kWh per year per customer in 2045, with the capacity factor remaining constant at 14 percent. Company data on its residential customers show the system size is increasing over time. In the 2005-2008 period, when solar installs were just beginning, the median installed system size was about 1.8 kW. Consistent with recent history, the residential PV penetration rate forecast follows a non-linear relationship between the penetration rate in year t and the number of residential customers in year t. Under this assumption, residential solar penetration will increase from 0.6 percent in 2024 to about 4.0 percent in 2045. This accumulation can be approximated by an exponential growth function. The base-line model assumes residential solar penetration will grow approximately 9.0 percent annually through 2045, producing 20 aMW in load reduction by 2045.

Commercial rooftop solar penetration, measured as the share of commercial solar customers to total commercial customers, continues to grow at present levels in the forecast. The starting average PV system size is set at 13 kW (DC) with a 14 percent capacity factor, or about 28,200 kWh per year per customer. These values reflect current Company data on customer installation size and system efficiency and assumes the starting system size will increase 1 percent annually to about 38,500 kWh per year per customer in 2045, with the capacity factor remaining constant at 14 percent. Like residential solar, this forecast assumes the commercial PV penetration rate will follow a non-linear relationship between the penetration rate in year t and the number of commercial customers in year t. Under this assumption, commercial solar penetration will increase from 0.3 percent in 2024 to about 0.6 percent in 2045. This accumulation can be approximated by an exponential growth function. The base-line model assumes commercial solar penetration will grow at approximately 4.0 percent annually through 2045, producing a 1 aMW in load reduction by 2045.

Figure 2.12 shows the net impact of EV and PV loads. As with EVs, there are several important barriers around the accumulation of residential PV systems in our service area. First, urban and rural forests surround many of the owner-occupied structures in our service area. Tree shade can significantly reduce solar generation. In the Spokane metro area, the largest metro area we serve, many of the areas with fewer trees are lower-income areas and/or are mainly composed of renter-occupied structures. Second, the heavy winter cloud cover also reduces solar generation. Avista recognizes future improvements in solar panels can reduce these barriers. For example, solar panels can be formed directly into roof top shingles or home siding. However, like many utilities in the West, Avista has discovered that smoke from wildfires can also significantly reduce the efficiency of solar generation.

5. Washington state's restrictions on using natural gas as a primary heating fuel and lowering connection incentives is reflected by assuming no additional commercial gas customers after 2023. This assumption means gas penetration will experience a steady decline over the forecast horizon, reflecting a shift towards electric usage as Washington's once future gas customers are shifted to electric only usage. This is accounted for by taking the difference between a no-restriction forecast for commercial gas customers (generated for Avista's 2023 Natural Gas IRP) and the number of commercial gas customers held constant at the current forecast level. An econometric estimate of UPC sensitivity to changes in the gas penetration rate is used to generate a forecast of future load impacts. Washington State recently implemented similar requirements on residential buildings after this forecast was generated. The Company is reviewing the new requirements to better understand if and how they should be incorporated into the electric load forecast. The full 2023 IRP to be finalized in June 2023 will include a revised forecast for new building energy usage for both commercial and residential customers.

Figure 2.12: Electric Vehicle and Rooftop Solar Load Changes



Long-Term Forecast Residential Retail Sales

Focusing on residential kWh sales, Figure 2.13 is the residential UPC growth plotted against the EIA's annual growth forecast of U.S. residential use per household growth. EIA's forecast is from the 2022 Annual Energy Outlook. EIA's forecast shows positive UPC growth by the mid-2030s, while Avista's growth becomes positive in the early 2030s. The higher EIA forecast reflects a population shift to warmer-climate states where air conditioning is typically required most of the year. In contrast, Avista's forecast of positive UPC growth starting in the early 2030s reflects the impact of regional EV growth.

Figure 2.13: UPC Growth Forecast Comparison to EIA

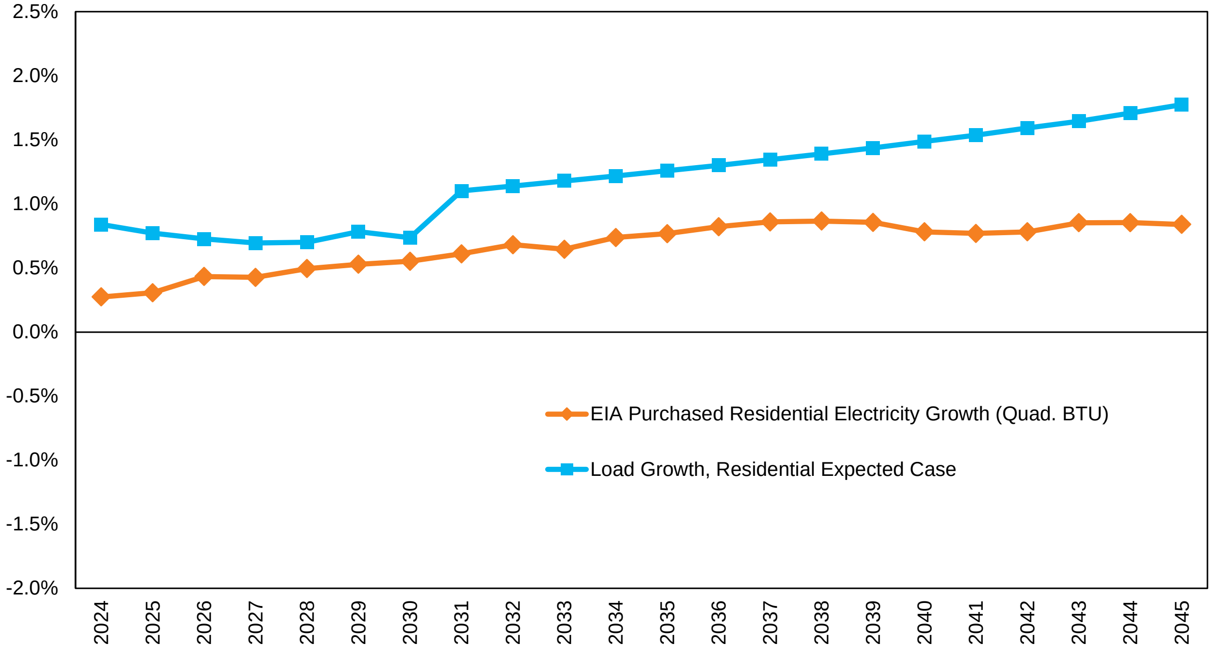
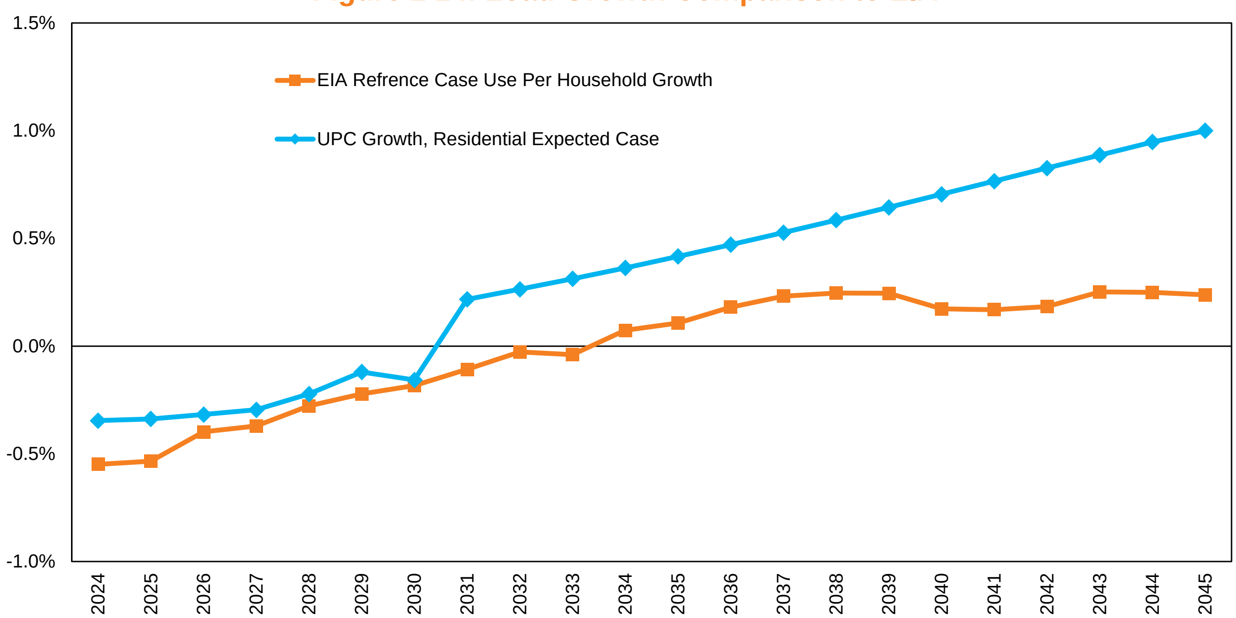


Figure 2.14 shows EIA and residential load growth forecasts. Avista's forecast is higher over the entire period, reflecting the assumptions for rapid EV adoption and a service area population growth that will exceed the U.S. average. The higher population forecast for Avista's service area is consistent with government and IHS forecasts for the far west and Rocky Mountain regions where Avista's service territory is located.

Figure 2.14: Load Growth Comparison to EIA



Future Temperature Forecast

As noted above, this forecast includes forecasted temperatures reflecting a warming trend. Climate impacts reflect the temperature forecasts from the RCP 4.5 climate model. The temperature forecast has a relatively small impact on annual load growth, but a significant impact on the distribution of load within the calendar year. The impact on load growth comes from the shift of load from winter to summer. However, the shift in load shares remains notable. Figure 2.15 compares the monthly share of load in 2045 in the expected case between the historical temperature method and RCP 4.5 forecast. In other words, the only difference between the temperature methods is the time path of heating and cooling degrees. That means, EV accumulation, solar accumulation, and natural gas restrictions are the same between the two scenarios. Figures 2.16 and 2.17 show the difference between the static HDD and CDD assumptions for the historical weather method, defined by 20-year average of HDD and CDD for the 2002-2021 period and the 20-year moving average of HDD and CDD predicted by the RCP 4.5 model.

Figure 2.15: Load Share Comparison Due to Temperature Forecasts

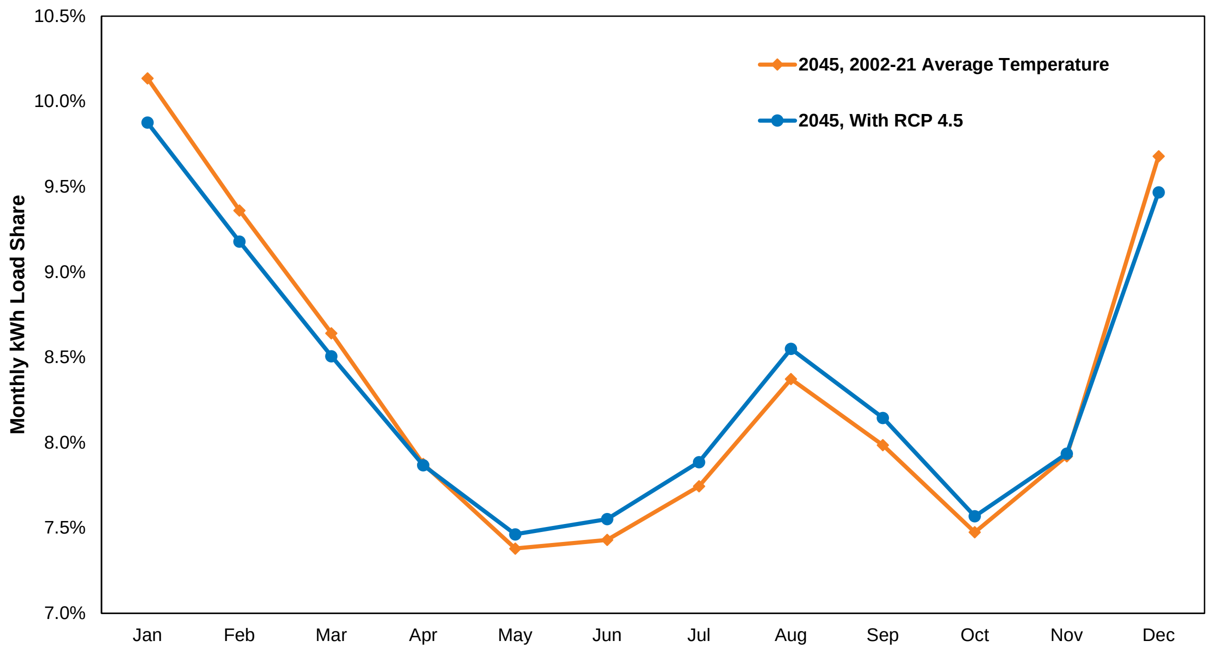
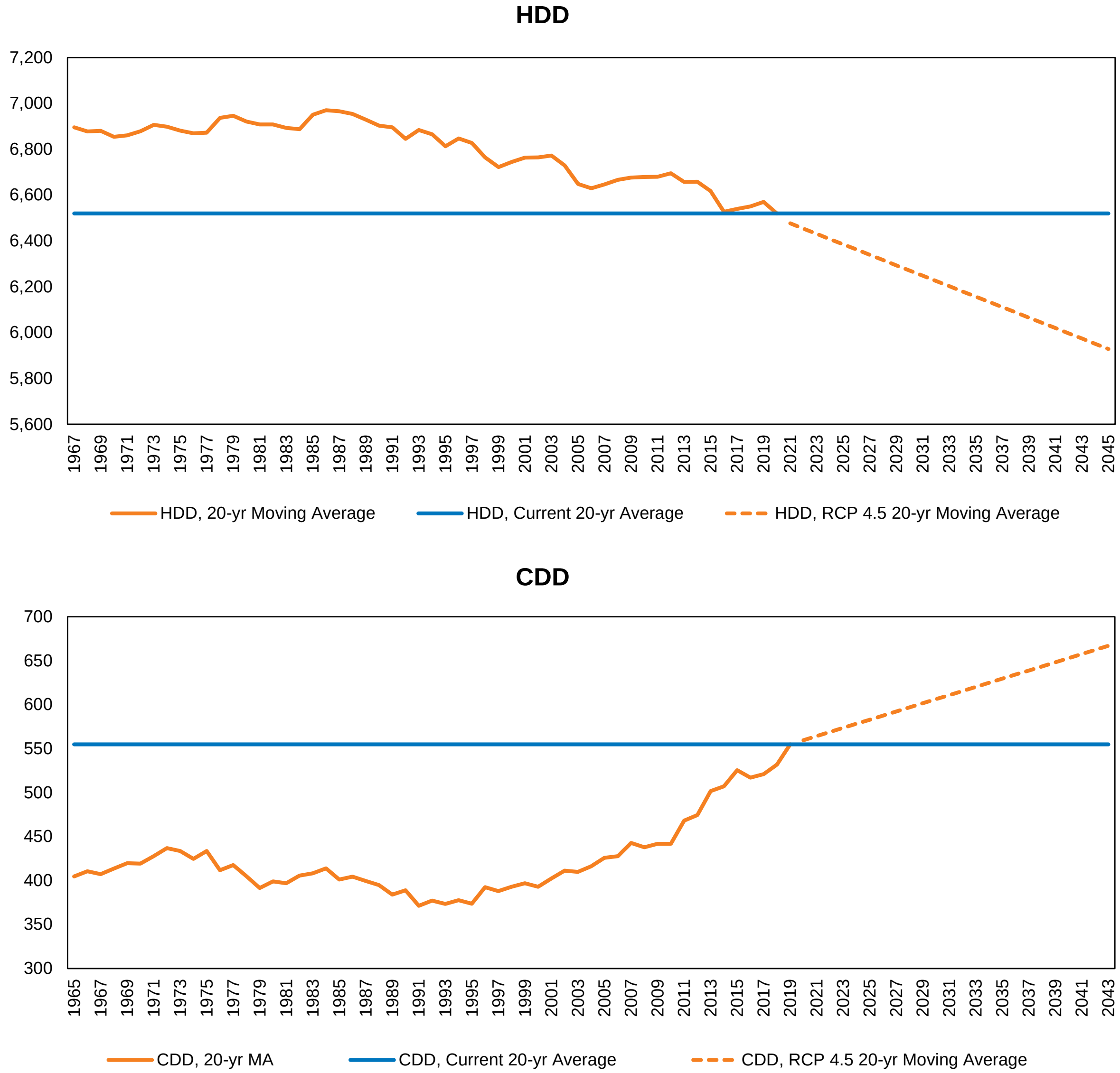


Figure 2.16: Load Share Comparison Due to Temperature Assumptions



Monthly Peak Load Forecast Methodology

The Peak Load Regression Model

The peak load hour forecast is used to determine the number of resources necessary to meet system peak demand. Avista must build generation capacity to meet winter and summer peak periods. Looking forward, the highest peak loads will most likely occur in the winter months, although in some years a mild winter followed by a hot summer could find the annual maximum peak load occurring in a summer hour. Equation 2.5 shows the current peak load regression model.

Equation 2.5: Peak Load Regression Model

$$hMW^{netpeak}_{d,t,y} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2$$
$$+ \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD^{HIGH}_{d,t,y} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1}$$
$$+ \phi_2 (D_{SUM} \cdot GDP_{t.y-1}) + \phi_3 (D_{WIN} \cdot GDP_{t.y-1}) + \boldsymbol{\omega_{WD} D_{d,t,y}} + \boldsymbol{\omega_{HD} D_{d,t,y}}$$
$$+ \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2005=1} + \epsilon_{d,t,y}\ for\ t,y = June\ 2004 \uparrow$$

Where:

- $hMW^{netpeak}_{d,t,y}$ = metered peak hourly usage on day of week d, in month t, in year y, and excludes two large industrial producers and special peak adders for future EVs, solar, and gas restrictions. The data series starts in June 2004.
- $HDD_{d,t,y}$ and $CDD_{d,t,y}$ = heating and cooling degree days the day before the peak.
- $(HDD_{d,t,y})^2$ = squared value of $HDD_{d,t,y}$.$HDD_{d-1,t,y}$ and $CDD_{d-1,t,y}$ = heating and cooling degree days the day before the peak.
- $CDD^{HIGH}_{d,t,y}$ = maximum peak day temperature minus 65 degrees.[14]
- $GDP_{t.y-1}$ = extrapolated level of real GDP in month t in year y-1.
- $(D_{SUM} * GDP_{t.y-1})$ is a slope shift variable for GDP in the summer months, June, July, and August.
- $(D_{WIN} * GDP_{t.y-1})$ is a slope shift variable for GDP in the winter months, December, January, and February.
- $\omega_{WD} D_{d,t,y}$ = dummy vector indicating the peak's day of week.
- $\omega_{SD} D_{t,y}$ = seasonal dummy vector indicating the month; and the other dummy variable control for an extreme outliers in March 2005.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) error term.

Peak Growth Rates Based on a GDP Driver and Temperatures

The estimated regression equation 2.5 is used to generate future peak loads by month for the 2022-2045 period. This is done by (1) assuming a long-term average annual growth rate in GDP of 1.8% to 2045 (this is consistent with the assumption in the expected energy forecast) and an extreme temperature forecast derived using RCP 4.5 forecasts. Because the RCP 4.5 forecasts are based on daily data, the RCP 4.5 forecasts are smoothed to capture trends that can be obscured by daily volatility. The smoothed temperatures are then used to calculate the monthly HDD and CDD required for regression equations. The temperatures in months January to May and October to December are smoothed with historical actuals using a 76-year moving average (the average starts with data back to the late 1940s); the months June to September are smoothed with historical actuals using a 20-year moving average (the average starts with data back to the early 2000s).

[14] This term provides a better model fit than the square of CDD.

The use of a moving average blended with historical and forecasted extremes in colder, HDD months reflects that although warming has occurred, the possibility of extreme cold has not gone away. In other words, although average winter temperatures have risen in our service area, and are expected to increase further under RCP 4.5, the distribution of extreme cold temperatures is still left-skewed—meaning there is still a greater likelihood of an unusually cold winter compared to an unusually warm winter. Blending both historical and forecasted temperatures means that skewness remains in place for planning purposes. Conversely, the use of a shorter moving average in warmer, CDD months means the peak forecast will more rapidly reflect the shift towards warmer summer temperatures predicted by RCP 4.5.

Using a 76-year moving average in cold months and 20-year moving average in warmer months maintains a winter temperature distribution that maintains the possibility of winters skewed towards extreme cold temperatures and a summer distribution that is increasingly skewed towards warmer summer temperatures than historically observed. As will be shown, the peak load forecast with RCP 4.5, in addition to adders for future EVs, solar, and gas restrictions, Avista will need to prepare for a near-term future as a dual summer and winter peaking utility.

The finalization of the peak load forecast occurs when the forecasted peak loads of two large industrial customers, EVs, solar, and gas restrictions are added to the forecasts generated by Equation 2.5. Table 2.3 shows estimated peak load growth rates with and without these adders. Figure 2.17 shows the forecasted time path of peak load out to 2045, and Figure 2.18 shows the high/low bounds based on a 1-in-20 event (95 percent confidence interval) using the standard deviation of the simulated historic peak loads. The potential impact of time-of-use pricing or other demand response options is not yet reflected in the current peak load forecast as it may or may not be used as a method to manage this load.

Table 2.3: Forecasted Winter and Summer Peak Growth, 2021-2045

Peak Load Annual Growth	Winter (Percent)	Summer (Percent)
Including Economic Growth, Large Industrial Customers, and adders for EVs, Solar, and WA Gas Restrictions	1.61	1.83
Including Economic Growth, but Excluding Large Industrial Customers, and adders for EVs, Solar, and WA Gas Restrictions	0.13	0.67

Figure 2.17 shows how the summer peak forecast grows faster than the winter peak, but the rapid accumulation of EVs results in similar winter and summer peaks over the forecast horizon. Figure 2.18 shows that the winter high/low bounds are larger than summer and reflects a historically greater range of temperature anomalies in the winter months.

Figure 2.17: Peak Load Forecast

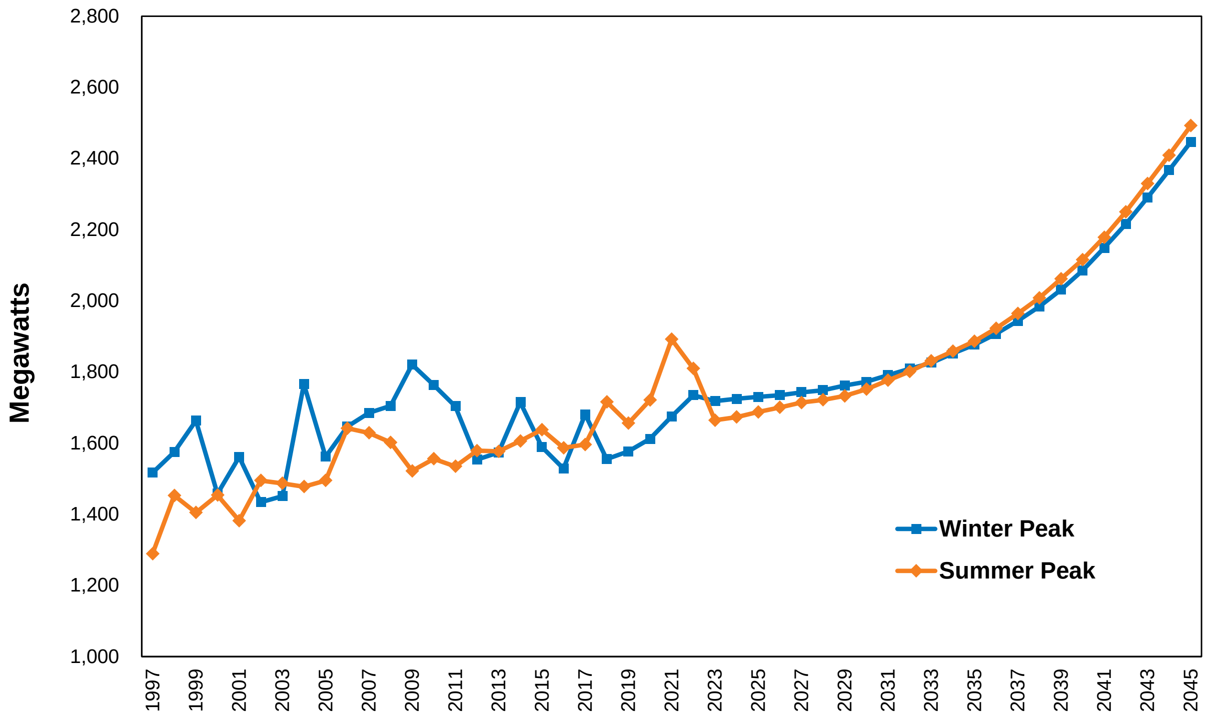


Figure 2.18: Peak Load Forecast with 1 in 20 High/Low Bounds

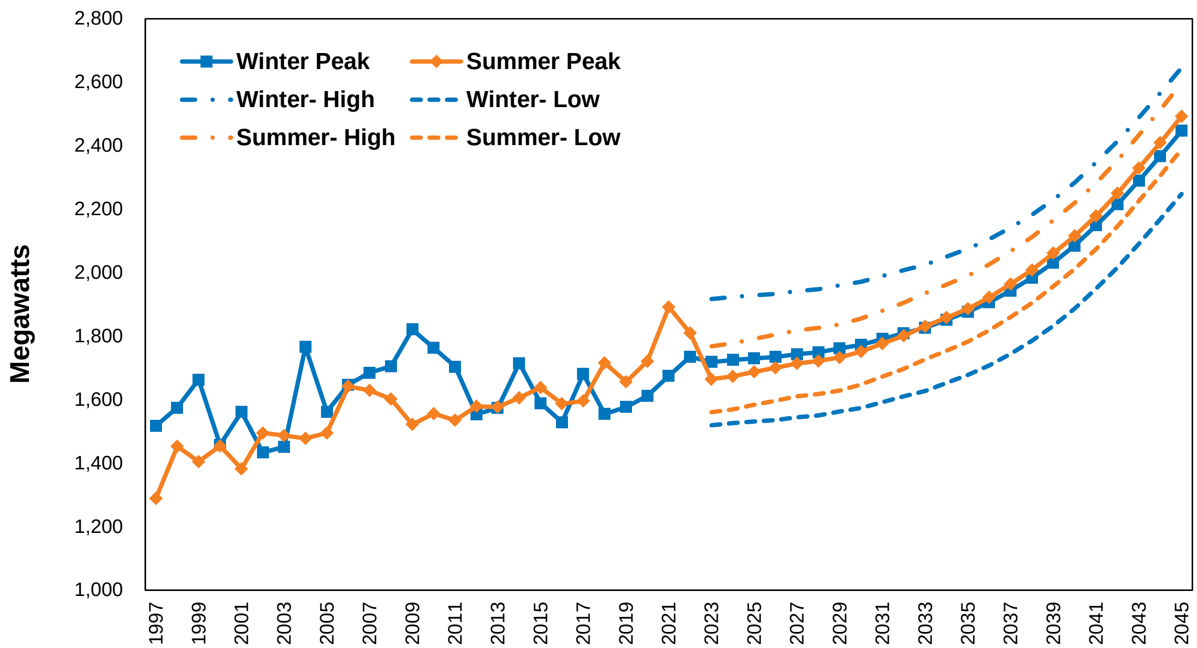


Table 2.4: Energy and Peak Forecasts

Year	Energy (aMW)	Winter Peak January (MW)	Summer Peak July (MW)
2024	1,119	1,725	1,673
2025	1,122	1,730	1,687
2026	1,127	1,734	1,700
2027	1,132	1,742	1,713
2028	1,139	1,748	1,721
2029	1,144	1,760	1,731
2030	1,149	1,769	1,748
2031	1,156	1,786	1,771
2032	1,164	1,801	1,793
2033	1,171	1,814	1,819
2034	1,179	1,834	1,840
2035	1,188	1,851	1,860
2036	1,197	1,870	1,885
2037	1,206	1,892	1,913
2038	1,216	1,914	1,938
2039	1,226	1,939	1,969
2040	1,238	1,966	1,996
2041	1,250	1,999	2,029
2042	1,263	2,032	2,067
2043	1,277	2,070	2,110
2044	1,293	2,110	2,152
2045	1,309	2,150	2,196

3. Existing Supply Resources

Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include ownership of five natural gas-fired projects, a biomass plant, and partial ownership of two coal-fired units. Avista also purchases energy from several independent power producers (IPPs) and regional utilities.

Section Highlights

- Hydro represents approximately half of Avista's winter generating capability.
- Natural gas-fired plants represent the largest portion of Avista's thermal generation portfolio.
- Recently signed agreements for hydro energy & capacity with Chelan PUD and Columbia Basin Hydro.
- Planned upgrades to Kettle Falls Generating Station and Post Falls Hydro.
- Additional resources are under negotiation to meet supply needs through 2030.

Figure 3.1 shows Avista's winter and summer resource capacity mix and Figure 3.2 shows the energy mix, considering the production capability rather than maximum generating capacity. Winter capability is the share of total capability of each resource type the utility can rely upon to meet winter peak load. The annual energy chart represents the energy as a percent of total supply; this calculation includes fuel limitations (for water, wind, and wood), maintenance and forced outages. Avista's largest energy supply in the peak winter months is from hydro at 50 percent, followed by natural gas-fired resources at 37 percent. On an annual basis, natural gas-fired generation can produce more energy (45 percent) than hydro (31 percent) because it is not constrained by fuel limitations (i.e., river conditions). The resource mix changes each year depending on streamflow conditions and market prices.

Figure 3.1: 2024 Avista Seasonal Capability

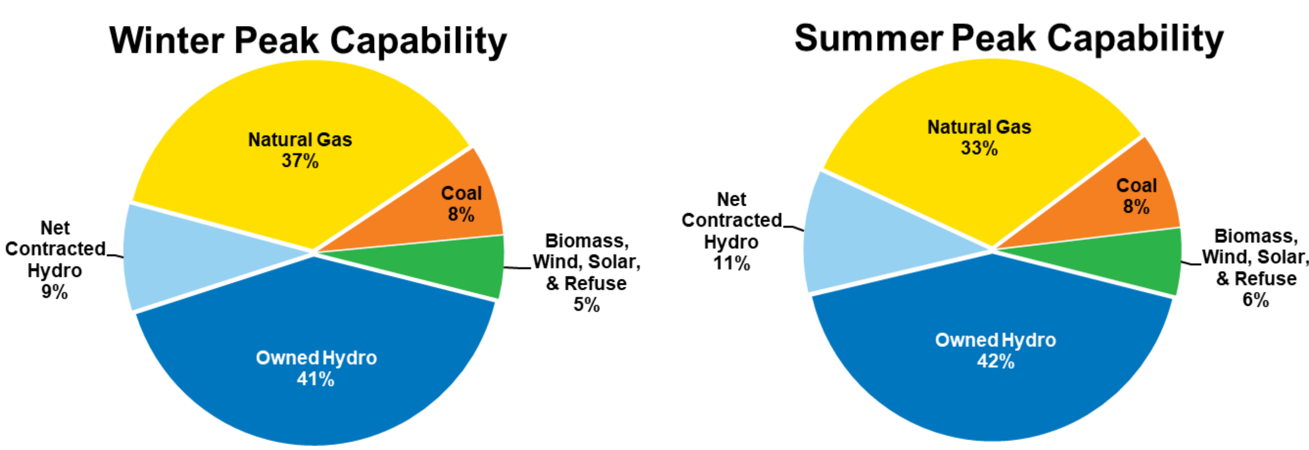
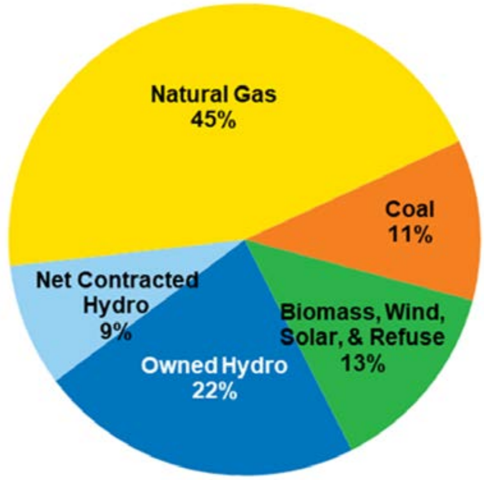
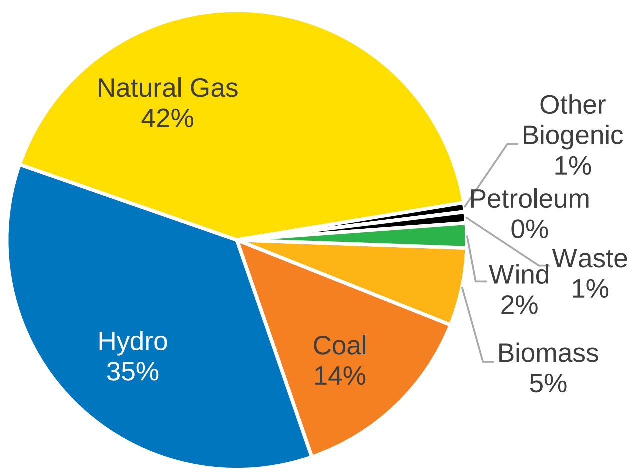


Figure 3.2: 2024 Annual Energy Capability



Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure[1]. The Washington State Department of Commerce calculates the resource mix used to serve load, rather than generation potential, by adding regional[2] estimates for unassigned market purchases and Avista-owned generation minus net renewable energy credit (REC) sales. Figure 3.3 shows Avista's 2020 Fuel Mix Disclosure. The Idaho fuel mix is nearly identical to Washington's except for its allocation of PURPA generation. Each state receives RECs based on their current authorized share of the system (approximately 65 percent Washington and 35 percent Idaho). Avista may retain RECs, sell them to other parties or transfer them between states. Avista transfers RECs from Idaho to comply with Washington's Energy Independence Act (EIA). Idaho customers are compensated for the value of RECs at market value whenever these transfers occur.

Figure 3.3: 2020 Avista's Washington State Fuel Mix Disclosure



[1] Report 11-A Utility Fuel Mix Market Summary–20200911 post adjust.pdf from Dep. of Commerce.
[2] For 2020, the region is approximately 55 percent hydroelectric, 13 percent natural gas, 11 percent unspecified, 10 percent coal, 4 percent nuclear, 5 percent wind and 1 percent other. When Avista sells RECs from its resources they are assigned an emissions level in the report equal to regional average emissions.

Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under a 50-year FERC operating license through June 18, 2059. The sixth, Little Falls, operates under separate authorization from the U.S. Congress. This section describes the Spokane River hydroelectric developments and provides the maximum on-peak and nameplate capacity ratings for each plant. The maximum on-peak capacity of a generating unit is the total amount of electricity it can safely generate with its existing configuration and the current mechanical state of the facility. Unlike other generation assets, hydro capacity is often above nameplate because of plant upgrades and favorable head or streamflow conditions. The nameplate, or installed capacity, is the original capacity of a plant as rated by the manufacturer. All six hydroelectric developments on the Spokane River connect directly to the Avista transmission system.

Post Falls

Post Falls is the hydroelectric facility furthest upstream on the Spokane River. It is located several miles east of the Washington/Idaho border. The facility began operating in 1906 and during summer months maintains the elevation of Lake Coeur d'Alene. Post Falls has a 14.75 MW nameplate rating but can produce up to 18.0 MW with its six generating units. Avista is currently evaluating upgrades to this facility as the generators and turbines are near end of life[3] this plan assumes turbine and generator replacement by 2029.

Upper Falls

The Upper Falls development sits within the boundaries of Riverfront Park in downtown Spokane. It began generating in 1922. The project is comprised of a single 10.0 MW unit.

Monroe Street

Monroe Street was Avista's first generation development. It began serving customers in 1890 in downtown Spokane at Huntington Park. Following a complete rehabilitation in 1992, the single generating unit has a 15.0 MW maximum capacity rating.

Nine Mile

A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone substantial upgrades with the installation of two new 8 MW units and two 10 MW units for a total nameplate rating of 36 MW. The incremental generation from the upgrades qualifies for Washington's EIA.

Long Lake

The Long Lake development is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The project's four units have a nameplate rating of 81.6 MW and 88.0 MW of combined capacity.

[3] Currently the 1 and a half units are not able to produce power.

Little Falls

The Little Falls development, completed in 1910 near Ford, Washington, is the furthest downstream hydroelectric facility on the Spokane River. The facility's four units generate 35.2 MW. Little Falls is not under FERC jurisdiction as it was congressionally authorized because of its location on the Spokane Indian Reservation. Avista operates Little Falls Dam in accordance with an agreement reached with the Tribe in 1994 to identify operational and natural resource requirements. Little Falls Dam is also subject to other Washington State environmental and dam safety requirements.

Clark Fork River Hydroelectric Development

The Clark Fork River Development includes hydroelectric projects located near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border on the Clark Fork River. The plants operate under a FERC license through 2046 and connect directly to the Avista transmission system.

Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit that entered service in 1977. Avista completed major turbine upgrades on units 1 through 4 between 2009 and 2012. The total capability of the plant is 610 MW under ultimate operating conditions.

Cabinet Gorge

Cabinet Gorge started generating power in 1952 with two units, and two additional generators were added the following year. Upgrades to units 1 through 4 occurred in 1994, 2004, 2001 and 2007, respectively. The current maximum on-peak plant capacity is 270.5 MW, modestly above its 265.2 MW nameplate rating.

Total Hydroelectric Generation

In total, Avista's hydroelectric plants have nearly 1,080 MW of capacity. Table 3.1 summarizes the location and operational capacities of Avista's hydroelectric projects, and the expected energy output of each facility based on an 80-year hydrologic record.

Table 3.1: Avista-Owned Hydroelectric Resources

Project Name	River System	Location	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	14.8	15.0	11.2
Post Falls	Spokane	Post Falls, ID	14.8	18.0	9.4
Nine Mile	Spokane	Nine Mile Falls, WA	36.0	32.0	15.7
Little Falls	Spokane	Ford, WA	32.0	35.2	22.6
Long Lake	Spokane	Ford, WA	81.6	89.0	56.0
Upper Falls	Spokane	Spokane, WA	10.0	10.2	7.3
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	196.5
Cabinet Gorge	Clark Fork	Clark Fork, ID	265.2	270.5	123.6
Total			**972.4**	**1,079.9**	**442.3**

Thermal Resources

Avista owns seven thermal generation assets located across the Northwest. These assets provide dependable energy and capacity serving base and peak-load obligations. Table 3.2 summarizes these resources by fuel type, online year, remaining design life, book value at the end of 2022 and the last year of expected service for IRP modeling purposes. Table 3.3 includes capacity information for each of the facilities along with the five-year historical forced outage rates used for modeling purposes.

Table 3.2: Avista-Owned Thermal Resources

Project Name	Location	Fuel Type	Start Date	Last Year of Service[4]	Book Value (mill. $)	Book Life (years)
Colstrip 3 & 4	Colstrip, MT	Coal	1984[5]	2025	50.2	See Note[6]
Rathdrum	Rathdrum, ID	Gas	1995	2044	27.5	10
Northeast	Spokane, WA	Gas	1978	2035	0.0	0[7]
Boulder Park	Spokane, WA	Gas	2002	2040	14.0	17
Coyote Springs 2	Boardman, OR	Gas	2003	n/a	116.6	17
Kettle Falls	Kettle Falls, WA	Wood	1983	n/a	61.6	18
Kettle Falls CT	Kettle Falls, WA	Gas	2002	2040	2.6	8

Table 3.3: Avista-Owned Thermal Resource Capability

Project Name	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)	Forced Outage Rate (%)
Colstrip 3	111	111	123.5	7.4
Colstrip 4	111	111	123.5	7.4
Rathdrum (2 units)	176	130	166.2	1.9
Northeast (2 units)	66	42	61.8	1.9
Boulder Park (6 units)	24.6	24.6	24.6	11.4
Coyote Springs 2	317.5	286	306.5	5.0
Kettle Falls	47	47	50.7	3.7
Kettle Falls CT	11	8	7.2	6.2
Total	**864.1**	**759.6**	**864.0**	

Colstrip Units 3 and 4

The Colstrip plant, located in eastern Montana, consists of two coal-fired steam plants (Units 3 and 4) connected to a double-circuit 500 kV line owned by each of the participating utilities. The utility-owned segment extends from Colstrip to Townsend, Montana. BPA's ownership of the 500 kV line starts in Townsend and continues west. Energy moves across both segments of the transmission line under a long-term wheeling

[4] The last year of service is estimated retirement or end of service for utility customers. This IRP assumes Coyote Springs 2 to be ineligible for Washington in 2045, but eligible to serve Idaho customers.
[5] Colstrip Unit 3 began operating in 1984 and Colstrip Unit 4 began in 1986.
[6] Avista is modeling Colstrip Units 3 and 4 with a depreciable life ending in 2025 in Washington and 2027 in Idaho, as approved by the Washington and Idaho Commissions.
[7] There is no remaining book life but there are seven years of remaining tax depreciation impacts to customers.

arrangement. Talen Montana, LLC operates the facilities on behalf of the six owners. Avista owns 15 percent of Units 3 and 4. Unit 3 began operating in 1984 and Unit 4 in 1986. Avista's share of Colstrip has a maximum net capacity of 222 MW, and a nameplate rating of 247 MW. Beginning on January 1, 2026, Colstrip will no longer serve Avista's Washington customers due to the passage of the Clean Energy Transformation Act (CETA).

Rathdrum

Rathdrum consists of two identical simple-cycle combustion turbine (CT) units. This natural gas-fired plant located near Rathdrum, Idaho connects to the Avista transmission system. It entered service in 1995 and has a maximum combined capacity of 176 MW in the winter and 126 MW in the summer. The nameplate rating is 166.5 MW. Chapter 6, Supply-Side Resource Options, provides details about modernization options under consideration at Rathdrum.

Northeast

The Northeast plant, located in Spokane, has two identical aero-derivative simple-cycle CT units completed in 1978. The plant can burn natural gas and oil, but air permits preclude the use of fuel oil. The combined maximum capacity of the units is 68 MW in the winter and 42 MW in the summer, with a nameplate rating of 61.8 MW. The plant air permit limits run hours to 100 hours per year, limiting its use primarily to reliability events. Avista assumes this plant will retire in 2035 for modeling purposes of this IRP.

Boulder Park

The Boulder Park project entered service in the Spokane Valley in 2002. It connects directly to the Avista transmission system. The site uses six identical natural gas-fired internal combustion reciprocating engines to produce a combined maximum capacity and nameplate rating of 24.6 MW. Avista assumes this plant will retire in 2040 for modeling purposes of this IRP.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine (CCCT) located near Boardman, Oregon. The plant connects to the BPA 500 kV transmission system under a long-term agreement. The plant began service in 2003 and has a maximum capacity of 317.5 MW in the winter and 285 MW in the summer with duct burners operating. The nameplate rating of the plant is 287.3 MW.

Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass generation plants in North America and connects to Avista on its 115 kV transmission system. The open-loop steam plant uses waste wood products (hog fuel) from area mills and forest slash but can also burn natural gas on a limited basis. A 7.5 MW combustion turbine (CT), added to the facility in 2002, burns natural gas and increases overall plant efficiency by sending exhaust heat to the wood boiler when operating in combined-cycle mode.

The wood-fired portion of the plant has a maximum capacity of 50 MW and a nameplate rating of 50.7 MW. Varying fuel moisture conditions at the plant causes correlated variation between 45 and 50 MW. The plant's capacity increases from 55 to 58 MW when operated in combined-cycle mode with the CT. The CT produces 8 MW of peaking capability in the summer and 11 MW in the winter. The CT can be limited in the winter when the natural gas pipeline is capacity constrained. The CT is not available when temperatures fall below zero.[8] This operational assumption reflects natural gas availability limits in the area.

As part of the 2022 All-Source Request for Proposals (RFP), an upgrade to the facility was selected as a cost-effective option to serve customers. This upgrade includes a 3rd party partner "Myno" who will provide Kettle Falls with steam from a biochar process. This steam adds 13 MW[9] of generation capability beginning in 2026 for a total capacity of 63 MW (net). Myno's process will use a portion of the wood fuel supply to create biochar for the agriculture industry and Avista will purchase the steam by by-product for power production. In total, the production increase at Kettle Falls will be 11 MW when accounting for energy consumed by Myno. Avista customers will benefit from this arrangement by increasing capacity, lowering production costs, and lowering air emissions related to wood combustion at Kettle Falls.

Small Avista-Owned Solar

Avista operates three small solar projects. The first solar project is three kilowatts located at its corporate headquarters as part of its former Solar Car initiative. Avista installed a 15 kilowatt solar system in Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. The 423-kW Avista Community Solar project, located at the Boulder Park property, began service in 2015.

Table 3.4: Avista-Owned Solar Resource Capability

Project Name	Project Location	Project Capacity (kW-DC)
Spokane Headquarters Solar	Spokane, WA	3
Rathdrum Solar	Rathdrum, ID	15
Boulder Park Solar	Spokane Valley, WA	423
Total		**441**

Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet a portion of its load requirements. These contracts provide many benefits by adding environmentally low-impact generation from low-cost hydro and wind power to the Company's resource mix. This section describes the contracts in effect during the timeframe of the 2023 IRP. Tables 3.4 through 3.6 summarize Avista's contracts.

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[8] Avista is reviewing its policies and may restrict the CT use when the pipeline is at lower pressures then the current standard. This change could further restrict the plant from producing power in winter months. For this IRP, Avista assumes no winter Kettle Falls CT capacity after 2023.

[9] As part of the change in generation the total steam production will be 18 MW.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, Public Utility Districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to loads served by the PUDs. Long-term contracts with public, municipal, and investor-owned utilities throughout the Northwest assisted project financing by providing a market for the surplus power. The contract terms obligate the PUDs to deliver power to Avista points of interconnection. Avista originally entered long-term contracts for the output of five projects “at cost”. Avista now competes in capacity auctions to retain the rights of these contracts as they expire. The Mid-Columbia contracts in Table 3.5 provide clean energy, capacity, and reserve capabilities.

The timing of the power received from the Mid-Columbia projects is a result of agreements including the 1961 Columbia River Treaty and the 1964 Pacific Northwest Coordination Agreement (PNCA). Both agreements optimize hydroelectric project operations in the Northwest U.S. and Canada. In return for these benefits, Canada receives return energy under the Canadian Entitlement. The Columbia River Treaty and the PNCA manage storage water in upstream reservoirs for coordinated flood control and power generation optimization. The Columbia River Treaty may end on September 15, 2024. Studies are underway by U.S. and Canadian entities to determine possible post-2024 Columbia River operations. Federal agencies are soliciting feedback from stakeholders and ongoing negotiations will determine the future of the treaty. This plan does not model alternative outcomes for treaty negotiations.

Table 3.5: Mid-Columbia Capacity and Energy Contracts[10]

Counter Party	Project(s)	Percent Share (%)	Start Date	End Date	On-Peak Capability (MW)	Annual Energy (aMW)	Canadian Entitle-ment
Grant PUD	Priest Rapids/ Wanapum	3.76	Dec-2001	Dec-2052	74.9	38.4	-2.1
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2016	Dec-2030	87.5	52.4	-2.7
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2024	Dec-2033	87.5	52.4	-2.7
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2026	Dec-2030	87.5	52.4	-2.7
Chelan PUD	Rocky Reach/ Rock Island	10.0	Jan-2031	Dec-2045	174.9	104.8	-5.4
Douglas PUD	Wells	2.76[11]	Oct-2018	Dec-2028	23.8	12.2	-6.2

[10] For purposes of long-term transmission reservation planning for bundled retail service to native load customers, replacement resources for each of the resources identified in Table 3.5 are presumed and planned to be integrated via Avista’s interconnection(s) to the Mid-Columbia region.

[11] Percent share varies each year depending on Douglas PUD’s load growth. Avista and Douglas PUD also have an exchange agreement through 2023 where Avista delivers 4x MW in exchange for 10 percent of the Wells project.

Columbia Basin Hydro

In December 2022, Avista reached an agreement to purchase the entire output from Columbia Basin Hydro's irrigation generation fleet through 2045. The agreement includes all generation and environmental attributes from seven hydroelectric projects totaling 146.3 MW of capacity. Avista will take delivery of projects over time as existing contracts with other utilities expire. Table 3.6 outlines the project delivery timeline, capacity, and energy deliveries. These projects are unique as they are based on the amount of irrigation used by central Washington farmers from March through October, with most of the generation occurring in May through August in a consistent firm energy delivery.

Table 3.6: Columbia Basin Hydro Projects

Project Name	Start Date	Capacity (MW)	Energy (aMW)
Russell D. Smith	1/1/2023	6.1	1.5
EBC 4.6	5/1/2023	2.2	0.9
Summer Falls	1/1/2025	94.0	41.4
PEC 66	3/1/2025	2.4	0.5
Quincy Chute	10/1/2025	9.4	3.6
Main Canal	1/1/2027	26.0	11.6
PEC Headworks	9/1/2030	6.2	2.3
Total		**146.3**	**61.8**

Public Utility Regulatory Policies Act (PURPA)

The passage of PURPA by Congress in 1978 required utilities to purchase power from resources meeting certain size and fuel criteria. Avista has many PURPA, or Qualifying Facility energy purchase contracts, shown in Table 3.7 accumulating to 139.9 MW, but fully net metered from customer load are shown in Table 3.8 for a total of 1.47 MW, power from these facilities is only purchased if generation exceeds load. The IRP assumes renewal of these contracts after current terms end based on Avista's experience with these contracts and ongoing communications with the project owners. Avista takes the energy as produced, does not control the output of any PURPA resources and does not receive the RECs from these projects. However, the Washington-based PURPA projects reduce the amount of load that needs to be met for CETA compliance.

Table 3.7: PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)	5 year avg. Gen. History (aMW)
Meyers Falls	Hydro	Kettle Falls, WA	12/2025	1.30	1.18
Spokane Waste to Energy	Waste	Spokane, WA	12/2037	22.70	13.85
Plummer Saw Mill	Wood Waste	Plummer, ID	12/2023	5.80	4.07
Deep Creek	Hydro	Northport, WA	12/2032	0.41	0.02
Clark Fork Hydro	Hydro	Clark Fork, ID	12/2037	0.22	0.11
Upriver Dam[12]	Hydro	Spokane, WA	12/2037	14.50	4.95
Big Sheep Creek Hydro	Hydro	Northport, WA	6/2025	1.40	0.82
Ford Hydro LP	Hydro	Weippe, ID	6/2024	1.41	0.44
John Day Hydro	Hydro	Lucile, ID	9/2041	0.90	0.30
Phillips Ranch[13]	Hydro	Northport, WA	n/a	0.02	0.00
City of Cove	Hydro	Cove, OR	10/2038	0.80	0.35
Clearwater Paper	Biomass	Lewiston, ID	12/2023	90.20	52.02
Total				**139.92**	**78.11**

Table 3.8: PURPA Agreements (net meter only)

Contract	Fuel Source	Location	Contract End Date	Size (MW)	Energy (aMW)
Spokane County Digester	Biomass	Spokane, WA	8/2021	0.26	0.14
Great Northern	Solar	Spokane, WA	5/2035	0.25	0.05
U of Idaho Steam Plant	CHP Steam	Moscow, ID	2/2042	0.83	0.74
U of Idaho Solar	Solar	Moscow, ID	2/2042	0.13	0.03
Total				**1.47**	**0.96**

Lancaster

Avista acquired output rights to the Lancaster CCCT, located in Rathdrum, Idaho, after the sale of Avista Energy in 2007. Lancaster directly interconnects with the Avista transmission system at the BPA Lancaster substation. Under the tolling contract, Avista pays a monthly capacity payment for the sole right to dispatch the plant through October 2026. In addition, Avista pays a variable energy charge and arranges for all fuel needs of the plant.

Palouse Wind

Avista signed a 30-year PPA in 2011 with Palouse Wind for the entire output of its 105 MW project starting in December 2012. The project directly connects to Avista's transmission system between Rosalia and Oaksdale, Washington in Whitman County.

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[12] Energy estimate is net of the City of Spokane's pumping load.
[13] Phillips Ranch had no generation in 2021, bringing it's 5-year average generation to 0.

Rattlesnake Flat Wind

Rattlesnake Flat was selected as the preferred project in Avista's 2018 RFP for 50 aMW of renewable energy. It is a 160.5 MW (limited by transmission constraints to 144 MW) 20-year PPA with an expected net annual output of 469,000 MWh (53.5 aMW). Located east of Lind, Washington in Adams County, the project went online in December 2020.

Adams-Nielson Solar

Avista signed a 20-year PPA for the Adams-Nielson solar project in 2017. The 80,000 panel, single axis, solar facility can deliver 19.2 MW of alternating current (AC) power and entered service in December 2018. The project is located north of Lind, Washington in Adams County. The project provides energy for Avista's Solar Select program. Solar Select allows commercial customers to voluntarily purchase through 2028. The solar energy attributes from the project for these customers are at no additional cost through a combination of tax incentives from the State of Washington and offsetting power supply expenses.

Sales Contracts

Avista has intermediate power sales contracts used to optimize Avista's energy position on behalf of customers. Avista currently has three sales contracts extending through 2023. These contracts include the Nichols Pumping sale of power at Colstrip; Douglas PUD, an exchange agreement tied to the 10 percent purchase of the Wells hydro project; and the Morgan Stanley contract to facilitate the sale of Clearwater Paper's generation. For resource planning purposes, Avista does not assume contract sale extensions. Table 3.9 describes Avista's other contractual rights and obligations.

Table 3.9: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity Contri-bution (MW)	Summer Capacity Contri-bution (MW)	Annual Energy (aMW)
Lancaster	Purchase	Natural Gas	2026	283.0	231.0	218.0
Palouse Wind	Purchase	Wind	2042	5.3	5.3	36.2
Rattlesnake Flat	Purchase	Wind	2040	7.2	7.2	53.5
Adams-Nielson	Purchase	Solar	2038	0.4	10.2	5.6
Nichols Pumping	Sale	System	2023[14]	-5.0	-5.0	-5.0
Morgan Stanley	Sale	Clearwater Paper	2023	-46.0	-46.0	-44.9
Douglas PUD	Sale	System	2023	-48.0	-48.0	-48.0
Total				**196.9**	**154.7**	**215.4**

[14] This obligation operates pumping loads in Colstrip. The end date reflects the energy sold to other Colstrip participants, Avista's obligation is approximately one megawatt and will end when Avista exits the plant.

Natural Gas Pipeline Rights

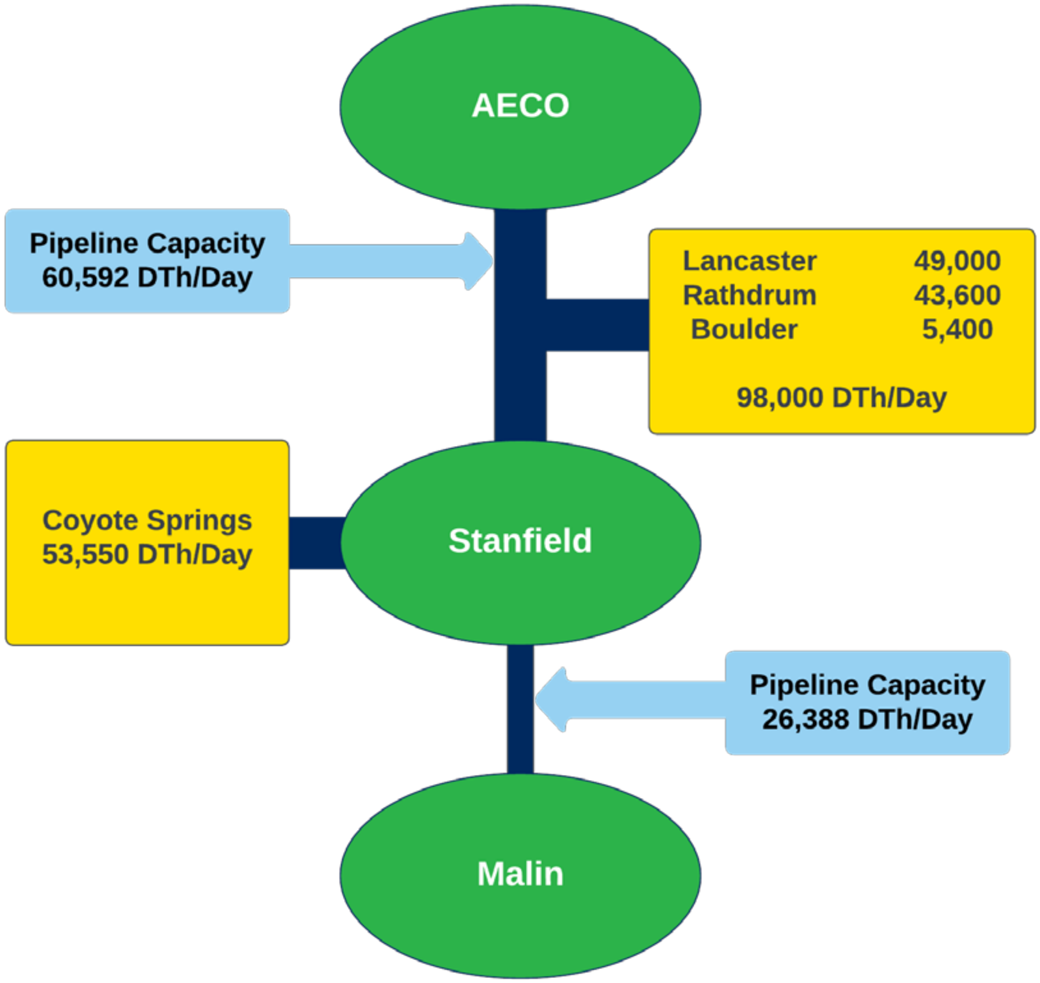
Avista transports natural gas to its natural gas-fired generators using the GTN pipeline owned by TC Energy (formally TransCanada). The pipeline runs between Alberta, Canada and the California/Oregon border at Malin. Avista holds 60,592 dekatherms per day of capacity from Alberta to Stanfield, but in November 2023, the capacity rights will increase to 69,989 dekatherms. Avista controls another 26,388 dekatherms per day from Stanfield to Malin. Figure 3.4 below illustrates Avista's natural gas pipeline rights. This figure includes the theoretical capacity if the plants under Avista's control run at full capacity for the entire 24 hours in a day on the system. The maximum burn by Avista is 140,214 dekatherms per day based on the average of the top five historical natural gas burn days of 2019, 2020 and 2022, as shown in Table 3.10.

As discussed above, Avista does not have firm transportation rights for the entirety of its natural gas generation capacity. Avista relies on short-term transportation contracts to meet needs above Avista's firm contractual rights. Adequate surplus transportation has historically been available because the GTN pipeline was not fully subscribed. Natural gas producers have recently purchased all remaining rights on the system to transport their supply south and take advantage of higher prices in the U.S. compared to Canada. However, these suppliers do not appear to have firm off-takers of their product, and therefore a lack of transportation likely will not lead to a lack of fuel for Avista's natural gas plants. This becomes a pricing issue rather than a supply issue when suppliers control the pipeline. Avista will continue acquiring natural gas delivery beyond its firm rights through the daily market. When the market begins to tighten, or if the premiums paid for delivery through suppliers increases greatly, Avista will revisit its options. These options include procurement through pipeline capacity expansions and investment in onsite fuel storage.

Table 3.10: Top Five Historical Peak Natural Gas Usage (Dekatherms)

Date	Boulder Park	Coyote Springs 2	Lancaster	Rathdrum	GTN Total	Firm Rights
3/2/2019	5,361	45,855	48,889	43,614	143,719	60,592
10/18/2022	5,491	48,938	45,611	42,067	142,107	60,592
3/1/2019	4,641	44,585	47,340	43,298	139,864	60,592
4/12/2020	4,427	45,651	44,150	44,106	138,333	60,592
4/5/2020	4,555	45,629	43,505	43,357	137,046	60,592

Figure 3.4: Avista Firm Natural Gas Pipeline Rights



Resource Environmental Requirements and Issues

Electricity generation creates environmental impacts subject to regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities Avista has ownership interests in are designed, operated and monitored to maintain compliance with applicable environmental laws. Avista conducts periodic reviews and audits of its facilities and operations to ensure continued compliance. To respond to or anticipate emerging environmental issues, Avista monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of Avista's generating plants and other assets.

Generally, environmental laws and regulations have the following impacts while maintaining and enhancing the environment:

- Increase operating costs of generation;
- Increase the time and costs to build new generation;
- Require modifications to existing plants;

- Require curtailment or retirement of generation plants;
- Reduce the generating capability of plants;
- Restrict the types of plants that can be built or contracted with;
- Creates resource adequacy challenges;
- Require construction of specific types of generation at higher cost; and
- Increase the cost to transport and distribute natural gas.

The following sections describe applicable environmental regulations in more detail.

Clean Air Act (CAA)

The CAA is a federal law setting requirements for thermal generating plants. States are typically authorized to implement CAA permitting and enforcement. States have adopted parallel laws and regulations to implement the CAA. Some aspects of its implementation are delegated to local air authorities. Colstrip, Coyote Springs 2, Kettle Falls and Rathdrum CT all require CAA Title V operating permits. Boulder Park and the Northeast CT require minor source permits or simple source registration permits to operate. These requirements can change as the CAA or other regulations change and agencies review and issue new permits. Several specific regulatory programs authorized under the CAA impact Avista’s generation, as reflected in the following sections.

Hazardous Air Pollutants (HAPs)

On April 16, 2016, the Mercury Air Toxic Standards (MATS), an EPA rule under the CAA for coal and oil-fired sources, became effective for all Colstrip units. Colstrip performs quarterly compliance assurance stack testing to meet the MATS site-wide limitation for Particulate Matter (PM) emissions (0.03 lbs./MMBtu) a measure used as a surrogate for all HAPs.

On May 22, 2020, EPA published its reconsideration of the “appropriate and necessary” finding and concluded that it is not “appropriate and necessary” to regulate electric utility steam generation units under section 112 of the CAA. EPA also took final action on the residual risk and technology review that is required by CAA section 112 and determined that emissions from HAP have been reduced such that residual risk is at acceptable levels. There are no developments in HAP emission controls to achieve further cost-effective reductions beyond the current standards and, therefore, no changes to the MATS rule are warranted.

Montana Mercury Rule

Montana established a site wide Mercury cap in 2010, requiring Mercury to be below 0.9 lbs. per trillion Btu. Colstrip installed a mercury oxidizer/sorbent injection system to comply with the cap. The Montana Department of Environmental Quality (MDEQ) recently reviewed the equipment and concurred with the plant’s assessment that units 3 and 4 operate at 0.8 lb. per Tbtu range. There are no indication mercury requirements will change in the planning horizon.

Regional Haze Program

EPA set a national goal in 1999 to eliminate man-made visibility degradation in national parks and wilderness areas by 2064. Individual states must take actions to make “reasonable progress” through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the absence of state programs, EPA may adopt Federal Implementation Plans (FIPs). On September 18, 2012, EPA finalized the Regional Haze FIP for Montana. In November 2012, several groups petitioned the U.S. Court of Appeals for the Ninth Circuit for review of Montana’s FIP. The Court vacated portions of the Final Rule and remanded back to EPA for further proceedings on June 9, 2015. MDEQ is in the process of retaking control of the program from EPA after issuing a Regional Haze Program progress plan for Montana in 2017 and Montana’s second planning period for regional haze to EPA on August 10, 2022. A combination of $LoNO_X$ burners, overfire air, and SmartBurn currently control NO_X emissions at Colstrip. Regional coal plant shutdowns indicate the NO_X emissions are below the glide path. This progress demonstrates reasonable progress; therefore, Avista does not anticipate additional NO_X pollution controls for Colstrip.

Coal Ash Management/Disposal

In 2015, EPA issued a final rule on coal combustion residuals (CCRs), also known as coal combustion byproducts or coal ash. The rule has been subject to ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations expressed largely through a 2012 Administrative Order on Consent (AOC). These binding state-issued requirements continue despite the 2018 federal court ruling.

In addition, under the AOC, the Colstrip owners must provide financial assurance, primarily in the form of surety bonds, to secure each owner’s pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required may vary due to the uncertainty associated with remediation activities. Please refer to the Colstrip section for additional information on the AOC/CCR related activities.

Particulate Matter (PM)

Particulate Matter (PM) is the term used for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to see with the naked eye. Others are so small they are only detectable with an electron microscope. Particle pollution includes:

- **PM_{10}:** inhalable particles, with diameters that are generally 10 micrometers and smaller; and
- **$PM_{2.5}$:** fine inhalable particles, with diameters generally 2.5 micrometers and smaller.

There are different standards for PM_{10} and $PM_{2.5}$. Limiting the maximum amount of PM to be present in outdoor air protects human health and the environment. The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for PM, as one of the six criteria pollutants considered harmful to public health and the environment. The law also requires periodic EPA reviews of the standards to ensure that they provide adequate health and environmental protection and to update standards as necessary.

Avista owns and/or has operational control of the following generating facilities that produce PM: Boulder Park, Colstrip, Coyote Springs 2, Kettle Falls, Lancaster, Northeast and Rathdrum. Table 3.11 below shows each of the plants, status of the surrounding area with NAAQS for $PM_{2.5}$ and $PM_{10,}$ operating permit, and PM pollution controls.

Appropriate agencies issue air quality operating permits. These operating permits require annual compliance certifications and renewal every five years to incorporate any new standards including any updated NAAQS status.

Threatened and Endangered Species and Wildlife

Several species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act (ESA). Efforts to protect these and other species have not significantly affected generation levels at our facilities. Avista is implementing fish protection measures at its Clark Fork hydroelectric project under a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana, consistent with requirements of Avista’s FERC license.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Some of Avista’s facilities can pose risks to a variety of such birds so avian protection plans are followed for these facilities.

Table 3.11: Avista Owned and Controlled PM Emissions

Thermal Generating Station	$PM_{2.5}$ NAAQS Status	PM_{10} NAAQS Status	Air Operating Permit	PM Pollution Controls
Boulder Park	Attainment	Maintenance	Minor Source	Pipeline Natural Gas
Colstrip	Attainment	Non-Attainment	Major Source Title V OP	Fluidized Bed Wet Scrubber
Coyote Springs 2	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Kettle Falls	Attainment	Attainment	Major Source Title V OP	Multi-clone collector, Electrostatic Precipitator
Lancaster	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Northeast	Attainment	Maintenance	Minor Source	Pipeline Natural Gas, Air filters
Rathdrum	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters

Climate Change - Federal Regulatory Actions

In June 2019, the EPA released the final version of the Affordable Clean Energy (ACE) rule, the replacement for the Clean Power Plan (CPP). The final ACE rule combined three distinct EPA actions. First, EPA finalized the repeal of the CPP. The CPP was comprised of three “building blocks” identified by the EPA as follows:

- Reducing CO_2 emissions by undertaking efficiency projects at affected coal-fired power plants (i.e., heat-rate improvements);
- Reducing CO_2 emissions by shifting electricity generation from affected power plants to lower-emitting power plants (e.g., natural gas plants); and
- Reducing CO_2 emissions by shifting electricity generation from affected power plants to new renewable energy generation.

Notably, the second and third building blocks, responsible for the majority of projected emission reductions, were premised on “beyond the fence” measures to reduce emissions. Second, the EPA finalized the ACE rule, comprising the EPA’s determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants and procedures to govern States’ promulgation of standards of performance for such plants within their borders. EPA set the final BSER as heat rate efficiency improvements based on a range of “candidate technologies” to be applied to a plant's operating units and requires each State to determine application to each coal-fired unit based on consideration of remaining useful plant life. Contrary to the CPP, ACE relied solely on emission reductions from the specific source, or “inside the fence.” Lastly, the ACE rule included implementing regulations for State plans.

In January 2021, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE Rule and remanded the record back to the EPA for further consideration consistent with its opinion, finding that the EPA misinterpreted the CAA when it determined that the language of Section 111 barred consideration of emissions reduction options that were not applied at the source. The Court also vacated the repeal of the CPP. The EPA will now act on remand, and it is still unclear what next steps the EPA will take. Given the complex and uncertain legal record with respect to the CPP, and the confirmation testimony of the EPA Administrator that the Court's ruling was an opportunity for the EPA to "take a clean slate" in this area, we expect new rulemaking in the future.

Climate Change - State Legislation and State Regulatory Activities

Washington State enacted Senate Bill 5116, CETA. As stated elsewhere in this Progress Report, CETA aims to reduce greenhouse gas emissions from specific sectors of the economy through direct regulation including electricity generation. CETA requires utilities to eliminate coal-fired resources from Washington retail rates by the end of 2025, achieve carbon neutrality by 2030 with no more than 20 percent of load met by alternative compliance means, and serve all retail load with renewable and non-emitting resources by 2045.

Washington and Oregon apply greenhouse gas emissions performance standards (EPSs) to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within those respective states or elsewhere. The EPS prevents utilities from constructing or purchasing generation facilities or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that, in any case, have emission levels higher than 1,100 CO_2 equivalency (CO_2e) pounds per MWh. The Washington State Department of Commerce reviews this standard every five years. The last review was completed in September 2018 where it adopted a new rate of 925 pounds CO_2e per MWh.

Energy Independence Act (EIA)

The EIA in Washington requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in Washington in 2020 and beyond. Utilities under EIA regulation must also meet biennial energy conservation targets. Failure to comply with renewable energy and efficiency standards result in penalties of as much as $50 per MWh plus inflation since 2006 of deficiency. Avista meets the requirements of the EIA through a combination of hydro upgrades, wind, biomass, and renewable energy credits. Beginning in 2030, if a utility is compliant with CETA, the utility is deemed to meet the requirements of the EIA.

Washington Climate Commitment Act

The Washington legislature passed its largest environmental program in 2021, the Climate Commitment Act (CCA). This act creates a state-wide emissions cap and trade program where emissions are to be reduced by 95 percent by 2050 for all industries. Beginning in 2023, entities will be required to cover their emissions by the purchase of "allowances" acquired through state auction or by purchasing offsets. Electric utilities are required to offset their emissions but will be given free allowances to cover most of their emissions. The full impacts of the CCA are not known at this time. The intent of this legislation allows for the Washington State program to join California and the Quebec markets to increase "allowance" liquidity possibly as early as 2025. California and Quebec still need to approve the addition of Washington to their program. The law also focuses on using proceeds from state allowance auctions to improve over-burdened communities and tribes, but also incent a clean energy transformation of Washington to electrify transportation and heating.

Colstrip

Colstrip was built as a four-unit coal plant in Eastern Montana. Avista is 15 percent owner in Units 3 and 4. Avista has no ownership interest in Units 1 and 2. A complete list of the ownership shares and sizes of the plant is in Table 3.12. Units 1 and 2 retired in early 2020. Washington's CETA requires utilities to eliminate coal-fired resources from their allocation of electricity by December 31, 2025.

Figure 3.5: Colstrip Plant

Table 3.12: Colstrip Ownership Shares

	Unit 3	Units 4
Operating Capacity (MW)	740	740
Year On-Line	1984	1986
Owners		
Avista	15%	15%
Northwestern Energy	0%	30%
PacifiCorp	10%	10%
Portland General Electric	20%	20%
Talen Energy, LLC	30%	0%
Puget Sound Energy	25%	25%

Coal Supply

Colstrip is supplied from an adjacent coal mine under coal supply and transportation agreements. Avista's coal supply agreement runs through 2025, with extension options. The specific terms of the agreement are confidential.

Water and Waste Management

Colstrip uses water from the Yellowstone River for steam production, air pollution scrubbers and cooling purposes. The water travels through a 29-mile pipeline to Castle Rock Lake, a surge pond and water supply source for the plant and the Town of Colstrip. From Castle Rock Lake, water moves to holding tanks as needed throughout the plant site. The water recycles until it is ultimately lost through evaporation, also known as zero-discharge. An example of this reuse is how the plant removes excess water from the scrubber system fly ash, creating a paste product similar to cement. The paste flows to a holding pond while clear water is reused. Similarly, the bottom ash flows to a holding pond, where it is dewatered and the water is reused.

The plant uses three major areas for water and waste management. The first are at-plant facilities, where all four units, including the now-retired Units 1 and 2, share use of the ponds. The second major area, supporting Units 3 and 4 operations, is the Effluent Holding Pond (EHP). This area is 2.5 miles to the southeast of the plant site. Avista is responsible for its proportional share of the EHP Area. The third storage area is the Stage One Effluent Pond (SOEP)/Stage Two Effluent Pond (STEP); these ponds dispose fly ash from the scrubber slurry/paste from Units 1 and 2. These ponds are nearly two miles to the northwest of the plant. Avista does not have ownership or responsibility in this area. Avista is therefore responsible for its share of the plant site area and EHP facilities. Figure 3.6 shows a map of the different storage areas at Colstrip.

Colstrip finished converting to dry ash storage in 2022. The master plan for site wide ash management is filed with the MDEQ-AOC[15] and additional information on CCRs is available at Talen's website[16]. This plan includes removing Boron, Chloride, and Sulfate from groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system along with a dry ash storage facility. Each of the new facilities are required, regardless of the length of the plant's continuing operations. Avista posted bonds for nearly $6 million in 2018 for cost assurance and an additional $7 million in 2019 related to Units 3 and 4 closure. These amounts are updated annually, increasing as clean-up plans are finalized and approved in the coming years and then eventually decreasing as final remediation activities are completed.

Post 2025 Colstrip Considerations

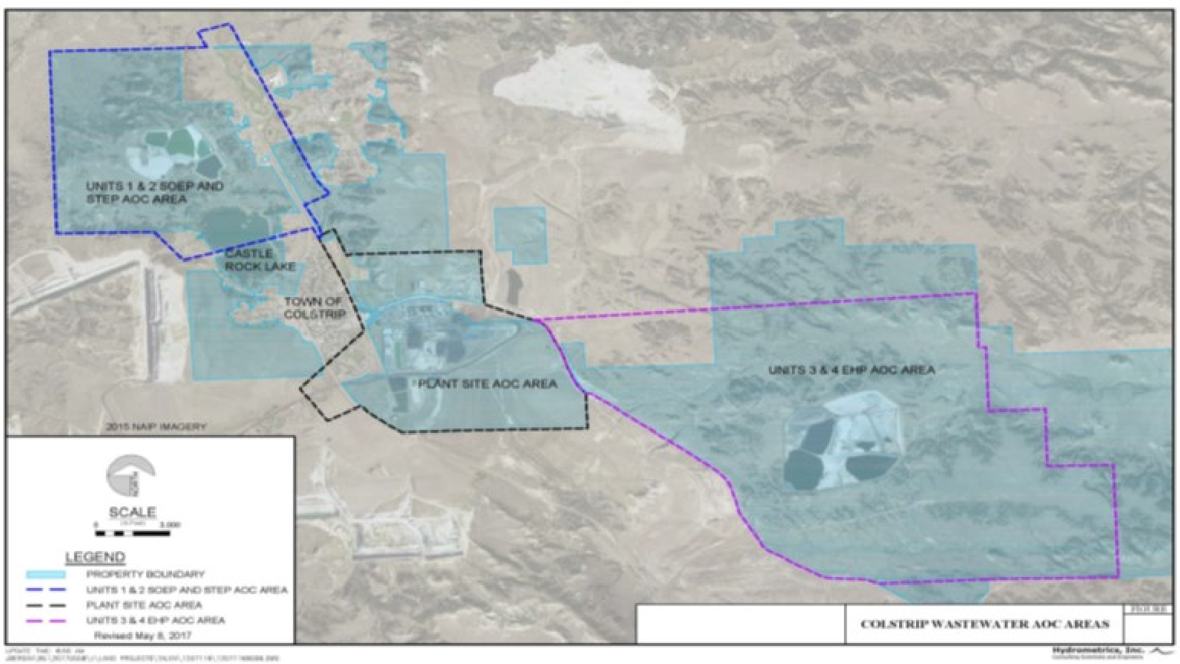
Three primary drivers affect operational and financial risks defining the future viability of the Company's share of Colstrip Units 3 and 4. These include the ownership and operating agreement, the coal contract, and Washington's CETA.

[15] http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation.
[16] https://www.talenenergy.com/ccr-colstrip/.

The ability to shut down Colstrip Units 3 and 4 is governed by the ownership and operation agreement. No decisions have been made by the ownership group regarding whether Colstrip Unit 3 and/or Unit 4 will continue to operate to the December 31, 2025 date imposed by CETA or if the units will continue to operate beyond 2025.

Avista obtains its share of the coal for Colstrip Units 3 and 4 pursuant to a coal supply agreement with Westmoreland Rosebud Mining, LLC. The coal supply agreement expires on December 31, 2025 but could be extended up to December 31, 2029. If the coal supply agreement is extended beyond December 31, 2025, the parties will need to negotiate a new price for coal for the extended term.

Figure 3.6: Map of Colstrip Water Storage



Section 3 of CETA states: "On or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity."[17] That is, after December 31, 2025, the costs and benefits associated with coal-fired resources (except for decommissioning and remediation costs), including costs and benefits associated with Avista's share of Colstrip Units 3 and 4, cannot be included in Avista's Washington retail electricity rates.[18] Coal-fired resources must be fully depreciated under the law by December 31, 2025.[19]

[17] "Allocation of electricity" means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity customers that are located in this state.

[18] *See* Clean Energy Transformation Act at Section 2 (defining "electric utility"); Clean Energy Transformation Act at Section 3.

[19] Clean Energy Transformation Act at Section 3.

It is difficult to speculate on all potential Colstrip scenarios; however, in general, there are three likely outcomes:

- one or both of the units will continue to operate with the same ownership;
- one or both of the units will continue to operate, but the ownership in the units will change; or
- both units will be shut down.

If units continue to operate beyond December 31, 2025, and Avista remains an owner, several items will need to be addressed. First, Avista will need to evaluate its contractual obligations under the ownership and operation agreement. Second, because Avista is contractually required to supply its share of coal to operate the unit(s), Avista will need to either extend its existing coal supply agreement or make other arrangements. Finally, Avista will need to determine how it is going to comply with the requirements of any applicable laws, including CETA.

4. Long-Term Position

Avista plans its resource portfolio to meet multiple long-term objectives including serving peak loads, providing operational and planning reserves, meeting monthly energy needs, and meeting clean energy goals established in Washington State law as well as other applicable policies. This chapter presents the long-term load and resource position at the end of 2022 and does not include resources being negotiated to be added to Avista's portfolio from the 2022 All-Source Request for Proposal (RFP). Notwithstanding future resource changes, there are several fundamental changes to Loads & Resources (L&R) planning included in this Progress Report since the 2021 IRP. The following developments have occurred since the last IRP:

- Additional long-term capacity and energy acquired from Chelan PUD, Columbia Basin Hydro, and plans to upgrade Kettle Falls Generating Station and Post Falls;
- The Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP) entered the first stage of non-binding program implementation and program metrics now guide some of Avista's resource adequacy planning;
- Future temperature changes are incorporated into Avista's base hydro and load forecasts;
- Risk planning including variability of hydro, wind, solar, and load for monthly energy planning; and
- Near term clean energy targets from Avista's Clean Energy Implementation plan are approved.

Section Highlights

- Avista's first capacity and energy resource deficit begins in November 2026 and may change once the 2022 All-Source RFP negotiations are completed.
- The WRAP's qualifying capacity credits (QCCs) are used for Avista's resource capacity position.
- Avista has sufficient clean energy resources to meet its projected Washington's CETA targets through 2033 under normal conditions.

Capacity Requirements

Avista must plan its resource portfolio to have the capacity to reliably meet system demand at any given time. Significant uncertainty is inherent in this exercise due to situations when load exceeds the forecast and/or resource output falls below expectations due to adverse weather, forced outages, poor water conditions, variability in wind and solar output or other unplanned events. Utilities plan to have more generating capacity, called a planning reserve margin, than is required to address this uncertainty and meet forecasted peak demand.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves because of the extra cost of carrying rarely used generating capacity. Traditionally, reserve resources have the physical capability to generate electricity, but most have high operating costs limiting normal dispatch and revenue.

Therefore, a balance must be achieved between having capacity to address any eventuality and the cost to carry the unused capacity.

Prior to the development of the WRAP, there was no Northwest energy industry standard reserve margin level, as it is difficult to enforce standardization across systems with varying resource mixes, system sizes and transmission interconnections. NERC defines reserve margins as 15 percent for predominately thermal systems and 10 percent for predominately hydro systems,[1] but does not provide an estimate for energy-limited hydro systems like Avista's.

The 2021 IRP used a planning reserve margin of 16 percent in the winter months and 7 percent in the summer months. Those margins were derived from a study of resources and loads using 1,000 simulations of varying weather for loads and thermal generation capability, forced outage rates on generation, water conditions for hydro plants and wind generation. The reserve margins ensure Avista's system could meet all expected load in 95 percent of the simulations, or a 5 percent loss of load probability (LOLP).

Beyond planning margins, a utility must maintain operating reserves to cover generator forced outages to maintain grid stability. Avista includes operating reserves in addition to the planning reserve margin. Per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 3 percent for balancing of area load and 3 percent for on-line balancing area generation. Within this quantity, 30 megawatts must also qualify as Frequency Response Reserve (FRR). Avista must also maintain reserves to meet load following and regulation requirements of within-hour load and generation variability equivalent to 16 MW at the peak hour. The combination of operating, load following, and planning reserves resulted in a total reserve margin of 24.6 percent in the winter months and 15.6 percent in the summer months.

Western Resource Adequacy Program

In response to the growing penetration of renewable variable energy resources and retirements of thermal generation in the West, the WPP initiated an effort in 2019 to understand capacity issues in the region and identify potential solutions. The product of these efforts is the WRAP. The purpose of the WRAP is to leverage diversity of loads and generation throughout the WECC so individual entities do not need to carry the full burden of supplying adequate capacity for their systems. The FERC filing to establish a tariff for the WRAP describes the program as follows:

> *The WRAP leverages the existing bilateral market structure in the West to develop a resource adequacy construct with two distinct aspects: (1) a Forward Showing Program through which WPP forecasts Participants' peak load and establishes a Planning Reserve Margin ("PRM") based on a probabilistic analysis to satisfy a loss of load expectation ("LOLE") of not more than one event-day in ten years, and Participants demonstrate in advance that they have sufficient qualified capacity resources (and supporting transmission) to serve their peak load and share of the PRM; and (2) a real-time Operations*

[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

Program through which Participants with excess capacity, based on near-term conditions, are requested to "holdback" capacity during critical periods for potential use by Participants who lack sufficient resources to serve their load in real-time.

The WRAP is a voluntary resource adequacy planning and compliance framework where program participants voluntarily join, but once committed are obligated to comply with requirements or be fined for non-compliance. The program is in the first phase of implementation with the initiation of a non-binding Forward Showing Program in Winter 2022/2023 and Summer 2023.[2]

To demonstrate compliance with the Forward Showing Program, participants must demonstrate their QCCs for resources and contracts are equal to or greater than peak demand less demand response programs plus the assigned monthly planning reserve margin. Load, hydro and renewable output, thermal resource capacity, forced outage data, and planned outage schedules are provided to the program operator who then provides QCC values for specific resources and an assigned peak load.

Metrics for the winter and summer Forward Showing Program for 2022 and 2023 have been established and are shown in Table 4.1. Avista has sufficient capacity to meet the requirements of the WRAP Forward Showing Program in the first non-binding period.

Table 4.1: Avista 2022-2023 Winter & Summer Forward Showing Metrics (MW)

Month	Planning Reserve Margin	Total Obligation	Total Portfolio QCC	Surplus/Deficient Capacity
Nov-22	21.6%	1,770	2,081	311
Dec-22	17.7%	1,882	2,184	302
Jan-23	19.0%	1,944	2,287	343
Feb-23	19.9%	1,911	2,347	436
Mar-23	26.9%	1,844	2,346	502
Jun-23	16.5%	1,696	2,165	469
Jul-23	10.4%	1,801	2,140	339
Aug-23	10.3%	1,836	2,098	262
Sep-23	17.9%	1,590	2,111	521

Interim Capacity Planning Methodology

As described above, the WRAP is currently in a non-binding phase. The binding phase is scheduled to begin Summer 2025. During the non-binding phase, Avista is using a hybrid approach to capacity planning. Capacity obligations include the same methodology for PRM as the 2021 IRP, where the forecasted peak load (1-in-2 event), a summer PRM of 13 percent, a winter PRM of 22 percent, operating reserves equal to 3 percent of the balancing area load and 3 percent of the balancing area generation, and 16 MW to meet load following and regulation requirements. The main difference from prior plans is resources utilize the QCC values assigned by the WRAP's Forward Showing Program.

[2] Winter forward showing period starts in November 2022.

Figure 4.1 presents the winter one-hour peak capacity load and resources balance, and Figure 4.2 presents the summer one-hour peak capacity load and resources balance. Starting in 2027 there is a winter capacity need and starting in 2028 there is a summer capacity need. The deficiencies increase over the planning horizon due to load growth, resource retirements and contract expirations. Winter 2026/27 requires 119 MW and summer of 2028 requires 6 MW, growing to 170 MW and 60 MW respectively by 2030.

Figure 4.1: Winter One-Hour Peak Capacity Load and Resources Balance

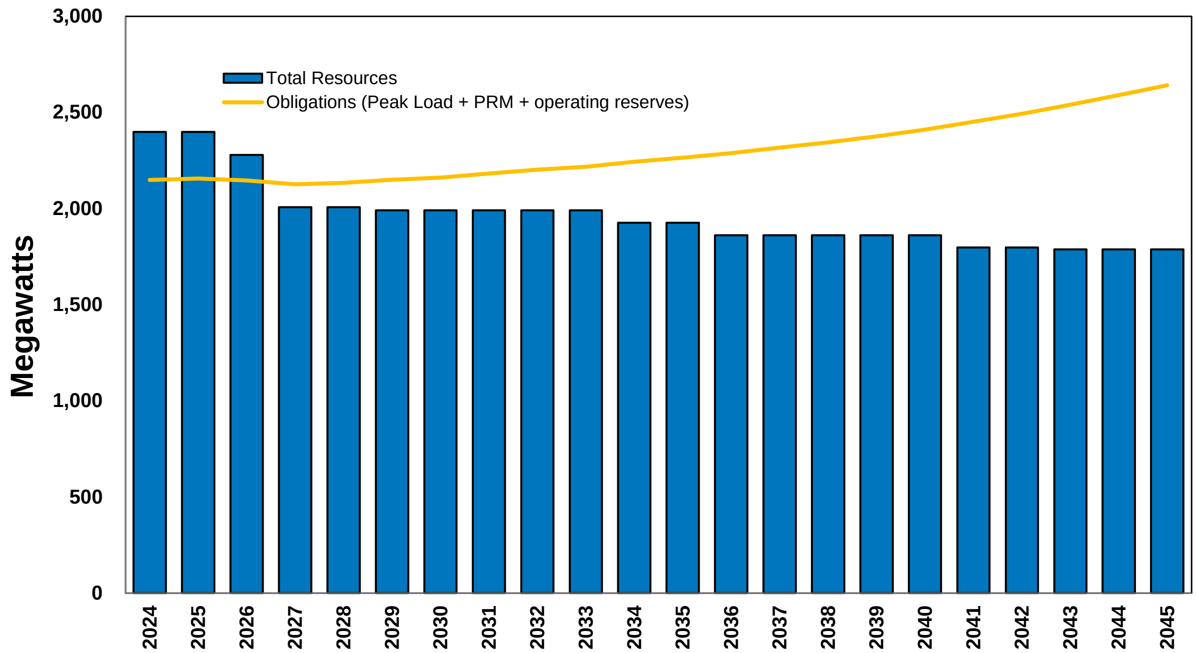
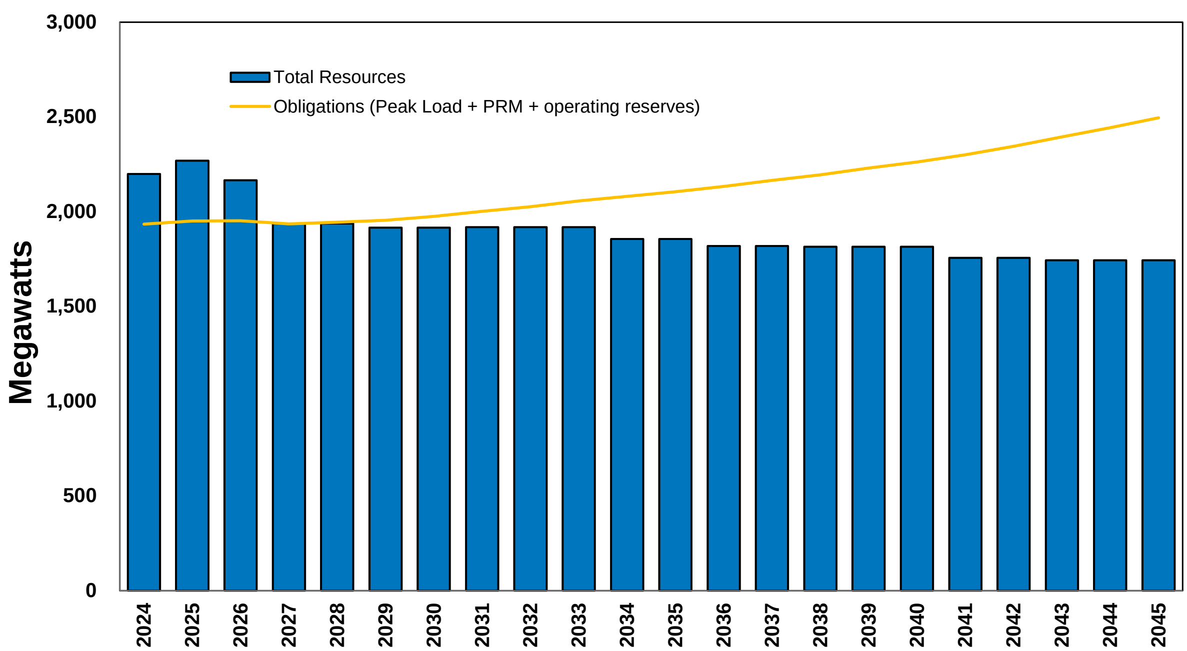


Figure 4.2: Summer One-Hour Peak Capacity Load and Resources Balance



Capacity Risk Planning

Future resource adequacy requires consideration of many risks. The 2021 IRP addressed seven risk factors:

1. Peak demand forecast
2. Demand-side resource contribution
3. Power plant retirements
4. Renewable contribution
5. Storage efficiency
6. Market availability
7. Resource acquisitions

Since Avista is joining the WRAP to address capacity risk at a regional level rather than at a utility scale and provide a framework for each utility to contribute a proportionate share to address regional capacity needs. Planning required to be a WRAP participant addresses risks such as variability in peak load resulting from differing weather conditions and variation in demand-side resources penetration. Renewable contributions are addressed by determining the QCC values over the geographic footprint of WRAP participants, and market availability is addressed by the real-time operations program and minimum PRM requirements. While the WRAP is in the non-binding phase, Avista will keep higher planning reserve margins than those required by the WRAP since the WRAP planning reserve margin is based on all utilities participating in the sharing program meeting the forward showing program requirements.

The Northwest Planning and Conservation Council is also evaluating the creation of a new resource adequacy metric based on outage probability of a 1 in 40-year outage. This metric covers frequency, duration, and magnitude of outages. Avista will follow this process to see if it should develop a metric beyond the metric required in the WRAP.

Energy Requirements

In contrast to peak planning, energy planning is an evaluation of the adequacy of resources used to meet monthly demand. This includes meeting monthly demand, renewable targets, and an evaluation of generation risk. Evaluation of monthly generation is specific to the resource in question, e.g., the factors impacting hydro generation are different than the factors impacting thermal generation. This section compares monthly generation and monthly demand to determine deficit and surplus conditions for the 2024-2045 period. A discussion of monthly demand is provided in Chapter 2. Table 4.2 details how monthly generation for each resource type is evaluated.

Table 4.2: Monthly Energy Evaluation Methodologies

Resource Type	Evaluation Methodology
Coal	Unit capacity reduced by a percentage according to planned and forced outage rates.
Biomass	Unit capacity reduced by a percentage according to planned and forced outage rates
Natural Gas Combined Cycle	Unit capacity adjusted for monthly ambient average temperature and reduced by a percentage according to planned and forced outage rates and any runtime limitations imposed by operating permits.
Natural Gas Peaker	Unit capacity reduced by a percentage according to planned and forced outage rates and any runtime limitations imposed by operating permits.
Wind	Five year monthly average output if available, or average output estimates provided by facility operator.
Solar	Five year monthly average output if available, or average output estimates provided by facility operator.
Hydro	Monthly median generation of the previous 30 years. Future years include both historical and forecasted monthly generation.

There are two important changes in this Progress Report from previous IRPs:

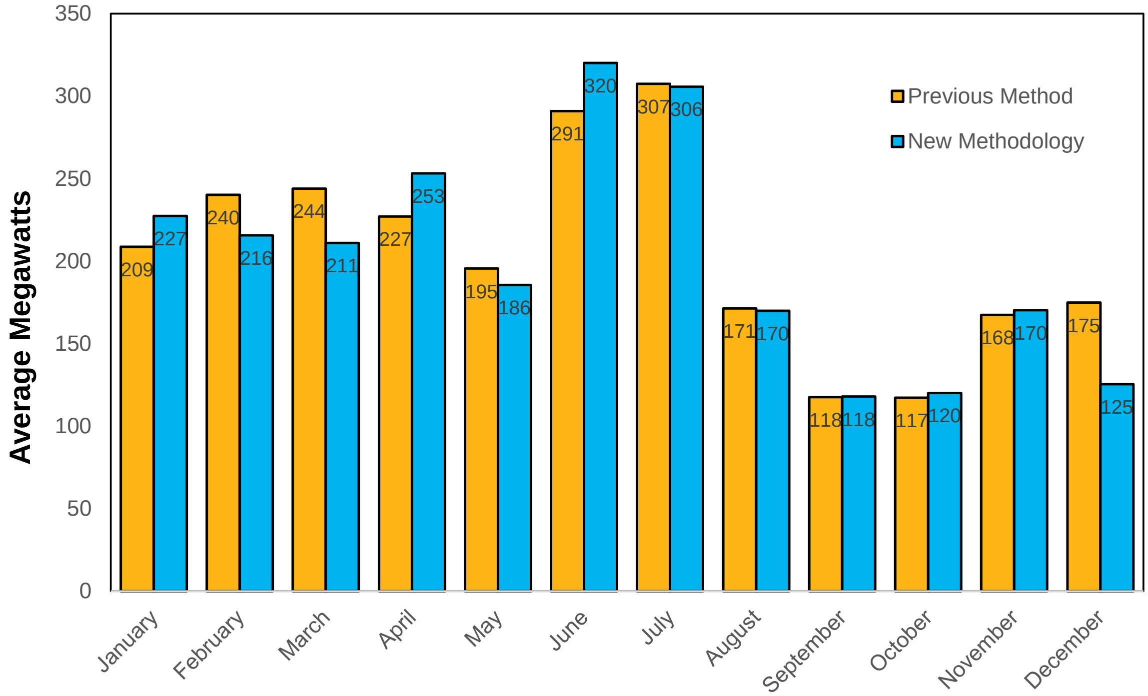
1. Hydro generation and load both include the predicted impacts of forecasted temperature changes; and
2. The risk evaluation includes variability in all renewables rather than just variation in hydro.

Energy Risk Evaluation

Energy planning is based on average conditions. The load forecast utilizes 20-year average weather while the hydrogeneration estimates are based on the median over a 30-year period. There is a risk the load can be larger and/or hydrogeneration can be lower than forecasted. Additionally, in the last decade, Avista has added wind and solar generation to its portfolio, both having variable output period to period. To address this risk Avista adds an energy planning margin to the load and resource balance evaluation.

As with capacity planning, there are no defined methods for establishing an energy planning margin or contingency adjustment. In prior plans, the energy contingency adjustment was based on the difference between average load and load at the 90 percent confidence interval added to the difference between monthly median hydrogeneration and the 10^{th} percentile hydrogeneration. A new methodology was used for this analysis. Monthly estimates of load and generation for each hydro, wind, and solar facility for weather conditions for the period 1948 to 2019 were developed using regression models of the relationship between weather variables, generation, and load. Total generation was subtracted from load. Large values occur when load is larger than average and/or generation is below average. The 95^{th} percentile of the monthly values was subtracted from the average value. This represents the energy necessary to meet above average loads during periods of low hydro, wind, and solar production.

Figure 4.3: Comparison of Energy Contingency Methodology



Net Energy Position

Avista's net energy position is determined by summing all generation rights from Avista facilities and power purchase agreements and subtracting obligations including forecasted monthly load, contracted sales, and accounting for the energy contingency shown in Figure 4.3. Figure 4.4 presents the net monthly energy position for 2024 through 2045 and Table 4.2 presents net monthly energy positions for 2025, 2030, 2035, 2040 and 2045. There is a positive net energy position until November 2026.

Figure 4.4: Net Monthly Energy Position

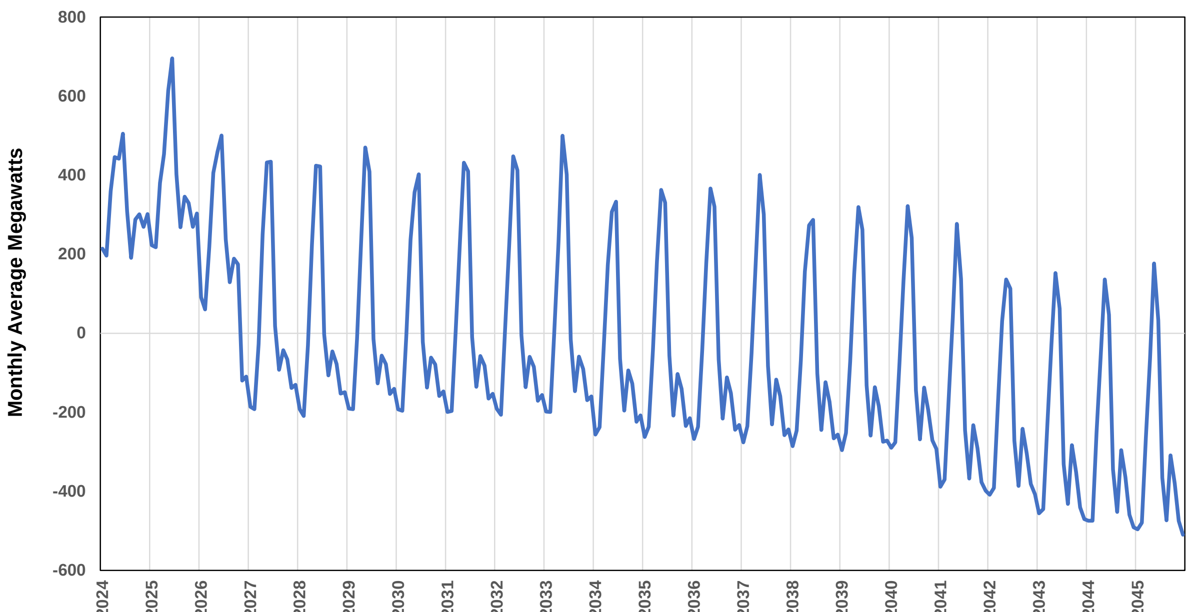


Table 4.3: Net Energy Position

	2025	2030	2035	2040	2045
January	223	-193	-263	-290	-496
February	218	-196	-236	-276	-480
March	380	-4	-44	-75	-264
April	454	237	181	133	-63
May	614	356	363	322	177
June	696	402	330	242	32
July	402	-22	-56	-145	-366
August	268	-137	-208	-269	-474
September	345	-62	-103	-137	-309
October	329	-79	-140	-194	-380
November	269	-159	-234	-271	-475
December	303	-147	-215	-293	-510

Forecasted Temperature & Precipitation Analysis

Projected temperature increases will impact hydrogeneration, natural gas turbine capacity and load. The following provides a summary of the analysis completed, results of the analysis, and a comparison to values used in the 2021 IRP.

The climate analysis is based on data developed for the Columbia River Basin by the River Management Joint Operating Committee (RMJOC) comprised of the Bonneville Power Administration (BPA), United States Army Corps of Engineers and United States Bureau of Reclamation. The RMJOC, in conjunction with the University of Washington and Oregon State University, completed two studies, one in 2018 and another in 2020, utilizing downscaled global climate models (GCMs), hydrology models and reservoir operation models to predict monthly river flows for the period 2020-2100 for locations throughout the Columbia River Basin, including all Avista's hydroelectric facility locations.

There is significant uncertainty in projecting future temperature and precipitation and the impact on streamflow and reservoir operations. The RMJOC used an ensemble approach to capture a range of potential outcomes. The approach used unique combinations of two representative concentration pathways (RCPs), ten GCMs, three downscaling techniques and four hydrology models. In total there were 172 unique modeling train combinations resulting in 172 streamflow datasets for each location. The streamflow data was then used in reservoir operation models generating monthly flows under current operating parameters for each of the Columbia Basin hydroelectric facilities. Flow data allows for an estimate of generation at each of the facilities.

Given the sheer volume of data, a method to select a representative set from the 172 modeling combinations was needed. Fortunately, BPA conducted this exercise and selected a subset of modeling combinations representing a sufficient cross section of outcomes to calculate generation. The subset represents 19 modeling combinations for both RCP 4.5 and RCP 8.5.

RCPs represent different greenhouse gas (GHG) emission scenarios varying from no future GHG reductions to significant GHG reductions. The Intergovernmental Panel on Climate Change (IPCC) describes the scenarios as follows:

- RCP 2.6 – stringent mitigation scenario
- RCP 4.5 & RCP 6.0 – intermediate scenarios
- RCP 8.5 – very high GHG scenarios.

Table 4.3 provides a comparison of the temperature increases projected under the various scenarios.

Table 4.4: Comparison of Temperature Increases by Representative Concentration Pathway

	Scenario	2046-2065		2081-2100	
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (°C)	RCP 2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP 4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP 6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP 8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

The RCP 4.5 and RCP 6.0 scenarios are similar during the current IRP planning horizon. Given 1) RCP 8.5 is at the high end of potential future GHG emissions, 2) there are significant worldwide efforts to mitigate GHG emissions, and 3) the intermediate scenarios are similar during the IRP planning horizon. Avista selected modeling results based on RCP 4.5.

For each of the 19 BPA selected modeling combinations monthly river flows at each Avista facility were converted to generation based utilizing a regression model relating flow to generation for each facility. The median of the 19 modeling combinations was selected to represent generation at each facility for each specific month and year.

Avista also has contracts to receive a specified portion of generation from five facilities on the Columbia River – Wells, Rock Island, Rocky Reach, Wanapum, and Priest Rapids – these are owned and operated by Douglas PUD, Chelan PUD, and Grant PUD. BPA analyzed generation at each of those facilities for each of the RCP 4.5 scenarios. As with the Avista facilities, the median of the 19 modeling combinations was selected to represent generation at each facility for each specific month and year over the planning horizon.

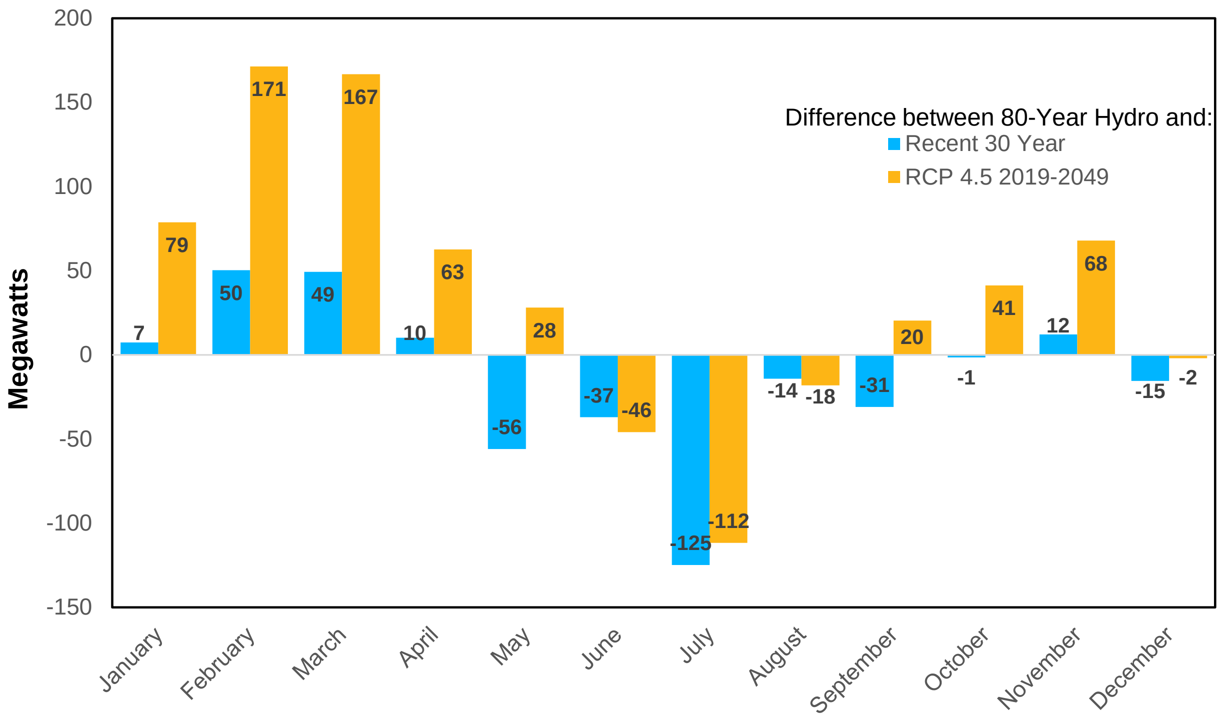
Prior IRPs used monthly hydrogeneration by estimating hydrogeneration occurring under current operating parameters for each water year from 1929 to 2008 (80-year hydro record) and taking the median value for each month for each facility. In this analysis, Avista changed the methodology to use the median monthly value of the previous 30 years, e.g. 2022 estimated generation is the median of generation values from 1992-2021. Future years incorporate a mix of historical generation data and forecasted generation data.

Table 4.5 and Figure 4.5 present the differences between the 80-year hydro record, the recent 30-year record, and the RCP 4.5 analysis. Annual hydrogeneration is similar between the 80-year hydro record and recent 30-year record, while it is projected warming temperatures will increase annual hydrogeneration. On a monthly basis there is an increase in hydrogeneration during the winter and early spring months and a decrease in the summer months. This is consistent with regional forecasts predicting an overall increase in annual precipitation with less falling as snow and an earlier snow pact melt.

Table 4.5: Comparison of Annual Generation (aMW): 80-Year, Recent 30-Year, and RCP 4.5 Hydrogeneration Forecast

	80-Year Hydro (1929-2008)	Recent 30-Year (1992-2021)	RCP 4.5 (2019-2049)
Mean	598	595	645
Median	597	585	636
10th Percentile	424	437	447
90th Percentile	776	756	858
Standard Deviation	142	137	169

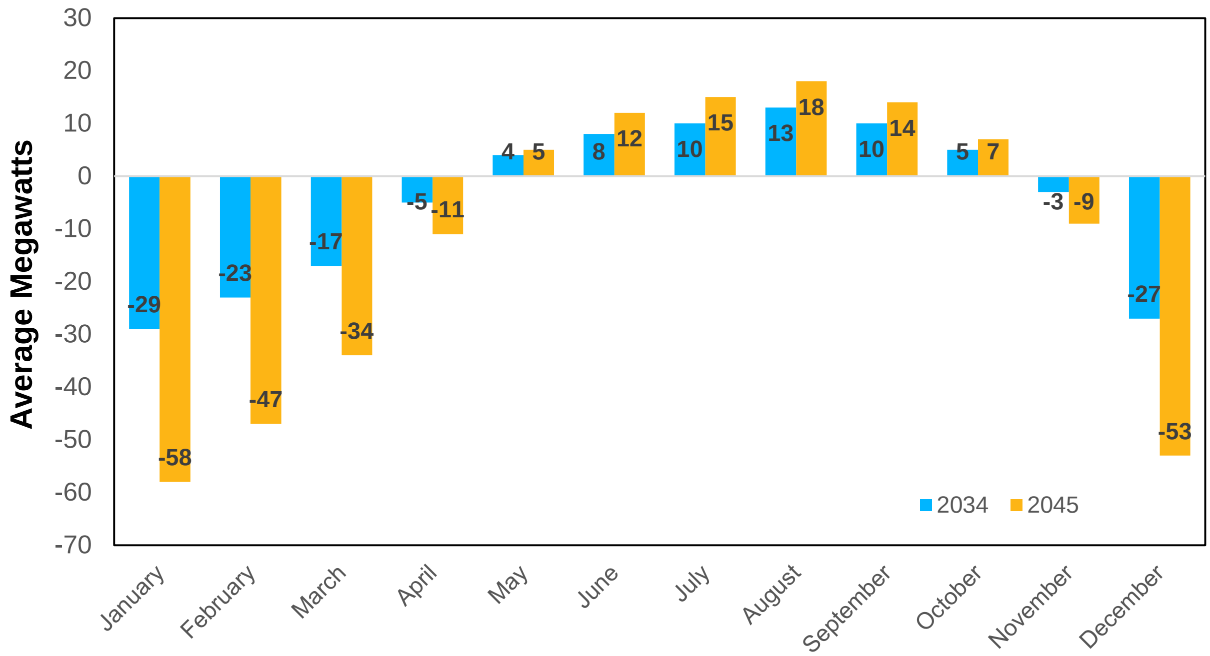
Figure 4.5: Comparison of Recent 80-Year, Recent 30-Year, and RCP 4.5 Generation



In addition to impacting hydrogeneration, warming temperatures will also impact demand. Specifically, there will be less heating required in the winter and more cooling required during the summer. To assess the load impacts, the temperature data sets used as the basis of the streamflow data sets were used in the load forecast described in Chapter 2.

Heating degree days (HDDs) and cooling degree days (CDDs) are inputs to the load forecast model. A 20-year moving average of the HDDs and CDDs is used. In the 2021 IRP the baseline forecast used the average of the most recent 20 years as a static input for all forward forecast years. In this analysis, the median daily average temperature of the RCP 4.5 model is used as the temperature data set compared to the 20-year moving average for each forecast year. Figure 4.6 presents the net change in load resulting from using the RCP 4.5 data in the forecast model compared to using the most recent 20-year average held constant over all future years. The net change is presented for 2034 and 2045. The impact increases as warming temperatures are incorporated into the 20-year moving average.

Figure 4.6: Impact of RCP 4.5 Temperature Data on Load Forecast



Washington State Renewable Portfolio Standard

Washington's Energy Independence Act (EIA) promotes the development of regional renewable energy by requiring utilities with more than 25,000 customers to source 15 percent of their energy from qualified renewables by 2020. Utilities must also acquire all cost-effective Energy Efficiency. In 2011, Avista signed a 30-year PPA with Palouse Wind to meet the EIA goal. In 2012, an amendment to the EIA allowed Avista's Kettle Falls biomass project to qualify toward the EIA goals beginning in 2016. More recently, Avista acquired the Rattlesnake Flat wind project and Adams Nielson Solar[3] projects and both qualify for EIA and CETA compliance. A planned upgrade to the Kettle Falls Generating Station project in 2026 and Post Falls in 2029 will add additional qualified generation.

[3] Adams Nielson can be used for the EIA after the voluntary Solar Select program ends in 2028.

Table 4.6 shows the forecasted renewable energy credits (RECs)[4] Avista needs to meet the EIA's renewable requirement and the amount of qualifying resources within Avista's current generation portfolio. This table does not reflect the additional flexibility available for the REC banking provision in the EIA. Avista uses this banking flexibility as needed to manage variation in renewable generation. After 2030, the renewable energy obligation to meet the EIA is met, if Avista is compliant with the requirements of Washington State Clean Energy Transformation Act (CETA).

Table 4.6: Washington State EIA Compliance Position Prior to REC Banking (aMW)

	2023	2025	2030
Two-Year Rolling Average WA Retail Sales Estimate	652.5	654.7	669.5
Renewable Goal	97.9	98.2	100.4
Incremental Hydro	17.4	17.4	17.4
Net Renewable Goal	**80.5**	**83.5**	**83.0**
Other Available RECs			
Palouse Wind with Apprentice Credits	46.0	46.0	46.0
Kettle Falls	36.1	36.1	46.8
Rattlesnake Flat with Apprentice Credits	60.6	60.6	60.6
Adams Neilson Solar	-	-	5.5
Boulder Community Solar	0.1	0.1	0.1
Rathdrum Solar	0.0002	0.0002	0.0002
Net Renewable Position (before rollover RECs)	**62.3**	**59.3**	**75.5**

Washington State Clean Energy Transformation Act

CETA requires Washington State electric utilities to serve 100 percent of Washington retail load with renewable and non-emitting electric generation by 2045. Beginning in 2030, 80 percent of generation must be from renewable and non-emitting electric generation and 20 percent can be met with alternative compliance options including making alternative compliance payments, using unbundled RECs, or investing in energy transformation projects. CETA requires the Washington Utilities & Transportation Commission (WUTC) to adopt rules for implementation. The 20 percent alternative compliance component decreases in five percent steps to zero in 2045.

On June 29, 2022, the WUTC amended rules in Chapter 480-100 WAC to address some, but not all, CETA requirements. The amended rules address CETA's prohibition of double counting of nonpower attributes, electric purchases from centralized markets, and treatment of energy storage, but do not address the interpretation of compliance with RCW 19.405.030(1)(a) defining "use".

While CETA rulemaking is not complete, Avista through its Clean Energy Implementation Plan (CEIP), has compliance targets approved by the WUTC for the period 2023-2025.

[4] These RECs are qualifying RECs within Avista's system. For state compliance purposes the Company may transfer RECs between a state's allocation shares at market prices. Avista may also sell excess RECs to reduce customer rates.

Avista's CEIP was approved with conditions in Docket UE-210628 by way of Order 01. The CEIP does not include a commitment for the remaining interim periods 2026-2029 or 2030-2044 period. Between 2030 and 2044, all generation used to serve Washington electric retail load must be greenhouse gas neutral. Twenty percent can be met through alternative compliance options. Interim targets to meet the 2045 standard will be determined in a future CEIP after final "use" rules have been adopted. Table 4.7 presents the approved interim targets for 2022-2025 and preliminary targets through 2045.

Table 4.7: CETA Compliance Targets

Period	Compliance Target	Alternative Compliance
2022	**40.0%**	0%
2023	**47.5%**	0%
2024	**55.0%**	0%
2025	**62.5%**	0%
2026	66.0%	0%
2027	69.5%	0%
2028	73.0%	0%
2029	76.5%	0%
2030 – 2033	80.0%	20%
2034 – 2037	85.0%	15%
2038 – 2041	90.0%	10%
2041 – 2044	95.0%	5%
2045	100.0%	0%
Note: A commitment has been made in the CEIP for values in bold.		

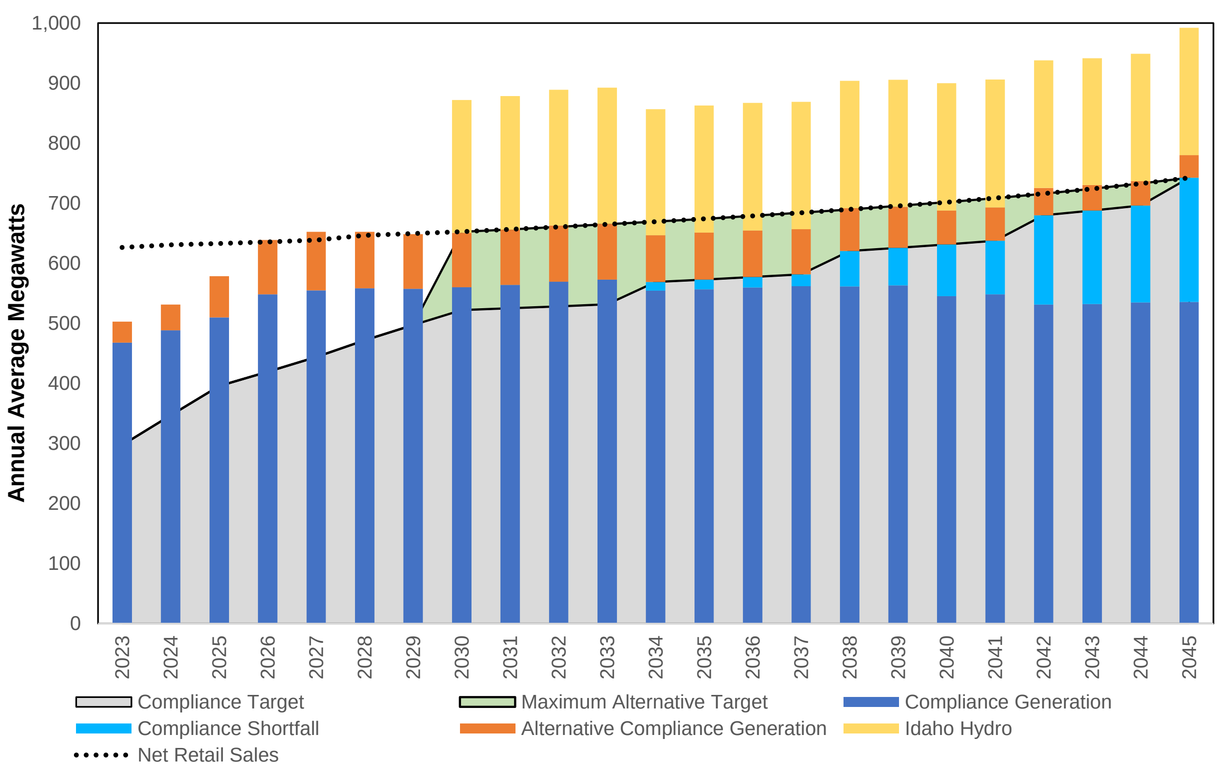
The following is a list of the assumptions included to develop the clean energy need assessment in Figure 4.7.

- Qualifying clean is determined by procurement and delivery of clean energy to Avista's system for all years.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary customer programs such as Solar Select.
- Customer voluntary REC programs, such as Avista's My Clean Energy™ program, do not qualify toward the CETA standard.
- Compliant and alternative compliance generation includes:
    - Washington's share of hydro generation operating or contracted before 2022 (legacy hydro),
    - All wind, solar, and biomass generation. Nonpower attributes associated with Idaho's portion of generation according to the established PT ratio will be purchased by Washington if used for compliance,
    - New acquired or contracted non-emitting generation including hydro, wind, solar, or biomass can be used for compliance using the same methodology as existing Avista-owned non-hydroelectric generation.

- Avista may transfer qualifying non-hydro clean energy generated for Idaho loads to Washington if needed for compliance by compensating Idaho at market-based REC prices.
- Avista is not planning to use Idaho's share of hydroelectric prior to 2030, however actual compliance may include them due to variability in clean resource availability.
- Avista uses total monthly generation to estimate whether clean energy counts toward the compliance target or alternative compliance. If Washington's clean energy total generation is greater than its "net retail load" excess generation counts toward alternative compliance, but all generation totaling below "net retail load" counts as compliant energy to meet the 4- year targets such as 80 percent by 2030.

A forecast based on a 30-year moving median of hydro conditions, average solar and wind generation and the current load forecast is presented in Figure 4.7. The analysis demonstrates Avista has enough qualifying resources to meet compliance targets through 2033.

Figure 4.7: Washington State CETA Compliance Position



5. Distributed Energy Resources

Avista has always included Distributed Energy Resources (DERs) in past IRPs, however the documentation has been across the energy efficiency, demand response, existing resources, and new resource options chapters. With the heightened focus on DERs, these resources are now presented in one chapter.

DER is defined in WAC 480-100-605 as:

> *Distributed energy resource means a non-emitting electric generation or renewable resource or program that reduces electric demand, manages the level or timing of electricity consumption, or provides storage, electric energy, capacity, or ancillary services to an electric utility and that is located on the distribution system, any subsystem of the distribution system, or behind the customer meter, including conservation and energy efficiency.*

Section Highlights

- Energy efficiency currently serves 155 aMW of load, representing nearly 11.4 percent of customer demand.
- Over 2,600 energy efficiency measures and 16 demand response options are considered for resource selection.
- Avista's net metering program includes 2,602 customers generating 18.8 megawatts.
- Community solar, roof-top solar, energy efficiency, demand response and distributed energy storage are options for utility resource selection.

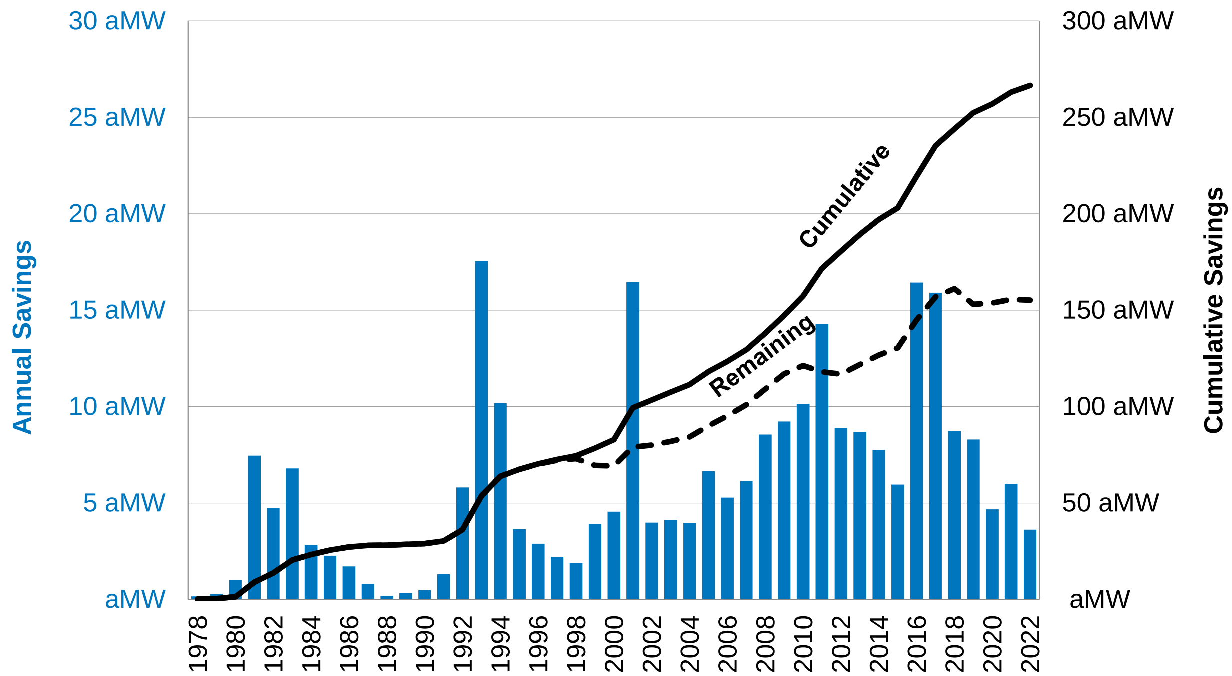
Energy Efficiency

Figure 5.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 266 aMW of energy efficiency since 1978; however, the 18-year average measure life means some measures are no longer reducing load as the measures have either became code or standard practice. The 18-year measure life accounts for the difference between the cumulative and online trajectories in Figure 5.1. Currently 155 aMW of energy efficiency serves customers, representing nearly 11.4 percent of 2021 load.

Avista's energy efficiency programs provide energy efficiency and education offerings to the residential (inclusive of low-income and named communities), commercial, and industrial customer segments. Program delivery mechanisms include prescriptive, site-specific, regional, upstream, behavioral, home energy audit, market transformation and third-party direct install options. Prescriptive programs provide fixed cash incentives based on an average savings assumption for the measure across the region. Prescriptive programs work best where uniform measures or offerings apply to large groups of similar customers. Examples of prescriptive programs include the installation of qualifying high-efficiency heating equipment or replacement of T8 florescent strip lighting with a high-efficiency LED lamp.

Site-specific programs, or customized offerings, provide cash incentives for cost-effective energy saving measures or equipment that are analyzed and contracted but do not meet prescriptive rebate requirements. Site-specific programs require customized approaches for commercial and industrial customers because of the unique characteristics of each premise and/or process. Other delivery methods build off these offerings with up- and mid-stream retail buy-downs of low-cost measures, free-to-customer direct install programs or coordination with regional market transformation efforts. In addition to developing and delivering incentive offerings, Avista also provides technical assistance in the forms of education, outreach, and other resources to customers to encourage participation in efficiency programs and measures.

Figure 5.1: Historical Conservation Acquisition (system)

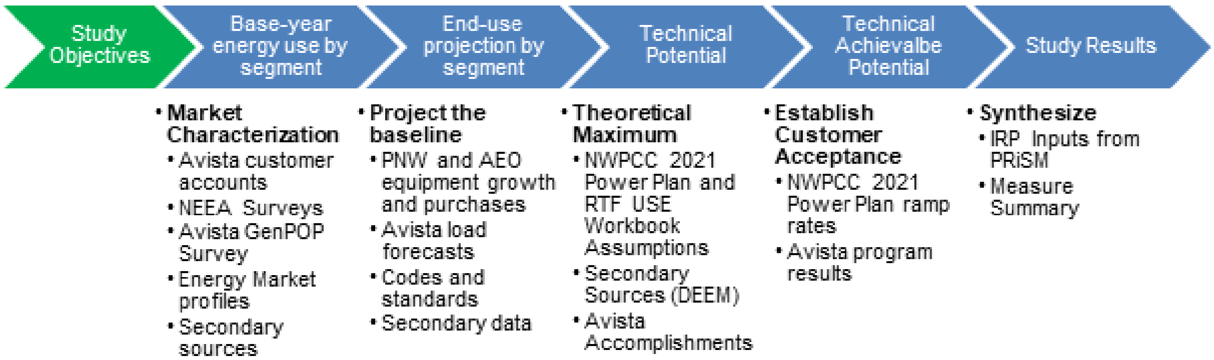


The Conservation Potential Assessment

Avista retained Applied Energy Group (AEG) as an independent consultant to assist in developing a Conservation Potential Assessment (CPA). The CPA is the basis for the energy efficiency portion of this plan. The CPA identifies the 22-year potential for energy efficiency and provides data on resources specific to Avista's service territory for use in the resource selection process and in accordance with the Energy Independence Act's (EIA) energy efficiency goals. The potential assessment considers the impacts of existing programs, the influence of known building codes and standards, technology developments and innovations, legislative policy changes to the long-term economic influences and energy prices. The CPA report is included in Appendix C along with a list of energy efficiency measures is in Appendix F.

AEG first developed estimates of *technical potential*, reflecting the adoption of all conservation measures, regardless of cost-effectiveness or customers' likeliness to participate. The next step identified the *achievable technical potential*; this measure modifies the technical potential by accounting for customer adoption constraints by using the Power Council's 2021 Plan ramp rates. The estimated achievable technical potential, along with associated costs, feed into the PRiSM model to select cost-effective measures. AEG took the following steps shown in Figure 5.2 to assess and analyze energy efficiency and potential within Avista's service territory.

Figure 5.2: Analysis Approach Overview



AEG's conservation potential assessment included the following steps:

1. Perform a market characterization to describe sector-level electricity use for the residential (inclusive of low income), commercial and industrial sectors for the 2022 base year.
2. Develop a baseline projection of energy consumption and peak demand by sector, by segment and by end use for 2023 through 2045.
3. Define and characterize several hundred conservation measures to be applied to all sectors, segments and end uses.
4. Estimate Technical Potential and Achievable Technical Potential at the measure level in terms of energy and peak demand impacts from conservation measures for 2023-2045.

Market Segmentation

The CPA considers Avista customers by state and by sector. The residential sector includes single-family, multi-family, manufactured homes, and low-income customers[1] using Avista's customer data and U.S. Census data from the American Community Survey (ACS). For the residential sector, AEG utilized Avista's customer data and prior CPA ratios developed from census information. AEG incorporated information from the Northwest Energy Efficiency Alliance's (NEEA) Commercial Building Stock Assessment to assess the commercial sector by building type, installed equipment and energy consumption. Avista analyzed the industrial sector for each state because of their unique energy needs. AEG characterized energy use by end use within each segment in each sector, including space heating, cooling, lighting, water heating, or motors; and by technology, including heat pumps and resistance-electric space heating.

[1] The low-income threshold for this study is 200 percent of the federal poverty level. Low-income information is available from U.S. census data and the American Community Survey data.

The baseline projection is a "business as usual" metric without future utility conservation or energy efficiency programs. It estimates annual electricity consumption and peak demand by customer segment and end use absent future efficiency programs. The baseline projection includes the impacts of known building codes and energy efficiency standards as of 2021 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential due to the reduction in remaining end uses with potential for efficiency savings. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;
- trends in end use and technology saturation levels;
- equipment purchase decisions;
- consumer price elasticity;
- income; and
- persons per household.

For each customer class, AEG compiled a list of electrical energy efficiency measures and equipment, drawing from the NPCC's (Council) 2021 Power Plan, the Regional Technical Forum, and other measures applicable to Avista. The individual measures included in the CPA represent a wide variety of end use applications, as well as devices and actions able to reduce customer energy consumption. The AEG study includes measure costs, energy and capacity savings and estimated useful life.

Avista, through its PRiSM model, considers other performance factors for the list of over 2,600 measures and performs an economic screening on each measure for every year of the study to develop the economic potential for Avista's service territory and individually by state.

Avista supplements energy efficiency activities by including potentials for distribution efficiency measures consistent with EIA's conservation targets and the NPCC 2021 Power Plan.

Overview of Energy Efficiency Potential

AEG's approach adhered to the conventions outlined in the National Action Plan for Energy Efficiency Guide for Conducting Potential Studies.[2] The guide represents comprehensive national industry standard practice for specifying energy efficiency potential. Specifically, two types of potential were included in this study, as discussed below. Table 5.1 shows the CPA results for Technical and Achievable Technical Potential by state.

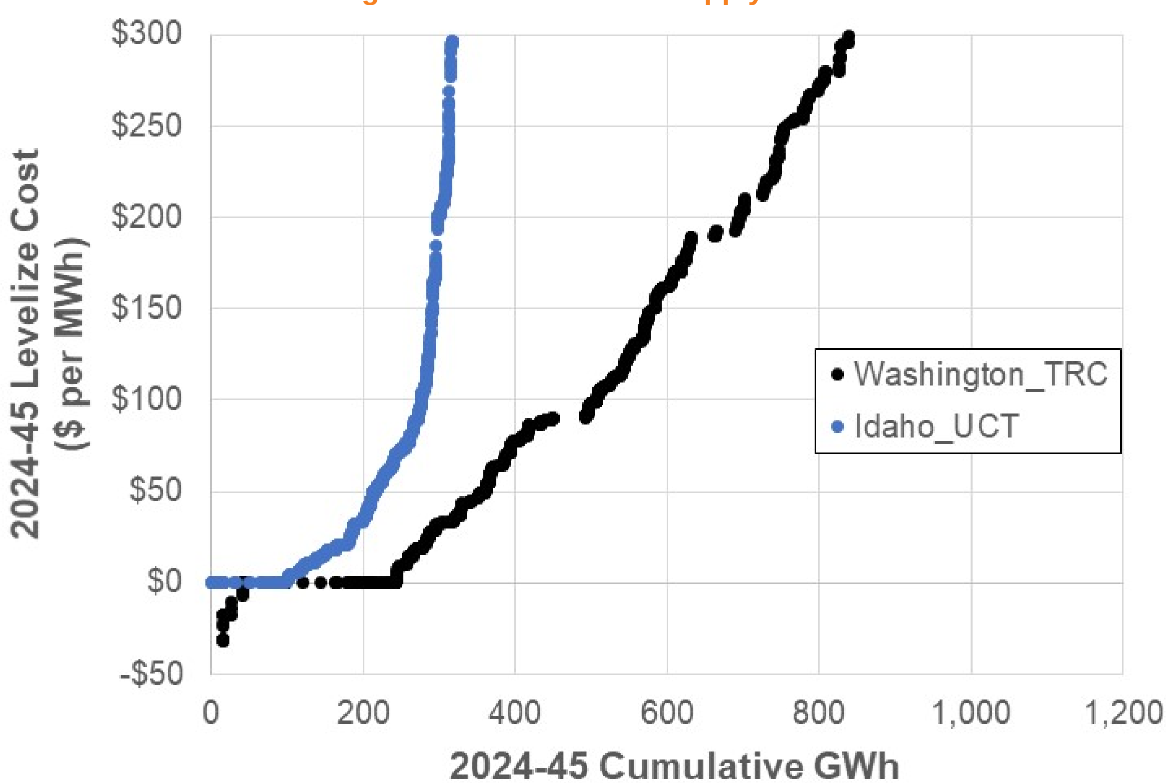
[2] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan.

Table 5.1: Cumulative Potential Savings (Across All Sectors for Selected Years)

	2024	2025	2030	2040	2042
Technical Potential (GWh)	308.7	480.8	1,365.6	2,439.6	2,536.9
Washington (GWh)	209.3	325.4	923.3	1,645.7	1,707.1
Idaho (GWh)	99.4	155.4	442.2	793.9	829.8
Total Technical Potential (aMW)	35.2	54.9	155.9	278.5	289.6
Technical Achievable Potential (GWh)	176.0	281.5	910.8	1,828.4	1,919.2
Washington (GWh)	117.9	188.8	613.3	1,234.0	1,292.6
Idaho (GWh)	58.1	92.7	297.6	594.4	626.6
Total Technical Achievable Savings (aMW)	20.1	32.1	104.0	208.7	219.1

Future programs must be cost effective to be selected for future implementation. Figure 5.3 illustrates the supply curve of this potential using their associated price per MWh. For Idaho savings, the potential has a near zero Utility Cost Test (UCT) until approximately 100 GWh, then quickly rises. As for Washington, using the Total Resource Cost (TRC) method, there is “no cost” energy efficiency until reaching approximately 250 GWh, then linearly increases until around 900 GWh, then goes up exponentially. The amount of energy efficiency selected will be where the supply curve meets the avoided cost. For example, if Washington’s avoided cost were $100 per MWh, then 500 GWh of energy efficiency would be selected. Avista uses a more sophisticated approach than this for resource selection where it looks at each program’s individual cost and benefits compared to alternatives, but the supply curve demonstration is a simplified cost and benefit illustration of the available energy efficiency.

Figure 5.3: Jurisdiction Supply Curve



Technical Potential

Technical Potential is the theoretical upper limit of energy efficiency potential. It assumes customers adopt all feasible measures regardless of cost. At the time of existing equipment failure, it assumes customers replace failed equipment with the most efficient option available.

In new construction, customers and developers also choose the most efficient equipment option relative to applicable codes and standards. Non-equipment measures could be installed apart from equipment replacements. They are implemented according to ramp rates developed by the Council for its 2021 Power Plan and apply to 100 percent of the applicable market. The Technical Potential case is a theoretical construct and is provided for planning and informational purposes.

Technical Achievable Potential

Technical Achievable Potential refines Technical Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity and other factors affecting market penetration of energy efficiency measures. AEG used ramp rates from the Council's 2021 Power Plan in development of the Technical Achievable Potential.

For the Technical Achievable Potential case, a maximum achievability multiplier of 85 to 100 percent is applied to the ramp rate per Council methodology. This factor represents a reasonable achievable potential to be acquired through available mechanisms, regardless of how energy efficiency is achieved. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs. Avista uses Technical Achievable Potential as an input to its resource selection.

Integrating Results into Business Planning and Operations

The CPA and IRP energy efficiency evaluation processes provide high-level estimates of cost-effective acquisition opportunities. Results establish baseline goals for continued development and enhancement of energy efficiency programs, but do not provide enough detail to form an actionable acquisition plan. Avista uses results from both processes to establish a budget for energy efficiency measures, determine the size and skillsets necessary for future operations and identify general target markets for energy efficiency programs. This section discusses recent operations of the individual sectors and energy efficiency business planning.

The CPA is used for implementing energy efficiency programs to:

- Identify conservation resource potentials by sector, segment, end use and measure. Energy efficiency staff uses CPA results to determine the segments and end uses/measures to target.
- Identify measures with the highest benefit-cost ratios to help the utility acquire the highest benefits for the lowest cost. Ratios evaluated include TRC in Washington and UCT in Idaho.

- Identify and target measures with large potential but significant adoption barriers that the utility may be well-positioned to address through innovative program design or market transformation efforts.
- Optimize the efficiency program portfolio by analyzing cost effectiveness, potential of current measures and programs; and by determining potential new programs, program changes and program sunsets.

The CPA illustrates potential markets and provides a list of cost-effective measures to analyze through the ongoing energy efficiency business planning process. This review of both residential and non-residential program concepts and sensitivity provides more detailed assumptions feeding into program planning.

Residential Sector Overview
Avista's residential portfolio of efficiency programs engages and encourages customers to consider energy efficiency improvements for their home. Prescriptive rebate programs are the main component of this portfolio, augmented with other interventions. Other interventions include select distribution of low-cost lighting and weatherization materials, direct-install programs as well as multi-faceted, multichannel outreach and customer engagement.

Residential customers received over $1.4 million in rebates in 2021 to offset the cost of implementing energy efficiency measures. All programs within the residential portfolio contributed over 2,982 MWh to the 2021 annual first-year energy savings.

Low-Income Sector Overview
Currently Avista leverages the infrastructure of several network Community Action Agencies (CAA) and one tribal weatherization organization to deliver energy efficiency programs for the low-income residential customers in Avista's service territory. CAAs have resources to income qualify, prioritize, and treat clients' homes based upon several characteristics beyond Avista's ability to reach. These agencies also have other resources to leverage for home weatherization and other energy efficiency measures beyond Avista's contributions. The agencies have both in-house and/or contract crews available to install many of the efficiency program measures.

Avista's general outreach for this sector is a "high touch" customer experience for vulnerable customer groups including seniors and those with limited incomes. Each outreach encounter includes information about bill payment options and energy management tips, along with the distribution of low-cost weatherization materials. Many events are coordinated each year, including Avista-sponsored energy fairs, and the energy resource van. Avista also partners with community organizations to reach these customers through other means such as area food banks/pantry distribution sites, senior activity centers, or affordable housing developments. Low-income energy efficiency programs contributed 460 MWh of annual first-year electricity savings in 2021.

Non-Residential Sector Overview
Non-residential energy efficiency programs deliver energy efficiency through a combination of prescriptive and site-specific offerings. Any measure not offered through

a prescriptive program is eligible for analysis through the site-specific program, subject to the criteria for program participation. Prescriptive paths for the non-residential market are preferred for small and uniform measures, but larger measures may also fit where customers, equipment and estimated savings are non-homogenous.

More than 2,802 prescriptive and site-specific nonresidential projects received funding in 2021. Avista contributed over $10.7 million for energy efficiency upgrades to offset costs in nonresidential applications. Non-residential programs realized over 40,686 MWh in annual first-year energy savings in 2021.

Demand Response Potential Study

Historically, demand response (DR) programs provide capacity at times when wholesale prices are unusually high, when generation, transmission, natural gas shortages occur, or during an emergency grid-operation situation. Traditional DR programs such as time-of-use rates, peak time rebates, direct load control (DLC) programs, and bi-lateral agreements incentivize load reductions to specific enrolled customers during such periods until the load event is over or the customer meets their commitment. More recently, DR driven initiatives are also providing reliable ancillary service support in wholesale markets.

Avista’s current DR resources include commercial EV Time-of-Use (TOU) rates and one bilateral agreement with an industrial customer for 30 MW. This contract was executed in 2022 for a four-year term with provisions to extend another six-years. Additional DR resources are planned as pilots in Washington State to begin in 2024 and include a TOU program, a Peak Time Rebate (PTR) program and a DLC program for grid-enabled water heaters. These pilots will influence future IRPs, just as past pilot experience influenced this IRP.

Historical Demand Response Programs and Pilots

Avista’s experience with DR dates back at least to the 2001 Western Energy Crisis. Avista responded with all-customer and irrigation customer buy-back programs and bi-lateral agreements with its largest industrial customers. These programs, along with enhanced commercial and residential energy efficiency programs, reduced the need for purchases in very high-cost wholesale electricity markets. A July 2006 multi-day heat wave prompted Avista to request DR voluntarily through media outlets by asking customers to voluntarily conserve energy and entered into short-term agreements with large industrial customers to curtail loads due to the extreme regional and local temperatures not seen in the Spokane Area since 1961.

Between 2007 and 2009, Avista piloted technologies to examine DR cost-effectiveness and customer acceptance. The pilot tested scalable DLC devices based on installations in approximately 100 volunteer households in Sandpoint and Moscow, Idaho. The sample allowed Avista to test DR with the benefits of a larger-scale project, but in a controlled, measurable, and customer-friendly manner. Avista installed DLC devices on residential heat pumps, water heaters, electric forced-air furnaces, and air conditioners to control operations during 10 scheduled events at peak times ranging from two-to-four hours. A separate group, within the same communities, participated in an in-home-display device study as part of the pilot. The program provided Avista and customers experience with "near-real time" energy-usage feedback equipment. Information gained from the pilot is summarized in a report filed with the Idaho Public Utilities Commission.[3]

Following the North Idaho DR pilot program, Avista was part of the 2009 to 2014 Northwest Regional Smart Grid Demonstration Project (SGDP) with Washington State University (WSU) and approximately 70 residential customers in Pullman and Albion, Washington. Residential customer assets included forced-air electric furnaces, heat pumps and central air-conditioning units. The non-traditional DLC approach was used, meaning the DR events were not prescheduled, but rather Avista controlled customer load through an automated process based on utility or regional grid needs while using predefined customer preferences[4]. More importantly, the technology used in the DR portion of the SGDP predicted if equipment was available for participation in the control event, which provided real time feedback of the actual load reduction due to the DR event. Additionally, WSU facility operators had instantaneous feedback due to the integration between Avista and their building management system. Residential customer notifications of the DR event occurred via customers' smart thermostat. Avista reported information gained from this project to the prime sponsor for use in the SGDP's final project report and compilation with other SGDP initiatives.[5]

Experiences from both pilots showed high customer engagement; however, recruiting participants was challenging. Avista's service territory has a high level of natural gas penetration meaning many customers cannot participate in typical DLC electric space and water heat programs with their natural gas appliances. Additionally, customers did not seem overly interested in the DLC programs as offered. BPA found similar customer interest challenges in their regional DLC programs.[6] A 2019 Avista survey, conducted by the Shelton Group, also found low customer interest to participate in DR programs.

Avista paid customers direct incentives for program participation in both DLC pilots. Incentive levels were a premium to recruit and retain customers and were not intended to be scalable. Avista will need additional analysis to determine cost effective payment strategies beyond pilots to mass-market DLC programs. Where Avista is not able to harness adequate customer interest at cost-effective incentive levels, the future of DR could be more limited than assumed in this Progress Report.

Demand Response Potential Assessment Study

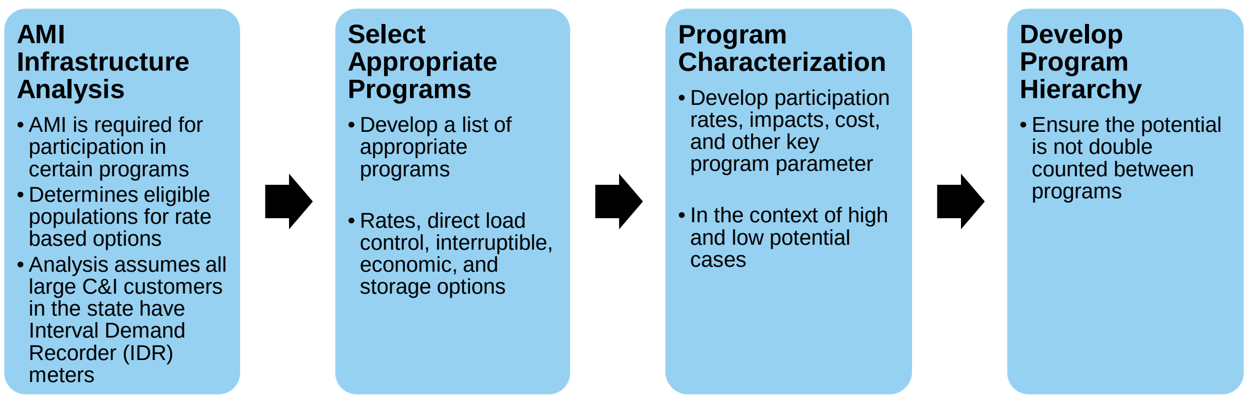
Avista retained AEG to study the DR potential for Avista's Washington and Idaho service territory for this IRP. The study estimates the magnitude, timing, and costs of DR resources likely available to Avista for meeting both winter and summer peak loads. Figure 5.4 outlines AEG's approach to determine potential DR programs in Avista's service territory. Many DR programs require Advanced Metering Infrastructure (AMI) for settlement purposes. All DR pricing programs, behavioral and third-party contract

[3] https://puc.idaho.gov/fileroom/cases/elec/AVU/AVUE0704/company/20100303FINAL%20REPORT.pdf
[4] For example, no more than a two-degree Fahrenheit offset for residential customers and an energy management system at WSU with a console operator.
[5] https://www.smartgrid.gov/files/OE0000190_Battelle_FinalRep_2015_06.pdf.
[6] BPA's partnership with Kootenai Electric Coop, https://www.bpa.gov/EE/Technology/demand-response/Documents/20111211_Final_Evaluation_Report_for_KEC_Peak_Project.pdf.

programs included in this study require AMI as an enabling technology. AMI deployment is complete in Washington, and AEG broadly assumed that Avista would follow with AMI metering in Idaho beginning in 2023 and a three-year ramp rate for full deployment, finishing in 2026.

AEG used the same market characterization for this potential assessment study as used in the CPA. This became the basis for customer segmentation to determine the number of eligible customers in each market segment for potential DR program participation and provided consideration for DR program interactions with energy efficiency programs. The study compared Avista's market segments to national DR programs to identify relevant DR programs for analysis.

Figure 5.4: Program Characterization Process



This process identified several DR program options shown in Table 5.2. The different types of DR programs include two broad classifications: curtailable/controllable DR and rate design programs. Except for the behavioral program, curtailable/controllable DR programs represent firm, dispatchable and reliable resources to meet peak-period loads. This category includes DLC, Firm Curtailment (FC), thermal and battery storage and ancillary services. Rate design options offer non-firm load reductions that might not be available when needed but still create a reliable pattern of potential load reduction. Pricing options include time-of-use, peak-time rebate, and variable peak pricing. Each option requires a new rate tariff for each state in Avista's service territory.

Table 5.2: Demand Response Program Options by Market Segment

DR Program		Participating Market Segment				Season Impacted	
Program Type	**Program Option**	**Res.**	**Sm. Com.**	**Large. Com./ Ind.**	**Extra Large Com./ Ind.**	**Winter**	**Summer**
Curtailable/ Controllable DR	DLC Central AC	X	X				X
	DLC Smart Thermostat – Cooling	X	X				X
	DLC Smart Thermostat – Heating	X	X			X	
	DLC CTA-2045 Water Heating	X	X			X	X
	DLC Water Heating	X	X			X	X
	DLC Vehicle Charging	X				X	X
	DLC Smart Appliances	X	X			X	X
	Third Party Contracts			X	X	X	X
	Thermal Energy Storage		X	X	X		X
	Battery Energy Storage	X	X	X	X	X	X
	Behavioral	X				X	X
	Ancillary Services	X	X	X	X	X	X
Rates	Time-of-Use Opt-in	X	X	X	X	X	X
	Variable Peak Pricing Rates	X	X	X	X	X	X
	Peak-Time Rebate	X	X			X	X
	Electric Vehicle Time-of-Use		X	X		X	X

Demand Response Program Descriptions

Direct Load Control

DLC programs for Avista's Residential and General Service customers in Idaho and Washington would aim to allow Avista to directly control a variety of customer end-use appliances during peak times throughout the year. DLC Smart Thermostat programs would leverage a customer's smart thermostat installation relying on the customer's WiFi for communications. Likewise, DLC Smart Appliances assume customer resources as the enabling technology. DLC Central AC, DLC Water Heating, and DLC CTA-2045 Water Heating programs assume the enabling technology is a utility provided version of a load control switch. Smart appliances included in this analysis include refrigerators, clothes washers and dryers. Typically, DLC programs take five years to ramp up to maximum participation levels.

Third Party Contracts - Firm Curtailment

Customers participating in a firm curtailment program agree to reduce demand by a specific amount or to a pre-specified consumption level during the event in exchange for fixed incentive payments. Customers receive payments while participating in the program even if they never receive a load curtailment request while enrolled in the program. The capacity payment typically varies with the firm reliability-commitment level. In addition to fixed capacity payments, participants receive compensation for reduced energy consumption. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads have the potential to replace a firm generation resource.

Customers with maximum demand greater than 200 kW and operational flexibility are attractive candidates for firm curtailment programs. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants and industries with process storage (e.g. pulp and paper, cement manufacturing). Customers with operations requiring continuous processes, or with relatively inflexible obligations, such as schools and hospitals, generally are not good candidates for curtailment programs. The study factors in these assumptions to determine the eligible population for participation in this program and assumes a third party would administer all aspects of the program.

Thermal Energy Storage

This emerging technology has been primarily used in non-residential buildings and applications but may have the potential to be used in the future for residential applications as the technology advances. Thermal energy storage technologies draw electricity during low demand periods and store it as ice sealed inside the unit. A variable speed fan can automatically circulate the cool air throughout a room using the stored energy (ice) rather than having to draw energy from the grid during peak times to chill the air.

Battery Energy Storage

Battery energy storage technologies draw electricity during low demand periods and store it for use later during peak times. This study assumes energy is stored using electrochemical processes as found with lithium-ion battery equipment.

Behavioral

A behavioral program is a voluntary reduction in response to digital behavioral messaging. These programs typically occur in conjunction with energy efficiency behavioral reporting programs and communicate the request to customers to reduce usage via text or email messages. AMI technology is needed to evaluate and measure the impact of the program for events.

Time of Use Rates (Opt-In)

A TOU rate is a time-varying rate. Relative to a revenue-equivalent flat rate, the rate during higher load or cost periods are higher, while the rate during other periods is lower. This provides customers with an incentive to shed or shift consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a demand-response option, per se, but rather a permanent load shedding or shifting opportunity. Large price differentials are generally more effective than smaller differentials for TOU programs.

The DR study considered two types of TOU pricing options. In an opt-in rate, participants voluntarily enroll in the rate. An opt-out rate places all customers on the time-varying rate, but they may opt-out and select another rate later. Avista only used TOU Opt-in for this analysis.

Variable Peak Pricing

The Variable Peak Pricing (VPP) amount changes daily to reflect system conditions and costs for peak hours. Under a VPP program, on-peak prices for each weekday are made available the previous day. Variable peak pricing bills customers for their actual consumption during the billing cycle at these prices. Over time, establishment of event-trigger criteria enables customers to anticipate events based on extreme weather or other factors. System contingencies and emergency needs are good candidates for variable peak pricing events. VPP program participants are required to be enrolled in a TOU rate option.

Peak Time Rebate

Participation in a Peak-Time-Rebate (PTR) program is voluntary. In an event, participants are notified a day in advance for a two- to six-hour event time during peak hours. If customers do not participate, there is no penalty. If they do participate, they receive a bill credit based on the amount of energy reduced as compared to a calculated baseline. PTR is not dependent on enrollment in other DR programs, but like the other pricing programs, it does require AMI for settlement purposes.

Electric Vehicle Time of Use

The study applied the most recent electric-vehicle load forecast to Avista's current rate schedules 13 and 23 in Washington. Rather than a typical TOU rate that applies on-off peak prices to whole building usage, the EV TOU rate program applies on-off peak prices exclusively to EV loads that are metered separately. When AMI is available in Idaho, a similar pricing program is assumed in the study.

Planned Pilot Programs

AEG assessed a set of pilot programs based on Avista's planned DR program roll-out beginning in 2024 and includes TOU rate options, PTR, and DLC of grid-enabled water heaters. Broad assumptions were made for all three pilot programs since all are still under development. AEG forecasted the potential for these programs to 2045 as if the programs ramped up to fully-fledged programs after the pilots. Each pilot will run for three years; the TOU Opt-in will have an optional two-year extension depending on results.[7] Each program will be offered to residential and general service customers only.

[7] Potential results for the TOU Opt-in Pilot do not include the two-year extension and are based on a three-year pilot.

Demand Response Program Participation

AEG's forecast for DR potential uses a database of existing program information and insights from market research results representing "best-practice" estimates for program participation. The industry commonly follows this approach for arriving at achievable potential estimates. However, practical implementation experience suggests there is uncertainties in factors such as market conditions, regulatory climate, the economic environment, and customer sentiments will influence customer participation in DR programs.

Once initiated, DR options require time to ramp up to a steady state because of the time needed for customer education, outreach, and recruitment; in addition to the physical implementation and installation of any hardware, software, telemetry, or other enabling equipment. DR programs included in the AEG study have ramp rates generally with a three- to five-year timeframe before reaching the steady state.

Table 5.3 shows the steady-state participation rate assumptions for each DR program option. Space cooling is split between DLC Central AC and Smart Thermostat options. Likewise, eligible EV charging, general service customers are split between the TOU (opt-in or opt-out) programs and the EV TOU program. Eligible customers for each customer class are calculated based on market characterization and equipment end use saturation.[8]

Table 5.3: DR Program Steady-State Participation Rates (Percent of Eligible Customers)

DR Program	Residential Service	General Service/ Small Commercial	Large General Service	Extra Large General Service
Direct Load Control (DLC) of central AC	10%	10%	-	-
DLC of domestic hot water heaters (DHW)	15%	5%	-	-
Smart Thermostats DLC Heating	5%	3%	-	-
CTA-2045 hot water heaters	50%	50%	-	-
Smart Thermostats DLC Cooling	20%	20%	-	-
Smart Appliances DLC	5%	5%	-	-
Third Party Contracts	-	15%	22%	21%
DLC Electric Vehicle Charging	15%	-	-	-
Time-of-Use Pricing Opt-in	13%	13%	13%	13%
Time-of-Use Pricing Opt-out	74%	74%	74%	74%
Variable Peak Pricing	-	-	25%	25%
Peak-Time Rebate	15%	15%	-	-
Electric Vehicle Time-of-Use	-	51%	51%	-
Thermal Energy Storage	-	0.5%	1.5%	1.5%
Battery Energy Storage	0.5%	0.5%	0.5%	0.5%
Behavioral	20%	-	-	-

[8] See the Demand Response Potential Appendix found within the 2022-2045 Avista Electric CPA found in Appendix C.

Cost and Potential Assumptions

Each DR program used in this evaluation is assigned an average load reduction per participant per event, an estimated duration of each event, and a total number of event hours per year. Costs are also assigned to each DR program for annual marketing, recruitment, incentives, program development, and administrative support. These assumptions result in potential demand savings and total cost estimates for each program independently and on a standalone basis.

If Avista offers more than one program, then the potential for double counting exists. To address this possibility, a participation hierarchy was assumed and defines the order customers take the programs for an integrated approach. These savings and costs results were then used in Avista's modeling. See Appendix C for additional detail on DR resource assumptions used in developing potential savings and cost results.

The estimated savings for reach program and its levelized costs is shown in Table 5.4. The cost of the programs within this table represents the on-going operations and capital cost required to start and maintain these programs. The capital costs are amortized and recovered over a 10-year period. These tables include the estimated potential megawatt savings for 2030 and 2045 for illustrative purposes of program potential. These estimates are the expected amount of demand reduction from all program participants using a "stand-alone" methodology, whereas potential may decline for a program in multiple programs are put in place. It is also worth noting, Avista will require a higher amount of contracted load to achieve these savings, these amounts are the expected net savings from all participants.

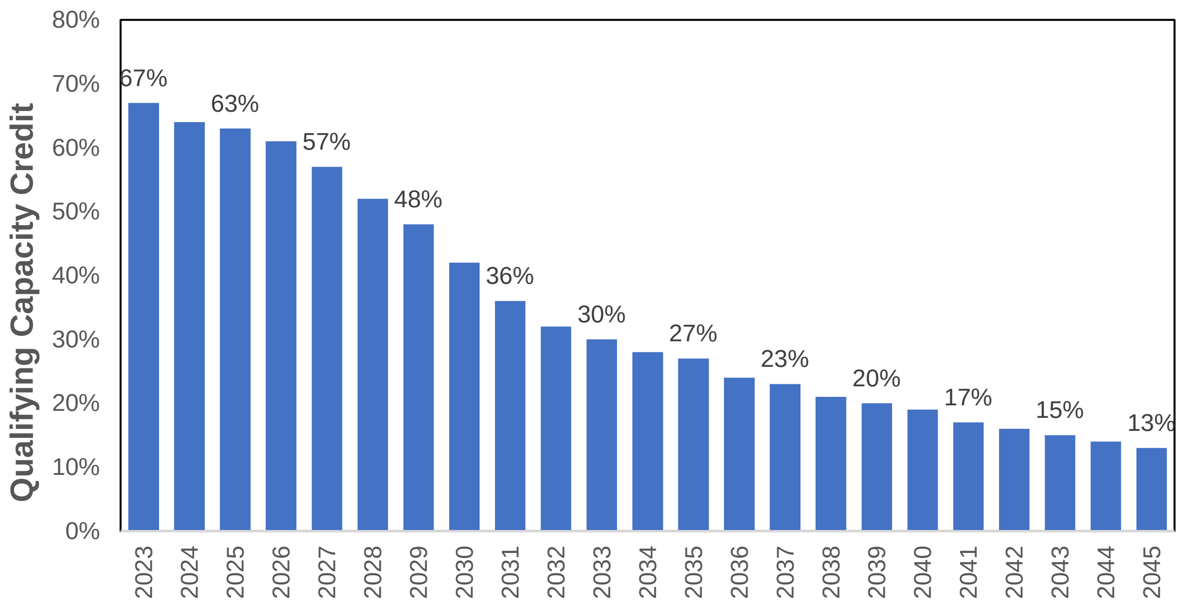
Table 5.4: System Program Cost and Potential

Program	$/kW-Month	Winter (MW)		Summer (MW)	
		2030	2045	2030	2045
Battery Energy Storage	47.1	1.3	5.5	1.3	5.5
Behavioral	13.3	3.2	4.2	3.4	4.4
DLC Central AC	13.9	-	-	10.9	15.4
DLC Electric Vehicle Charging	90.9	2.3	29.3	2.3	29.3
DLC Smart Appliances	27.3	3.2	3.7	3.2	3.7
DLC Smart Thermostats-Cooling	14.7	-	-	21.9	30.7
DLC Smart Thermostats-Heating	2.5	4.9	5.8	-	-
DLC Water Heating	52.7	2.1	2.4	2.1	2.4
CTA-2045 ERWH	34.8	1.8	5.7	1.7	5.3
CTA-2045 HPWH	61.4	0.5	2.6	0.2	1.0
Thermal Energy Storage	60.7	-	-	0.7	0.8
Third Party Contracts	8.4	24.8	29.6	24.4	29.1
Time-of-Use Opt-in	4.9	7.8	9.9	8.1	10.3
Electric Vehicle TOU Opt-in	23.5	0.3	4.7	0.3	4.7
Variable Peak Pricing Rates	2.6	4.7	5.5	4.6	5.4
Peak Time Rebate	3.4	11.2	14.8	11.8	15.5
Total Potential		**68.3**	**123.6**	**97.1**	**163.6**

There are a few other factors including the evaluation of DR the PRiSM model considers, the first is energy value of the program. Some program opportunities reduce energy usage permanently, but most programs have snap back load where additional energy returns later. Avista determined the net value of these load changes using hourly wholesale market prices discussed in Chapter 9 compared to a time series of how the load profile would result if the program was dispatched.

The second major factor related to whether a program is cost effective compared to other alternatives is the resources' ability to qualify as load reduction or the programs Qualifying Capacity Credit (QCC). At this time, the QCC is uncertain for these types of programs in the future Western Resource Adequacy Market (WRAP), but this analysis assumes a 6-hour reduction is required to receive 100 percent QCC, whereas the QCC is a percentage of the hour reduction. For example, a 4-hour program is 67 percent and a 3-hour program is 50 percent. These values assume today's system and will reduce as the regional electric system's load is met with more variable energy resources and storage. Currently, the WRAP has not completed a study of the long-term QCC of DR or any other resources, therefore Avista's assumption hinges on regional studies of reduced effective load carrying capability (ELCC) studies in the public domain, such as the March 2019 E3 Study on Resource Adequacy in the Pacific Northwest to make this estimate, the resulting QCC value is shown for a 4-hour program in Figure 5.5.

Figure 5.5: Demand Response QCC Forecast for 4-hour Program



Distributed Generation Resources

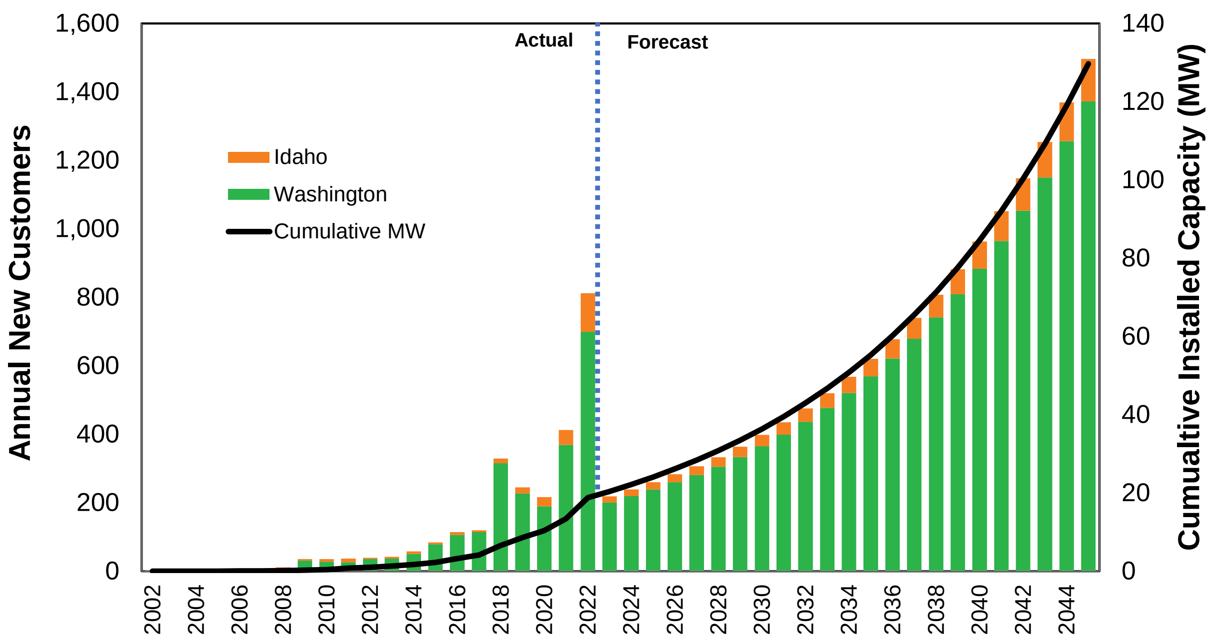
Customer-Owned Generation

Avista has 2,602 customer-installed net-metered generation projects on its system by November 2022, representing a total installed capacity of 18.8 MW. Eighty-nine percent of installations are in Washington; most are in Spokane County. Figure 5.6 shows annual net metering customer additions since 2002[9] and forecasted installations from Avista's load forecast. Solar is the primary net metered technology followed by wind, combined solar and wind systems, and biogas. The average size of the customer installations is 7.2

[9] The 2022 results are through September.

kilowatts. In Idaho, solar installation rates continue to increase each year without a major subsidy, but total only 280 customers compared to Washington's 2,322 customer installations. In addition, in recent years, net-metered installations are exponentially increasing due to federal incentives, increasing solar vendor sales, environmental concerns, rising energy costs and expiring state incentives. In addition, 2021 and 2022 is seeing a "catch-up" on the installation back-log that occurred during the COVID-19 pandemic. If net-metering customers continue to increase, Avista may need to adjust rate structures for these customers. Much of the cost of utility infrastructure to support reliable energy delivery is recovered in energy rates. Net metering customers continue to benefit from this infrastructure but are no longer purchasing as much energy, thereby transferring some of their grid infrastructure costs to customers not generating their own power.

Figure 5.6: Avista's Net Metering Customers



Avista-Owned Solar

Avista operates three small solar DER projects. The first solar project is three kilowatts located at its corporate headquarters. Avista installed a 15-kilowatt solar system in Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. The 423-kW Avista Community Solar project, located at the Boulder Park property, began service in 2015.

Table 5.5: Avista-Owned Solar Resource Capability

Project Name	Project Location	Project Capacity (kW-DC)
Spokane Headquarters Solar	Spokane, WA	3
Rathdrum Solar	Rathdrum, ID	15
Boulder Park Solar	Spokane Valley, WA	423
Total		**441**

Generation & Storage Opportunities

Past IRP analysis included utility owned distribution sized generation and storage, but this analysis also includes residential, commercial, and community sized projects. Customer or distribution sized resources have gained traction as avenues to promote equitable outcomes to specific communities or solve local supply issues. For this analysis these DERs are included as resource options for the Named Community Investment Fund (NCIF) but can be selected otherwise if cost effective. The resource configurations and costs are shown in Table 5.6. The costs are shown in nominal levelized cost dollars and include the benefits of the Inflation Reduction Act through 2033, the cost assumptions are based on information provided by TAC members and the 2022 NREL resource cost study[10]. The Low-Income Community Solar option included is based on the expected net cost to Avista customers after accounting for grants given by the State of Washington. The costs are levelized cost of energy for solar resources over the life of the asset and for energy storage is the levelized cost of capacity for the life of the asset assuming battery reconditioning.

Table 5.6: DER Generation & Storage Options Size and Cost

Project Name	Increment Size (kW)	2024$ /MWh	2035$ /MWh	2024$ / kW-Month	2035$ / kW-month
Existing res. building solar	6 (17 sites)	160	351	-	-
Existing res. building solar with storage	6 (17 sites)	160	351	22.92	40.33
New res. building solar	6 (17 sites)	148	323	-	-
New res. building solar with storage	6 (17 sites)	148	323	21.67	37.75
Com. building solar	200	124	186	-	-
Com. building solar with storage	200	124	186	27.50	40.75
Utility owned solar array	100	75	78	-	-
Utility owned solar array with storage	100	75	78	14.25	16.42
Stand-alone energy storage (4hr)	500	-	-	18.75	22.83
Stand-alone energy storage (8hr)	500	-	-	33.25	38.92
Low-income Community Solar Program	100	25	n/a	-	-

DER Evaluation Methodology

Avista models each of the DERs discussed in this chapter in the same economic selection model as other utility asset options. Avista's intent is to include all known utility costs and, where required (i.e., Washington), known non-energy or social impacts. Recently, the WUTC is working on a proposal[11] for evaluating DERs as part of a workshop process with the assistance of Synapse Energy Economics. Currently, the WUTC has put out a draft proposal of the types of considerations utilities should use when conducting resource planning activities. While this concept is currently in draft form, it does provide an opportunity for Avista to demonstrate the types of costs and considerations used in the evaluation of these resources. The list of options from the strawman proposal is shown in Table 5.7 for those resources applicable to this plan.

[10] NREL (National Renewable Energy Laboratory). 2022. 2022 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

[11] Washington Cost-Effectiveness Test for Distributed Energy Resources, Straw Proposal for the Primary Test, November 7, 2022. Docket UE-210804.

Due to the complexity and size of the list of considerations, the answers within the boxes are high level, where "Direct" means there is a value used within the PRiSM optimization model for this value. "Indirect" indicates this value is included by the savings compared to other resources; for example, if choosing energy efficiency lowers capacity needs from other resources. Items listed as "N/A" indicate the values are not applicable to the DER. "No" indicates the value is not included. Avista will continue to provide feedback to the WUTC on how to address DER analysis but believes if additional non-energy values are included for DERs the analysis must include similar cost and benefits to utility scale assets. Further, many of the values discussed are qualitative and difficult to quantify for use in modeling.

DER Potential Study

As part of the Washington CEIP approval process[12], Avista agreed to conduct a distribution level analysis of DER opportunities within its Washington service territory. This includes a distribution feeder level analysis of future availability and likely adoption of resources and load changes. The completed analysis will be available for the 2025 IRP and used in future distribution planning activities. Currently, Avista plans to meet this requirement by using outside consulting assistance with experience conducting such an analysis. The RFP for services is included as Appendix G and the project should begin late first quarter of 2023. The planned work will cover the following and include additional analysis for Named Community potential taking out income limitations:

- Electric Vehicles
    - Local charging: light, medium, heaving duty
    - Charging related to interstate travel
- New Generation & Storage
    - Residential and commercial solar
    - Residential and commercial storage
    - Other renewables (i.e., wind, small hydro, fuel cell, internal combustion engines)
    - Combined heat and power
- Load Management
    - Energy Efficiency
    - Demand Response

Avista envisions five tasks for this project following the schedule below shown in Table 5.8. As part of this plan includes presenting preliminary results to technical and equity advisory groups to get feedback on the results prior to finalization. For energy efficiency and DR, Avista will work with AEG to apply its potential studies discussed in this chapter to the local level by feeder following a similar schedule as shown for other resources.

[12] Condition 14: Avista will include a Distributed Energy Resources (DERs) potential assessment for each distribution feeder no later than its 2025 electric IRP. Avista will develop a scope of work for this project no later than the end of 2022, including input from the IRP TAC, EEAG, and DPAG. The assessment will include a low-income DER potential assessment. Avista will document its DER potential assessment work in the Company's 2023 IRP Progress Report in the form of a project plan, including project schedule, interim milestones, and explanations of how these efforts address WAC 480-100-620(3)(b)(iii) and (iv).

Table 5.7: DER Cost & Benefit Impacts

Category	Impact	Energy Efficiency	Demand Response	Solar	Storage
Generation	Energy Generation	Direct	Direct	Direct	Direct
	Capacity	Indirect	Indirect	Direct	Direct
	Environmental Compliance	Indirect	Indirect	Indirect	Indirect
	Clean Energy Compliance	Indirect	Indirect	Direct	Indirect
	Market Price Effects	Direct	Direct	Direct	Direct
	Ancillary Services	Indirect	Indirect	Direct	Direct
Transmission	Transmission Capacity	Direct	No	Direct	Direct
	Transmission System Losses	Direct	Direct	Direct	Direct
Distribution	Distribution Cost	Direct	Direct	Direct	Direct
	Distribution Voltage	No	No	Indirect	Indirect
	Distribution System Losses	Direct	Direct	Direct	Direct
General	Financial Incentives	N/A	Direct	No	No
	Program Admin Cost	Direct	Direct	Direct	No
	Utility Performance Incentives	No	No	No	No
	Compensation Mechanisms	No	No	No	No
	Credit and Collection Costs	Indirect	Indirect	Indirect	Indirect
	Risk	No	No	No	No
	Reliability	No	No	No	No
	Resilience	No	No	No	No
Host Customer Energy Impacts	Measure Costs	Direct	Direct	N/A	N/A
	Transaction Costs	Direct	Direct	N/A	N/A
	Interconnection Fees	N/A	N/A	Direct	Direct
	Risk	No	No	No	No
	Reliability	No	No	No	No
	Resilience	No	No	No	No
	Other Fuels	n/a	No	No	No
	Tax Incentives	Direct	No	Direct	Direct
Host Customer Non-Energy Impacts	Water	No	No	No	No
	Asset Value	Indirect	No	No	No
	Productivity	Direct	No	No	No
	Economic well-being	Direct	No	No	No
	Comfort	Direct	No	No	No
	Health & Safety	Direct	No	No	No
	Empowerment & Control	No	No	No	No
	Satisfaction & Pride	Indirect	No	No	No
	Low-Income NEIs	Direct	No	No	No
Societal Impacts	Greenhouse Gas Emissions	Direct	Indirect	Indirect	Indirect
	Other Environmental	No	No		
	Public Health	Direct	No	Direct	Direct
	Economic & Jobs	Direct	No	Direct	Direct
	Resilience	No	No	No	No
	Energy Security	No	No	No	No

Table 5.8: DER Potential Study Schedule

Number	Due Date	Deliverable
Task 1	July 2023	(a) A survey of other utility or other entity efforts to conduct similar DER potential studies. The study shall include comparison of the other utility's size, rates, climate, and customer demographics. (b) A summary of best practices for development of future adoption of new DER technologies. (c) An overview of Avista's current DER resources (i.e., 2022 baseline).
Task 2	September 2023	A description of the methodology used to develop the estimates for each DER, related scenarios and electric vehicles.
Task 3	Draft March 2024 Final May 2024	(a) Matrix including each feeder and the quantity of each electric vehicle by class. An hourly load shape for each vehicle class, by weekday type and month. A second matrix is required for feeders within named communities. (b) Matrix including each feeder and the amount of DER resources in kW and/or kWh for each resource type by year and customer class. The summary shall also include an estimated portion of the resource opportunity providing ancillary services[13] along with adjustments for higher potential due to income limits from named communities.
Task 4	Q1 2024	Present draft results of study to Avista's Advisory Committees for comment and question. Advisory committees may include: Electric Integrated Resource Planning Technical Advisory Committee, Energy Efficiency Advisory Group, and the Distribution Planning Advisory Group.
Task 5	Draft April 2024 Final June 1, 2024	(a) Final report including tasks 1 through 4, (b) Summary of comments and suggestions from non-Avista parties and how they are addressed in the final report, (c) Recommendations for future studies, (d) Documentation of methods and procedures to transition Avista to be able to update these forecasts for future use.

[13] Ancillary services include the resource's ability to provide regulation, load following, operating reserves, and voltage support.

6. Supply-Side Resource Options

Avista evaluates several different generation options including Distributed Energy Resources (DER) and utility-scale resource options to meet future resource deficits. This Progress Report evaluates upgrading existing resources, constructing, and owning new generation facilities, and/or contracting with other energy companies. This section describes the costs and characteristics of resource options Avista is considering in the 2023 IRP. The options are mostly generic, as actual resources are typically acquired through competitive processes such as a Request for Proposal (RFP). This process may yield resources differing in size, cost, and operating characteristics due to siting, engineering, or financial requirements, and it also may reveal existing resource options available in the region.

Section Highlights

- Solar, wind, and other renewable resource options are modeled as Purchase Power Agreements (PPA) instead of utility ownership.
- Future competitive acquisition processes might identify different technologies available to Avista at a different cost, size or operating characteristics and may include existing generation options.
- Inflation Reduction Act tax incentives are included in resource costs.
- Avista models several energy storage options including pumped storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air, hydrogen, iron-oxide, and ammonia.

Assumptions

Resource options within this analysis include both commercially available resources and future resource technology options with a strong likelihood of commercial availability. The analysis does not include theoretical or technologies in pre-commercial phases. Resource opportunities must be located within or near Avista’s service territory with verifiable costs and generation profiles priced as if Avista developed and owned the generation or acquired generation from Independent Power Producers (IPPs) through a PPA. Resources using PPAs rather than ownership include pumped hydro storage, wind, solar (with and without storage), geothermal, and nuclear. Avista modeled these resource types as PPAs since historically IPPs financially capture tax benefits for these resources earlier and can leverage lower cost of capital, thereby reducing the cost to customers.

Resource options assuming utility ownership include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, ammonia-fired SCCT, energy storage, hydrogen fuel cell, biomass, and thermal unit upgrades. Upgrades to coal-fired units were not included or considered. Modeling resources as PPAs or ownership does not preclude the utility from acquiring new resources in other manners but serves as a cost estimate for the new resources. Several other resource options described later in the chapter are not included in the portfolio analysis but are discussed as potential resource options since they may appear in a future request for resources acquisition.

It is difficult to accurately model potential contractual arrangements with other energy companies as an option in the plan specifically for existing units or system power, but such arrangements may offer a lower customer cost when a competitive acquisition process is completed. Avista plans to use competitive RFP processes for resource acquisitions where possible to ensure the lowest cost resource is acquired for customers. However, another acquisition process may yield better pricing on a case-by-case basis, especially for existing resources available for shorter periods. Avista uses the IRP, RFPs, and market intelligence to determine and validate its upgrade alternatives when evaluating upgrades to existing facilities. Upgrades typically require competitive bidding processes to secure contractors and equipment.

The costs of each resource option do not include the cost related to upgrading the transmission or distribution system described in Chapter 7 or third-party wheeling costs. All costs are considered at the busbar. Avista excludes these costs to allow for consistent cost comparison as resource costs at specific locations are highly dependent on the location in relation to Avista's system. These costs are included when Avista evaluates the resources for selection in an RFP and within the IRP's portfolio analysis. All costs are levelized by discounting nominal cash flows by the 6.7 percent-weighted average cost of capital approved by the Idaho and Washington Commissions in recent rate case filings. All costs in this section are in 2023 nominal dollars unless otherwise noted. All cost and operating characteristic assumptions for generic resources and how PPA pricing were calculated are available in Appendix F and are also available on Avista's website.

Avista relies on several sources of resource costs including the National Renewable Energy Laboratory (NREL), Lazard, Northwest Power and Conservation Council (NPCC or Council), press releases, regulatory filings, internal analysis, other publicly available studies, developer estimates and Avista's experience with certain technologies to develop its generic resource assumptions. In addition, Avista's 2022 All-Source RFP and 2020 Renewable RFP were utilized to ensure assumed costs for solar, wind, solar/storage, and other resource options were in line with pricing available from actual projects within or near Avista's service territory.

Levelized resource costs illustrate the differences between generator types. The values show the cost of energy if the plants generate electricity during all available hours of the year. In actual operation, plants do not operate at their maximum generating potential because of market and system conditions. Costs are separated between energy in \$/MWh and capacity in \$/kW-year to better compare technologies.[1] Without this separation of costs, resources operating infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources are lower total cost when operating only a few hours each year. Avista levelizes the cost using the production capability of the resource. For example, a natural gas-fired turbine is available 92 to 95 percent of the time when accounting for maintenance and forced outages. Avista divides the cost by the amount of megawatt hours the machine is available to produce

[1] Storage technologies use a \$ per kWh rather than \$ per kW because the resource is both energy and capacity limited.

energy. For resources limited by fuel availability such as solar or wind the resource costs are divided by its expected production.

Tables at the end of this section show incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs, and qualifying capacity credits (QCC) for each resource option.[2] Table 6.1 compares the levelized costs of different resource types over a 30-year asset life.

Distributed Energy Resources

This Progress Report includes several distributed energy resource options. DERs are both supply- and demand-side resources located at either the customer location or at a utility-controlled location on the distribution system. Demand side DERs include energy efficiency and demand response (DR). Additional details about these program options are found in Chapter 5. In addition to modeled demand-side DER options, Avista includes forecasts for customer-owned solar and electric vehicles as part of its load forecast discussed in Chapter 2.

In addition to demand-side DERs, supply-side resource options include small scale solar and battery storage. Avista includes specific cost estimates for smaller scale projects described later in this chapter along with the energy, capacity, and ancillary service benefits traditional utility scale projects offer. Due to the location, additional benefits such as line loss savings over alternative utility scale projects are also included. Other locational benefits may also be credited to the project if it alleviates distribution constraints. Projects on the customer system may also provide reliability benefits to the specific customer.

Natural Gas-Fired Combined Cycle Combustion Turbine

Natural gas-fired CCCT plants provide reliable capacity and energy for a relatively modest capital investment. The main disadvantages of a CCCT are generation cost volatility due to reliance on natural gas unless utilizing hedged fuel prices and plant emissions. This analysis models CCCTs as a “one-on-one” (1x1) configuration with duct fire capability, using hybrid air/water cooling technology and zero liquid discharge. The 1x1 configuration consists of a single gas turbine with a heat recovery steam generator (HRSG) and a duct burner to gain more generation from the steam turbine. The plants have nameplate ratings between 180 MW and 312 MW each depending on configuration and location.

Cooling technology is a major cost driver for CCCTs. Depending on water availability, lower-cost water cooling technology could be an option, similar to Avista’s Coyote Springs 2 plant. However, absent water rights, a more capital-intensive and less efficient air-cooled technology may be used. Avista assumes water is available for plant cooling based on its internal analysis, but only enough water rights for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

This analysis includes one CCCT plant option sized at 312 MW in 1x1 configuration with a duct fire capability. Avista reviewed several CCCT technologies and sizes and selected

[2] Peak credit is the amount of capacity a resource contributes at the time of system one-hour peak load.

this plant as the best fit for the needs of Avista's customers. If Avista were to pursue a new CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes at both Avista's preferred and other locations. It is also possible Avista could acquire an existing CCCT resource from one of the many units in the Pacific Northwest.

The most likely location for a new CCCT is in Idaho, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington and no state taxes or fees on the emission of carbon dioxide.[3] CCCT sites likely would be on or near Avista's transmission system to avoid third-party wheeling costs. Another advantage of siting a CCCT resource in Avista's Idaho service territory is access to relatively low-cost natural gas on the GTN pipeline. Avista already secured a site with these potential connection points if it needs to add additional capacity from a CCCT or other technology.

Combined cycle technology efficiency has improved since Avista's current CCCT generating fleet entered service with heat rates as low as 6,400 Btu/kWh for a larger facility and 6,700 for smaller configurations. Duct burners can add additional capacity with heat rates in the 7,200 to 8,400 Btu/kWh range.

The anticipated capital costs for the modeled CCCTs, located in Idaho on Avista's transmission system with AFUDC on a greenfield site, are approximately $1,316 per kW in 2023 dollars. These estimates exclude the cost of transmission and interconnection. Table 6.1 shows levelized plant cost assumptions split between capacity and energy for the combined cycle option discussed here, and the natural gas peaking resources discussed in the next section. The costs include firm natural gas transportation, fixed and variable O&M and transmission. Table 6.2 summarizes key cost and operating components of natural gas-fired resource options. With competition from alternative technologies and the need for additional flexibility for intermittent resources, it is likely to put downward pressure on future CCCT costs.

Natural Gas-Fired Peakers

Natural gas-fired SCCTs and reciprocating engines, or peaking resources, provide low-cost capacity capable of providing energy as needed. Technological advances coupled with a simpler design relative to CCCTs allow SCCTs to start and ramp quickly, providing regulation services and reserves for load following and variable resources integration.

This analysis models frame and reciprocating engine technologies only, other technologies would be considered in resource acquisition. Peakers have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. The levelized cost for each of the technologies is in Table 6.1. Table 6.2 shows cost and operational characteristics based on internal engineering estimates.

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[3] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.852 percent. Washington also has higher sales taxes and carbon dioxide mitigation fees for new plants.

Firm natural gas fuel transportation is an electric generation reliability issue with FERC and is also the subject of regional and extra-regional forums. For this plan, Avista continues to assume it will not procure firm natural gas transportation for peaking resources and will use its current supply or short-term transportation for peaking needs. This assumption is being reviewed on a regular basis as the amount of firm and non-firm natural gas transportation changes over time. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours. Where non-firm transportation options become inadequate for system reliability, four options exist: contracting for firm natural gas transportation rights, purchasing an option to exercise the rights of another firm natural gas transportation customer during peak demand times, on-site fuel oil or nearby storage such as liquefied natural gas in tanks or trailers.

Table 6.1: Natural Gas-Fired Plant Levelized Costs

Plant Name/Location	Total $/MWh	$/kW-Yr Capability	Variable $/MWh	Winter Capacity (MW)
7F .04 CT Frame Greenfield (Idaho)	60.3	102.1	48.3	180
7F .04 CT Frame Greenfield (Washington)	62.3	104.6	50.0	
Reciprocating Engine (ICE) Machine (Idaho)	61.6	152.9	43.6	185
Reciprocating Engine (ICE) Machine (Washington)	63.4	156.7	45.0	
NG CCCT (1x1 w/DF) (Idaho)	57.7	183.8	36.0	312
NG CCCT (1x1 w/DF) (Washington)	59.3	187.6	37.2	

Table 6.2: Natural Gas-Fired Plant Cost and Operational Characteristics[4]

Item	Capital Cost with AFUDC ($2023/kW)	Fixed O&M ($2023/ kW- yr)	Heat Rate (Btu/ kWh)	Variable O&M ($/MWh)	Total Project Size (MW)	Total Cost (Mil$-2023)
7F .04 CT Frame Greenfield (Idaho)	833	5.2	10,040	3.10	180	155
7F .04 CT Frame Greenfield (Washington)	845					159
Reciprocating Engine (ICE) Machine (Idaho)	1,317	5.2	8,190	5.93	185	244
Reciprocating Engine (ICE) Machine (Washington)	1,351					251
NG CCCT (1x1 w/DF) (Idaho)	1,317	30.5	6,820	4.75	312	410
NG CCCT (1x1 w/DF) (Washington)	1,351					421

Wind Generation

Wind resources benefit from having no direct emissions or fuel costs but are not dispatchable to meet load. Avista models four general wind location options in this plan: Montana, Eastern Washington, the Columbia River Basin, and offshore. Configurations

[4] Costs based on Idaho. Washington's costs would be slightly higher due to a higher sales tax rate of 8.9% compared with Idaho's 6.0% rate.

of wind facilities are changing given regional transmission limitations, federal tax credits, low construction prices and the potential for storage. These factors allow for sites being built with higher capacity levels than the transmission system can currently integrate. When the wind facilities generate additional MWh above the physical transmission limitations,[5] the generators typically feather (i.e., stop or reduce generation) or store energy using onsite energy storage. At this time, Avista is not modeling wind with onsite storage or wind facilities with greater output capabilities than can be integrated on the transmission system. Avista's modeling process allows for storage to be sited at a wind facility if cost effective.

On-shore wind capital costs, including construction financing, for various start dates is shown in Table 6.3 as well as fixed O&M costs in kW-yr. for various years in Table 6.4. Fixed O&M does not include indirect charges to account for the inherent variation in wind generation often referred to as variable wind integration. The cost of wind integration depends on the penetration and diversity of wind resources in Avista's balancing authority and the market price of power.

Wind capacity factors in the Northwest range between 32 and 35 percent depending on location and in the 43 to 51 percent range in Montana and offshore locations. This plan assumes Northwest wind (Washington and Oregon) has a 34 percent average capacity factor, while Montana and offshore wind have average capacity factors of 43 and 50 percent, respectively. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on the wind regime in each year (see stochastic modeling assumptions section for details in Chapter 8).

Offshore wind has potential for higher annual capacity factors (51 percent), but development and operating costs are higher. At the time of this plan's analysis, developers have not been offering an offshore product in the Pacific Northwest and are still in the early stages of permitting and cost estimation. The pricing and costs are estimates based on early proposals in California and Oregon.

As discussed above, levelized wind costs change substantially due to the capacity factor but can be impacted even more from tax incentives and the ownership structure of the facility. Table 6.5 shows the nominal levelized prices with different start dates for each modeled location. These price estimates assume a 20-year PPA with a flat pricing structure, includes costs associated with the cost of the PPA, excise taxes, commission fees, and uncollectables[6] to customers. These costs do not include the transmission costs for either capital investment or wheeling purchases or integration costs. If a PPA is selected in Avista's resource strategy, the model assumes the PPA will extend through at least 2045.

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[5] If transmission is limited due to contractual reasons, an additional option is to buy non-firm transmission to move the power.

[6] Uncollectables refer to additional revenue collected from customers to cover the payments not received from other customers.

Photovoltaic Solar

Avista models solar system configurations as resource options, whereas the under 5 MW distributed systems are discussed in Chapter 5, the utility scale options are discussed here. Utility-scale on-system solar facilities assume a minimum capacity of 100 MW to take advantages of economies of scale and single axis systems. There are also two locations for resource selection, the first is local on-system resources in areas within Avista's transmission system with higher capacity factor potential, and a second option further south either in Oregon or Idaho, requiring transmission acquisition. Avista expects other locations to participate in future RFPs. Tables 6.3 and 6.4 show capital and fixed O&M forecasts for these resources and the levelized prices for a 20-year PPA is shown in Table 6.5. These costs do not include transmission costs associated with either new construction or wheeling purchases or integration costs.

Table 6.3: Forecasted Solar and Wind Capital Cost ($/kW)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2025	1,203	1,462	1,652	5,549
2030	1,027	1,285	1,496	5,711
2035	1,094	1,361	1,597	6,037
2040	1,163	1,438	1,700	6,463
2045	1,233	1,514	1,807	6,972

Table 6.4: Forecasted Solar and Wind O&M ($/kW-yr.)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2025	21.55	48.60	48.60	97.01
2030	20.14	51.54	51.54	99.40
2035	21.72	55.31	55.31	104.23
2040	23.40	59.27	59.27	110.67
2045	25.19	63.40	63.40	118.44

Table 6.5: Levelized Solar and Wind Prices ($/MWh)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2025	41.89	43.89	34.22	124.74
2030	34.75	32.32	24.75	121.19
2035	43.87	60.87	53.66	152.02
2040	49.13	60.07	53.66	155.38
2045	48.96	57.25	52.16	158.02

Solar with Energy Storage (Lithium-Ion Technology)

As previously discussed, storage paired with energy storage lowers cost due to sharing of local infrastructure, it can also directly shift energy deliveries, manage intermittent generation, use common equipment, increase peak reliability, and can prevent energy oversupply.

Lithium-ion technology prices are declining (absent recent price spikes related to supply chain disruption) and will likely continue to fall due to increasing manufacturing levels and product enhancements. Avista estimates the cost three storage level types in Table 6.6 for solar PPAs, these costs are based on 100 MW solar facility. Avista modeled one two-hour duration and two four-hour duration options. Avista's experience with solar generation from its 19.2 MW Adams-Neilson PPA shows significant energy variation due to cloud cover and on-site storage could be beneficial, but at this time other resources can provide this service at a lower cost. For this analysis, Avista considers the benefits for reducing the variable generation integration costs and enhanced resource adequacy of the storage device within the resource selection model. Currently, due to the complexity and range of potential storage configurations, the analysis considers only the four-hour and two-hour designs. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power.

Table 6.6: Additional Levelized Cost for Combined Lithium-Ion Storage Solar Facility ($/kW-month)

Year	100 MW/ 400 MWh	100 MW/ 200 MWh	50 MW/ 200 MWh
2025	11.8	7.2	4.1
2030	11.1	7.1	4.0
2035	13.6	8.7	4.8
2040	14.9	9.6	5.2
2045	12.1	7.8	4.1

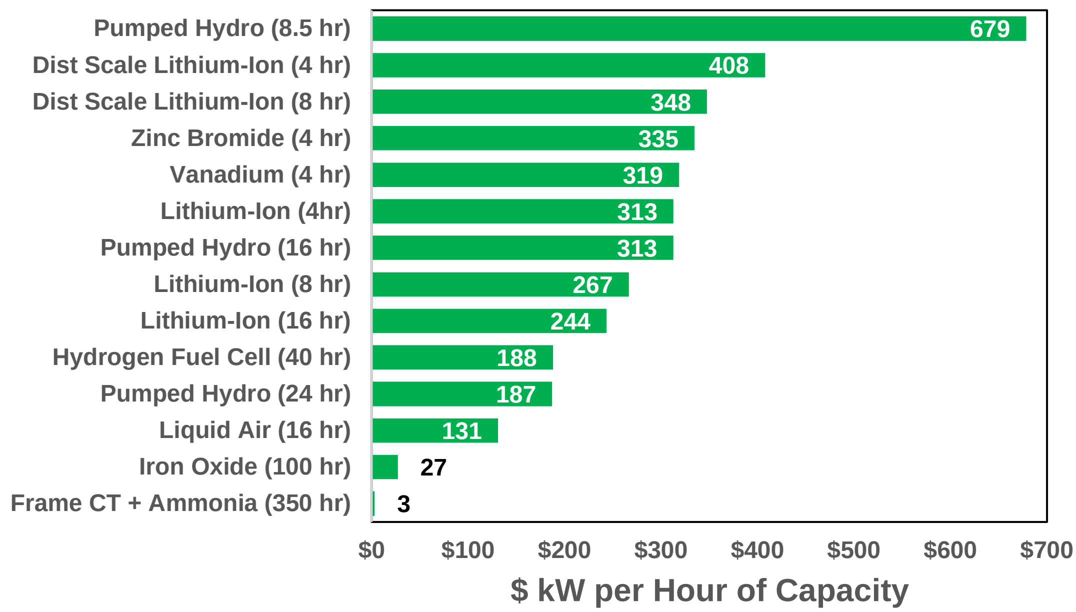
Stand-Alone Energy Storage

Energy storage resources are gaining significant traction to meet short term capacity needs in the western U.S. Energy storage does not create energy but shifts it from one period to another in exchange for a portion of the energy stored. Avista modeled several energy storage options including pumped hydro storage, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and iron oxide. In addition to the technology differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is rapidly changing due to the technology advancements. In addition to changing prices for existing technologies, new technologies are entering the storage space. The rapid change in pricing and new available technologies justifies the need for frequent updates to the IRP analysis. Passage of the 2022 Inflation Reduction Act (IRA) creates energy tax credits for all storage technologies through 2032.

Another challenge with storage concerns pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Storage is also gaining attention to address transmission and distribution expansion, where the technology can alleviate conductor overloading and short duration load demands rather than adding physical line/transmission capacity.

Storage cannot be shown in $ per MWh as with other generation resources because storage does not create energy, but rather stores it with losses. The analysis shown in Figure 6.1 illustrates the cost differences between the technologies when capital cost is divided by duration of storage but does not consider the efficiency of the storage process or the pricing of the energy stored. This analysis is performed in the resource selection process. Figure 6.1 summarizes the storage technologies based on upfront capital cost and duration using costs in 2030 dollars.

Figure 6.1: Storage Upfront Capital Cost versus Duration



Pumped Hydro Storage

The most prolific energy storage technology currently used in both the U.S. and the world is pumped hydro. This technology requires the use of two or more water reservoirs with different elevations. When prices or load are low, water is pumped to a higher reservoir and released during higher price or load periods. This technology may also help meet system integration issues from intermittent generation resources. Currently only one of these projects exists in the northwest and several more are in various stages of the permitting process. An advantage with pumped hydro is the technology has a long service life and is a technology Avista is familiar with as a hydro generating utility. The greatest disadvantages are large capital costs and long-permitting cycles.

The technology has good round trip efficiency rates, Avista assumes 80 percent for most options. When projects are developed, they are designed to utilize the amount of water storage in each reservoir and the generating/pump turbines are sized for how long the capacity needs to operate. Avista models the technology with three different durations: 8.5, 16, and 24 hours. These durations indicate the number of hours the project can run at full capacity. The pricing and durations of these facilities are based on projects currently being developed in the Northwest. As an energy-limited system, Avista includes different duration times to ensure resources have sufficient energy to provide reliable power over an extended period in addition to meeting single hour peaks. The complete range in levelized cost for pumped hydro is shown in Table 6.7. Options also include a $0.58 per MWh (escalating with inflation) variable payment for each MWh generated.

Table 6.7: Pumped Hydro Options Cost ($/kW-month)

Year	8.5 hours	16 hours	24 hours
2025	45.89	40.09	36.21
2030	51.20	44.72	40.39
2035	57.08	49.86	45.04
2040	63.64	55.59	50.21
2045	70.96	61.99	55.98

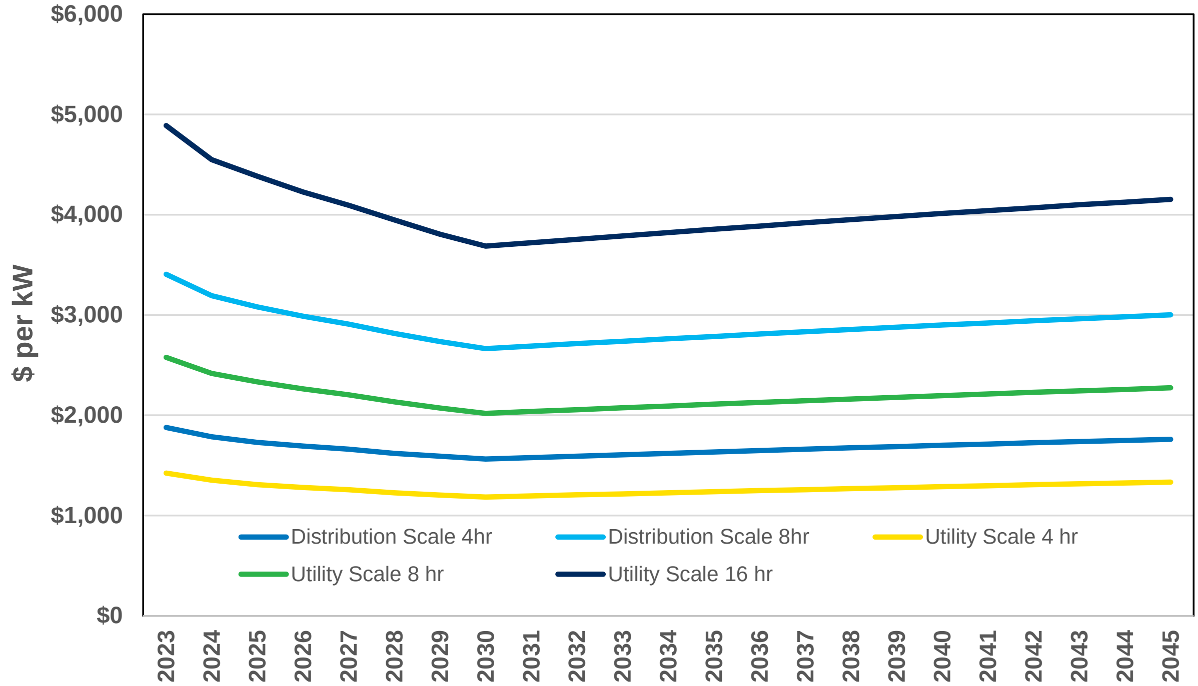
Lithium-Ion Batteries

Lithium-ion technology is one of the fastest growing segments of the energy storage space. This discussion focuses on using energy storage as a stand-alone resource rather than coupled with solar as discussed earlier. Stand-alone lithium-ion assumes a utility owned asset for modeling purposes, but it could be acquired through a PPA as well with two 10-year cycles for a 20-year life. Fixed O&M costs include replacement cells to maintain the energy conversion efficiency and capacity for this storage option. Estimated costs include federal tax credits passed as part of the 2022 IRA.

The lithium-ion technology is an advanced battery using ionized lithium atoms in the anode to separate their electrons. This technology can carry high voltages in small spaces making it a preferred technology for mobile devices, power tools, and electric vehicles. The large manufacturing sector of the technology is driving prices lower permitting the construction of utility scale projects.

Avista modeled five stand-alone configurations for lithium-ion batteries. Two DER small-scale sizes (<5 MW) with four- and eight-hour durations for modeling the potential for use on the distribution system and three larger systems (25 MW) including four- and eight-hour durations as well as a theoretical 16-hour configuration were derived from publicly available energy consultant sources. Figure 6.2 show the forecast for each of the sizes and durations considered. Avista classifies the four-hour battery as the standard technology with a capital cost of $1,423 per kW in 2023 dollars. Avista assumes an annual Fixed O&M cost of $149 per kW-year in 2023 for the four-hour technology.

Figure 6.2: Lithium-ion Capital Cost Forecast



Storage technology is often displayed differently to illustrate the cost since it is not a traditional capacity resource. Table 6.8 shows levelized cost per kW-month for each configuration. This calculation factor levelizes the cost for the capital, O&M, and regulatory fees including capital reinvestments over 20 years divided by the capacity. These costs do not consider the variable costs, such as energy purchases.

Table 6.8: Lithium-Ion Levelized Cost ($/kW-month)

Year	Utility Scale 4 hour	Utility Scale 8 hour	Utility Scale 16 hour
2025	11.63	20.57	38.44
2030	10.79	18.39	33.59
2035	14.56	24.81	45.31
2040	14.57	24.84	45.37
2045	14.31	24.38	44.54

Flow Batteries

This plan models vanadium and zinc bromide flow batteries options. Other technologies are beginning to enter the marketplace. Flow batteries have the advantage over lithium-ion of not degrading over time leading to longer operating lives. The technology consists of two tanks of liquid solutions flowing adjacent to each other past a membrane and generate a charge by moving electrons back and forth during charging and discharging. Avista assumed an acquisition size of 25 MW of capacity with four-hours in duration for each technology.

Capital costs are $1,378 per kW for the vanadium in 2023 and nominal costs fall 15 percent by 2032. Zinc bromide's capital cost are $1,448 per kW in 2023 and similarly fall. Fixed O&M costs are $64.78 per kW-year for vanadium and $72.88 per kW-year for zinc bromide and increase with inflation. Round-trip efficiency for the vanadium is 70 percent and for the zinc bromide is 67 percent. Given Avista's recent experience with vanadium flow batteries, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 6.9 shows the levelized cost per kW-month of capacity.

Liquid Air Storage

A new technology with promise to provide long duration and long service life is liquid air storage. This is similar to compressed air storage, but rather than compressing the air, the air is cryogenically frozen and stored in a tank to increase storage duration capability. The conversion process requires a liquefier to liquefy the air for storage. It is possible to use waste heat from existing natural gas-fired turbines to increase the efficiency of liquefying the air molecules. A round-trip efficiency of 65 percent is assumed. After the air is stored, it can later be used by pushing the air through an air turbine.

Liquid air has not been widely used in the electric sector but relies on common technology from other industries requiring liquefaction of gases. This experience in the technology gives promise as a new technology that could benefit from short commercialization periods. Avista models a 25 MW unit with 400 MWh hours of storage (16 hours) as the resource option. Another advantage of this technology is the ability to add storage capacity by adding more tanks while using the same turbine and liquefaction systems.

Avista estimates liquid air storage capital costs at $1,661 per kW (2023 dollars) and increases with inflation due to the use of mature industrial technology. Fixed O&M is $25.79 per kW-year and carries a $5.93 per MWh variable charge. The levelized cost of the storage is estimated to be $14.45 per kW-month for 2023 and future years increase with inflation.

Iron Oxide Storage

Another new storage technology is an iron oxide battery where energy is stored using energy created through the oxidization process. Iron is less expensive and more readily available than lithium-ion or other storage technology elements. This technology uses oxygen to convert iron inside the battery to rust and later convert it back to iron. Due to the low cost of iron compared to other elements a long-duration resource can be obtained at similar cost to current shorter duration technologies.

This analysis assumes a 100 MW iron-oxide battery with a 36.5 percent round-trip efficiency with 100 hours of storage or 10,000 MWh of storage. Capital costs are estimated at $2,528 per kW (2023 dollars) and increase due to inflation. Fixed O&M is $30.95 per kW-year and the levelized cost of iron oxide storage is $249 per kW ($20.75 per kW-month) increasing for inflation in future periods. The actual costs are uncertain given this resource is relatively new for commercial energy use.

Table 6.9: Flow Battery Levelized Cost ($kW-Month)

Year	Vanadium	Zinc Bromide	Iron Oxide	Liquid Air
2025	15.94	17.26	20.98	15.11
2030	16.07	17.46	21.51	16.86
2035	19.95	21.60	29.77	25.39
2040	20.89	22.65	30.44	28.31
2045	21.91	23.81	31.17	31.57

Other “Clean” Resource Options

Other “clean” resource options include renewable hydrogen applications such as fuel cell, woody biomass, geothermal, nuclear, and ammonia, which are described in more detail below.

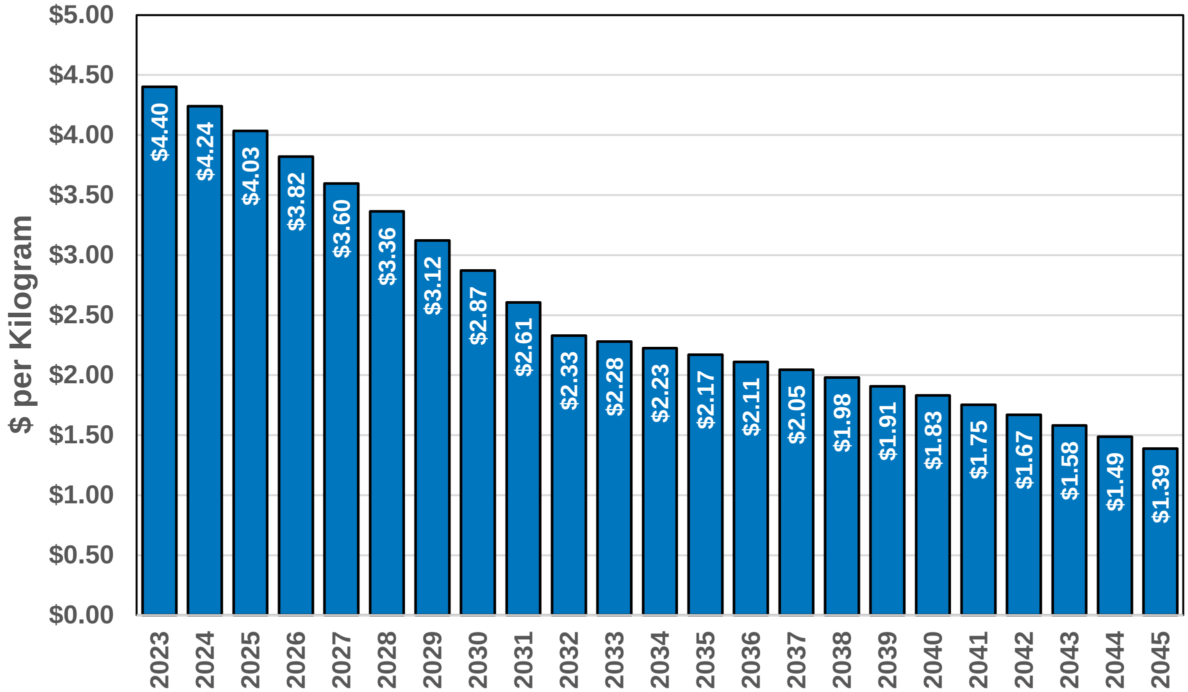
Renewable “Green” Hydrogen

The idea of using green hydrogen using renewable energy to power an electrolyzer in the energy sector has been a perennial option for the distant future. This technology is an avenue for long-duration energy storage with the potential to store power to continuously run for up to several days. Hydrogen would be delivered by pipeline, truck, or rail and stored in tanks and then converted back to power (and water) when needed using a fuel cell or hydrogen-fueled turbine. The ability to store hydrogen in tanks similar to liquid air means medium term duration times can be obtained. Significant research and development (R&D) is being dedicated to green hydrogen technologies in transportation and other sectors which may result in reduced costs or increased operating efficiency. It is also possible transportation and other sectors could utilize the electric power system to create a cleaner form of hydrogen to offset gasoline, diesel, propane, or natural gas.

Most hydrogen today uses methane-reforming techniques to remove hydrogen from natural gas or coal. This technology is primarily used in the oil and natural gas industries but results in similar levels of greenhouse gas emissions from the combustion of the underlying fuels absent sequestration or carbon capture. If green hydrogen is obtained from “clean” energy through electrolysis of water, the amount of greenhouse gas emissions can be greatly reduced. If renewable energy prices fall and there is an available water supply, the operating cost of creating green hydrogen could also fall, however capital costs would remain steady without significant technology enhancements.

Converting hydrogen back into power could be done by using a hydrogen fuel cell or direct burning in a combustion turbine similar to natural gas-fired generation. Figure 6.3 shows the forecasted delivered price of hydrogen to a potential green hydrogen fuel facility in Avista’s service territory. The development and delivery of green hydrogen is estimated based on the projected cost of electrolyzer technology with reduction in costs due to scaling and access to low-cost renewable electric power and water.

Figure 6.3: Wholesale Green Hydrogen Costs per Kilogram



The second step in the hydrogen concept is to convert the hydrogen back to power. For this conversion, a 25 MW fuel cell would be assembled for utility scale needs. The estimated capital cost for a fuel cell is $6,071 per kW with a forty-hour storage vessel plus fixed O&M at $181.16 per kW-year (2023 dollars). Table 6.10 shows the all-in levelized cost of hydrogen including both the fuel cell capital recovery fixed cost and the fuel cost per MWh.

There are significant safety concerns relative to hydrogen to be resolved and mitigated as hydrogen ignites more easily than gasoline or natural gas. Therefore, adequate ventilation and leak detection are important elements in the design of a safe hydrogen storage system. Hydrogen burns with a nearly invisible flame which requires special flame detectors. Some metals become brittle when exposed to hydrogen, so selecting the appropriate metal is important to the design of a safe storage system. Finally, appropriate training in safe hydrogen handling would be necessary to ensure safe use. Appropriate engineering along with safety controls and guidelines could mitigate the safety risk of hydrogen but would add to the high capital and operating costs of this resource option. Another option to generate power with hydrogen is to use it in a combustion turbine, currently co-firing and pure hydrogen fueling is being tested. While this is a viable option, Avista presents a similar option below to solve storage and safety concerns below in the ammonia turbine option.

Ammonia

A new resource option to this plan is a gas turbine fueled with “clean” ammonia. Ammonia could be sourced from the same electrolysis process as hydrogen, using either directly from a renewable energy source or from grid power. Ammonia requires an additional step to the hydrogen process by adding nitrogen using the Haber-Bosch process. Ammonia can be stored in larger volumes and transported in larger quantities than hydrogen at a lower cost due to large geologic storage for hydrogen is not known to exist near Avista's service area. For this option, two 74 MW capacity combustion turbines (148 MW) using a common 10.9 million gallon storage tank could hold 52,500 MWh hours of energy storage, enough to generate power for 350 consecutive hours at full capacity.

Ammonia storage tanks are common technology in the agriculture industry for fertilizer and modified natural gas turbines capable of ammonia combustion are being developed by turbine manufactures. Another advantage of this technology is the creation of "green" ammonia for use in agriculture. This secondary use can reduce investment cost and risk to a utility by partnering with other industries needing ammonia.

Avista estimates ammonia gas turbine capital costs at $882 per kW (2023 dollars) and increasing with inflation due to the use of mature technology. Fixed O&M is $15.48 per kW-year and carries a $3.10 per MWh variable charge in addition to the cost of the ammonia. The forecasted price of ammonia is based on the hydrogen price forecast shown in Figure 6.3 adjusted for conversion and transportation costs. Since ammonia will be created from electric generation, the pricing of the hydrogen includes the associated power and power delivery costs. The resulting levelized fixed and operating cost are shown in Table 6.10.

Table 6.10: Hydrogen Based Resource Option Costs

	Hydrogen Fuel Cell		Ammonia Turbine	
Year	Fixed Cost ($/kW-month)	Fuel & Variable Cost ($/MWh)	Fixed Cost ($/kW-month)	Fuel & Variable Cost ($/MWh)
2025	85.27	139.77	11.24	258.46
2030	95.12	105.81	12.54	198.83
2035	106.06	81.51	13.98	155.78
2040	118.25	57.04	15.59	111.94
2045	131.84	33.39	17.38	68.94

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management and are considered renewable and a "clean" resource. In the biomass generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale level generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually or about 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity but varies with the moisture content and quality of the fuel. The viability of another Avista biomass project depends on the long-term availability, transportation needs and cost of the fuel supply. Unlike wind or solar, woody biomass can be stockpiled and stored for later use. Many announced biomass projects fail due to the lack of a reliable long-term fuel source.

Based on market analysis of fuel supply and expected use of biomass facilities, a new facility could be a wood-fired peaker. With high levels of intermittent renewable generation, a wood-fired peaker could generate during low renewable output months or days. The capital cost for this type of facility would be $4,907 per kW plus O&M amounts of $29.66 per kW-year for fixed costs and $3.62 per MWh of variable costs (2023 dollars). The levelized cost is $650.53 per kW-year ($54.21 per kW-month) for a 2023 project plus fuel and variable O&M costs.

Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal greenhouse gas emissions (zero to 200 pounds per MWh). Some forms of geothermal technology extract steam from underground sources to run through power turbines on the surface while others utilize an available hot water source to power an Organic Rankine Cycle installation. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to develop locally. Geothermal energy often struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust with no guarantee of reaching useable geothermal resources. Ongoing geothermal costs are low, but the capital required for locating and proving a viable site are significant. The cost estimate for a future geothermal PPA is $55.72 per MWh in 2023 at the busbar.

Nuclear

Avista includes nuclear power options as another "clean" fuel resource option, but given the uncertainty of their economics, regional political issues with the technology, U.S. nuclear waste handling policies and Avista's modest needs relative to the size of modern nuclear plants Avista is unlikely to select a nuclear project in its preferred portfolio even if economic. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power into their resource mix and offer Avista a PPA or if cost effective small-scale nuclear plants become commercially available.

The viability of nuclear power could change as national policy priorities focus attention on decarbonizing the nation's energy supply. The limited amount of recent nuclear construction experience in the U.S. makes estimating construction costs difficult. Cost projections are from industry studies, recent nuclear plant license proposals and the small number of projects currently under development. Modular nuclear design could increase the potential for nuclear generation by shortening the permitting and construction phase and making these traditionally large projects a better fit to the needs of smaller utilities. Given this possibility, Avista included an option for small scale nuclear power. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $140.18 per MWh assuming capital costs of $7,574 per kW (2023 dollars) as a PPA.

Other Generation Resource Options

Resources not specifically included as options in this analysis include cogeneration, landfill gas, anaerobic digesters, and central heating districts. This plan does not model these resource options explicitly but continues to monitor their availability, cost, and operating characteristics to determine if state policies change or the technology becomes more economically viable.

Exclusion from the analysis does not automatically exclude non-modeled technologies from Avista's future resource portfolio. The non-modeled resources can compete with resources identified in the resource strategy through competitive acquisition processes when a resource shortage is known, and the Company seeks resources to fill those needs. Competitive acquisition processes identify technologies to displace resources otherwise included in the resource strategy. Another possibility is acquisition through a PURPA contract. PURPA allows developers to sell qualifying power to Avista at set prices and terms[7] outside of the RFP process.

Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The costs of a landfill gas project depend on the site specifics. The Spokane area had a project at one of its landfills, but it was retired after the fuel source depleted to an unsustainable level. Much of the Spokane area uses the Spokane Waste to Energy Plant instead of landfills for solid waste disposal. Using publicly available costs and the NPCC estimates, landfill gas resources are economically promising, but are often limited in their size, quantity, and location. Many landfills are considering cleaning the landfill gas to create pipeline quality gas due to low wholesale electric market prices. This form of renewable natural gas has become an option for utilities to offer a renewable gas alternative to customers. This form of gas and the duration of the supply depends on the on-going disposal of trash, otherwise the methane could be depleted in six to nine years.

Anaerobic Digesters (Manure or Wastewater Treatment)

The number of anaerobic digesters is increasing in the Northwest. These plants typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power generators or directly inject a cleaned fuel into the natural gas pipeline. These facilities tend to be significantly smaller than most utility-scale generation projects and are often less than five megawatts. Most digester facilities are located at large dairies and cattle feedlots.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed helps the economics of a project significantly, although costs range greatly depending on system configuration. Retrofits to existing wastewater treatment facilities are possible but tend to have higher costs. Many projects offset energy needs of the facility so there may be little, if any, surplus generation capability. Avista currently has a 260-kW wastewater system under a PURPA contract with a Spokane County wastewater facility. Due to the ability to produce pipeline quality gas these resources have also shifted to selling renewable natural gas.

[7] Rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

Small Cogeneration

Avista has few industrial customers with loads large enough to economically support a cogeneration project. If an interested customer developed a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel, capital, and emissions control costs, as well as credit toward Washington's EIA efficiency targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. Few compressor stations exist in Avista's service territory, but the existing compressors in our service territory have potential for this generation technology. A big challenge in developing any new cogeneration project is aligning the needs of the industrial facility with the utility need for power. The optimal time to add cogeneration is during the creation or retrofit of an industrial process, but the retrofit may not occur when the utility needs new capacity. Another challenge to cogeneration is estimating costs when host operations drive costs for a project. The best method for the utility to acquire this technology is probably through the PURPA process or through a future RFP.

Coal

New coal-fired plants are extremely unlikely due to current policy, emission performance standards and the shortage of utility scale carbon capture and storage projects. The risks associated with future carbon legislation and projected low natural gas and renewables costs make investments in this technology highly unlikely. It is possible in the future there will be permanent carbon capture and sequestration technology at price points to compete with alternative fuels. Avista will continue to monitor this development for future IRPs.

Heating Districts

Historically heating districts were preferred options to heat population dense city centers. This concept relies on a central facility to either create steam or hot water then distribute via a pipeline to buildings to provide end use space and water heating. Historically, Avista provided steam for downtown Spokane using a coal-fired steam plant. This concept is still used in many cities and college campuses in the U.S. and Europe. Developing new heating districts requires the right circumstances, partners, and long-term vision.

These requirements recently came together in a new concept of central heating districts being tested by a partnership between Avista and McKinstry in the Spokane University District, also called the Eco-District. The Hub facility contains a central energy plant to generate, store and share thermal and electrical energy with a combination of heat pumps, boilers, chillers, thermal, and electrical storage. The Hub controls all electric consumption for the campus and balances this against the needs of both the development and the grid. Future buildings within the district will be served by the Hub's central energy plant, expanding the district's shared energy footprint. A part of the Eco-District development will involve studying the costs and benefits of this configuration. The success of the district will determine how it could be implemented in the future for Avista's customers.

Bonneville Power Administration

For many years, Avista received power from the Bonneville Power Administration (BPA) through a long-term contract as part of the settlement from WNP-3. Most of the BPA's power is sold to preference customers or in the short-term market. Avista does not have access to power held for preference customers but engages BPA on the short-term market. Avista has two other options for procuring BPA power. The first is using the New Resource NR rate. BPA's power tariff outlines a process for utilities to acquire power from BPA using this rate for one year at a time. Since this offering is short-term and variable, Avista does not consider it a viable long-term option for planning purposes, however, it is a viable alternative for short-run capacity needs. The other option to acquire power from BPA is to solicit an offer. BPA is willing to provide prices for periods of time when it believes it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs and likely take place after current agreements with public power customers end in 2027.

Existing Resources Owned by Others

Avista has purchased long-term energy and capacity from regional utilities in the past, specifically the Public Utility Districts in the Mid-Columbia region and has a tolling agreement for the Lancaster Generating Station. Avista contracts are discussed in Chapter 3, but extensions or new agreements could be signed. If utilities are long on capacity, it is possible to develop agreements to strengthen Avista's capacity position. Since these potential agreements are based on existing assets, prices are dependent on future markets and may not be cost based. Avista could acquire or contract for energy and capacity of other existing facilities without long-term agreements. Avista anticipates these resources will be offered into future RFPs and may replace any selected resources.

Renewable and Synthetic Natural Gas

Avista did not model the option to use renewable natural gas (RNG) or synthetic natural gas for electric generation. RNG is methane gas sourced from waste produced by dairies, landfills, wastewater treatment plants, and other facilities. The amount of RNG is limited by the output of the available processes. The amount of greenhouse gas emissions the RNG offsets differs depending upon the source of the gas and the duration of the methane abatement used. Avista considers the cost-effective use of this fuel type in its Natural Gas IRP and believes its best use is to reduce emissions from the direct use of natural gas rather than for use as a fuel in natural gas-fired turbines due to higher end-use efficiency in customers' homes. Avista's Natural Gas IRP also includes synthetic natural gas as a resource option, in this case hydrogen is paired with a carbon molecule to create methane. This methane could be used within the natural gas system and supply gas to existing generation. This resource is not included due to the similarity to the ammonia option, but at a higher cost.

Thermal Resource Upgrade Options

Avista investigated opportunities to add capacity at existing facilities for the last several IRPs, implementing these projects when cost effective. Avista is modeling two potential options at Rathdrum CT.

Rathdrum CT 2055 Uprates

By upgrading certain combustion and turbine components, the firing temperature can increase to 2,055 degrees from 2,020 degrees providing a 5 MW increase in output.

Rathdrum CT Inlet Evaporation

Installing a new inlet evaporation system could increase the Rathdrum CT capacity by 10 MW on a peak summer day, but no additional energy is expected during winter months.

Variable Energy Resource Integration Cost

Intermittent energy resources (VER) such as wind and solar require other resources to help balance the variable energy supply. This results in a cost required by shifting from otherwise more efficient operations. This is challenging for Avista because the cost could be the difference of running stored water hours later compared to now. Avista began studying these costs on its system in 2007. This analysis created the methodology the Avista Decision Support System (ADSS) model now uses to not only study the costs of the intermittent resources, but also better equip our real-time operations team with information to use in managing when to dispatch resources. In this analysis, wind adds $18.30 per kW-year and Solar $4.6 per kW-year using the previous IRP's methodology.

Avista is updating its VER integration costs with the assistance of Energy Strategies.[8] To minimize cost and utilize ADSS, this is an iterative process between Energy Strategies and Avista. Energy Strategies has completed base case assumptions for all portfolio mixes ranging from all wind to a mix of wind/solar to all solar. Currently, Avista is using ADSS to model sensitivities for the 400 MW wind case to address the next 10 plus years from the 2021 IRP's Preferred Resource Strategy with low/base/high hydro and low/base/high market prices. Results are anticipated to be complete by the end of March 2023. By the end of the second quarter in 2023, Energy Strategies will complete the integration study deliverables including finalizing the calculation of integration costs, presentation and report of full analysis and results and providing Avista with a tool to calculate reserves for future scenarios and mixes of VERs.

Sub Hourly Resource and Ancillary Services Benefits

Many of the resources discussed in this chapter may provide reliability benefits to the electrical system beyond traditional energy and capacity due to intra hour needs and system reliability requirements. Some resources can provide reserve products such as frequency response or contingency reserves. Avista is required to hold generating reserves of 3 percent of load and 3 percent of on-line generation. This means resources need to be able to respond within 10 minutes in the event of other resource outages on the system. Within the reserve requirement, 30 MW must be held as frequency response to provide instantaneous response to correct system frequency variations. In addition to these requirements, Avista must also hold capacity to help control intermittent resources and load variance, this is referred to as load following and regulation. The shorter time steps minute-to-minute is regulation and longer time steps such as hour-to-hour is load

[8] https://www.energystrat.com/

following. Together these benefits consist of ancillary services for the purposes of this analysis.

Many types of resources can help with these requirements, specifically storage projects, natural gas-fired peakers and hydro generation. Some DR options may help in the future as well. The benefits these projects bring to the system greatly depend on many external factors including other "capacity" resources within the system, the amount of variation of both load and generation, market prices, market organization (i.e., EIM), and hydro conditions. Internal factors also play a role, such as the ability for the resource to respond in speed and quantity. Avista conducted a study on its Turner Energy Storage project along with the Pacific Northwest National Lab to understand the operating restrictions of the technology. For example, if the battery is quickly discharged, the efficiency lowers and depending on the current state of charge the efficiency is also affected. These nuances make it more difficult to model in existing software systems.

Avista will continue studying the benefits of energy storage by modeling additional scenarios including price, water year, and level of renewable penetration. It will also need to study the benefits of using a sub-hourly model rather than using variability estimates within the hour. Avista is refining the ADSS model to provide this complete analysis, although Avista does not expect more detailed analysis to change the current results of these studies. Avista presented results from two studies regarding the potential analysis with the ADSS system. These analyses were completed using existing markets and showed the potential to provide benefits from new resources with flexibility. As Avista enters a future with additional on-system renewables and an EIM, these estimates will need to be revised. Table 6.11 outlines the assumed values for Ancillary Service or within hour benefits for new construction projects. These estimates also apply to DERs if they can respond to utility signals.

Table 6.11: Ancillary Services and Sub-hourly Value Estimates (2023 dollars)

Resource	$/kW-yr.
Combustion turbine/reciprocating engine	1.00
Lithium-ion battery	4.74
Lithium-ion battery connected to solar	4.58
Pumped hydro	4.74
Flow battery	1.74
Liquid Air	0.50

Qualifying Capacity Credit

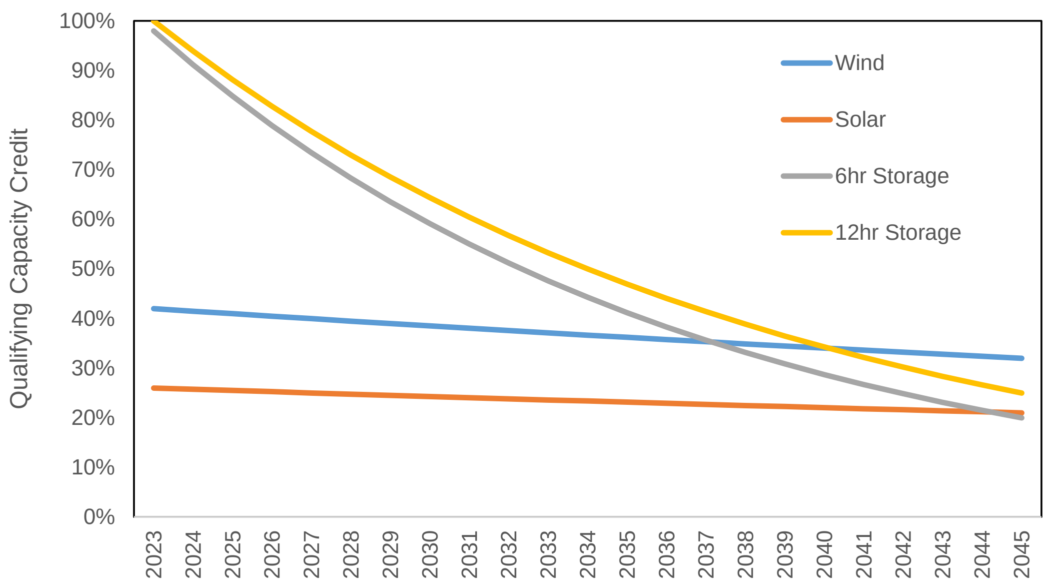
As discussed in Chapter 4, Avista is participating in the first non-binding period of the Western Resource Adequacy Program (WRAP). One purpose of the WRAP is to develop QCC values for regional resources. For storage hydro resources, a customized methodology was used to determine the QCC considering 10 years of each resource's actual historic output (2011 – 2020), water in storage, reservoir levels, and both power and non-power constraints. For run of river resources, an effective load carrying capability (ELCC) analysis of historical data was performed which resulted in a monthly ELCC for each resource. An ELCC analysis of historical data was performed and monthly ELCC were developed by zone. VER zones were defined based on climate and fuel supply, not transmission. Thermal QCC methodology used unforced capacity (UCAP) analysis of historical data and incorporated six years of historical data removing the worst performing year) for each season.

Table 6.12: New Resource QCC Values

Resource	January (percent)	August (percent)
Northwest solar	3	24
Northwest wind	8	18
Montana wind	28	13
Off-shore wind	16	36
Storage 4- hour duration	83	83
Storage 8-, 16-, or 100-hour duration	98	98
Solar + Storage	25	100

Avista expects the WRAP will lower QCC values over time as more variable energy resources and storage are added to the system. While it intends to do so, the WRAP has yet to conduct this analysis. However, there are studies in the public domain estimating changes in ELCC over time. Avista relies on a regional resource adequacy study[9] for this assumption investigating high renewable and energy storage penetrations. The resulting QCC forecast assumed in this Progress Report for VER and energy storage is shown in Figure 6.4. These values were determined by using the amount of regional resources from the wholesale price forecast described in Chapter 8 to the applicable ELCC forecast value from the regional study.

Figure 6.4: QCC Forecast for VER and Energy Storage



[9] *Resource Adequacy in the Pacific Northwest,* March 2019.

Other Environmental Considerations

All generating resources have an associated greenhouse gas emissions profile, either when it produces energy, during operations, when constructed, retired, or all the above. For this analysis, Avista modeled associated emissions with the production of energy as well as emissions associated with the manufacturing and construction of the facility where emissions information was available, such as from the NREL data for greenhouse gas emissions related to construction and operations.

This analysis includes upstream greenhouse gas emissions from natural gas. Natural gas directly emits 119 pounds of equivalent greenhouse gases per dekatherm when including the other gases within the supply mix. In addition to those emissions, there could be upstream emissions from the drilling process and the transportation of the fuel to the plant also known as fugitive emissions. While not required by the final CETA rules, this analysis includes these emissions for the Washington customer portion of resource optimization. The combusted upstream natural gas is estimated to be 0.77 percent[10] assuming a Canadian sourced natural gas supply. The remaining percentage is derived from estimated methane releases using a 34-year conversion factor from methane to CO_2e. This adjustment results in a 9.8 percent emissions adder to cover upstream methane leakage and combusted natural gas in the supply.

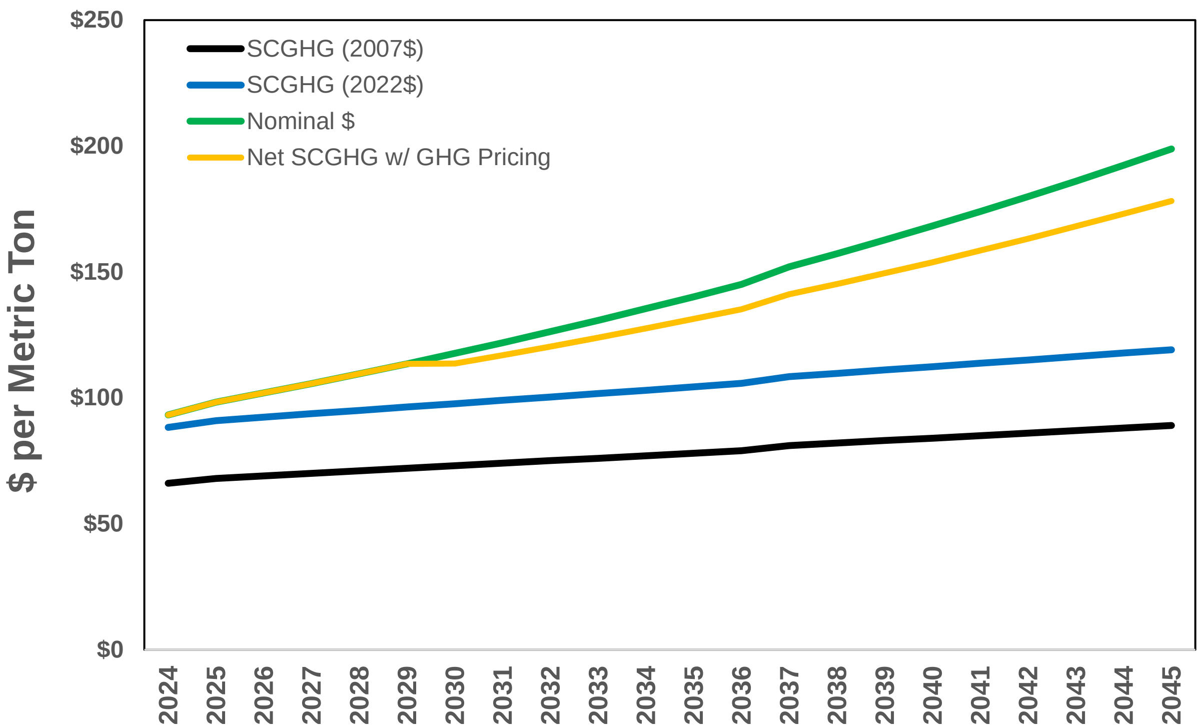
Social Cost of Greenhouse Gas

The social cost of greenhouse gas (SCGHG) is included for thermal resource project additions along with projected emissions reduction from energy efficiency for Washington's load obligations. The SCGHG is shown in Figure 6.5. Avista uses the pricing method and the 2.5 percent discount rate identified by the Washington Commission for CETA. The prices are inflated from 2007 to 2022 using the Bureau of Economic Analysis inflation data and then inflated at 2.25 percent each year thereafter. Due to a greenhouse price being included in resource dispatch decisions the within the wholesale electric price forecast, the values used in the resource optimization model are reduced by this amount (shown as "Net SCGHG w/GHG Pricing"). The net nominal price used in the study is also shown in Figure 6.5.

PRiSM, Avista's portfolio optimization model, uses the SCGHG as a cost adder to Washington's share of greenhouse emitting resources for both existing and new resource options and the associated regional emission reductions from energy efficiency. Any emissions associated with operations and construction are also included in the social cost of greenhouse gas analysis. Avista does not use the social cost of greenhouse gas pricing for market transactions. After review of Section 14 of the CETA, focusing on these costs shall be included for evaluating energy efficiency programs and evaluating intermediate term and long-term resource options in resource plans. Given this section of the law, it excludes short term transactions.

[10] The emission rate is from recent environmental impact studies for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility.

Figure 6.5: Social Cost of Greenhouse Gas



Other Environmental Considerations

There are other environmental factors involved when siting and operating power plants. Avista considers these costs in the siting process. For example, new hydro projects or modifications to existing facilities must be made in accordance with their operating license. If new or upgraded facilities require operations outside this license, the license would be reopened. When siting solar and wind facilities, developers must solicit and receive approvals from local, state, and federal governing boards or agencies to ensure all laws and regulations are met.

If Avista sites a new natural gas-fired facility, it will have to meet all state and local air requirements for its air permit. Requirements are at levels these governing bodies find appropriate for their communities. Currently, Avista is not evaluating emissions costs outside of these considerations.

Non-Energy Impacts

Washington's CETA requires investor-owned utilities to consider equity-related non-energy impacts (NEIs) in integrated resource planning. To accomplish this, Avista contracted with DNV to perform a NEI study on supply-side resources with a goal to 1) conduct a jurisdictional scan to identify additional NEIs that were not specifically listed in Avista's scope, 2) identify NEIs available through federal and regulatory publications, 3) develop quantitative estimates on a $/MWh or $/kW basis as appropriate for each resource, and 4) conduct a gap analysis to provide recommendations to prioritize future research based on the necessary level of effort or anticipated value.

A supply-side NEI database and a final report was completed on April 8, 2022. Accordingly, Avista includes NEIs within the resource strategy analysis for the supply-side resources modeled. This is in addition to the NEIs that had previously been included on energy efficiency. These impacts include the societal impacts of Avista's decision making of Avista's resources and represent quantifiable values to prioritize resource choices. By including these impacts, the analysis can prioritize resource decisions equitably. For example, resources with air emissions versus those without are properly evaluated to consider the environmental impact on local communities. The NEI values used for this analysis are in Table 6.13. Where Avista did not have a value from DNV it estimated its value by using approximation techniques.

There were areas where there was insufficient information for DNV to provide estimated NEI values for any specific NEI types for specific supply-side resources. For many of these areas, the research value and effort to address these gaps were significant. Examples of some of these with insufficient information were related to public health, safety, reliability and resiliency, energy security, environmental (wildfire, land use, water use, wildlife, surface air effects), economic, and decommissioning relative to some or all resource types (e.g., battery storage, hydrogen electrolyzer, etc.). Washington directives indicate a movement to require NEIs in resource planning and research to quantify these would require significant time and investment, it seems a more cost-effective consistent approach would be best conducted at a state-wide level. DNV's Supply Side Non-Energy Impacts report covering the values, assumptions and the gap analysis is included in Appendix D.

Table 6.13: Resource NEI Values

Resource	Operating Impact ($/MWh)	Construction Impact ($/kW)
Solar	0.41	44.8
Wind	0.83	89.6
Natural Gas	-2.86	59
Storage	0	44.27
Wood Biomass	-7.54	102.8
Small Modular Nuclear Reactor	1	102.8
Pumped Hydro	8.22	458
Hydrogen Fuel Cell	0.28	59

7. Transmission & Distribution Planning

This chapter introduces the Avista Transmission and Distribution (T&D) systems and provides a brief description of how Avista studies these systems and recommends capital investments to maintain reliability while accommodating future growth. Avista's Transmission System is only one part of the networked Western Interconnection with specific regional planning requirements and regulations. This chapter summarizes planned transmission projects and generation interconnection requests currently under study and provides links to documents describing these studies in more detail. This section also describes how distribution planning is incorporated into the IRP and Avista's merchant transmissions system rights.

Section Highlights

- Avista actively participates in regional transmission planning forums.
- Avista develops annual transmission and distribution system plans.
- Transmission Planning estimates costs of locating new generation on the Avista system for the IRP.
- Avista formed a Distribution Planning Advisory Group (DPAG) for additional stakeholder involvement, education, and transparency.

Avista Transmission System

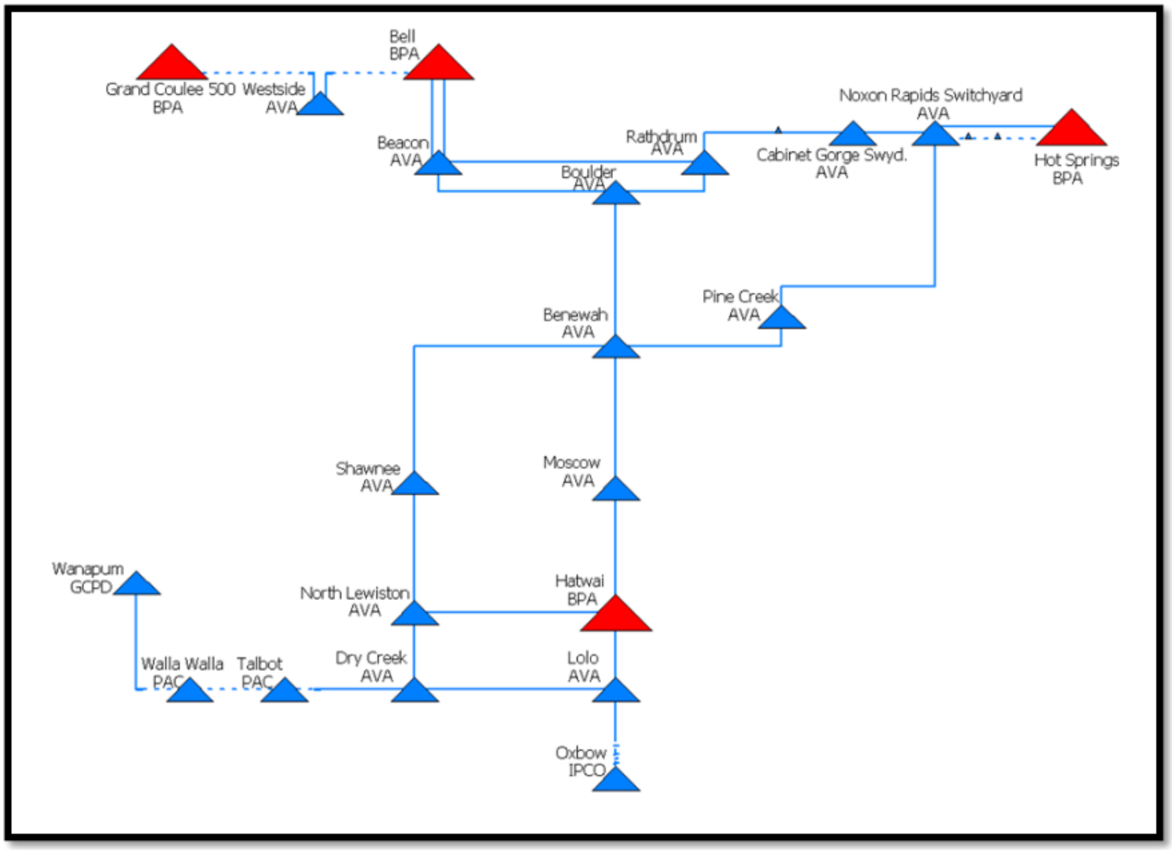
Avista owns and operates a system of over 2,200 miles of electric transmission facilities including approximately 700 miles of 230 kV transmission lines and 1,570 miles of 115 kV transmission lines (see Figure 7.1).

Figure 7.1: Avista Transmission System

230 kV Transmission System

The backbone of the Avista Transmission System operates at 230 kV. Figure 7.2 shows a station-level drawing of Avista's 230 kV Transmission System including network interconnections to neighboring utilities. Avista's 230 kV Transmission System is interconnected to Bonneville Power Administration's (BPA) 500 kV transmission system at the Bell, Hatwai, and Hot Springs substations.

Figure 7.2: Avista 230 kV Transmission System



In addition to providing enhanced transmission system reliability, network interconnections serve as points of receipt for power from generating facilities outside Avista's service area. These interconnections provide for the interchange of power with entities within and outside the Pacific Northwest, including integration of long- and short-term contract resources.

Transmission Planning Requirements and Processes

Avista coordinates transmission planning activities with neighboring interconnected transmission owners. Avista complies with Federal Energy Regulatory Commission (FERC) requirements related to both regional and local area transmission planning. This section describes several of the processes and forums important to Avista's transmission planning.

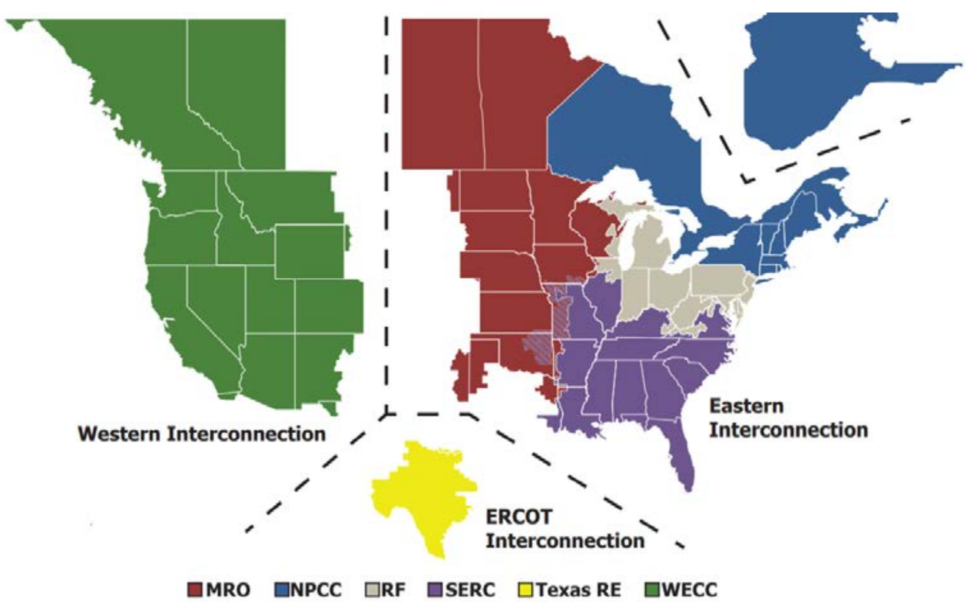
Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is responsible for promoting bulk electric system reliability, compliance monitoring and enforcement in the Western Interconnection. This group facilitates the development of reliability standards and coordinates interconnected system operation and planning among its membership. WECC is the largest geographic territory of the regional entities with delegated authority from the National Electric Reliability Council (NERC) and the FERC. It covers all or parts of 14 Western states, the provinces of Alberta and British Columbia and the northern section of Baja, Mexico.[1] See Figure 7.3 for the map of NERC Interconnections including WECC.

RC West

California Independent System Operator's (ISO) Reliability Coordinator (RC) West performs the federally mandated reliability coordination function for a portion of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system, RC West has the authority to direct specific actions to maintain reliable operation of the overall transmission grid.

Figure 7.3: NERC Interconnection Map



Western Power Pool

Avista is a member of the Western Power Pool (WPP), an organization formed in 1942 when the federal government directed utilities to coordinate river and hydro operations to support war-time production. The WPP serves as a northwest electricity reliability forum, helping to coordinate present and future industry restructuring, promoting member cooperation to achieve reliable system operation, coordinating power system planning

[1] https://www.wecc.biz/Pages/About.aspx.

and assisting the transmission planning process. WPP membership is voluntary and includes the major generating utilities serving the Northwestern U.S., British Columbia, and Alberta. The WPP operates several committees, including its Operating Committee, the Reserve Sharing Group Committee, the Western Frequency Response Sharing Group Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group and the Transmission Planning Committee (TPC).

NorthernGrid

NorthernGrid formed on January 1, 2020. Its membership includes fourteen utility organizations within the Northwest and many external stakeholders. NorthernGrid aims to enhance and improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. Consistent with FERC requirements issued in Orders 890 and 1000, NorthernGrid provides an open and transparent process to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives) and provide a decision-making forum and cost-allocation methodology for new transmission projects. NorthernGrid is a new regional planning organization created by combining the members of ColumbiaGrid and the Northern Tier Transmission Group.

System Planning Assessment

Development of Avista's annual System Planning Assessment (Planning Assessment) encompasses the following processes:

- Avista Local Transmission Planning Process – as provided in Attachment K, Part III of Avista's Open Access Transmission Tariff (OATT);
- NorthernGrid transmission planning process – as provided in the NorthernGrid Planning Agreement; and
- Requirements associated with the preparation of the annual Planning Assessment of the Avista portion of the Bulk Electric System.

The Planning Assessment, or Local Planning Report, is prepared as part of a two-year process as defined in Avista's OATT Attachment K. The Planning Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's Network Customers and Native Load Customers, and meet all other Transmission Service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The Planning Assessment process is open to all interested stakeholders, including, but not limited to Transmission Customers, Interconnection Customers, and state authorities.

Avista's OATT is located on its Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat. Additional information regarding Avista's System Planning work is in the Transmission Planning folder on Avista's OASIS site. Avista's System Planning Assessment is posted on OASIS. Avista's most recent transmission planning document highlights several areas for additional transmission expansion work including:

- **Big Bend** - Transmission system capacity and performance will significantly improve upon completion of the new Othello Substation and Othello Switching

Station 115 kV Transmission Line. These projects are the last phase of the Saddle Mountain 230 kV system reinforcement adding a fourth source into the load center. The addition of communication aided protection schemes and other reconductor projects will improve reliability and lessen the impacts of system faults. This project is needed for continued load growth in the area and integration of utility scale renewable generation.

- **Coeur d'Alene** - The completion of the Coeur d'Alene – Pine Creek 115 kV Transmission Line rebuild project and Cabinet – Bronx – Sand Creek 115 kV Transmission Line rebuild project will improve transmission system performance in northern Idaho. The addition and expansion of distribution substations and a reinforced 115 kV transmission system are needed in the near-term planning horizon to support load growth and ensure reliable operations in this area.

- **Lewiston/Clarkston** - Load growth in the Lewiston/Clarkson area contribute to heavily loaded distribution facilities. Additional performance issues have been identified related to the ability for bulk power transfer on the 230 kV transmission system. A system reinforcement project is under development to accommodate the load growth in this area.

- **Palouse** - Completion of the Moscow 230 kV station rebuild project added capacity and mitigated several performance issues. The remaining issue is a potential outage of both the Moscow and Shawnee 230/115 kV transformers. An operational and strategic long-term plan is under development to best address a possible double transformer outage in this area.

- **Spokane** - Several performance issues exist with the present state of the transmission system in the Spokane area and are expected to worsen with additional load growth. The Westside 230 kV station capacity increase and Sunset Substation rebuild are near completion. The Irvin 115 kV switching station is now complete adding much needed reliability and flexibility to the Spokane Valley. The staged construction of new facilities to support load growth at the Garden Springs 230 kV station is under development. Dependency on the 230 kV Beacon station leaves the system susceptible to performance issues for outages related to transmission lines terminating at the station.

Generation Interconnection

An essential part of the IRP is estimating transmission costs to integrate new generation resources onto Avista's transmission system. A summary of proposed IRP generation options along with a list of Large Generation Interconnection Requests (LGIR) are discussed in the following sections. The proposed LGIR projects have independent detailed studies and associated cost estimates and are listed below for reference.

IRP Generation Interconnection Options and Estimates

IRP Generation Interconnection Options (Table 7.1) shows the projects and cost information for each of the IRP-related studies where Avista evaluated new generation options. These studies provide a high-level view of generation interconnection costs and are similar to third-party feasibility studies performed under Avista's generator interconnection process. In the case of third-party generation interconnections, FERC policy requires a sharing of costs between the interconnecting transmission system and the interconnecting generator. Accordingly, Avista anticipates all identified generation integration transmission costs will not be directly attributable to a new interconnected generator.

Table 7.1: 2023 IRP Generation Study Transmission Costs

Point of Interconnection (POI) Station or Area of Integration	Request (MW)	POI Voltage	Cost Estimate ($ million)[2]
Big Bend area near Lind (Tokio)	100/200	230kV	138.2
Big Bend area near Odessa	100	230kV	167.1
Big Bend area near Odessa	200/300	230kV	168.0
Big Bend area near Othello	100/200	230kV	222.2
Big Bend area near Othello	300	230kV	262.4
Big Bend area near Reardan	50	115kV	9.7
Big Bend area near Reardan	100	115kV	10.3
Clarkston/Lewiston area	100/200/300	230kV	1.9
Kettle Falls substation, existing POI	12/50	115kV	1.8
Kettle Falls substation, existing POI	100	115kV	24.9
Lower Granite area	100/200/300	230kV	2.9
Northeast substation, existing POI	10	115kV	1.6
Northeast substation, existing POI	100	115kV	6.7
Palouse area, near Benewah (Tekoa)	100/200	230kV	2.4
Rathdrum substation, existing POI	25/50	115kV	11.5
Rathdrum substation, existing POI	100	230kV	16.7
Rathdrum substation, existing POI	200	230kV	27.0
Rathdrum Prairie, north Greensferry Rd	100	230kV	32.7
Rathdrum Prairie, north Greensferry Rd	200	230kV	43.0
Rathdrum Prairie, north Greensferry Rd	300	230kV	54.4
Rathdrum Prairie, north Greensferry Rd	400	230kV	91.5
Thornton substation, existing POI	10/50	230kV	1.9
West Plains area north of Airway Heights	100	230kV	2.4
West Plains area north of Airway Heights	200/300	230kV	4.7

Large Generation Interconnection Requests

Third-party generation companies may request transmission studies to understand the cost and timelines required for integrating potential new generation projects. These requests follow a strict FERC process to estimate the feasibility, system impact and facility requirement costs for project integration. After this process is completed, a contract offer to integrate the interconnection project may occur and negotiations can begin to enter into a transmission agreement, if necessary. Table 7.2 lists information associated with potential third-party resource additions currently in Avista's interconnection queue.[3]

[2] Cost estimates are in 2022 dollars and use engineering judgment with a 50 percent margin for error.
[3] https://www.oasis.oati.com/woa/docs/AVAT/

Table 7.2: Third-Party Large Generation Interconnection Requests

Serial or Cluster Number	Former Queue Number	Size (MW)	Type	County	State
Senior	46	126	Wind	Adams	WA
Senior	52	100	Solar	Adams	WA
Senior	60	150	Solar	Asotin	WA
Senior	66	71	Wood Burner/ CT	Stevens	WA
Senior	59	116	Solar/Storage	Adams	WA
Senior	63	26	Hydro	Kootenai	ID
Senior	79	2.1	Solar	Spokane	WA
Senior	80	19	Solar	Spokane	WA
Senior	84	5	Solar	Stevens	WA
Senior	97	100	Solar/Storage	Nez Perce	ID
TCS-02	62	123	Wind	Adams	WA
TCS-03	67	80	Solar/Storage	Adams	WA
TCS-04	73	94	Solar/Storage	Adams	WA
TCS-05	76	114	Solar	Grant	WA
TCS-06	81	94	Solar/Storage	Adams	WA
TCS-07	85	5	Solar	Adams	WA
TCS-08	99	200	Solar/Storage	Franklin	WA
TCS-09	100	100	Solar/Storage	Spokane	WA
TCS-10	103	40	Solar	Lincoln	WA
TCS-11	104	120	Wind	Spokane	WA
TCS-12	105	5	Solar	Stevens	WA
TCS-14	110	375	Wind/Solar/Storage	Garfield	WA
TCS-16	112	125	Solar/Storage	Lincoln	WA
TCS-18	119	200	Solar/Storage	Grant	WA

Distribution Resource Planning

Avista continually evaluates its distribution system for reliability, level of service, and future capacity. The distribution system consists of approximately 350 feeders covering 30,000 square miles, ranging in length from three to 73 miles. Avista serves 410,000 electric customers on its grid.

Avista has taken several steps since the 2021 IRP to meet the goal of including resource benefits in the studies performed to ensure the adequacy of the distribution system. Some steps are a result of ongoing planning improvements, and others are prescribed in Washington's CETA.

Beyond resource planning or the day-to-day business of keeping the system functional, the future of the distribution system is dynamic in terms of needs. Electric transportation, all-electric buildings, behind the meter generation and storage, and data centers are examples of modern disruptions to the distribution system. Understanding these applications and predicting the system impacts is challenging. To do so requires more data, more tools, and more people. Avista has hired two new distribution planning engineers to help in these efforts.

Avista developed several tools to assist in understanding how the system is currently used, how it may be used in the future, and building models for analysis. The tools forecast long- and short-term demand, and weather adjusted demand, using common automated statistical methods. These tools are useful but may require future enhancements. At some point, Avista may need to source tools from the industry with vetted and acceptable results across several utilities.

In the State of Washington, Avista has completed its implementation of an advance metering infrastructure (AMI), giving the utility a rich data source for analysis. Consuming the data and understanding it is a challenge. Early returns indicate a future without AMI would be challenging given policy directions. The data gives visibility to the entire distribution system. At any given moment the performance of every distribution element is being measured, including trunks, secondary trunks, and laterals. Without AMI these systems were rarely measured. The data is also correlated to time. Time series analysis is essential when anticipating resource and mitigation opportunities in the future.

As part of CETA, Avista has committed to starting the Distribution Planning Advisory Group (DPAG). Avista's website has been updated to include a landing page for the DPAG and provide opportunities for interested parties to join the advisory group. The intention of the group is to gain feedback from interested parties about distribution planning and the associated inputs and outputs of planning.

In 2022, a Avista and a consultant formulated a process change for non-wire alternatives and distributed energy resources (DERs) to be considered for grid mitigation. Non-traditional mitigation alternatives were shown to require new steps in the development and eventual operation of a project. The process developed covers the spectrum from planning, to operations, to stakeholder engagement[4]. This work has been completed and is being incorporated into the existing planning process. The development of a DER potential assessment will help determine the availability of non-traditional mitigation alternatives for specific geo-graphic areas.

Deferred Distribution Capital Investment Considerations

New technologies such as energy storage, photovoltaics, and demand response programs may help the electric system by deferring or eliminating future capital investments in distribution and transmission. This benefit depends on the new technologies' ability to solve system constraints and meet customer expectations for reliability. An advantage in using these technologies may be additional benefits incorporated into the overall power system. For example, energy storage may help meet overall peak load needs or provide voltage support on the distribution feeder or at the distribution substation.

The analysis for determining the capital investment deferment value for DERs is not the same for all locations on the system. Feeders differ by whether they are summer- or winter-peaking, the time of day when peaks occur, capacity thresholds, and the rate of local load growth. It is not practical to have a deferment estimate for each feeder in an

[4] Modern Grid Solutions® Work Product

IRP, but it is prudent to have a representative estimate included in the IRP resource selection analysis.

To fairly evaluate and select the most cost-effective solutions to mitigate system deficiencies, the planning process needs to identify the deficiency well in advance of it becoming a performance issue. Longer evaluation periods provide for a comprehensive evaluation so the solution can take a holistic approach to include system resource needs. A shorter period can lead to immediate action that does not lend itself to a stacked value analysis due to time constraints for acquiring and constructing a non-wire alternative.

Identifying future deficiencies in a timely matter has become a focus of System Planning. As previously mentioned, spatial forecasting, load data, time series analysis, and accurate modeling are critical to making decisions as early as possible. Although DER opportunities will continue to be evaluated, System Planning needs the tools, processes, and time to evaluate whether DERs are the preferred solution in any given situation.

At this time, Distribution Planning has not identified any projects meeting the criteria for an economic non-wire alternative. The near-term distribution projects require capacity increases and duration requirements exceeding reasonable DER capacity.

Reliability Impact of Distributed Energy Storage

Utility-scale batteries may offer benefits to grid operations. Reliability is one benefit often associated with batteries. This is particularly true in situations where the battery system is commissioned as a mitigation solution on the distribution system.

There is an industry trend to broaden the list of remedies available to alleviate grid deficiencies beyond traditional wires-based solutions. The solutions are typically called non-wire alternatives, but it may be more informative to call them non-traditional alternatives. The motivation behind the trend is reasonable as non-traditional approaches may be less expensive than legacy options and may also incorporate other ancillary benefits, such as in the case of batteries. Utilities should consider all viable options to arrive at a least cost and reliable solution to distribution issues. In addition to solving grid issues, some non-wire alternatives may also serve as a system resource. These alternatives are referred to as DERs. Batteries, the subject of this section, are one such non-wire alternative with other benefits.

It is often presumed batteries increase system reliability. This may be true in some applications, but in the narrow sense of non-wire alternatives, this would typically not be the case. In the simplest of terms, reliability can decrease with the addition of a battery because the battery and its control system are additional failure points in the existing system chain. It is difficult to identify a case where this reduction in reliability from the added potential failure points is not true.

A common issue on the distribution grid is feeder capacity constraints. A constrained feeder typically approaches the operational constraint during the daily peak load. The historical mitigation for this type of constraint is to increase the capacity of the constraining element by installing a larger conductor, different regulators, a larger transformer, or building a new substation. With the advent of utility-scale batteries, utilities have another option to mitigate these types of feeder constraints. Employing battery storage can effectively shift load from the daytime, when limited and expensive resources are the norm, to the nighttime, when more abundant and less expensive resources may be available.

When DERs are used to solve a constraint in this manner, the battery, or other generating resource, is added to existing distribution facilities. It does not replace existing facilities, and this is a key point as the probability of failure of the existing facilities remains. The probability of failure of the battery or other non-wire alternative system is now an additional failure point. This is analogous to a feeder as a chain where each link is a potential failure point. If the chain consists of 100 links, there are 100 points of possible failure along the entire chain. In the same manner, adding a battery to a feeder to mitigate an issue simply adds another link, and another possible failure point, in the chain. Instead of 100 possible points of failure, there are now 101 possible points of failure. Granted there are temporal aspects to this as well, but the battery will not always be required solution to fix a constraint. If a failure occurs in the battery when there is no constraint, the feeder can continue operating as normal with no adverse impacts to the system. But there will be times when the battery is needed to meet a local peak event and during those times the battery becomes an additional failure point with the expanded system. The annual net effect on the feeder is potentially reduced reliability especially as the reliability of current battery technology is less the other traditional solutions.

The shift in reliability is more significant if a traditional solution was chosen. Existing older links in the failure chain would be replaced with new, often more robust, and more reliable, links. To take the chain analogy even further, if a new substation is built, links are removed from the failure chain as each affected feeder becomes shorter and has less environmental exposure. In addition, there is increased resiliency due to added operational flexibility and the ability to serve load from different directions. The net effect of a traditional solution is increased reliability, and it facilitates future DER resource additions because traditional solutions allow the grid to more readily accept additional DERs.

Quantifying the real effect of a grid-fixing battery or similar resource on reliability is difficult and situational. Indeed, it may not rise to a level of concern given the temporal nature of the decrease in reliability. The benefit of the resource may outweigh the short period of time it increases failure probability. However, if the failure probability increases significantly, an alternate solution may be warranted. From an IRP perspective, the notion of solving a distribution grid deficiency while simultaneously providing a system resource is intriguing and worthy of consideration, but system reliability improvements cannot be assumed.

Merchant Transmission Rights

Avista has two types of transmission rights. The first rights include Avista’s owned transmission. This transmission is reserved and purchased by Avista’s merchant department to serve Avista customers. Avista-owned transmission is also available to other utilities or power producers. FERC separates utility functions between merchant and transmission functions to ensure fair access to Avista’s transmission system. The merchant department dispatches and controls the power generation for Avista and purchases transmission from the Avista transmission operator to ensure energy can be delivered to customers. Avista must show a load serving need to reserve transmission on the Avista-owned transmission system to ensure equitable access to the transmission capacity. Appendix E shows the projected need and future use of the Avista transmission system.

Avista also purchases transmission rights from other utilities to serve customers. This transmission is procured on behalf of the merchant side of Avista. The merchant group has transmission rights with BPA, Portland General Electric (PGE), and a few smaller local electric utilities. Table 7.3 shows the third-party transmission rights contracted by Avista's merchant group.

Table 7.3: Merchant Transmission Rights

Counterparty	Path	Quantity (MW)	Expiration
BPA	Lancaster to John Day	100	6/30/2026
BPA	Coyote Springs 2 to Hatwai	97	8/1/2026
BPA	Coyote Springs 2 to Benton	50	8/1/2026
BPA	Garrison to Hatwai	196	8/1/2026
BPA	Coyote Springs 2 to Vantage	125	10/31/2027
BPA	Coyote Springs 2 to Vantage	50	07/30/2026
BPA	Townsend to Garrison	210	9/30/2027
PGE	John Day to COB	100	12/31/2028
Northern Lights	Dover to Sagle	As needed	n/a
Kootenai Electric	Rockford to Worley	As needed	12/31/2028

8. Market Analysis

A fundamental energy market analysis is an important consideration to support the Avista's resource strategy over the next 20 plus years. Avista uses forecasts of future market conditions to optimize its resource portfolio options. Electric price forecasts are used to evaluate the net operating margin of each supply- and demand-side, including DER options, for comparative analysis between each resource type. The model tests each resource in the wholesale marketplace to understand its profitability, dispatch, fuel costs, emissions, curtailment, and other operating characteristics.

Section Highlights

- Solar and wind dominate future generation across the West while natural gas and increasing amounts of storage will ensure resource adequacy as more coal and natural gas plants shut down or reduce dispatch.
- By 2045, 94 percent of generation in the Pacific Northwest will be carbon free, up from approximately 70-80 percent today depending on hydro conditions.
- Greenhouse gas emissions will fall to historic lows with the expansion of renewables and continued coal and natural gas plant retirements. By 2045, expected emissions will be 62 percent less than in 1990.
- The 22-year wholesale electric price forecast (2024-2045) is $35.34 per MWh. Expansion of renewables reduces future mid-day prices, but evening and nighttime prices will be at a premium compared to today's pricing.
- Natural gas prices continue to remain low; for example, the levelized price at Stanfield (2024-2045) is $3.98 per dekatherm.

Avista conducts its wholesale market analysis using the Aurora model by Energy Exemplar. The model includes generation resources, load estimates and transmission links within the Western Interconnect. This chapter outlines the modeling assumptions and methodologies for this Progress Report and includes Aurora's primary function of electric market pricing (Mid-Columbia for Avista), as well as operating results from the analysis. The Expected Case is the average of 300 simulations of future outcomes using the best available information on policies, regulations, and resource costs.

Electric Marketplace

Avista simulates the entire Western Interconnect electric system for its Progress Report planning; shown as WECC[1] in Figure 8.1. The rest of the U.S. and Canada are in separate electrical systems. The Western Interconnect includes the U.S. system west of the Rocky Mountains plus two Canadian provinces and the northwest corner of Mexico's Baja peninsula.

[1] WECC is the Western Electrical Coordinating Council. It coordinates reliability for the Western Interconnect.

The Aurora market simulation model represents each operating hour between 2024 and 2045. It simulates both load and generation dispatch for sixteen regional areas or zones within the west. Avista's load and most of its generation is in the Northwest zone identified in Table 8.1. Each of these zones include connections to other zones via transmission paths or links. These links allow generation trading between zones and reflect operational constraints of the underlying system, but do not model the physics of the system as a power flow model. Avista focuses on the economic modeling capabilities of the Aurora platform to understand resource dispatch and market pricing effects resulting in a wholesale electric market price forecast for the Northwest zone or Mid-Columbia marketplace.

The Aurora model estimates its electric prices using an hourly dispatch algorithm to match the load in each zone with the available generating resources. Resources are selected to dispatch considering fuel availability, fuel cost, operations and maintenance cost, dispatch incentives/disincentives, and operating constraints. The marginal cost of the last generating resource needed to meet area load becomes the electric price. The IRP uses these prices to value each resource (both supply and load side) option and select from among them to achieve a least reasonable cost plan meeting all load and reliability obligations. Avista also conducts stochastic analyses for its price forecasting, where certain assumptions are drawn from 300 distributions of potential inputs. For example, each forecast randomly draws from an equally weighted probability distribution of the 30-year rolling hydro record.

The next several sections of this chapter discuss the assumptions used to derive the wholesale electric price forecast, resulting dispatch and greenhouse gas emissions profiles for the west for the 300 stochastic studies.

Figure 8.1: NERC Interconnection Map

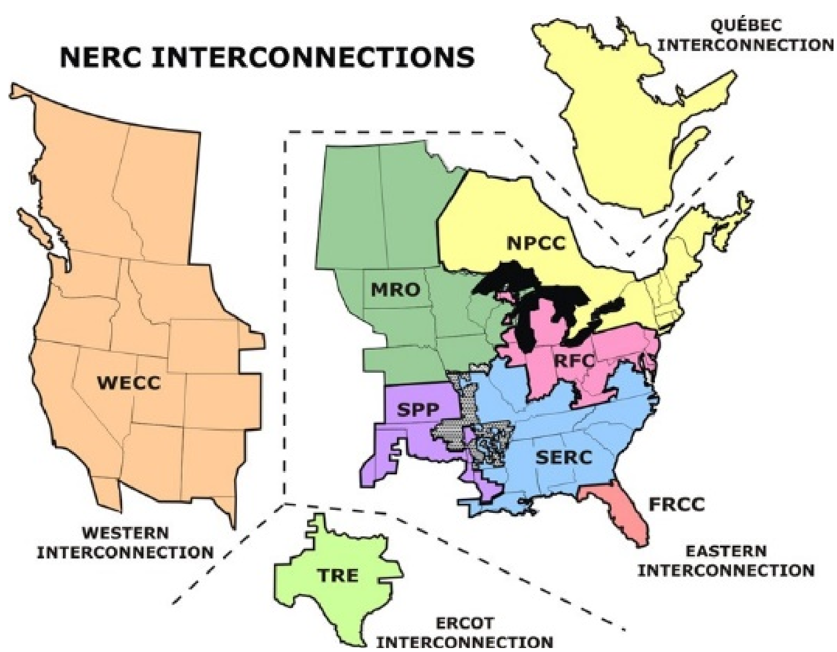


Table 8.1: AURORA Zones

Northwest- OR/WA/ID/MT	Southern Idaho
Utah	Wyoming
Eastern Montana	Southern California
Northern California	Arizona
Central California	New Mexico
Colorado	Alberta
British Columbia	South Nevada
North Nevada	Baja Mexico

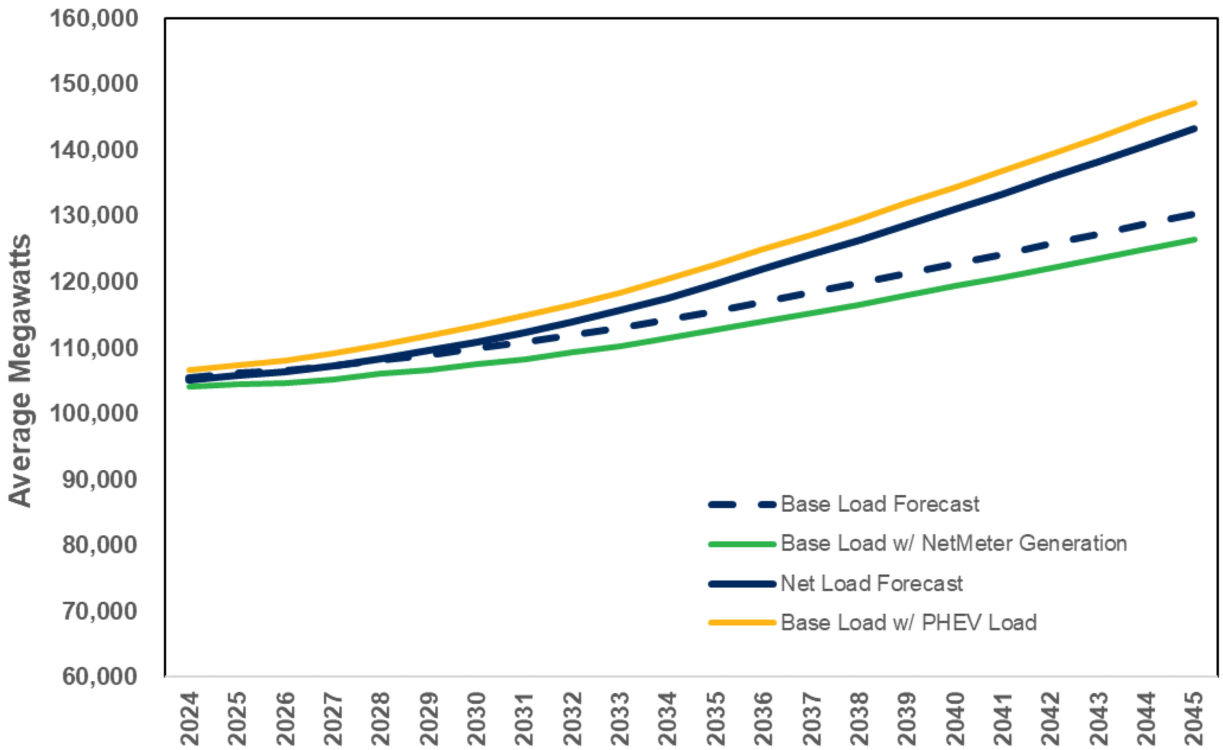
Western Interconnect Loads

Each of the sixteen zones in Aurora require hourly load data for all 22 years of the forecast plus 300 different stochastic studies for weather variation. Future loads may not resemble past loads from an hourly shape point of view due to the continual increase in electric vehicles (EVs) and rooftop solar. Changes in energy efficiency, demand curtailment/demand response, population migration, and economic activity increase the complexity. While each of these drivers are important to the forecast of power pricing, it takes a large amount of analytical time to estimate or track these macro effects over the region. Avista uses the following methods to derive its regional load forecast for power price modeling to account for these complexities.

Avista begins with Energy Exemplar's demand forecast included with the Aurora software package. This forecast includes an hourly load shape for each region along with annual changes to both peak and energy values. Avista updates the load forecast using a national consultant's expectations on future loads. Figure 8.2 shows this base forecast as the black dashed line. Western Interconnect load grows 0.95 percent per year. Avista adjusts this initial forecast to account for changes in EV penetration and net-metered generation, including rooftop solar. Annual EV load grows at 14.0 percent and net-metered generation grows at 5.3 percent.[2] These adjustments increase the load forecast growth rate to approximately 1.4 percent per year. Within the year, the hourly load shapes adjust to reflect charging patterns of both residential and commercial vehicles in addition to most net-metered generation being modeled as fixed roof mount solar panels.

[2] Avista uses forecasts provided by a national consulting firm to assist in the development of these forecasts.

Figure 8.2: 22-Year Annual Average Western Interconnect Load Forecast



Regional Load Variation

Several factors drive load variability. The largest short-run driver is weather. Long-run economic conditions, like the Great Recession, tend to have a larger impact on the load forecast. The load forecast increases on average at the levels discussed earlier in this chapter, but risk analyses emulate varying weather conditions and base load impacts. Avista continues with its previous practice of modeling load variation using FERC Form 714 load data from 2015 to 2019 as presented in the 2021 IRP. To maintain consistent west coast weather patterns, statistically significant correlation factors between the Northwest and other Western Interconnect load areas represent how electricity demand changes together across the system. This method avoids oversimplifying Western Interconnect loads. Absent the use of correlations, stochastic models may offset changes in one variable with changes in another, virtually eliminating the possibility of broader load excursions witnessed by the electricity grid. The additional accuracy from modeling loads this way is crucial for understanding wholesale electricity market price variation as well as the value of peaking resources and their use in meeting system variation.

Generation Resources

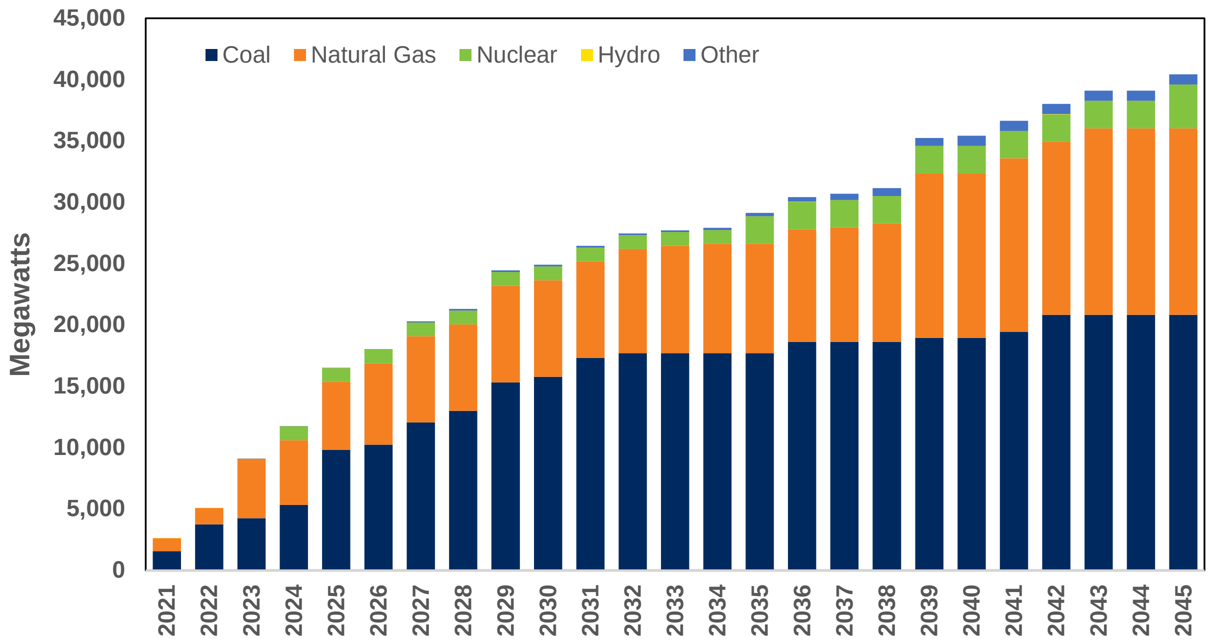
The Aurora model needs a forecast of generation resources to compare and dispatch against the load forecast for each hour. A generation availability forecast includes the following components:

- Resources currently available or known upgrades;
- Resources retiring or converting to a new fuel source;

- New resources for capacity and load service;
- New resources for renewable energy compliance;
- Transmission/distribution additions; and
- Fuel prices, fuel availability and operating availability.

Aurora contains a database of existing generating resources with the location, size and estimated operating characteristics for each resource. When a resource has a publicly scheduled retirement date or is part of an approved provincial phase-out plan, it is retired for modeling purposes on the expected date. Avista does not project retirements beyond those with publicly stated retirement dates or phase out plans. Plants that become less economic in the forecast dispatch fewer hours. Several coal plant retirements have or are expected to occur in the Northwest during this IRP, including Boardman, Colstrip Units 1 and 2, North Valmy, and Centralia. Figure 8.3 shows the total retirements included in the electric price forecast. Approximately 21,000 MW of coal, 15,000 MW of natural gas, 3,600 MW of nuclear,[3] and 827 MW of other Western Interconnect resources including biomass, hydro and geothermal are known to be retiring by the end of 2045.

Figure 8.3: Cumulative Resource Retirement Forecast



New Resource Additions

To meet future load growth, considering state clean energy goals and replacement of retired generation, a new generation forecast must include enough resources to meet peak load. Furthermore, some states include emission constraints or require emission pricing for new resource additions. Avista uses a resource adequacy-based forecast for new resource additions along with data estimates provided by a third-party consultant. The process begins with a forecast of new generation by resource type from a nationally based third-party consultant. Consultants with multiple clients and dedicated staff can,

[3] Avista will re-assess the Diablo Canyon closure assumption in the 2025 IRP.

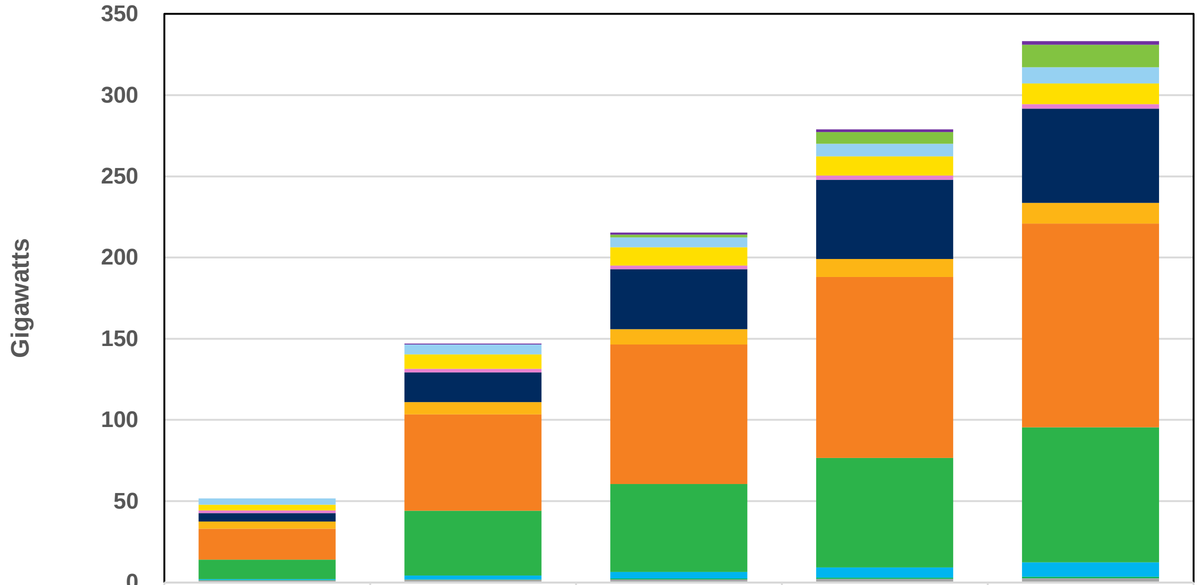
and more efficiently than Avista, research new resource costs and operating characteristics on likely resource construction in the West, especially in areas where Avista has no market presence or local market knowledge. These forecasts for new generation account for environmental policies and localized cost analysis of resource choices to develop a practical new resource forecast.

The next step in this process adjusts the clean energy additions to reflect changes in state policies for additional renewable energy requirements to ensure the new renewable resource build out matches requirements given the load forecast for each region. The last step runs the model for 300 simulations to see if each area can meet a resource adequacy test. The goal is for each area to serve all load in at least 285 of the 300 iterations, a 95 percent loss-of-load threshold measuring reliability.

Figure 8.4 shows the 370 GW of added generation included in this forecast. The added resources include 116 GW of utility-scale solar, 71 GW of wind, 22 GW of natural gas combined cycle CTs, 94 MW of storage,[4] 36 GW of natural gas CTs and 31 GW of other resources including hydro, biomass, geothermal, and net-metering.

[4] Storage energy to capacity ratio averages 3 hours in 2024 and increases to 6 hours by 2045. This change assumes technological advances in the duration of batteries and other storage technologies.

Figure 8.4: Western Generation Resource Additions (Nameplate Capacity)



	2025	2030	2035	2040	2045
NH3CT	0.0	0.0	0.0	0.0	0.0
H2CT	0.0	0.5	1.4	1.7	2.4
OSWind	0.0	0.0	1.5	7.1	13.7
CCCT	3.8	6.2	6.2	7.9	10.0
SCCT	3.6	8.9	11.1	11.8	12.8
DR	1.5	2.1	2.3	2.5	2.8
Storage	5.2	18.3	37.0	48.7	58.1
Net-Meter	4.5	7.6	9.5	11.1	12.8
Solar	19.0	59.4	85.8	111.5	125.4
Wind	11.9	39.8	54.2	67.5	83.2
Geothermal	0.7	2.5	4.1	6.2	8.9
Biomass	0.1	0.3	0.5	0.7	0.8
Hydro	1.3	1.5	1.8	2.1	2.5

Generation Operating Characteristics

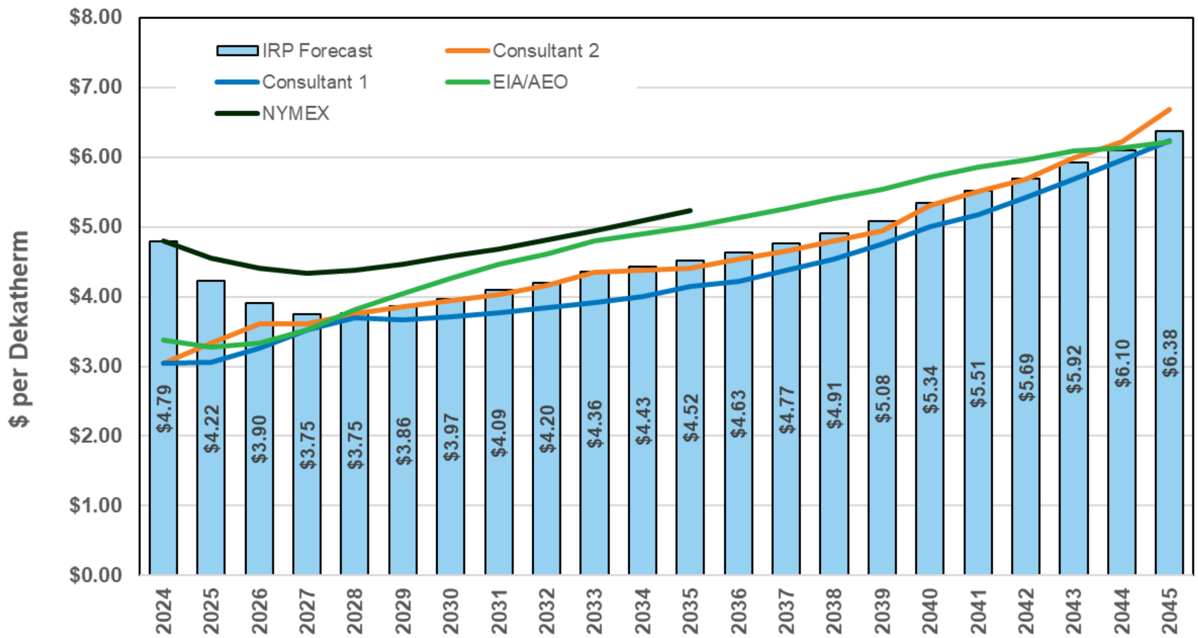
Several changes are made to the resources available to serve future loads to account for Avista's specific expectations, such as fuel prices, and to reflect potential variation of resource supply such as wind and hydro generation.

Natural Gas Prices

Historically, natural gas prices were the greatest indicator of electric market price forecasts. Between 2003 and 2021 the correlation (R^2) between natural gas and on-peak Mid-Columbia electric prices was 0.81, indicating a strong but recently decreasing correlation between the two prices than has been historically observed. Natural gas-fired generation facilities were typically the marginal resource in the northwest except for times when hydro generation was high due to water flow. In addition, natural gas-fired generation met 34 percent of the load in the U.S. Western Interconnect in 2021. With the large increases in new solar and wind generation in the west, the number of hours where natural gas-fired facilities will set the marginal market price is expected to decline.

For modeling purposes, Avista uses a baseline of monthly natural gas prices and varying prices based on a distribution for each of the 300 stochastic forecasts. The forecasts begin with the Henry Hub forecast. Since Avista is not equipped with fundamental forecasting tools, nor is it able to track natural gas market dynamics across North America and the world, it uses a blend of market forward prices, consultant forecasts, and the Energy Information Administration (EIA) forecast. The EIA forecast is compared below in Figure 8.5 against forecasted Henry Hub prices from two consultants with the capability to follow the fundamental supply and demand changes of the industry. The 22-year nominal levelized price of natural gas is $4.49 per dekatherm.[5]

Figure 8.5: Henry Hub Natural Gas Price Forecast



Natural gas generation facilities in the West do not use Henry Hub as a fuel source, but natural gas contracts are priced based on the Henry Hub index using a basin differential. Northwest basins include Sumas for coastal plants on the Northwest pipe system. Power plants on the GTN pipeline obtain fuel at prices based on AECO, Stanfield, or Malin depending on contracted delivery rights. Table 8.2 shows these basin differentials as a percent change from Henry Hub for the deterministic case. This table also includes basin nominal levelized prices for 22 years for selected basins.

[5] The natural gas pricing data is available on the IRP website as “Natural Gas Prices”.

Table 8.2: Natural Gas Price Basin Differentials from Henry Hub

Year	Stanfield	Malin	Sumas	AECO	Rockies	Southern CA
2024	93.4%	97.0%	95.6%	87.8%	100.3%	100.9%
2025	88.0%	95.9%	90.4%	81.2%	99.0%	101.5%
2030	88.8%	95.4%	91.2%	76.4%	105.3%	102.2%
2035	89.9%	96.7%	93.0%	78.6%	108.2%	104.1%
2040	87.6%	93.5%	91.0%	78.3%	102.1%	100.7%
2045	85.5%	89.6%	89.7%	79.1%	97.1%	97.7%
22 yr.	**$3.98**	**$4.26**	**$3.73**	**$3.54**	**$3.99**	**$4.20**

As described earlier, natural gas prices are a significant predictor of electric prices. Due to this significance, the IRP analysis studies prices described on a stochastic basis for the 300 iterations. The methodology to change prices uses an autocorrelation algorithm allowing prices to experience excursions, but to not move randomly. The methodology works by focusing on the monthly change in prices. The forecast's month-to-month Expected Case change in prices is used as the mean of a lognormal distribution; then for the stochastic studies, a monthly change in natural gas price is drawn from the distribution. The lognormal distribution shape and variability uses historical monthly volatility. Using the lognormal distribution allows for the large upper price excursions seen in the historical dataset.

The average of the 300 stochastic prices is similar to the expected price forecast described earlier in this chapter. Figure 8.6 illustrates the simulated data for the stochastic studies compared to the input data for the Stanfield price hub. The stochastically derived nominal levelized price for 22 years is $3.95 per dekatherm. These values likely would converge with a sample size much larger than 300. The median price is lower at $3.78 per dekatherm. Another component of the stochastic nature of the forecast is the growth in variability. In the first year, prices vary 15 percent around the mean, or the standard deviation as a percent of the mean. By 2040, this value is 40 percent, and holds close to 40 percent through 2045. Avista uses higher variation in later years because the accuracy and knowledge of future natural gas prices becomes less certain.

Figure 8.6: Stochastic Stanfield Natural Gas Price Forecast

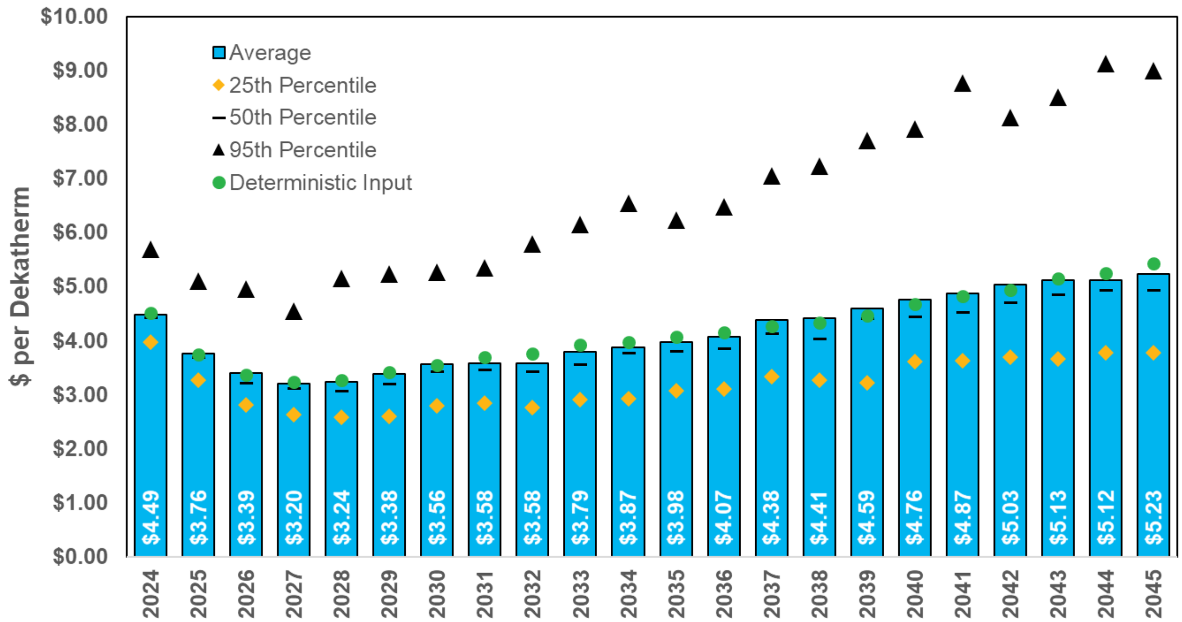
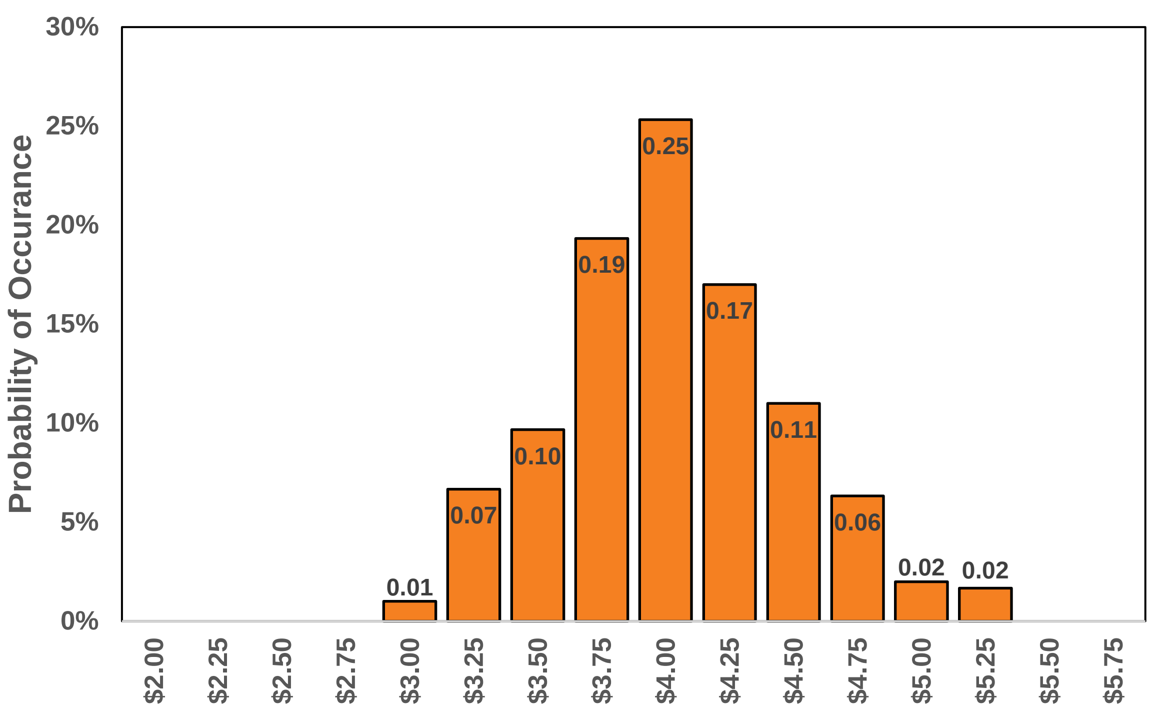


Figure 8.7 shows another way to visualize Avista's natural gas price forecast assumptions. This chart shows the 22-year nominal levelized prices for Stanfield as a histogram to demonstrate the skewness of the natural gas price forecast.

Figure 8.7: Stanfield Nominal 20-Year Nominal Levelized Price Distribution



Regional Coal Prices

Coal-fired generation facilities are still an important part of the Western Interconnect. In 2021, coal met 17 percent of Western Interconnect loads, falling from 34 percent in 2001. Coal pricing is typically different from natural gas pricing, providing diversification and mitigating price volatility risk. Natural gas is delivered by pipeline, whereas coal delivery is by rail, truck, or conveyor. Coal contracts are typically longer term and supplier specific. Avista uses the coal price forecast provided by the software vendor’s default database. The software’s forecast is based on FERC filings for each of the coal plants and is used to determine historical pricing. Future prices are based on the EIA Annual Energy Outlook.

Coal price forecasts have uncertainty like natural gas prices, yet the effect on market prices is less because coal-fired generation rarely sets marginal prices in the Western Interconnect. While labor, steel cost, and transportation costs drive some portion of coal price uncertainty, transportation is its primary driver. There is also uncertainty in fuel suppliers as the coal industry is restructuring. Given the relatively small effect on Western Interconnect market prices, Avista chose not to model this input stochastically.

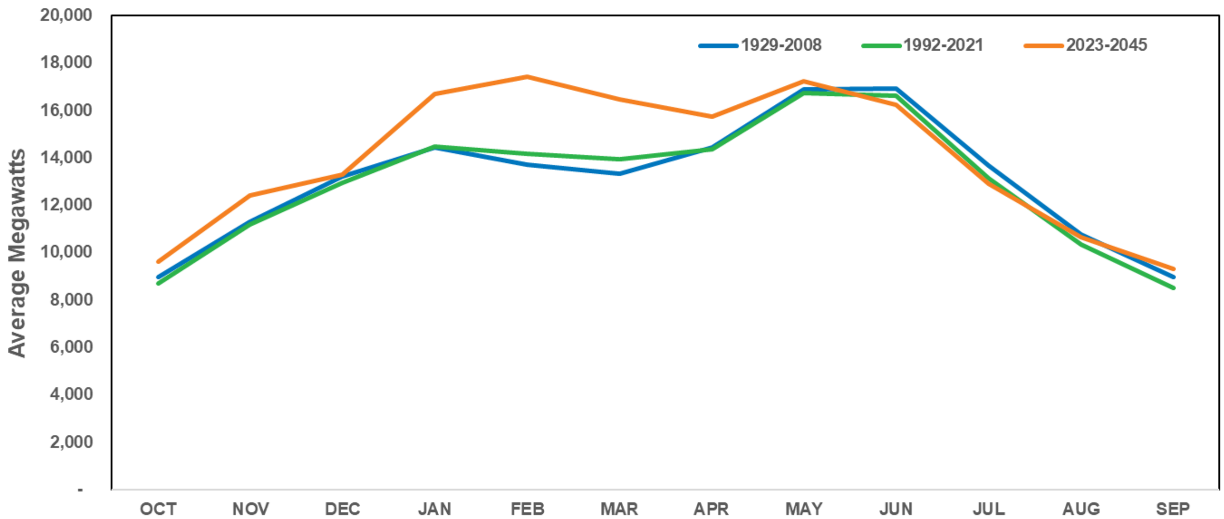
Hydro

The Northwest U.S., British Columbia, and California have substantial hydro generation capacity. Hydro resources were 55 percent of Northwest generation in 2021, although hydro generation is only 19 percent of generation in the Western Interconnect. A favorable characteristic of hydro power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. Hydro generation is valuable for meeting peak load, following general intra-day load trends, storing and shaping energy for sale during higher-valued hours and integrating variable generation resources. The key drawback to hydro generation is its variability and limited fuel supply.

The deterministic forecast uses a rolling 30-year median of hydro production including a combination of historic water years and forecasted generation that incorporates the temperature change predictions in RCP 4.5.[6] As you move through the 22-year planning horizon, there is a greater percentage of forecasted generation included in the 30-year period. For example, for planning year 2030, hydro is based on a median of historic water years from 2000-2021 and forecasted hydro for years 2022-2029. See Figure 8.8 for a hydro comparison of this methodology with the former average of 80-year hydro.

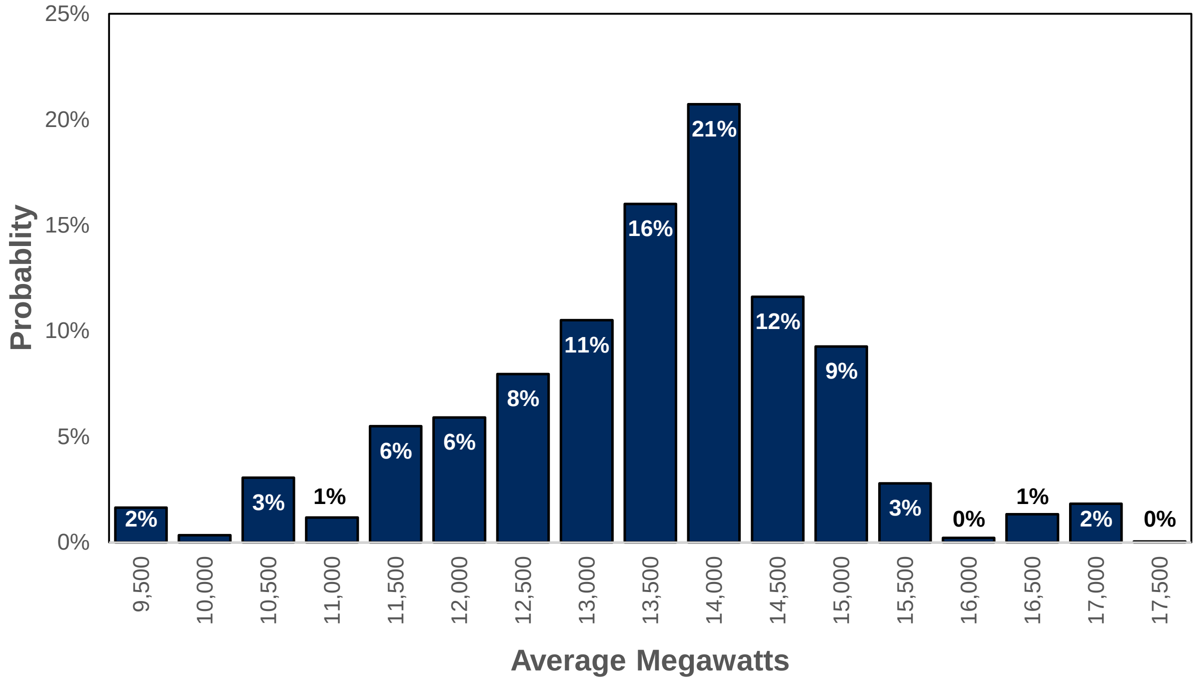
[6] See Chapter 7 for more detail on the hydro forecast and climate assumptions included.

Figure 8.8: Northwest Hydro Generation Comparison



Many forecasts use an average of the hydro record, whereas the stochastic study randomly draw from the record, as the historical distribution of hydro generation is not normally distributed. Avista uses both methodologies. Avista's stochastic forecast incorporates the same combination of the historic water years and forecasted hydro as used in the deterministic study, however, hydro is randomly selected for the 300 iterations to simulate risk of different hydro conditions. Figure 8.9 shows the average hydro energy as 13,255 aMW (median 13,454 aMW) in the Northwest over the 22-year study, defined here as Washington, Oregon, Idaho, and western Montana. The chart also shows the range in potential energy used in the stochastic study, with a 10th percentile water year of 11,292 aMW (-15 percent) and a 90th percentile water year of 14,764 aMW (+11 percent).

Figure 8.9: Northwest Expected Energy



Wind Variation and Pricing

Wind is a growing generation source to meet customer load. Western Interconnect wind generation increased from nearly zero in 2001 to 12 percent in 2021.[7] Capturing the variation of wind generation on an hourly basis is important in fundamental power supply models due to the volatility of its generation profile and the effect of this volatility on other generation resources and electric market prices. Energy Exemplar recently made significant progress populating a larger database of historical wind data points throughout North America. This analysis leverages this work and takes it one step further by including a stochastic component to change the wind shape for each year. Avista uses the same methodology for developing its wind variation as discussed in previous IRPs. The technique includes an auto correlation algorithm with a focus on hourly generation changes. It also reflects the seasonal variation of generation.

To keep the problem manageable, Avista developed 15 different annual hourly wind generation shapes that are randomly drawn for each year of the 22-year forecast. By capturing volatility this way, the model can properly estimate hours with oversupply compared with using monthly average generation factors.

Solar

Like wind, solar is quickly increasing its market share in the Western Interconnect. In 2021 solar was 4 percent[8] of the total generation, up from 2 percent in 2014 (both estimates exclude behind the meter solar). The Aurora model includes multiple solar generation shapes with multiple configurations, including fixed and single-axis technologies, along

[7] Wind represented 11.6 percent of Northwest generation in 2021.
[8] Solar represented 1 percent of Northwest generation in 2021.

with multiple locations within an area. As solar continues to grow, additional data will be available and incorporated into future IRP modeling. One of these new techniques may include multiple hourly solar shapes like those used with wind, so the model can account for solar variation from cloud cover.

Other Generation Operating Characteristics

Avista uses the Energy Exemplar database assumptions for all other generation types not detailed here, except for Avista owned and controlled resources. For Avista's resources, more detailed confidential information is used to populate the model.

Forced outage and mechanical failure is a common problem for all generation resources. Typically, the modeling for these events is through de-rating generation. This means the available output is reduced to reflect the outages. Avista uses this method for solar, wind, hydro, and small thermal plants; but uses a randomized outage technique for larger thermal plants where the model randomly causes an outage for a plant based on its historical outage rate, keeping the plant offline for its historical mean time to repair.

Negative Pricing and Oversupply

Avista includes adjustments in the Aurora model to account for oversupply in the Mid-Columbia market, including negative price effects. Negative pricing occurs when generation exceeds load. This occurs most often in the Northwest when much of the hydro system is running at maximum capacity in the spring months due to high runoff and wind projects are also generating and lacking an economic incentive to shut off due to their requirement to generate for the Production Tax Credit (PTC), environmental attributes (e.g., RECs) or sale obligations. While hydro resources are dispatchable, they may not be able to dispatch off due to total dissolved gas issues forcing spill instead of generating. This phenomenon will likely increase as wind and solar generation is added to the system where there are tax credits in place or where environmental attributes are needed for clean energy requirements. To model this effect in Aurora, Avista changes the economic dispatch prices for several resources that have dispatch drivers beyond fuel costs.

The first change Avista made is to the hydro dispatch order. This makes hydro resources a "must run" resource or last resource to turn off. To do this, hydro generation is assigned a negative $30 per MWh price (2020 dollars).[9] The next change assigns an $8 per MWh (2020$) reduction in cost for qualifying renewable resources to reflect a preference for meeting state renewable portfolio standards (RPS); this price adjustment accounts for the intrinsic value of the REC. The last adjustment is to include a PTC for resources with this benefit. After these adjustments, the model turns off resources in a fashion similar to periods of excess generation seen today. In an oversupply condition such as this, the last resource turned off sets the marginal price.

[9] These plants cannot be designated with a "must run" designation due to the "must run" resources requiring resources to dispatch at minimum generation and for modeling purposes, hydro minimum generation is zero in the event of low flows.

Greenhouse Gas Pricing

Many states and provinces have enacted greenhouse gas emissions reduction programs with others considering such programs. Some states have emissions trading mechanisms while others chose clean energy targets. Aurora can model either policy, but different policy choices can result in dissimilar impacts to electric wholesale pricing. Clean energy target programs, such as Washington's Clean Energy Transformation Act (CETA), generally depress prices due to the bias for increasing the incentives to construct low marginal-priced resources. California's cap and trade program has the opposite effect and pushes wholesale prices upwards. Avista includes known pricing programs in California, British Columbia, and Alberta in its modeling as a carbon tax. The modeling also includes effects of Washington's Climate Commitment Act (CCA) and Oregon's Clean Energy Targets (HB 2021).

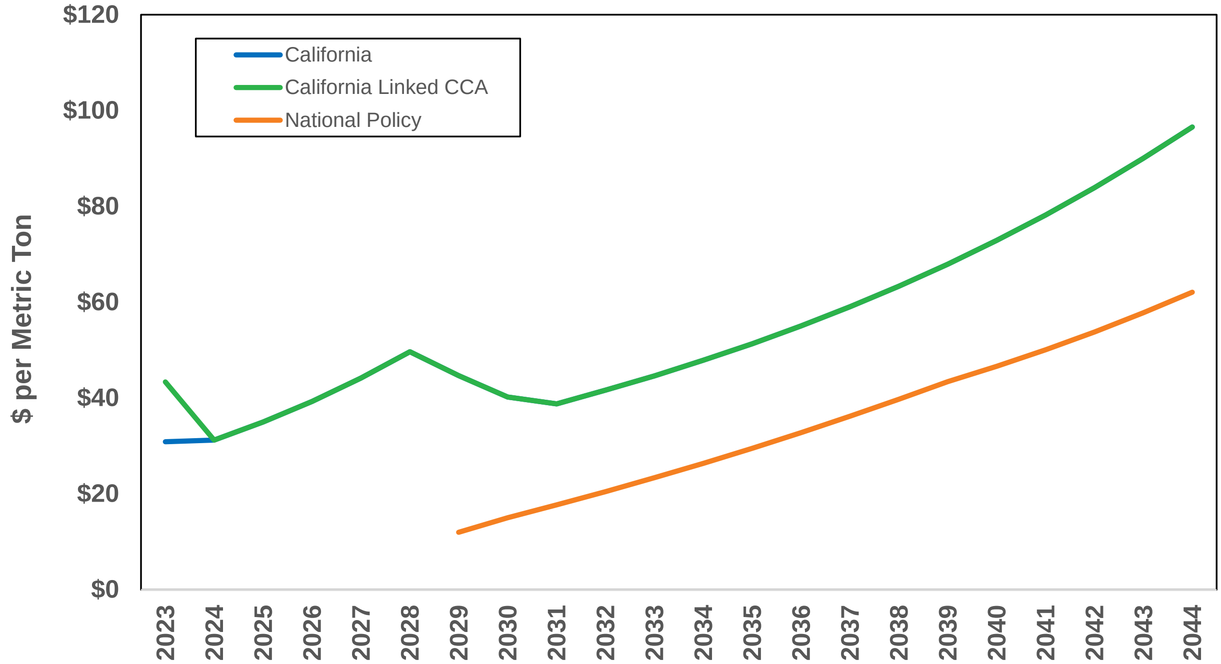
The Washington State Legislature passed the CCA in 2021 enacting the potential for carbon pricing for Washington generation resources beginning in 2023.[10] Final CCA rules were released only this past October 2022 and all regulated entities are still striving to comprehend its complete impacts. The regulatory entity responsible for enacting the law is the Washington State Department of Ecology (Ecology). Ecology has not yet provided detailed descriptions or examples to aid regulated entities such as Avista in calculating compliance costs and it is unclear how this legislation will impact energy markets. Therefore, carbon pricing continues to be extremely uncertain and modeling methodologies will be updated in a future resource plan once the full requirements are known. In the meantime, the prices included in the analysis are shown in Figure 8.10 and the methodology used for these assumptions[11] is described below.

1) **Utility controlled generation within Washington state** – No greenhouse gas prices are included within the dispatch decision since allowances will be no-cost for generation controlled by Washington utilities serving Washington customers and trued up at the end of the compliance period.
2) **Non-utility owned generation within Washington state** – This pricing is a blend of the Vivid Economics price scenario where Washington joins the California market in 2025 and the Revised 2019 Integrated Energy Policy Report (IEPR) Carbon Price Projections. Specifically, the Vivid Economics price is used through 2024, the average of IEPR's low- and mid- prices are used between 2025 and 2029, and beginning in 2030, the price trends down to IEPR's low price by 2032[12]. This is labeled as the "California Linked CCA" price in Figure 8.10.
3) **Utility controlled generation within Washington state serving other states** – applies the pricing used from #2 above using the ratio of the utility's out of state load share.
4) **Northwest Imports**- Any power imported into the Northwest uses the pricing from #2 above based on the greenhouse gas intensity rate of the exporting region.

[10] Pricing relative to other emission sources was also enacted but irrelevant to this IRP.
[11] Various approaches were discussed with the TAC at multiple meetings and through email. Input and/or enhancements to this process were sought and included based on the best available information at the time of the analysis.
[12] These prices were presented as "Scenario 2" to the IRP TAC.

5) **National Carbon Price –** assumes the 33 percent probability of the U.S adopting a national carbon tax or national cap-and-trade in 2030 of $12 per metric ton increasing to $62 per metric ton by 2045. Washington facilities assume this cost within its dispatch, but facilities in California do not. These prices are referenced as "National Policy" in Figure 8.10.

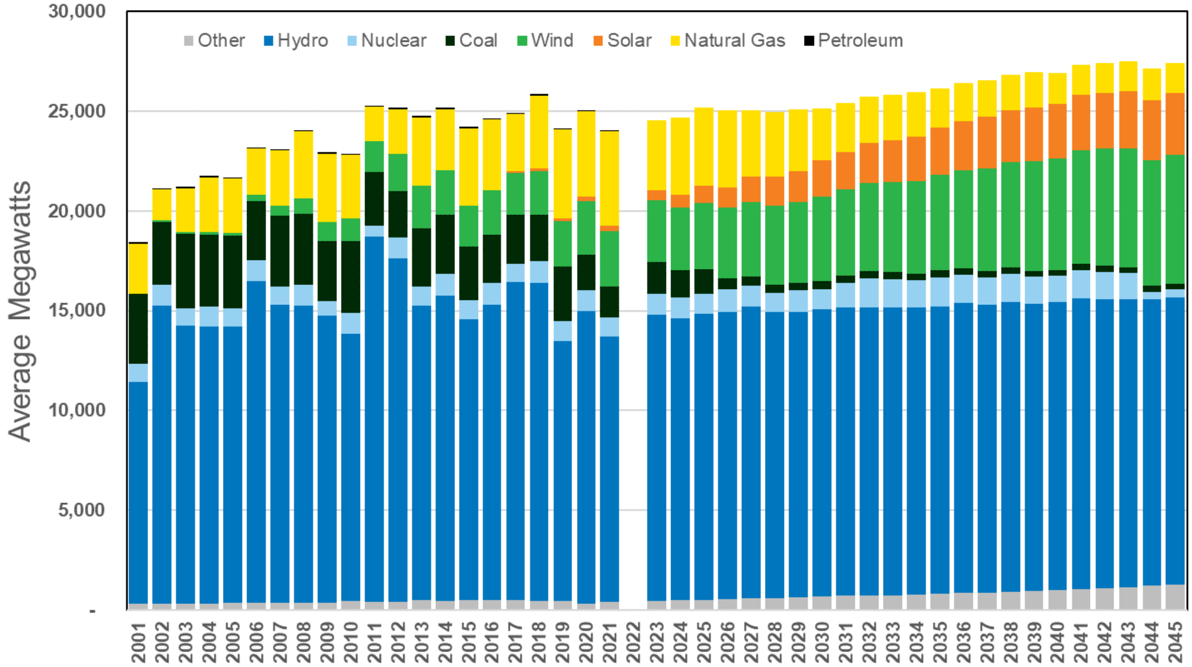
Figure 8.10: Carbon Price Comparison



This forecast assumes a continuing shift to clean energy resources across the Western Interconnect over the next 22 years. Figure 8.11 shows the historical and forecast generation for the U.S. portion of the Western Interconnect. In 2021, 49 percent of load is served by clean energy, increasing to 73 percent by 2030, and 81 percent by 2045. To achieve this shift in energy, while also serving new loads, solar and wind production will displace coal and natural gas. Absent significant new storage technologies, thermal resources are still required to help meet system needs during peak weather events, especially in Northwest winters.

The Northwest will undergo significant changes in future generation resources. This forecast expects coal, natural gas, and nuclear generation to be limited by 2045, and the remaining generation requirements will be met with solar, wind and hydro generation. As of 2021, 74 percent of the Northwest generation was clean, increasing to 88 percent in 2030 and 94 percent by 2045 as shown in Figure 8.12. Achieving these ambitious clean energy goals will require more than doubling of wind generation and a nearly 12-fold increase in solar energy from the 2021 generation levels. This results in solar providing 11 percent of future generation and wind 24 percent.

Figure 8.11: Northwest Generation Technology History and Forecast



Regional Greenhouse Gas Emissions

Greenhouse gas emissions are likely to significantly decrease with the retirement of coal generation and new solar/wind resources displacing additional natural gas-fired generation. Electric generation related greenhouse gas emissions within the U.S. Western Interconnect were approximately 214 million metric tons in 2020, a considerable reduction from the 1990 emissions level of 234 million metric tons. Avista obtained historical data back to 1980 from the EPA; the emissions minimum since 1980 was 161 million metric tons in 1983.

Avista's market modeling only tracks emissions at their source and does not estimate assignment to each state from energy transfers, such as emissions generated in Utah for serving customers in California. Figure 8.12 shows the percent totals for 2020 and the 2045 forecast. The largest emitters by state are Arizona and California, followed by Colorado, Utah, and Wyoming. The four northwest states generate 14 percent of the total emissions in the Western Interconnect.

By 2045, Avista estimates emissions fall 62 percent compared to 1990 levels as shown in Figure 8.13. All states will have a reduction in emissions in this forecast. The greatest reductions by percentage are Utah (87 percent), Oregon (85 percent), New Mexico (72 percent), and Wyoming (70 percent). The greatest reductions by tons are Utah (23 MMT), Wyoming (21 MMT), California (17 MMT), and Colorado (14 MMT).

Figure 8.12: 2020 and 2045 Greenhouse Gas Emissions

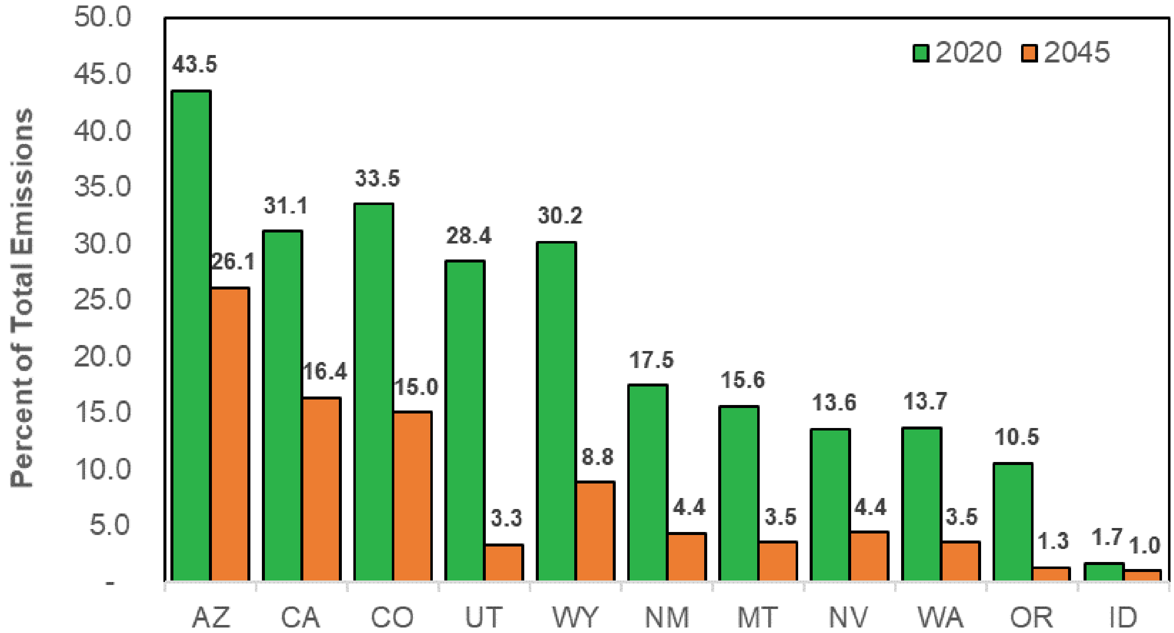
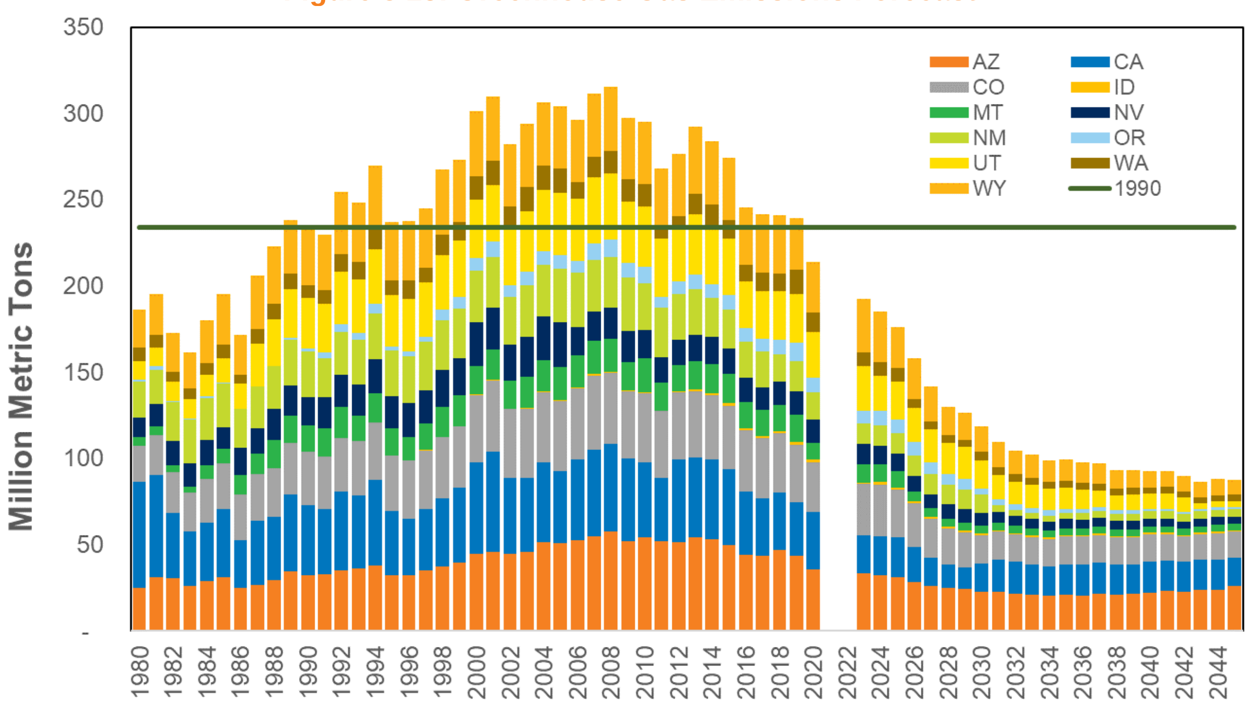


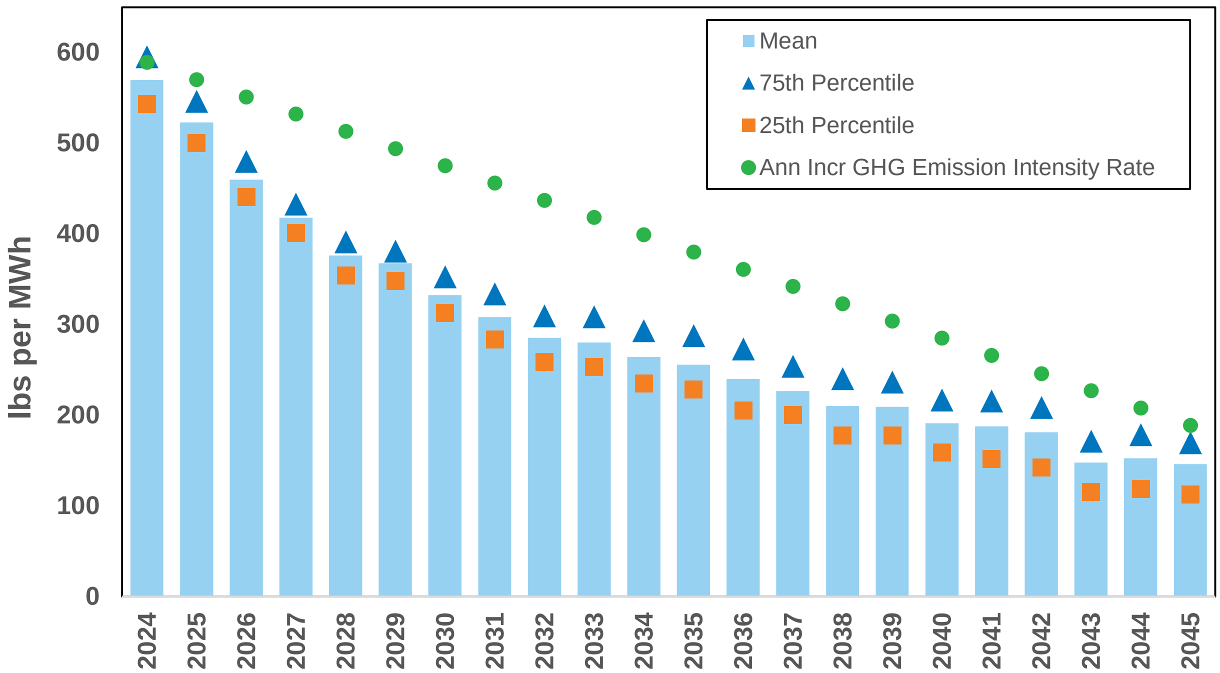
Figure 8.13: Greenhouse Gas Emissions Forecast



Regional Greenhouse Gas Emissions Intensity

To understand the greenhouse emissions from the regional market Avista may purchase power within, Avista uses regional emissions intensity per MWh to estimate the associated emissions from these short-term acquisitions. Avista uses the mean values shown in Figure 8.13 for each of the 300 simulations. The chart below shows the mean, 25th and 75th percentiles for regional emissions intensity. The emissions are included from Washington, Oregon, Idaho, Montana, Utah, and Wyoming. Emissions intensity falls as renewables are added and coal plants retire, but the intensity rate depends on the variation in hydro production. The locations for Avista's area for potential market purchases is consistent with Washington's energy and emissions intensity report but is higher than Avista's likely counter parties for market purchases. This figure also includes incremental regional emissions to evaluate efficiency programs. In this case, Avista determines the incremental regional emission per MWh using a second forecast with additional load within the northwest system, then the change in emissions is compared to the change in load.

Figure 8.14: Northwest Regional Greenhouse Gas Emissions Intensity



Electric Market Price Forecast

Mid-Columbia Price Forecast

There are two wholesale prices forecasts within this resource plan, a deterministic version where all 8,760 hours for the 22-year period are simulated and a stochastic version using two-week hourly sampling for each future month. Each study uses hourly time steps between 2024 and 2045. This process is time consuming when conducted 300 times for the stochastic forecast. The 300 future simulations take more than one week of continuous processing on 33 separate processor cores to complete. Time constraints limited the number of market scenarios Avista is ultimately able to explore in each resource plan. In prior IRPs, Avista's stochastic studies included 500 iterations of hourly time steps, however, the increase in future storage resources within the marketplace requires optimization techniques to determine pricing. This process significantly increases the modeling time such requiring the number of iterations to be reduced and sampled for two weeks per month rather than all time periods. Analysis was performed to ensure the 300 iterations was sufficient to encompass most of the distribution of uncertainty.

The annual average of all hourly prices from both studies are shown in Figure 8.15. This chart shows the annual distribution of the prices using the 10th and 95th percentiles compared to the mean, median and deterministic prices. The pricing distribution is lognormal as prices continue to be highly correlated with the lognormally distributed natural gas prices. The 22-year nominal levelized price of the deterministic study is $35.47 per MWh and $35.34 per MWh for the stochastic study is shown in Table 8.3. Table 8.4 includes the super peak evening (4 to 10 p.m.) period to illustrate how prices behave during this high-demand period where solar output is falling, and rising prices encourage dispatching of other resources.

Figure 8.15: Mid-Columbia Electric Price Forecast Range

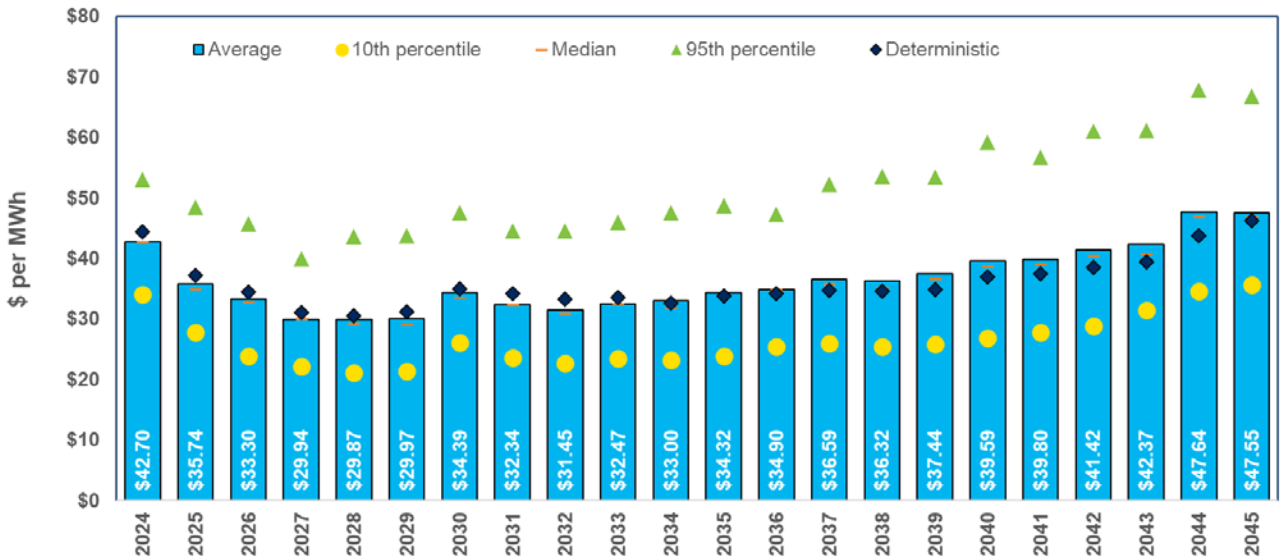


Table 8.3: Nominal Levelized Flat Mid-Columbia Electric Price Forecast

Metric	2024-2045 Levelized ($/MWh)
Deterministic	$35.47
Stochastic Mean	$35.34
10th Percentile	$31.80
50th Percentile	$35.26
95th Percentile	$40.51

Average on-peak prices between 7 a.m. and 10 p.m. on weekdays plus Saturday have historically been higher than the remaining off-peak prices. However, this forecast shows off-peak prices outpacing on-peak prices on an annual basis beginning in 2029 due to increasing quantities of solar generation placed on the system depressing on-peak prices. As more solar is added to the system, this effect spreads into the shoulder months. Only in the winter season, where solar production is lowest, does the traditional relationship of today's on- and off-peak pricing continue.

Depending on the future level of storage and its duration, price shapes could flatten out rather than inverting the daytime spread. Mid-day pricing will be low in all months going forward, driving on-peak prices lower. Super peak evening prices after 4 p.m., when other resources will need to dispatch to serve load, can be high if startup costs effect market pricing as expected in this forecast.

Table 8.4: Annual Average Mid-Columbia Electric Prices ($/MWh)

Year	Flat	Off-Peak	On-Peak	Super Peak Evening
2024	$42.70	$38.50	$45.85	$59.07
2025	$35.74	$32.65	$38.05	$51.34
2026	$33.30	$31.07	$34.97	$48.72
2027	$29.94	$28.90	$30.72	$44.76
2028	$29.87	$29.71	$30.00	$44.47
2029	$29.97	$30.52	$29.55	$44.69
2030	$34.39	$35.76	$33.36	$50.37
2031	$32.34	$33.74	$31.29	$49.16
2032	$31.45	$33.33	$30.03	$47.81
2033	$32.47	$34.37	$31.04	$50.28
2034	$33.00	$34.99	$31.50	$51.02
2035	$34.32	$37.12	$32.21	$52.55
2036	$34.90	$38.00	$32.58	$53.65
2037	$36.59	$39.06	$34.74	$57.80
2038	$36.32	$38.89	$34.40	$58.31
2039	$37.44	$40.47	$35.16	$59.87
2040	$39.59	$42.16	$37.66	$66.14
2041	$39.80	$42.45	$37.81	$66.72
2042	$41.42	$43.17	$40.11	$71.40
2043	$42.37	$43.91	$41.22	$73.28
2044	$47.64	$49.08	$46.56	$81.12
2045	$47.55	$48.97	$46.49	$80.43
2024-2045	$35.34	$35.74	$35.04	$54.12

Figures 8.16 through 8.19 show the average prices for each hour of the season for every five years of the price forecast. The spring and summer prices generally stay flat throughout the 22 years as these periods have large quantities of hydro and solar generation to stabilize prices, but mid-day prices decrease over time while prices for the other time periods increase. The winter and autumn prices will have larger price increases due to less available solar energy to shift unless enough long-term storage materializes. With this analysis, current on/off-peak pricing will need to change into different products such as a morning peak, afternoon peak, mid-day, and night. Pricing for holidays and weekends likely will be less impactful on pricing except for the morning and evening peaks. Future pricing for all resources will need to reflect these pricing curves so they can be properly valued against other resources.

Figure 8.16: Winter Average Hourly Electric Prices (December - February)

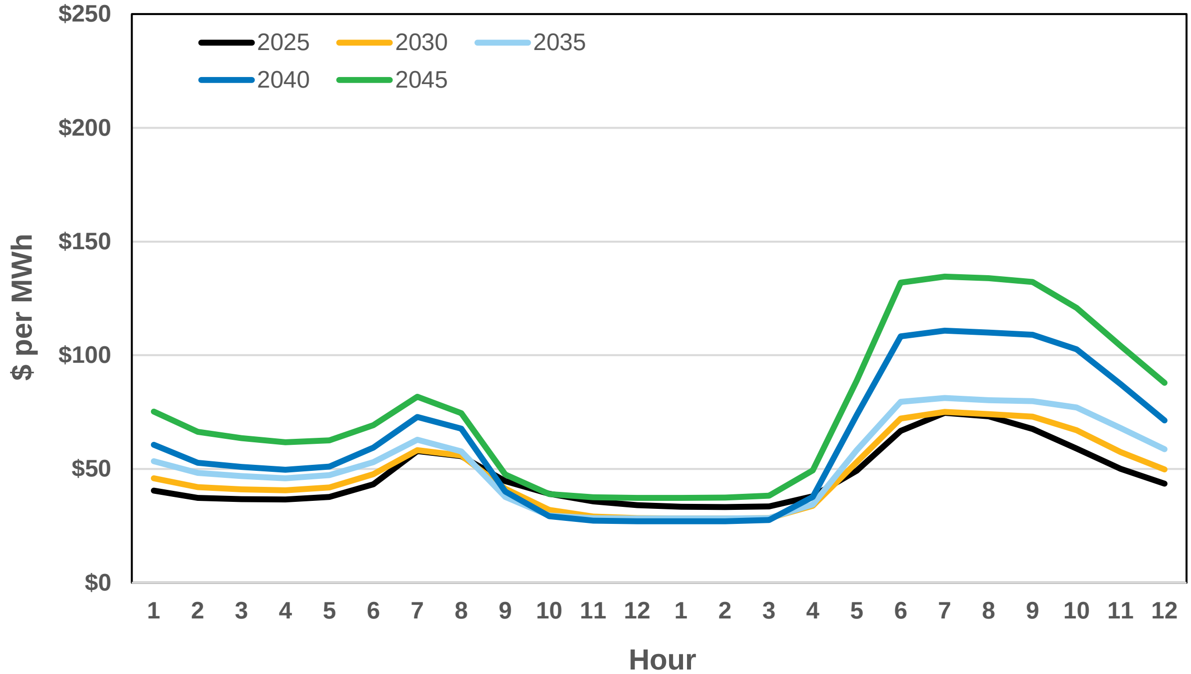


Figure 8.17: Spring Average Hourly Electric Prices (March - June)

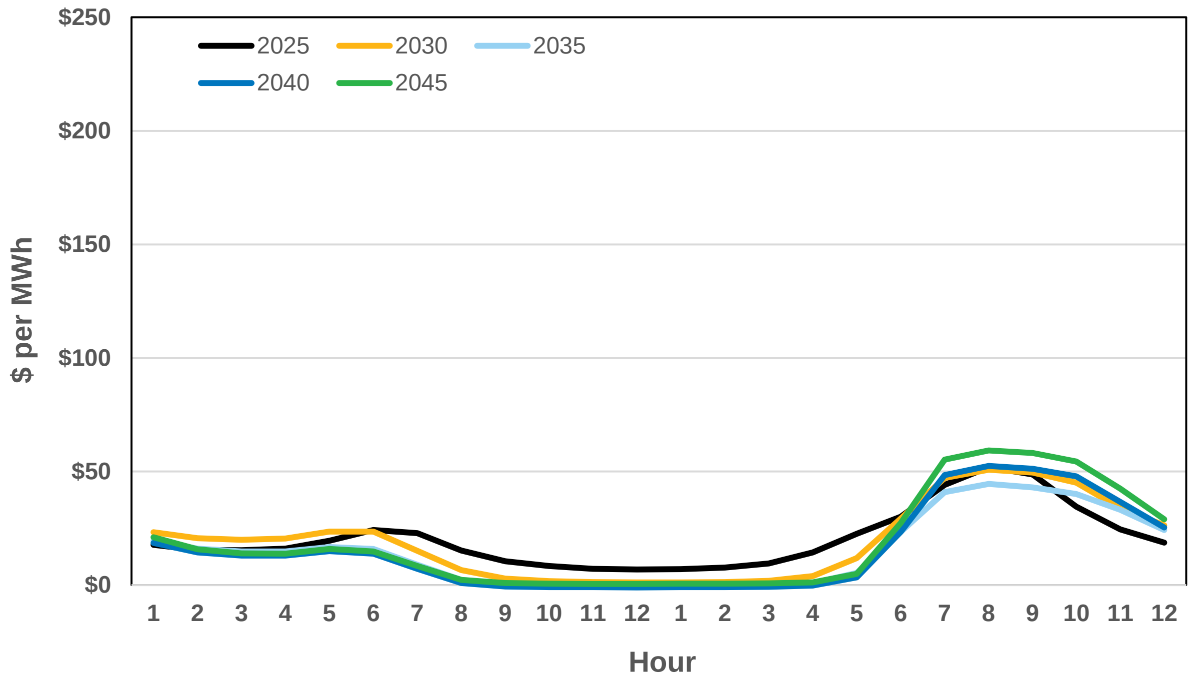


Figure 8.18: Summer Average Hourly Electric Prices (July - September)

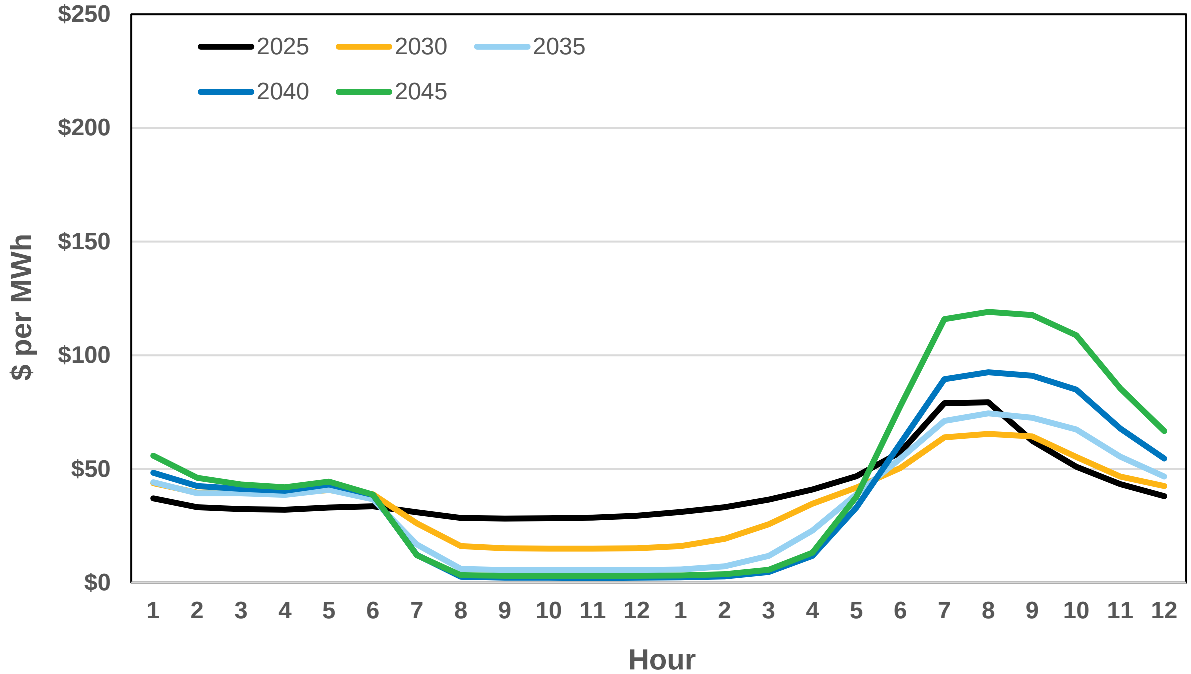
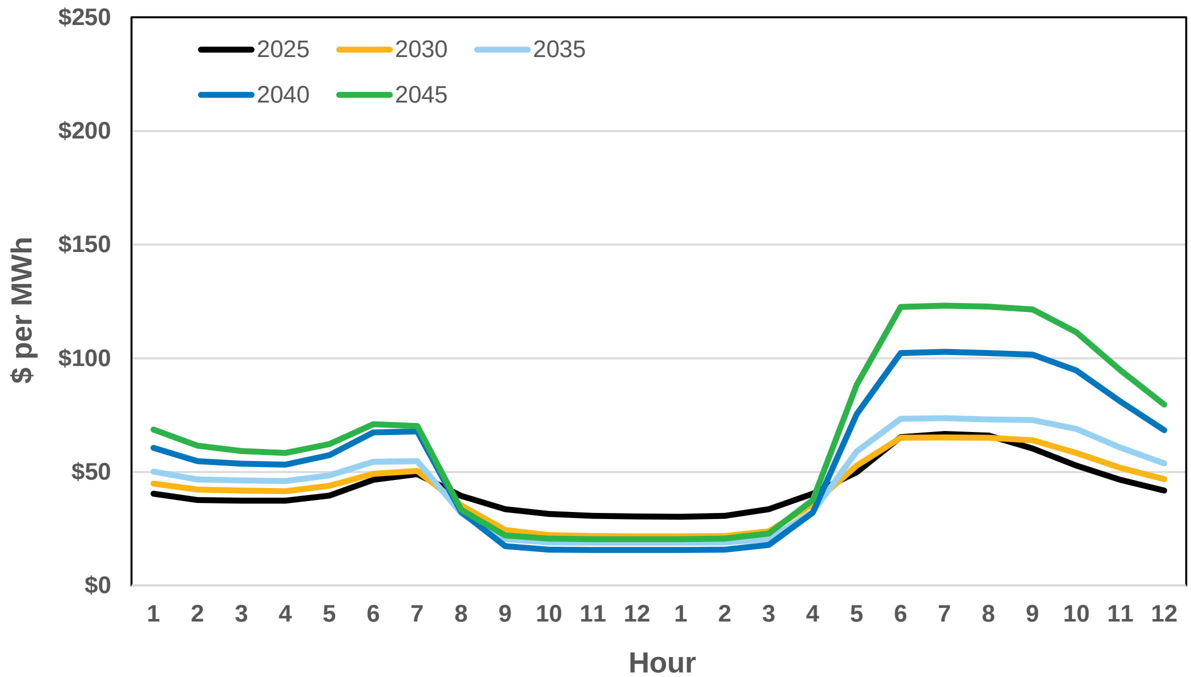


Figure 8.19: Autumn Average Hourly Electric Prices (October - November)



9. Placeholder Resource Strategy

Avista is currently negotiating with several energy providers for significant resource acquisitions from Avista's 2022 All-Source Request for Proposal. The timing of this Progress Report does not align from a timing point of view with those resource additions. Because the selected resources will have substantial effects on the future resource strategy, the resource strategy discussed here is a placeholder for the purpose of estimating the amount of cost-effective energy efficiency for the next biennium as required in this Progress Report and providing insight about resource needs beyond 2030. This resource strategy will be updated to include acquired resources and will be included in the final 2023 IRP filed on June 1, 2023.

Section Highlights

- The 2022 All-Source RFP resource selections will be reflected in the 2023 IRP to be filed in June 2023.
- Energy Efficiency meets over 30 percent of future load growth.
- Named Community Investment Funding (NCIF) will increase Energy Efficiency acquisition and may add small renewables and storage to the system.
- Non-energy impacts are included to evaluate demand- and supply-side resource selection.
- Avista will need long-duration storage to serve customers in peak hours in both states after 2030.
- New transmission is needed to achieve Washington's 100 percent clean energy goals.

Background

Avista issued an All-Source RFP in early 2022 to meet renewable energy and capacity needs through the end of the decade. Avista expects to complete the resource acquisitions in the first quarter of 2023. Avista has already announced the acquisitions from Columbia Basin Hydro Power and other resources from the 2022 All-Source RFP are in the process of negotiation, including upgrades to the Kettle Falls facility. These efforts follow acquisitions of two separate purchases of 5 percent shares of Chelan PUD's Rocky Reach and Rock Island facilities from the 2020 Renewable RFP. Avista has also indicated in both past IRPs and the 2021 Clean Energy Implementation Plan (CEIP) an intention to upgrade the Post Falls hydroelectric facility, currently projected to be complete at the end of 2028. This upgrade is undergoing additional analysis to determine the best path forward with new tax incentives in the Inflation Reduction Act (IRA). This may lead to increased investment in additional capacity beyond the amount indicated in the Company's CEIP required by the Clean Energy Transformation Act (CETA).

As stated before, this resource strategy is a placeholder until final resources are included and the IRP is complete. It is noteworthy to indicate actual resource acquisitions differ from IRPs for several reasons:

- IRP resource options are primarily "new" resource options – an RFP may determine if existing resources can be acquired at similar or lower cost than the assumed IRP new resource options. This is evident in most of Avista's past acquisitions when it acquired shares of Chelan PUD's and Columbia Basin Hydro's resources.
- Not all resources within an IRP option list bid into RFPs. For example, Avista models several energy storage and renewable energy options, but not all technology types were bid in Avista's recent RFPs.
- Pricing in the RFP is based on Bidder's pricing, not generic estimates used in IRPs. Location, transmission availability, supplier availability, credit ratings, and bidder margin all impact resource pricing, where IRPs attempt to estimate general average industry cost for the resource. Further, existing resources have cost advantages (i.e., savings) of depreciation of the assets since its original construction - especially those with long asset lives.
- The IRP selects resources by state. Currently, Avista does not have a resource specific cost allocation agreement at the time of its 2022 All-Source RFP, and until Avista reaches such agreement, resources are acquired on a system basis and allocated using Avista's PT[1] ratio.
- RFP selection analysis is based on real costs with some societal impacts included, whereas IRPs have higher levels of societal impacts included such as the social cost of greenhouse gas as required for IRPs.
- RFP selections have a substantial weighting toward the resource being able to deliver the project to completion whereas the least priced bid may not be selected due to other deliverability risks. Existing resources not modelled in the IRP significantly benefit from this. Further, the strength of the bidder's financial condition and ability to acquire materials and permits for construction impact the selections.
- Projects selected in the RFP must be able to deliver power to customers via transmission. Often, resource ideas do not have a clear path to deliver the power to customers and require substantial transmission construction increasing the total project cost.

Due to the interdependencies of the newly acquired resources, **this Placeholder Resource Strategy should only be used for avoided costs purposes until the full IRP is complete in June 2023**. Further, the resource strategy is based on information known at the time of the analysis regarding the impact of Washington's Climate

[1] PT ration refers to the production-transmission ratio used for cost allocation between Idaho and Washington.

Commitment Act (CCA) and (CETA). At this time, the impacts to Avista customers are not fully known until rules and requirements are further developed.

Resource Strategy Objectives

Avista must acquire reliable sources of power to meet peak planning requirements for both summer and winter peak loads and control enough energy to meet customers' normal demand and enough clean generation resources to meet Washington State's clean energy goals. To achieve these goals, Avista must maintain system reliability, while meeting the regulatory and legal obligations of Idaho and Washington, including CETA requiring service of its state's retail loads with 100 percent non-emitting resources by 2045.

The 2023 Progress Report acquisition strategy uses the best information available at the time of its analyses, including Avista's interpretation of potential CETA requirements. However, some rules for CETA are still incomplete such as the "use" rule determining what renewable energy will qualify as "primary" versus "alternative" compliance. The IRP utilizes a least-cost planning methodology using specific social costs specified by the law's planning requirements and the Non-Energy Impact (NEI) studies conducted by DNV in Appendix D.

Avista's Placeholder Resource Strategy describes the lowest reasonable cost portfolio of resources given Avista's need for new capacity, energy, and clean non-carbon emitting resources, while accounting for social and economic factors prescribed by state policies. The Placeholder Resource Strategy includes supply-side resources, energy efficiency, demand response, and other DER options to serve customer demand. The Progress Report compares resource options to find the lowest-cost portfolio considering the non-power costs to meet capacity deficits in both the winter and summer, annual energy and clean energy/CETA requirements. The analysis considers a minimum spending threshold for using the NCIF[2] available to enhance the equitable transition to clean energy in highly impacted communities and vulnerable populations (i.e., Named Communities) in Avista's electric service territory.

Resource Selection Process

Avista utilizes a mixed integer optimization model to select both supply and demand resources to meet customer energy and capacity needs. Avista developed PRiSM (Preferred Resource Strategy Model) to aid in resource selection using information from its dispatch model Aurora. PRiSM evaluates each resource option's capital recovery, fixed operation costs, and non-energy financial impacts relative to their operating margins from Aurora and the options capability to serve energy, peak loads, and clean energy obligations. PRiSM then determines the lowest-cost mix of resource options meeting

[2] The Named Community Investment Fund was proposed in the Company's 2021 CEIP committing to spend up to $5 million annually on specific actions in Named Communities.

Avista's resource needs. The model can also measure and optimize the risk of various portfolio additions when informed by Monte Carlo data. For the analysis, Avista includes its forecast of 300 Monte Carlo market futures rather than a single forecast for its evaluation. PRiSM is publicly available on Avista's IRP website.

PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in the 2003 IRP. The model continues to support the IRP as enhancements have improved the model over time. PRiSM uses a mixed integer programming routine to support complex decision making with multiple objectives. Its results ensure optimal values for variables given system constraints. The model uses an add-in function to Excel from Lindo Systems named *What's Best* along with *Gurobi's* solver. Excel then becomes PRiSM's user interface. PRiSM simultaneously solves to meet system reliability, energy obligations and jurisdictional clean energy standards while minimizing costs.

The model analyzes resource needs by state for the entire Avista system to ensure each state will be assigned the appropriate incremental costs (if any) of new resource choices. PRiSM includes state-level load and resource balances by month, and resources must be added to satisfy deficits for both the system and for each state in calendar year segments. The model can also retire existing resources when they become uneconomic[3].

The model solves using the net present value of utility costs given the following inputs:

1. Expected future deficiencies for each state and the system
    - Summer Planning Margin (13 percent, May through September)
    - Winter Planning Margin (22 percent, October through April)
    - Monthly energy targets by state
    - Monthly clean energy requirements
2. Costs to serve future retail loads as if served by the wholesale marketplace (from Aurora)
    - Existing resource and energy efficiency contributions
    - Operating margins
    - Fixed operating costs
    - Capital Costs
    - GHG emission levels
    - Upstream GHG emission levels
    - Operating GHG emissions
2. Supply-side resource, energy efficiency and demand response options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes

[3] Resources can only be retired at the system level. PRiSM is not setup to "retire" a resource from serving only one state and transferring the output to the other state.

- Power Purchase Agreements
- Peak Contribution from WRAP/E3 Regional Study
- Generation levels
- GHG emission levels
- Upstream GHG emission levels
- Construction and operating GHG emissions
- Transmission costs

3. Constraints
   - Must meet energy, capacity, and Washington's clean energy shortfalls without market reliance for each state
   - Named Community Investment Fund minimum spending
   - Resource quantities available to meet future deficits

The model's operation is characterized by the following objective function:

Minimize: (WA "Societal" $NPV_{2023\text{-}45}$) + (ID $NPV_{2023\text{-}45}$)
Where:

- WA $NPV_{2023\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Social Cost of Carbon + Non-Energy Impacts + Energy Efficiency Total Resource Cost

- ID $NPV_{2023\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Energy Efficiency Utility Resource Cost

Subject to:

- Generation availability and timing
- Energy efficiency potential
- Demand response potential
- Winter peak requirements
- Summer peak requirements
- Annual energy requirements
- Washington's clean energy goals
- Named Community Investment Fund outlays

"Placeholder" Resource Strategy

Currently there are three major energy policies in Washington impacting long-term resource strategies, none of these policies are understood to a level to properly optimize resources. The current policy issues are: 1) CETA's determination of "use" for compliance with the 2030 primary compliance standard, 2) Climate Commitment Act's impacts on multijurisdictional utilities compliance requirements for importing power into the State of Washington, and 3) state building code changes to residential and commercial buildings effecting the use of natural gas. In addition to the uncertainty in policies there are also uncertainties in projected resource costs due to supply chain issues, inflation concerns, development of new technology and the influences of market price conditions on analysis and future acquisitions. To address these uncertainties, Avista presented its assumptions to the IRP Technical Advisory Committee (TAC) to discuss any concerns and seek input on any alternative options for Avista to consider. This IRP Progress Report reflects Avista's decisions based on input from its TAC.

The Placeholder Resource Strategy includes several components: 1) required investments as part of Avista's commitment through its NCIF, 2) demand response or retail rate pricing strategies, 3) energy efficiency, 4) supply-side resources, and 5) transmission needs. While the 2023 IRP will identify final resource decisions given known future resource needs, the quantity of energy efficiency and NCIF projects discussed here are likely not to significantly change. However, demand response may change subject to capacity needs and how resource selection will be fulfilled through the end of the decade.

Named Community Investment Fund

This progress report is the first instance of including projects from the NCIF approved in Avista's first CEIP. This fund targets investments for specific communities with additional investments beyond those traditionally determined in least cost resource acquisition to improve disadvantaged communities as the industry transitions to cleaner resources. This Progress Report attempts to estimate resource decisions based on available funding with impacts to resource strategy.

The IRP focuses on ensuring enough energy is created to meet customer load at the right time. Specific NCIF projects are unknown, but some projects may result in energy benefits useful in resource planning. Therefore, actual decisions for funding may or may not impact overall resource need and are subject to the EAG's advice for using these funds. Given an IRP cannot forecast specific future projects chosen, this analysis is designed to estimate possible projects by selecting resources or energy efficiency programs meeting the objectives of the NCIF. This is done by requiring the model to select an additional $2 million dollars of energy efficiency (upfront spending estimated by the present value of the UCT cost) and $0.4 million of incremental supply-side DER cost each year (after tax incentives).

The result of this effort includes approximately a total of 8 MW of community solar, 2 MW of locally distributed solar with 8 MWh of energy storage designed to directly benefit customers residing in a Named Community. The quantity of community solar is a direct result of state and NCIF funding covering 100 percent of the solar costs including land and administration costs. In addition to solar, Avista's energy efficiency targets are higher by 2.4 GWh to reflect additional investments in low-income communities. The following forecast of these specific resources is in Table 9.1. Both energy efficiency and solar fall toward the end of the forecast due to various reasons; for solar it is due to losing the state funding incentive, as for energy efficiency, the resource potential is mostly met at this time with the resource potential assumed to be mostly in place in the first 10 years, savings beyond 2033 will be insignificant compared to prior years.

Table 9.1: NCIF Resource Selection

Program	Community Solar	Energy Efficiency
2024-2033	710 kW per year	240 MWh per year
2034-2045	100 kW per year + 100 kW (400 kWh) of energy storage	2 MWh per Year

Demand Response Selections

Demand Response (DR) and/or retail rate load control programs could be integral to Avista's strategy to meet customer peak load requirements with non-emitting resources. Since the 2021 IRP, Avista added 30 MW of industrial demand response and agreed to pilot three DR programs (see Chapter 5). Currently DR's treatment in the upcoming Western Resource Adequacy Market is uncertain on how much will meet the PRM due to the historic inability to be time limited and load snap back effects. Further, some programs using retail rates, such as time of use are not dispatchable and are dependent on the customers' willingness to participate at the time of the DR event.

In this analysis, ***voluntary time of use rates (TOU)*** in Washington state is the only cost-effective DR option in the Placeholder Resource Strategy given the cost and benefit assumptions. Avista will be piloting this project to determine if the program delivers the perceived benefits. If the program is implemented post-pilot, it would begin in 2025 for all customers. Further analysis in the full IRP may delay this need until Avista is closer to a capacity deficit. The total estimated peak savings from TOU rates is nearly 7 MW by 2045. This program is cost-effective over other programs due to significant energy savings assumed for the program rather than just its load reduction capability.

Energy Efficiency Selections

Energy efficiency meets more than 30 percent of all future load growth, where prior IRP forecasts found energy efficiency met nearly 70 percent of future load growth. This change is related to expectations of new load from electric transportation and building electrification. Over 2,600 individual energy efficiency measures were studied in this IRP. Avista models energy efficiency programs individually to ensure each program's capacity and energy contributions are valued in detail for the system. This method ensures an accurate accounting of peak savings that is not possible if programs were bucketed or simply compared to a levelized price of energy.

Avista's load forecast is net of future energy efficiency savings. This energy efficiency selection exercise is trying to determine the amount of energy efficiency and the cost-effective programs Avista should pursue. Avista adds selected quantity of savings back efficiency to the load forecast through an iteration technique in PRiSM until the amount of energy efficiency selected and the amount of load added are nearly equal.

Over the course of the plan, 703 cumulative gigawatt-hours are saved through energy efficiency between 2024 and 2045. When considering transmission and distribution losses, loads are 85 aMW less with these programs. Figure 9.1 shows total energy and peak hour savings by state for both winter and summer. Winter peaks are reduced by nearly 86 MW and summer peaks are reduced by 89 MW. Over the IRP planning horizon, 29 percent of new energy efficiency comes from Idaho customers and 71 percent from Washington customers. Washington has more energy efficiency savings than Idaho relative to its share of load because of the higher avoided costs driven by CETA and other regulations in Washington.

Most energy efficiency savings are from commercial customers (57 percent), followed by residential customers (29 percent), with the remainder from industrial customers. The greatest sources of energy efficiency, at nearly 71 percent, are from lighting, space heating, and water heating measures. Figure 9.2 shows the program type by share of the total savings by percentage through 2045.

Figure 9.1: Energy Efficiency Annual Forecast

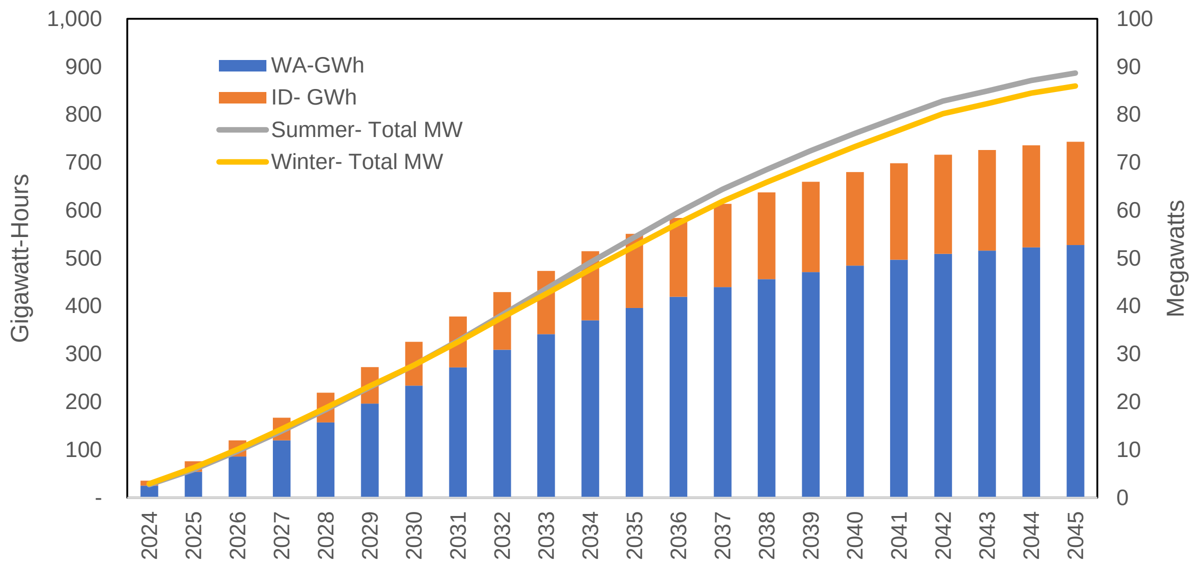
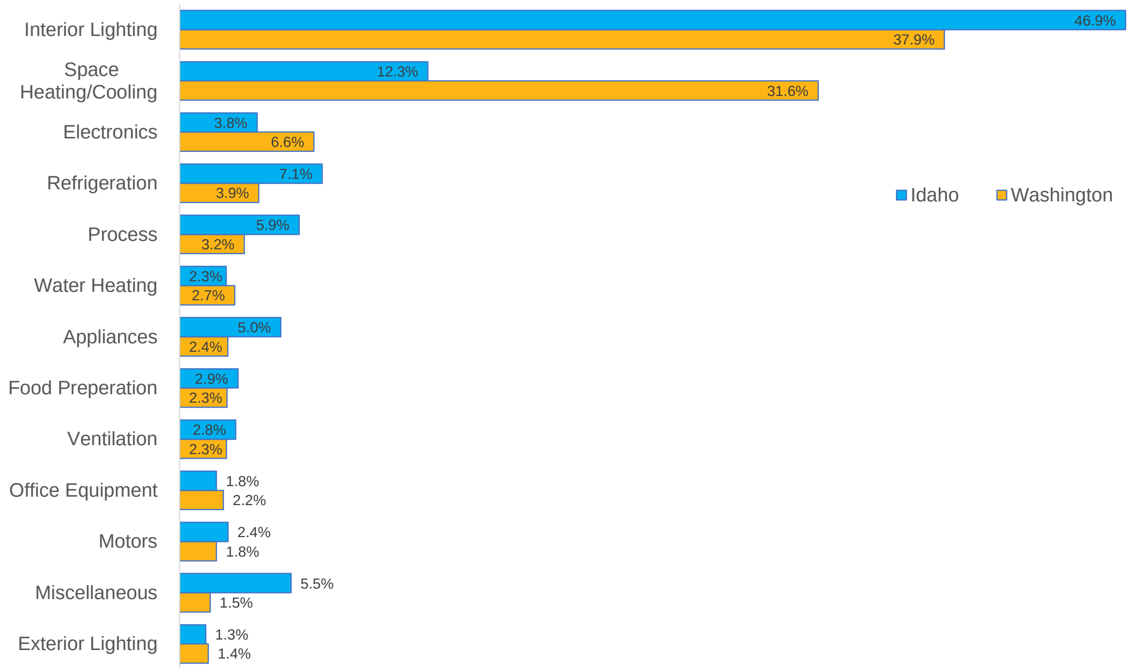


Figure 9.2: Energy Efficiency Savings Programs by Share of Total



Washington Biennial Conservation Plan

The amount of energy efficiency identified in the Placeholder Resource Strategy will lead to specific program creation in Washington and Idaho. The IRP informs the Avista energy efficiency team in determining cost-effective solutions and potential new programs for business planning, budgeting, and program development to meet the state targets specifically for Washington's Energy Independence Act (EIA) Biennial Conservation Plan (BCP). Pursuant to requirements in Washington, the biennial conservation target must be no lower than a pro rata share of the utility's ten-year conservation potential. In setting the Company's target, both the two-year achievable potential and the ten-year pro rata savings are determined with the higher value used to inform the EIA Biennial target. Figure 9.3 shows the annual selection of new energy efficiency compared to the 10-year pro-rata share methodology.

For the 2024-2025 Conservation Potential Assessment (CPA), the two-year achievable potential is 69,174 MWh for Washington electric operations. The pro-rata share of the utility's ten-year conservation potential is 102,566 MWh and is used in the calculation of the biennial target. Table 5.2 contains achievable conservation potential for 2022-2023 using the PRiSM methodology. Also included is the energy savings expected from the 2022 and 2023 feeder upgrade projects shown below in Table 9.2.

Figure 9.3: Washington Annual Achievable Potential Energy Efficiency (Gigawatt Hours)

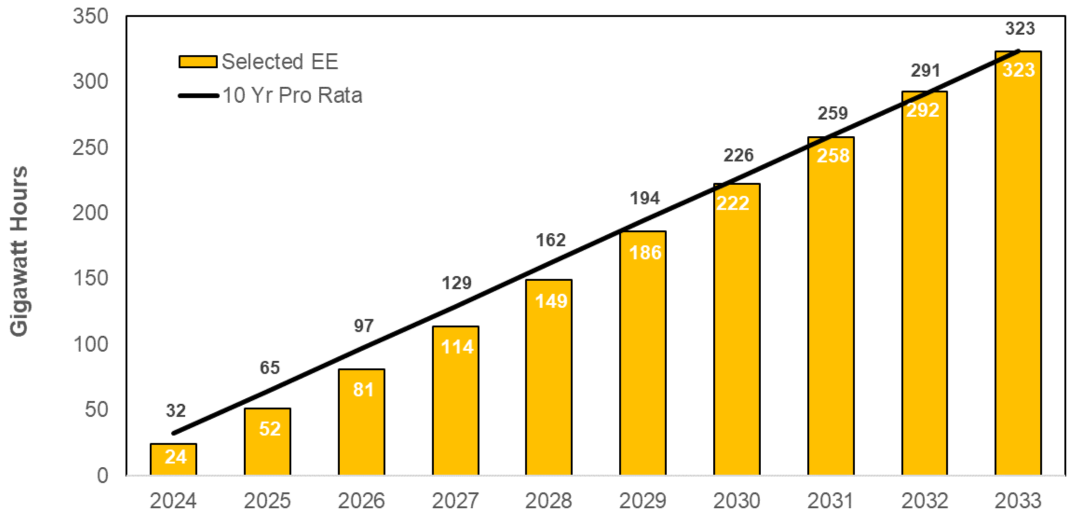


Table 9.2: Biennial Conservation Target for Washington Energy Efficiency

2024-2025 Biennial Conservation Target (MWh)	
EIA Target	64,667
Decoupling Threshold	3,233
Total Utility Conservation Goal	67,900
Excluded Programs (NEEA)	-10,162
Utility Specific Conservation Goal	57,739
Decoupling Threshold	-3,233
EIA Penalty Threshold	54,505

Supply-Side Resource Selections

Avista will require new resources beginning in November 2026 due to the expiration of the Lancaster Purchase Power Agreement (PPA). This Placeholder Resource Strategy is designed to fill resource needs with generic new construction resources as described in the DER (Chapter 5) and supply-side resource (Chapter 6) chapters. Avista considers the selected resource strategy to be used only for temporary avoided cost calculations and estimating energy efficiency targets until the final resource strategy is completed and filed within its full 2023 electric IRP on June 1, 2023. The resulting resource strategy is shown in simplistic form only for this Progress Report due to the temporary nature of the resources selected. Detailed results can be found within Appendix F.

Table 9.3: Utility Scale Supply Side Resource Selection (Nameplate MW)

	Washington				Idaho			
Resource Type	2024 to 2030	2031 to 2035	2036 to 2040	2041 to 2045	2024 to 2030	2031 to 2035	2036 to 2040	2041 to 2045
Natural Gas	0	0	3	0	186	0	2	0
Baseload Renewable	0	20	0	20	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0
NW Wind	150	0	0	891	0	0	0	0
Montana Wind	125	175	0	0	0	0	0	0
Off-Shore Wind	0	0	0	0	0	0	0	0
Utility Scale Solar	0	0	0	0	0	0	0	0
Short Duration Storage (<8hr)	61	0	51	25	0	0	0	38
Medium Duration Storage (8-24hr)	0	0	0	0	0	0	0	0
Long Duration Storage (>24hr)	0	147	60	463	0	0	31	154
Total	**336**	**342**	**115**	**1,398**	**186**	**0**	**33**	**192**

While the Placeholder Resource Strategy is temporary, several conclusions can be drawn from the results:

1) Renewables are selected to meet energy and capacity needs prior to 2030 rather than for near term CETA purposes. This is a result of the social cost of greenhouse gases forcing out lower cost natural gas capacity (as seen in the Idaho results).

2) Long duration energy storage is key to the future portfolio to provide capacity as shorter duration storage is likely not able to provide sustained capacity as too many variable energy resources (VERs) will be in the regional market. Long duration storage, both iron-oxide batteries and ammonia-based combustion turbines were selected in this study. Both technologies are in their infancy and will need to be further developed in the commercial space before Avista begins any development of these assets.

3) To meet CETA's 100 percent clean energy targets in 2045, even on the monthly average basis, Avista will require a substantial amount of wind as shown by the nearly 900 MW[4] of NW wind selected between 2041 and 2045. In this case, either additional transmission from other regions or within the Avista system will be needed to bring this wind to our system.

4) DERs other than energy efficiency cannot compete with utility scale resources on cost. Avista included several DER options, however, due to substantial cost premiums these resources will not be cost effective unless policy requires them.

5) Solar resources are not favored due to two reasons: 1) the expectation of other regional utilities adding a substantial amount of solar and depressing mid-day

[4] This includes 245 MW of PPA renewals of Avista's existing wind resources.

wholesale market prices, and 2) due to Avista's recently signed Columbia Basin Hydro contract adding summer capability. With Columbia Basin Hydro, both summer energy and capacity shortages compared to winter are met. Ammonia-based CTs may use dedicated solar to produce the hydrogen used as the primary fuel source of the ammonia.

6) Higher cost technologies such as offshore wind and nuclear are not selected. Off-shore wind may be required if there is a shortage of on-shore wind availability over the next two decades, but this route may require additional transmission. Nuclear could become a cost-effective option in extreme high load scenarios from building and transportation electrification. Avista will investigate this further when it studies scenarios in the full IRP and as policies and new nuclear technologies develop.

7) Washington requires significantly more new nameplate capacity compared to Idaho. Currently, Idaho's loads are nearly half of Washington's, but Washington's proposed nameplate resource selection is over five times higher than Idaho due to requirements for renewables and storage.

Transmission & Interconnection Requirements

Chapter 7 outlines the transmission investments required for each supply-side option. While actual transmission needs are difficult to estimate until resource procurement is made due to location specific requirements, the IRP selection can be helpful to guide resource decisions for multi-year complex transmission needs, as without new transmission build outs, some resources will just not be available if they cannot be delivered to customers.

The PRiSM model is designed to estimate resource selection based on direct project cost, interconnection, and delivery cost. Selection can occur where a more expensive resource is preferred to avoid a higher total cost due to transmission interconnection. By the 2040s, Avista is likely to either have consumed the lower cost connected resources or other utilities may export these resources off Avista's system. In either case, Avista will need to reinforce its transmission system in renewable rich and transmission congested areas such as the Big Bend area to be able to provide resources to customers in the future. Due to the historical long-lead time to develop transmission, Avista's transmission department should evaluate long-term system needs and begin permitting and acquiring land as early as possible.

The Placeholder Resource Strategy also indicates the potential for new transmission needs in the North Idaho and Spokane areas. For example, long duration storage using ammonia-based turbines could be sited at existing or greenfield sites, but subject to area load growth, state policies, and capacity needs, additional reinforcement between North Idaho and Spokane will be needed. Because of the urban nature of these areas, Avista's transmission group should further investigate objectives to alleviate these constraints.

Lastly, Avista may need additional transmission to reach existing or new markets. With the amount of off-system wind resources selected, 300 MW of Montana wind[5] in the first half of the plan and 500 MW of Northwest wind toward the end of the plan, the model selected off-system wind with wheeling charges over on-system wind due to the cost of building new transmission. However, the ability to import resources from off-system could compete with other utilities also trying to bring those resources to their systems. Further, with the amount of VER resources (subject to storage charging), Avista will be an exporter of energy as the amount of acquired resources will likely exceed average customer load and Avista may not be able to sell this excess generation without expanding existing transmission capacity. Purchasing non-firm transmission could be an option, but its availability may have limitations due to regional pressures to acquire transmission for I-5 corridor loads. A Regional Transmission Organization (RTO) solution could help relieve some of these pressures, but further analysis is required to study external connection requirements and the cost and benefits of an RTO. Avista will be further analyzing market related transmission needs in preparation of the 2025 IRP.

Cost and Rate Projections

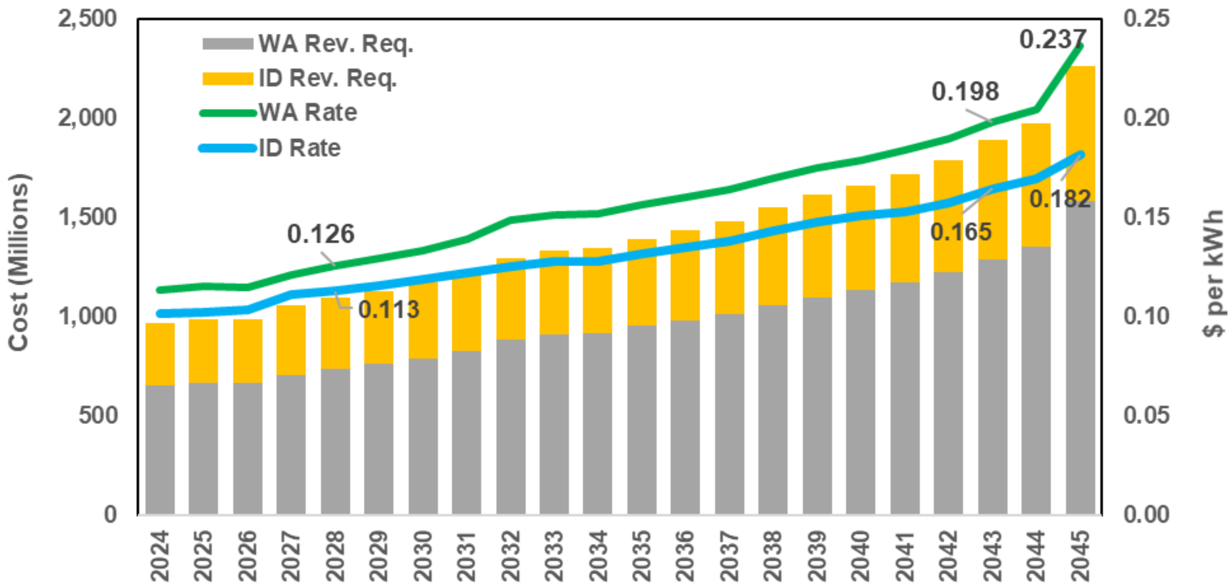
The IRP cost and rate projection does not include detailed transmission,[6] distribution, administrative, and O&M recovery costs. Avista assumes these non-generation costs increase by 3.8 percent per year to approximate an annual average customer rate estimate using historic non-power supply cost growth rates. Annual projected rates and revenue requirements are shown in Figure 9.4. Rates are calculated by the total revenue requirement divided by retail sales and does not represent rate class forecasts. Also, rates will be determined by actual investments, this analysis should only be used for comparative and informational purposes.

Washington revenue requirement grows at 4.2 percent a year and rates increase 3.5 percent a year. Although the last 5 years of the study, costs and rates grow faster at 6.9 percent and 5.8 percent respectively. Cost and rates for Idaho are generally lower where the average revenue requirement grows at 3.6 percent each year and rates are less at 2.8 percent annually. Over the last 5 years, Idaho rates also grow at a faster rate due to resource retirements but are 5.1 percent (revenue requirement) and 3.8 percent (rates).

[5] Assumes transmission is available from other plan closures and new facilities are constructed to integrate new wind resources to existing transmission

[6] Unrelated to specific generation acquisition.

Figure 9.4: Revenue Requirement and Rate Forecast by State



Energy Efficiency Related Financial Impacts

The Washington EIA requires utilities with over 25,000 customers to acquire all cost-effective and achievable energy conservation.[7] Penalties could be accessed for utilities not achieving EIA targets. Avista uses the TRC plus non-energy impacts with a social cost of greenhouse gas savings to estimate its cost-effective energy savings Idaho only use the utility cost test. The estimated avoided cost of energy efficiency in Washington is shown in Figure 9.5 and Idaho's is shown in Figure 9.6. The total 20-year Washington energy avoided cost[8] of energy efficiency is $82.27 per MWh and capacity is $112.91 per kW-yr. These estimates do not include non-energy benefits as these benefits are program specific and will increase the avoided cost depending on if the program has a non-energy impact.

Idaho avoided cost is less due to the exclusion of clean energy premiums, Power Act preference, and avoidance of the social cost of greenhouse gas. Idaho energy avoided costs is $37.63 per MWh and capacity is $102.65 per kW-yr. Avista includes the savings of future transmission and distribution expenses and line loss savings in both states' avoided cost.

[7] The EIA defines cost effective as 10 percent higher cost than a utility would otherwise spend on energy acquisition.
[8] Resulting from this temporary Placeholder Resource Strategy and subject to change when the final Preferred Resource Strategy is finalized after completion of the 2022 All-Source RFP.

Figure 9.5: Washington Energy Efficiency Avoided Cost

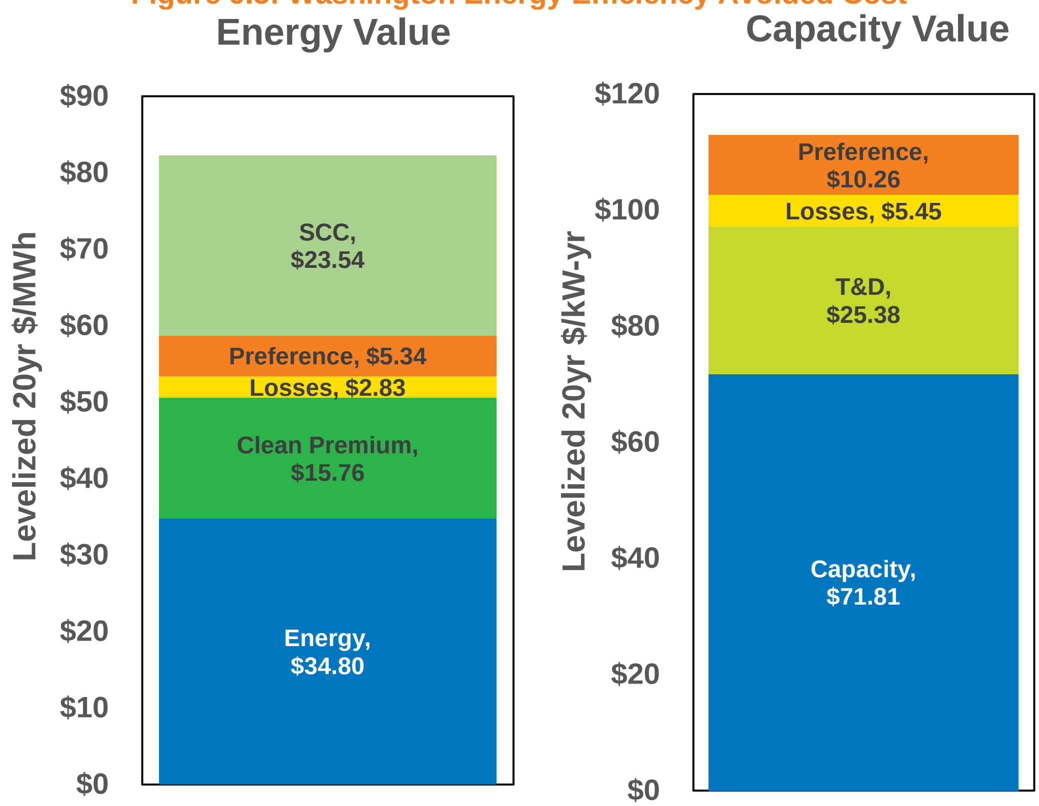
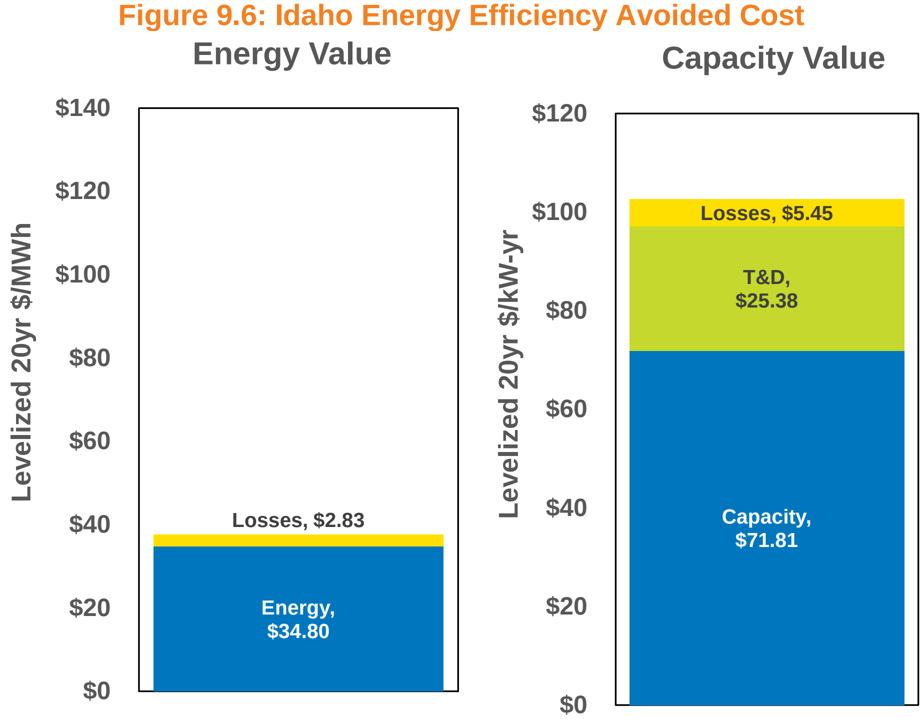


Figure 9.6: Idaho Energy Efficiency Avoided Cost



Incremental Cost Cap Analysis

Avista conducted an incremental cost analysis for Washington-related CETA costs using the incremental cost methodology provided by rule. The Placeholder Resource Strategy is compared to an Alternative Lowest Reasonable Cost Portfolio. In this portfolio, PRiSM solves to meet customer demand without the clean energy requirements and NCIF spending. In this specific scenario, it also excludes an exit of Coyote Springs 2 in 2045 for Washington customers and the recently signed Columbia Basin Hydro contract. The difference in costs between these studies represents the annual incremental cost, this value is then compared to a two percent annual rate increase of the Alternative Lowest Reasonable Cost Portfolio cost. The analysis shows Avista does not reach the cost cap in any of the future 4-year compliance windows but is much closer in the last “2042 to 2045” window. Since it is unclear if 2045 would be covered in this four-year block there is a strong likelihood, given these assumptions, exceeding the 2045 cost cap could be used as alternative compliance to meet the primary compliance requirement.

Table 9.4: 2022-2024 Cost Cap Analysis (millions $)

	2026 to 2029	2030 to 2033	2034 to 2037	2038 to 2041	2042 to 2045
Cost Cap Spending Limit	$136m	$159m	$183m	$210m	$244m
Incremental Cost w NCF spending	$10m	$40m	$51m	$43m	$212m
Delta	$125m	$118m	$133m	$167m	$31m

Avista is concerned with how the Alternative Lowest Reasonable Cost Portfolio is defined. The concern is if the baseline cost of the portfolio used to estimate the two percent cost cap includes past higher cost resource acquisitions, then the resulting two percent cost cap calculation is higher than two percent, since it likely would not have acquired the associated energy at the price it paid. To overcome this issue, Avista suggests a future WUTC workshop to define how this portfolio should be drafted, as one interpretation could be to exclude any resource acquisition made after 2020 meeting CETA clean energy requirements and let the model select resources to fill in those capacity/energy deficits or use a historically based model. Given the options, future discussion with stakeholders is necessary since this calculation is critical to resource selection especially toward the end of the plan and is likely more critical to other utilities with less clean energy than Avista.

Avoided Cost

Avista calculates the avoided or incremental cost, to serve customers by comparing the Placeholder Resource Strategy cost to alternative portfolios. These calculations can be useful to evaluate new PURPA agreements or other resource acquisition. The calculations here are not used for setting Schedule 62 rates but may inform its calculation.

New Resource Avoided Costs

Avoided costs change as Avista's loads and resources change, as well as with changes in the wholesale power market. Avoided costs are a best-available estimate at the time of analysis. Specific project characteristics will likely change the value of a resource. The prices shown in Table 9.5 represent energy and capacity values for different periods and product types, including those providing clean energy. For example, a new generation project with equal annual deliveries in all hours has an energy value equal to the flat energy price shown. The table also includes traditional on- and off-peak pricing compared to the flat price for illustrating how pricing changes with a different delivery period. In addition to the energy prices, these theoretical resources receive capacity value for production at the time of system peak. This value begins in 2027, although can be adjusted back to November 2026, when Avista is first short capacity, although after 2022 RFP negotiations are complete the first short position may change.

Capacity value is the resulting average cost of capacity each year. Specifically, the calculation compares a portfolio where the objective is to build resources to meet only capacity requirements (excluding social cost of greenhouse gas) against a lower cost portfolio with no resource additions. Avista uses these annual revenue requirements[9] differences to create annualized costs of capacity beginning in the first year of a major resource deficit. Recognizing cash flows are lumpy by nature, the variability in annual values is levelized and tilted using a two percent inflation rate. The next step divides the costs by added capacity amounts during the winter peak. This value is the cost of capacity per MW or cost per kW-year. The capacity payment applies to the capacity contribution of the resource at the time of the winter peak hour.

Capacity pricing at the full capacity payment shown in Table 9.5 assume a 100 percent QCC or ELCC in the winter. For example, solar receives a two percent QCC credit based on Equivalent Load Carrying Capability (ELCC) analysis and would receive two percent of the capacity payment compared with its nameplate capacity. No matter the resource, Avista will need to either conduct an ELCC analysis or utilize the value from the Western Resource Adequacy Program (WRAP) for any specific project it evaluates to determine its peak credit. The current forecast assumes Avista's capacity deficit is higher in the winter then summer for all future years of the planning horizon.

VERs consume ancillary services because their output cannot be forecasted with great precision. VERs seeking avoided cost pricing may receive reduced payments to compensate for ancillary service costs if the resource is different than proposed in the Placeholder Resource Strategy. The clean energy premium includes the VER cost as part of the estimated value.

The clean energy premium calculation is similar to the capacity credit but estimates the cost to comply with CETA by comparing the Placeholder Resource Strategy to the same portfolio used to calculate the Capacity Cost. Avista uses the annual revenue requirement

[9] Transmission costs associated with new resources are included within the capacity cost. These include the interconnection of the resource to the system and the cost to wheel power to Avista's customers.

differences to create an annualized cost of clean energy beginning with the first year of clean energy acquisition with an annual price adjustment of two percent per year. This new annual cost is divided by the incremental megawatt hours of generation and the resulting value shows the amount of extra cost per MWh needed to meet clean energy requirements. This benefit includes the cost associated with changing to cleaner capacity resources, but also adding clean energy resources. Clean energy premiums assume no change to renewable energy tax incentives but will include any tax incentives if they are extended beyond the current Inflation Reduction Act (IRA) amounts.

Table 9.5: New Resource Avoided Costs

Year	Flat ($/MWh)	On-Peak ($/MWh)	Off-Peak ($/MWh)	Clean Premium (MWh)	Capacity ($/kW-Yr)
2024	$42.70	$45.85	$38.55	$0.00	$0.00
2025	$35.74	$38.05	$32.66	$0.00	$0.00
2026	$33.30	$34.97	$31.00	$0.00	$0.00
2027	$29.94	$30.72	$28.90	$16.85	$78.0
2028	$29.87	$30.00	$29.70	$17.19	$79.6
2029	$29.97	$29.55	$30.50	$17.54	$81.2
2030	$34.39	$33.36	$35.74	$17.89	$82.8
2031	$32.34	$31.29	$33.76	$18.24	$84.5
2032	$31.45	$30.03	$33.38	$18.61	$86.2
2033	$32.47	$31.04	$34.35	$18.98	$87.9
2034	$33.00	$31.50	$34.94	$19.36	$89.6
2035	$34.32	$32.21	$37.01	$19.75	$91.4
2036	$34.90	$32.58	$37.91	$20.14	$93.3
2037	$36.59	$34.74	$39.04	$20.55	$95.1
2038	$36.32	$34.40	$38.88	$20.96	$97.0
2039	$37.44	$35.16	$40.45	$21.38	$99.0
2040	$39.59	$37.66	$42.18	$21.80	$100.9
2041	$39.80	$37.81	$42.44	$22.24	$103.0
2042	$41.42	$40.11	$43.17	$22.68	$105.0
2043	$42.37	$41.22	$43.94	$23.14	$107.1
2044	$47.64	$46.56	$49.09	$23.60	$109.3
2045	$47.55	$46.49	$48.87	$24.07	$111.5
22 yr. Levelized	**$35.34**	**$35.04**	**$35.73**	**$15.01**	**$69.51**

10. Customer Impacts

Consistent with CETA Standards in WAC 480-100-610 (4) (c), and in accordance with the required content of an Integrated Resource Plan (IRP) described in WAC 480-100-620 (9), this Progress Report includes an assessment of energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk. These benefit areas are considered in various portfolio analyses and incorporated into the Placeholder Resource Strategy through the inclusion of metrics related to non-energy impacts (NEIs) and Customer Benefit Indicators (CBIs) where applicable. Using these metrics, Avista estimates the degree these benefits will be equitably distributed and/or burdened over the planning horizon.

Including these requirements in resource planning, as well as resource and program selection (occurs outside the IRP process), ensures a focus on communities who may have historically been excluded from receiving the benefits of resources or programs. Further, it provides a method to measure the success of the transition to clean energy and keeps Avista accountable for its resource and program choices. While Avista is committed to ensuring the equitable implementation of the specific actions identified in the CEIP, there are several circumstances where NEIs or CBIs are not applicable to the planning process. In these circumstances, NEIs and CBIs are utilized for evaluation and selection of programs offered by the Company or in resource selection through a proposal process. The 2021 CEIP was approved in Docket No. UE-210628 with 38 numbered conditions. In accordance with CEIP Condition No. 2, Avista consulted with its TAC and Energy Efficiency Advisory Group (EEAG) in the applicability of each resource and program selection and/or implementation. In addition, the methodology was reviewed with the Equity Advisory Group (EAG) to ensure the application was equitable.

This chapter provides a review of each CBI and its relationship to resource planning, selection, and implementation in accordance with Condition No. 35, stating:

> *Avista recognizes that not all CBIs will be relevant to resource selection (for example, some CBIs pertain to program implementation). For its 2023 IRP Progress Report, and future IRPs and progress reports, Avista should discuss each CBI and where the CBI is not relevant to resource selection, explain why.*

Equity Impacts

CETA requires a focus on equity and Energy Justice. The core tenants of Energy Justice include the following:[1]

- Distribution justice refers to the distribution of benefits and burdens across populations. This objective aims to ensure that marginalized and vulnerable populations do not receive an inordinate share of burdens or are denied access to benefits.

- Procedural justice focuses on inclusive decision-making processes and seeks to ensure that proceedings are fair, equitable, and inclusive for participants, recognizing that marginalized and vulnerable populations have been excluded from decision-making processes historically.

- Recognition justice requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequities

- Restorative justice uses regulatory government organizations or other interventions to disrupt and address distributional, recognitional, or procedural injustices, and to correct them through laws, rules, policies, orders, and practices.

These requirements create a new perspective to evaluate resource strategies within the traditional IRP planning process through increased stakeholder input specific to equity issues and continuous evaluation of progress. Throughout the CEIP process, the EAG was instrumental in identifying communities or individuals who have historically, or are currently, experiencing inequities. The Company has taken a first step to incorporate "recognition justice" into its planning efforts. These groups are described in the "Named Communities" below. These six equity areas are categorized and briefly discussed in Table 10.1.

CBIs were developed in the 2021 CEIP process to measure the equitable distribution or "distribution justice" of the benefits or reduction of burdens in resource or program selection. In compliance with Condition No. 35 of the CEIP, additional information is provided below about the development and applicability of CBIs to resource planning as well as resource selection and program implementation.

Finally, a Public Participation Plan was filed with the Commission in April 2021[2] and implemented to ensure Procedural Equity within the development of the CEIP. Avista continues to improve its Public Participation Plan in collaboration with the EAG and its third-party consultant, Public Participation Partners (P3). In addition, a Work Plan was filed for the 2023 Progress Report/IRP to provide TAC meeting topics and a discussion

[1] WUTC Docket UG-210755 Final Order 09, paragraph 56.
[2] See Docket UE-210295.

forum for inputs into the IRP ahead of the meetings. The development of the IRP and Washington's 2023 Electric IRP Progress Report includes input and feedback from the TAC, ensuring representation from stakeholders and individuals where additional policies and procedures are to be identified and considered going forward.

Table 10.1: Named Communities

Topic	Observations
Affordability	• Factors impacting ability to pay for energy • Balance of electric bill with other expenses
Energy Resilience and Security	• Factors limiting the ability to have power quickly restored such as location, condition, etc. • Factors limiting the consistency and security of power services
Access to Clean Energy	• Factors limiting the ability to access clean energy programs and services • Language, cultural, and economic barriers • Limited transportation electrification infrastructure
Environmental	• Factors may result in a disproportionate impact to environmental harms • Housing conditions • Location to pollution
Community Development	• Factors going beyond only individual socio-economic or sensitivities • Factors pertaining to larger group of individuals
Public Health	• Factors disproportionally impacting health associated with social indicators or environmental indicators

Creating an equitable energy system requires identifying and eliminating any systemic barriers in existing processes. Avista engaged a consultant to help identify ways to mitigate barriers to public participation and engagement throughout its CEIP work. This plan will be evaluated to determine how it may apply these to future resource planning.

Named Community Identification

Avista must identify communities who are disproportionally impacted by adverse socioeconomic conditions, pollution, and climate change to ensure Avista's planning and implementation processes are fair and have an equitable distribution of benefits through the transition to clean energy. To do this Avista identifies two types of community groups; Highly Impacted Communities and Vulnerable Populations (WAC 480-100-605) these are jointly referred to as Named Communities and are defined as follows:

- **Highly Impacted Community** means a community designated by the Washington Department of Health based on cumulative impact analyses in section 24 of this act or a community located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C. Sec. 1151.12.

- **Vulnerable Populations** mean communities that experience a disproportionate cumulative risk from environmental burdens due to:
  - o Adverse socioeconomic factors, including unemployment, high housing, and transportation costs relative to income, access to food and health care, and linguistic isolation; and
  - o Sensitivity factors, such as low birth weight and higher rates of hospitalization.

Avista relies on information provided by the Washington State Health Disparities Map from the Department of Health (DOH) to help identify the Highly Impacted Communities. For each census tract in the state, the DOH developed a score to measure disparities between 1 and 10 for each of the four categories shown in Figure 10.1. Communities where the combined average score of the four categories was nine or higher are considered Highly Impacted Communities. The DOH also included any areas fully or partially within “Indian Country”.[3]

Figure 10.1: Named Communities

Environmental Exposures	Environmental Effects	Socioeconomic Factors	Sensitive Populations
o NO_X-diesel emissions o Ozone concentration o PM 2.5 concentration o Populations near heavy traffic o Toxic releases from facilities	o Lead risk from housing o Proximity to hazardous waste treatment facilities o Proximity to risk management plan facilities o Wastewater discharges	o Limited English o No high school diploma o People of color o Population living in poverty (<= 185% of federal poverty level) o Transportation expense o Unaffordable housing (>30% of income) o Unemployed %	o Death from cardiovascular disease o Low birth weights

In the 2021 CEIP, Avista’s method to determine Vulnerable Population characteristics was conditionally approved.[4] Avista, with the help of its EAG and other advisory groups, determined the geographic boundaries of Vulnerable Populations for the 2021 CEIP by using the Health Disparities Map’s[5] community rating system for Socioeconomic Factors and Sensitive Population. The map rates areas on a scale of 1 to 10, where 10 is an area

[3] The DOH’s list of Highly Impacted Communities originally included areas misidentified as “Indian” country due to GIS borderline errors. Avista excluded these census tracts from its list for this report.

[4] Docket No. UE-210628

[5] https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmental-health-disparities-map

with the most significant health disparity. Avista focused on identifying census tracts not otherwise identified as a Highly Impacted Community whose socioeconomic factor or sensitive population score was 9 or 10. This methodology was conditionally approved and contingent upon the incorporation of additional metrics as identified by Avista and its EAG. The maps of both types of Named Communities are shown in Figure 10.2 through Figure 10.4. Avista will continue to work with the EAG to identify additional criteria to distinguish Vulnerable Populations.

Figure 10.2: Spokane Named Communities

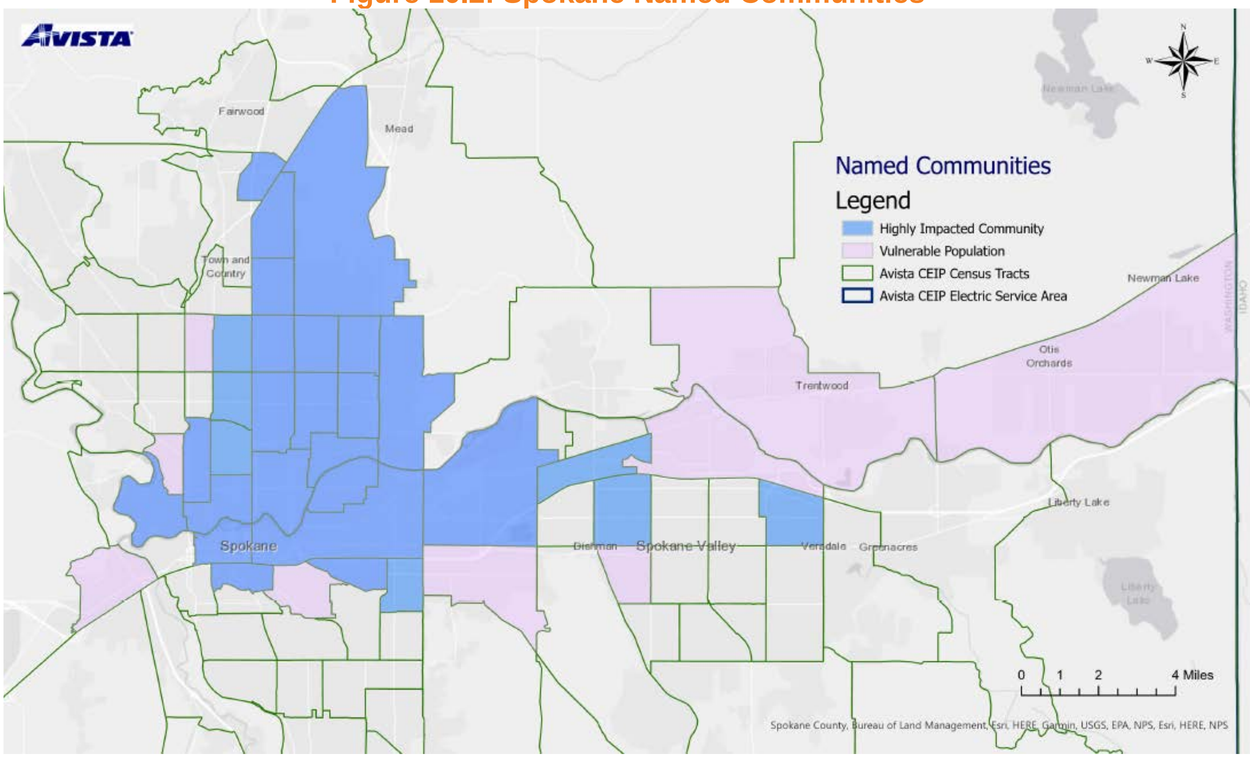


Figure 10.3: Washington Service Area Named Communities

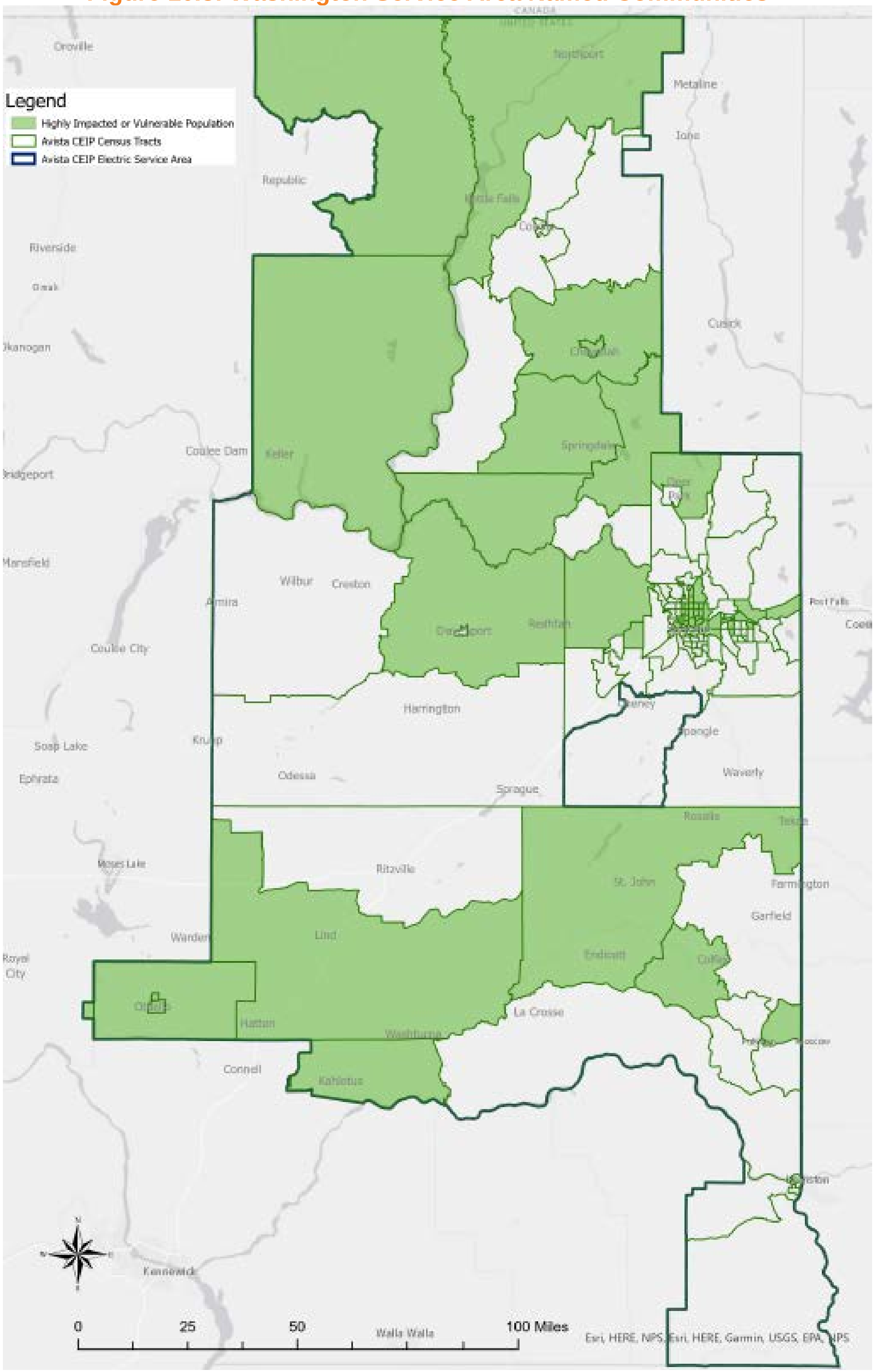
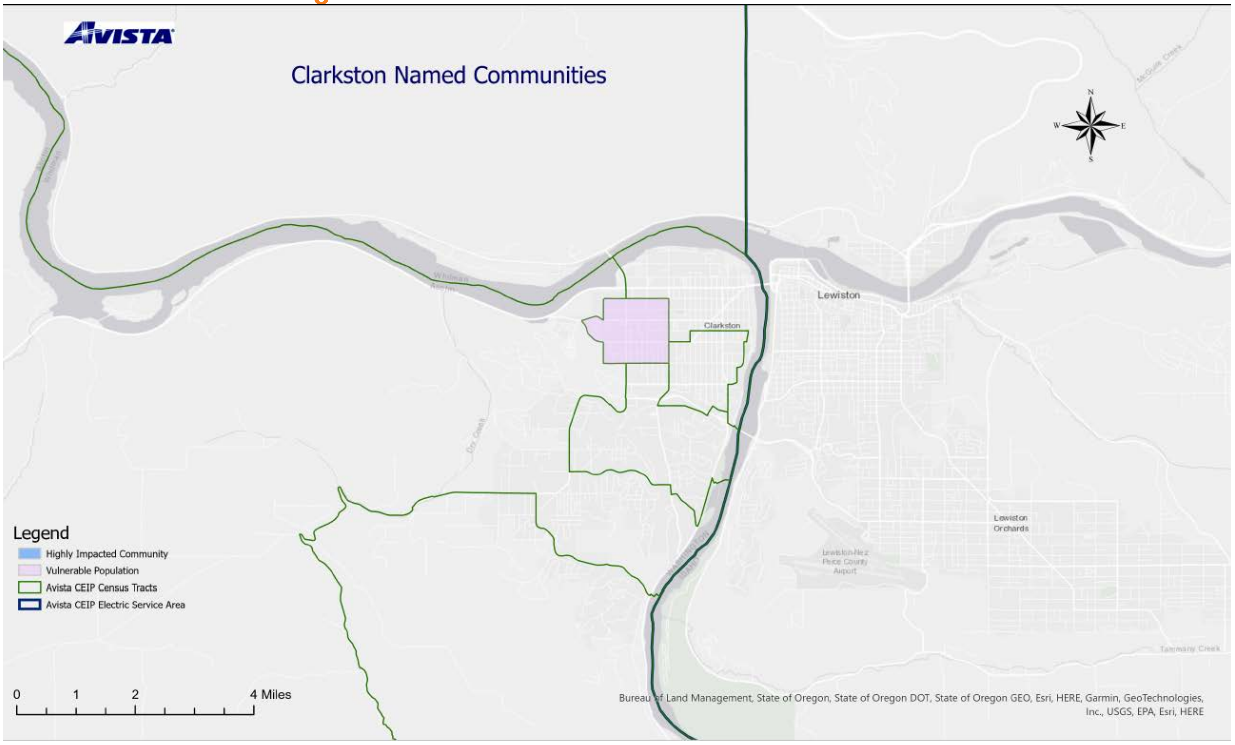


Figure 10.4: Clarkston Area Named Communities



Non-Energy Impacts (NEI)

In certain circumstances, the benefits associated with energy efficiency (i.e., demand-side) or supply-side resources may include additional impacts beyond energy or bill savings. Defined as non-energy impacts, these benefits may be significant compared to energy savings. Typically, these benefits are separated into specific benefits as follows:

- Utility impacts – reduced costs, reduction of losses through more efficient use of energy, and less demand may reduce the number of resources needed to serve customers.
- Societal impacts – benefits or burdens associated with broader economic development or environmental benefits such as regional reductions in emissions.
- Participant impacts – benefits or burdens which extend beyond energy bill savings including improvements in comfort, lighting quality, equipment operations and/or maintenance, health, and safety, etc. These impacts can be related to public health, safety, reliability and resiliency, energy security, environment (land use, water, wildfire, wildlife), and economic impacts.

NEIs were incorporated in the selection of energy efficiency[6] programs/measures before but using NEIs for supply-side resource planning is new to resource planning. Avista engaged with a consultant, DNV[7], to identify and quantify both energy efficiency and

[6] NEI for energy efficiency resources were incorporated into the 2021 IRP.
[7] https://www.dnv.com/

supply-side non-energy impacts. After input from recent WUTC workshops and the advisory groups, quantified NEIs[8] will be included in resource planning efforts for energy efficiency and supply-side resources as identified in the most recent NEI study. Quantification of more NEIs may be included in the future as more studies are complete, specifically for solar, storage, demand response and other DERs. Avista agreed as part of CEIP Condition No. 2 to incorporate NEI values in this Progress Report. While outside the resource planning process, NEIs are also used in resource selection such as Avista's 2022 All-Source RFP.

For energy efficiency, Avista only uses the positive NEI values applied as levelized cost per kWh for applicable measures. While the NEI values vary between measures and sectors, the largest area of benefit is with low-income residential customers. Weatherization measures such as windows, insulation and insulated doors have received the highest overall NEI values with Health and Safety being the largest overall contributor. These values from are up to $0.75 per kWh. A summary and how these were calculated is included in Appendix D.

DNV also studied NEIs for potential and existing supply-side resources. Costs or benefits were estimated at a $/MWh of production-based impacts such as air emissions or $/kW of project size (levelized over the life of the asset) such as economic impacts. The DNV report for this study is in Appendix D and was also presented to the IRP TAC. The NEI value for resources is in the PRiSM model and used to select new resources.

The value of NEIs can be useful in resource planning but obtaining some NEIs determination is too expensive to estimate for a utility of Avista's size, as such, it would be more efficient to determine consistent estimates on a regional basis. Many of the non-quantified values from the studies require more research, analysis, and peer review to develop proxy values.[9] The additional NEI items could be best handled through a jointly funded NEI study, potentially directed by the WUTC.

Named Community Investment Fund

To increase focus on the equitable distribution of projects and programs, the Named Community Investment Fund (NCIF) was proposed and approved, as part of the Company's 2021 CEIP. This fund facilitates investments in programs, projects, initiatives, and other support that traditionally would not be undertaken.

Avista proposed to spend up to approximately $5 million[10], or 1 percent of its electric retail revenue at the time, each year through the NCIF on projects to improve the equitable distribution of energy and non-energy benefits within Named Communities. The anticipated NCIF allocation is:

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[8] Avista also include proxy NEI values for resources without an NEI identified in the DNV study.
[9] Such as the 10 percent adder for energy efficiency in the Northwest Power Act.
[10] See Order 01 in Docket UE-220350.

- 40 percent or up to $2 million to supplement and support Avista's targeted energy efficiency efforts for Named Communities. If approved, this funding would be recovered through the energy efficiency tariff rider (Schedule 91 – Energy Efficiency).
- 20 percent or up to $1 million for distribution resiliency efforts for Named Communities.
- 20 percent or up to $1 million for incentives or grants to local customers or third parties to develop projects benefitting Named Communities.
- 10 percent or up to $500,000 for targeted outreach and engagement efforts in Named Communities to reduce barriers to participation for their access to energy.
- 10 percent or up to $500,000 for all other projects, programs, or initiatives benefitting Named Communities.

Avista focused its recent efforts on developing a NCIF governance structure to include project identification, application, application requirements, evaluation, and selection criteria. The Energy Efficiency Department will oversee the planning, resource allocation, and implementation of the approximately $2 million allocated to energy efficiency projects. One quarter of the $2 million, is dedicated to partnering with Avista's EAG on community-identified projects. Avista will work closely with the EAG and EEAG for input and feedback on program design and outreach methods. Meeting notes and recordings about NCIF discussions with the EAG are on Avista's website.[11] A placeholder for potential projects considered within the IRP are discussed in Chapter 9.

Customer Benefit Indicators

This Progress Report's includes forecasts of the impacts of the resource selection to CBIs for those CBI's relevant to resource selection. As illustrated in Table 10.2, the CEIP includes 14 CBIs, including several metrics for measuring the impact of those CBIs. The metrics boldly highlighted are forecasted in this plan. These metrics will measure the effects of the clean energy transition and broaden the focus on equity among customers.

In some cases, there is a direct correlation between a CBI and an NEI. For instance, reduction in air emissions, where the NEI includes the estimated financial value of the societal harm of those emissions. As such, energy efficiency addresses CBIs in its NEI calculations for resource planning purposes. For metrics related to resource planning, this Progress Report shows both available historical baselines and a forecast for these CBIs.

While Avista is committed to increasing the impact of equity in its decision making and planning, some CBIs cannot be forecast with enough certainty to include in its evaluation criteria for resource planning. The resource planning forecast only includes quantifiable indicators. Avista will continue evaluating CBIs to see if more qualitative measures can be included in future resource planning efforts. This may require an end-use model which is likely not cost-effective given the labor, time, and expense.

[11] https://www.myavista.com/about-us/washingtons-clean-energy-future

Table 10.2 shows in "bold" the CBIs forecasted in resource selection and implementation depending upon the availability of data. As noted above, while Avista is committed to ensuring the equitable implementation of the specific actions identified in the CEIP, there are circumstances where NEIs or CBIs are not applicable to the resource planning process. In these circumstances, NEIs and CBIs are utilized for evaluation and selection during the resource selection and program implementation processes. Figure 10.3 illustrates the planning process for resource needs and how those resources are secured and implemented, and how they impact the next IRP's load and resource needs. Whereas some CBIs have data available to forecast on a long-term basis and can be included in the IRP, others will take CBIs into consideration when evaluating options during implementation. The applicability and timing of CBI inclusion is described below. In either circumstance, Avista is measuring and tracking the impact of business decisions to focus on equitable outcomes.

Figure 10.5: Planning Process

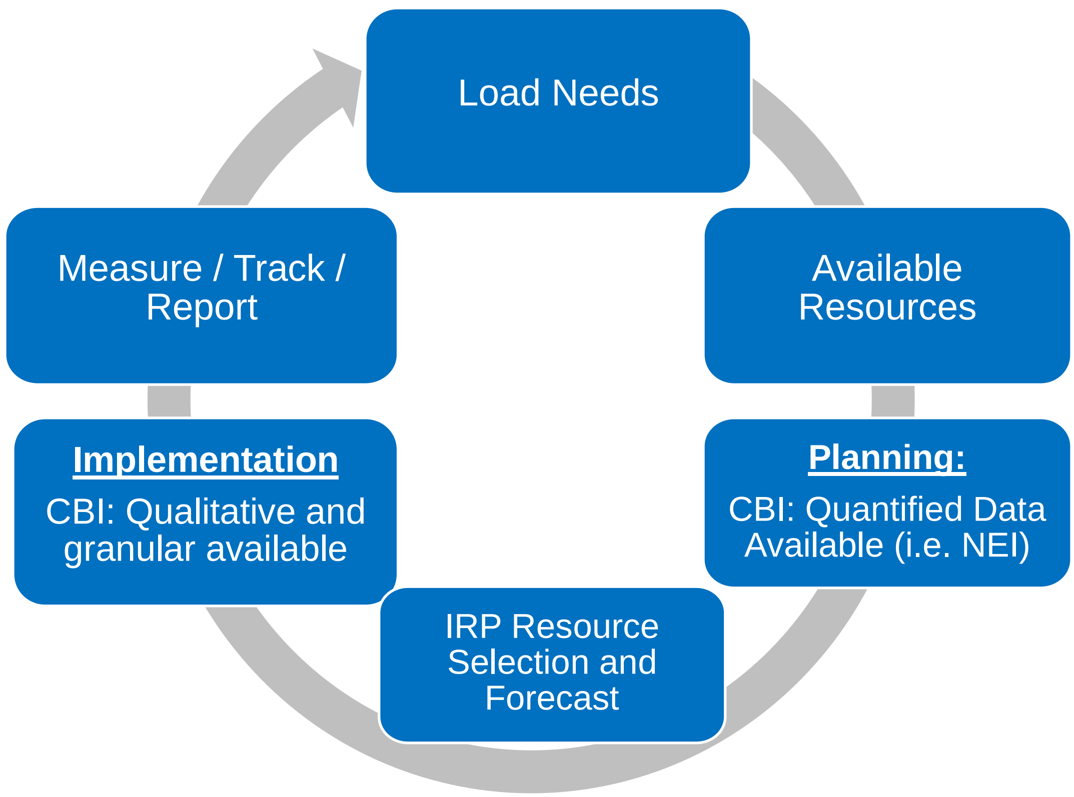


Table 10.2: Customer Benefit Indicators

CBI	CBI Measurement Metrics
(1) Participation in Company Programs	Participation in weatherization programs and energy assistance programs (all customers and Named Communities)
	Saturation of energy assistance programs (all customers and Named Communities)
	Residential appliance and equipment rebates provided to customers residing in Named Communities and rental units (Condition No. 17)
(2) Number of households with a High Energy Burden (>6%)	**Number and percent of households** (known low income, all customers, Named Communities) (Condition No. 18)
	Average excess burden per household
(3) Availability of Methods/Modes of Outreach and Communication	Number of outreach contacts
	Number of marketing impressions
	Translation services (Condition No. 19)
(4) Transportation Electrification	Number of trips provided by Community Based Organizations (CBOs) for individuals utilizing electric transportation
	Number of annual passenger miles provided by CBOs for individuals utilizing electric transportation
	Number of public charging stations located in Named Communities
(5) Named Community Clean Energy	**Total MWh of distributed energy resources 5 MW or less**
	Total of MWh of energy storage resources under 5 MW
	Number of sites/projects of renewable distributed energy resources and energy storage resources
(6) Investments in Named Communities	**Incremental spending each year In Named Communities**
	Number of customers and/or CBOs served
	Quantification of energy/non-energy benefits from investments (if applicable)
(7) Energy Availability	Average outage duration
	Planning Reserve Margin (Resource Adequacy)
	Frequency of customer outages
(8) Energy Generation Location	**Percent of generation located in Washington or connected to Avista transmission**
(9) Outdoor Air Quality	Weighted average days exceeding healthy levels
	Avista plant air emissions
	Decreased wood use for home heating
(10) Greenhouse Gas Emissions	**Regional GHG emissions**
	Avista GHG Emissions
(11) Employee Diversity	Employee diversity representative of communities served by 2035
(12) Supplier Diversity	Supplier Diversity of 11 percent by 2035
(13) Indoor Air Quality	In development
(14) Residential Arrearages and Disconnections for Nonpayment	Number and percent of residential electric disconnections for non-payment
	Residential arrearages as reported to Commission in Docket U-200281

CBIs Not Applicable to Resource Planning

The following CBIs are not related to the planning phase. These items will be utilized in resource selection, program implementation, or evaluation to focus on equity areas. In accordance with Condition No. 35, the following information is applicable to these CBIs.

CBI No. 1 – Participation in Company Programs

This CBI aims to increase overall participation levels for all customers in Avista's energy efficiency and energy assistance programs, with special emphasis on Named Communities. While the priority is to increase participation within Named Communities specifically, Avista will consider the current participation levels in energy efficiency programs as part of its baseline when measuring increases to participation. The intent of these efforts is to prioritize distributional equity by addressing direct or indirect barriers impacting a customer's ability to participate in energy efficiency programs.

This metric emphasizes overall participation; however, the impact of these efforts is directly related to reducing customers' overall energy burden and making energy more affordable. Energy Efficiency efforts have known energy and NEI values with direct benefits to customers from both affordability and overall wellbeing standpoints. Avista can monitor the successful steps contributing to this increase in participation when combined with CBI No. 3. The Company will monitor the following metrics included in this CBI:

- Participation in weatherization, efficiency, and energy assistance programs (all customers and Named Communities)
- Saturation of energy assistance programs (all customers and Named Communities)
- Residential appliance and equipment rebates provided to customers residing in Named Communities and rental units (Condition No. 17).

Tracking the metrics for this CBI is granular in nature and requires data for each individual customer, as well as each customer in a Named Community. This requires extensive data analysis utilizing Avista's Customer Care and Billing system. In IRP planning, energy efficiency is forecast based on a total energy savings by program type and customer segment (i.e., residential and commercial customers). Typically, those energy efficiency measures identified to be cost effective through the CPA are implemented, but the IRP doesn't go to the individual customer level as required in this CBI. The EEAG will be instrumental in developing a method for prioritizing programs to ensure they are equitably distributed.

CBI No. 3 – Availability of Method/Modes of Communication

This CBI focuses on increasing access to clean energy and reaching customers who have not participated in Avista energy efficiency and energy assistance programs due to language barriers or other limitations such as not knowing about the programs or understanding the application process. Increased participation will lead to lower energy usage and costs, again impacting accessibility and affordability. This CBI seeks to increase participation in energy efficiency programs. The metrics for this CBI are:

- Number of Outreach Contacts
- Number of Marketing Impressions
- Translation Services

This CBI focuses on addressing inequities in serving Avista's customers by identifying and overcoming barriers in participation, such as language or economic limitations. These barriers make it more difficult and expensive for Named Communities. Increased and expanded customer outreach will grow energy efficiency and energy assistance participation making energy service more affordable for disadvantaged customers. Further, increased energy efficiency participation benefits all customers by reducing the need for more generation.

This CBI is not quantifiable for resource planning. Avista is working with its advisory groups about ways to increase participation. This CBI is applicable during the implementation of Company programs and tracking Avista's outreach effectiveness with its customers.

CBI No. 4 – Transportation Electrification

This CBI considers transportation electrification (TE) efforts and impacts on customers in Named Communities. Avista's Transportation Electrification Plan (TEP)[12] provides a path to a cleaner energy future by 2045 by electrifying transportation. The TEP outlines guiding principles, strategies, and an action plan with detailed program descriptions, cost and benefit estimates, and regular reporting details. The TEP has an aspirational goal of 30 percent of overall Avista spending on programs benefiting disadvantaged communities, low-income customers, or Named Communities. Tariff Schedule 77 and the TEP commits to regular reporting of TE efforts through several metrics.

Avista will track TE in Named Communities with three metrics:

- Annual trips provided by Community Based Organizations (CBOs) by electric transportation.
- Annual passenger miles provided by CBOs by electric transportation; and,
- Public charging ports available to the public in Named Communities.

The impacts of TE are embedded in Avista's load forecast and its resource planning process. This accounts for TE at a high level during the planning process. During TE program implementation, much detail is required to focus on who and where the impacts of our efforts will be located. Avista will continue collaboration with CBOs to ensure a focus on Named Communities throughout the implementation process.

[12] WUTC Docket UE-200607, acknowledged by the Commission on October 15, 2020.

CBI No. 6 – Investments in Named Communities

This CBI targets new investments in Named Communities that lead to positive impacts on Avista customers living in those communities. Benefits may include lower energy burdens, economic development, affordability, resiliency, or other safety and health matters. The potential investments will not include capital, O&M, energy efficiency, or energy assistance already deployed in the normal course of business. This CBI focuses on the equitable distribution of non-energy and energy benefits to all customers and specifically those in Named Communities.

Avista will measure the following metrics for this CBI:

- Incremental annual spending of investments in a Named Community;
- Number of customers and/or Community Based Organizations served each year; and,
- Applicable quantification of annual energy and non-energy benefits from investments.

Avista does include a related forecast of potential Named Community investments later in this chapter, the results use total low-income energy efficiency investments, energy resources developed from the NCIF and pro-rata share of selected DR. Due to the investment required from this CBI, the forecast is an indicator of potential investments to be tracked in this CBI.

CBI No. 7 – Energy Availability

This CBI aims to ensure customers in Named Communities are not disproportionally impacted by power outages due to their socio-economic or sensitivity factors. Recently, Named Community customers have experienced outages 11 minutes longer than other communities. This CBI tracks the location of outages and will inform future implementation and system development to minimize the potential for outages.

Avista will measure the following metrics.

- Average Outage duration by Customer Average Interruption Duration Index (CAIDI) - Not included in resource planning
- Frequency of Customer Outages by Customer Experiencing Multiple Interruptions (CEMI) - Not Included in resource planning
- Planning Reserve Margin (Resource Adequacy) - Included in resource planning

Avista has a duty to provide safe and reliable energy to its entire customer base. Historical customer outage information provides customers with a measure of resiliency and reliability by calculating the time it takes to restore a customer’s service from an outage but does not show the cause of the outage. Most outages have been related to the distribution system as power is moved to customers and can be interrupted by weather, equipment failure, maintenance, or other factors. Monitoring these two metrics will provide data and inform Avista where new distribution resources may be located to best address inequities. The newly formed Distribution Planning Advisory Group (DPAG) will provide insight into this distribution process as it develops.

In other instances, customer outages may be due to a lack of generation. The third metric attempts to isolate Avista's ability to generate enough energy to meet customer demand to ensure reliability through resource adequacy. This metric is included in resource planning as each demand- and supply-side resource may result in different degrees of reliable energy when it is needed, dependent upon types of resource. Please see the section on CBIs applicable to resource selection for more information.

CBI No. 9 – Outdoor Air Quality

Displacing fossil fuel generation will help outdoor air quality metrics such as SO_2, NO_X, Mercury, and Volatile Organic Compounds (VOC). Avista will track the following metrics for this CBI:

- Weighted average days exceeding healthy levels
- Decreased wood use for home heating
- Avista's Washington resource air emissions

The impact to the total weighted days exceeding healthy levels measure will be from Avista's efforts to reduce emissions and actions taken by others in our service territory. This metric is not included in the resource planning process.

Decreased wood use for home heating is not quantifiable at this time on a 20 plus year planning horizon and is not part of the resource planning process. However, Avista will continue to partner with the Spokane Clean Air Agency to track wood use as a primary heating source. Avista will work with the EAG to develop an alternative method per CEIP Condition No. 20 and track in resource planning if appropriate.

The final outdoor air quality metric is Avista's Washington resource air emissions, and it is modeled in the IRP and will be included in resource and program selection and implementation. Through the NEI study, Avista can quantify the impacts of certain facility's impact to overall outdoor air quality. This is explained in the section below discussing the metrics utilized in the IRP.

CBI – No. 11 Employee Diversity and No. 12 Supplier Diversity

The purpose behind these CBIs is to generate awareness and therefore promote recognitional justice. Tracking employee diversity and supplier diversity is a first step in recognizing the potential of systemic racism embedded within existing processes and procedures. Tracking these metrics will result in an increased focus towards identifying and changing policies to eliminate inequities. This CBI is not intended to be utilized as a resource planning metric; however, as an implementation tool the Company includes diversity metrics in its selection criteria for resource selection.

The EAG raised the issue of ending systemic racism as a major concern and discussed what Avista could do to help with this wide-ranging issue. CBIs No. 11 and No. 12 are an initial attempt to track and improve Avista's employee diversity to match the diversity and genders of the communities it serves. This aspirational goal will be tracked by craft, non-craft, managers and directors, and executives for race and gender with a goal of matching the communities being served by 2035.

CBI No. 13 – Indoor Air Quality

This metric will measure the impact of energy efficiency efforts on indoor air quality. It is still in the development phase. Once this metric is developed and data is available, it will be tracked and may be included in resource selection if applicable. Avista will provide an update for this CBI in the Biennial CEIP Update Report.

CBI No. 14 – Residential Arrearages and Disconnections for Non-Payment

This CBI tracks residential arrearages and disconnections for non-payment. Connection to energy service was identified by stakeholders as a key element of energy security. This CBI is not applicable to resource planning. For planning purposes, a certain level of price elasticity is included relating to the cost of resource selection and may ultimately impact arrearages and disconnections for non-payment. Further resource decisions include the cost of arrearages, and energy efficiency evaluations include this savings in the calculation of avoided costs. Reporting this CBI keeps the issue at the forefront of affordability or energy burden conversations during implementation of future investments. Avista includes a utility NEI for less calls to the contact center for certain low-income energy efficiency measures to account for reductions in future disconnects.

CBIs Applicable to Resource Selection

As discussed above, most of Avista's CBIs are not related to resource planning, but some directly impact or are impacted by resource selection and can be forecasted and tracked. For example, constraints or requirements can be created in the PRiSM model to ensure certain metrics are met such as Planning Reserve Margin requirements or to include financial incentives such as NEIs to incent certain decisions. These constraints may drive different outcomes than traditional planning. The following section outlines CBI forecasts. For all these metrics and CBIs, the specific data used to estimate the values are included with the PRiSM model in Appendix F. While this next section "tracks" CBI's, the intent of Avista's methodology of resource selection is to use resource costs and benefits, the NCIF, CETA requirements, and NEI values to dictate resource outcomes while not specifically meeting any preconceived CBI targets or expectations. These results can also be measured against a future scenario "Maximum Customer Benefits" are achieved through increasing CBIs to theoretical levels. In the end, it will be discretionary if the resource selection and the expected CBI outcomes are justified as equitable.

CBI No. 2 – Number of Households with High Energy Burden

There are two forecastable metrics[13] related to household energy burden included within resource selection modeling:

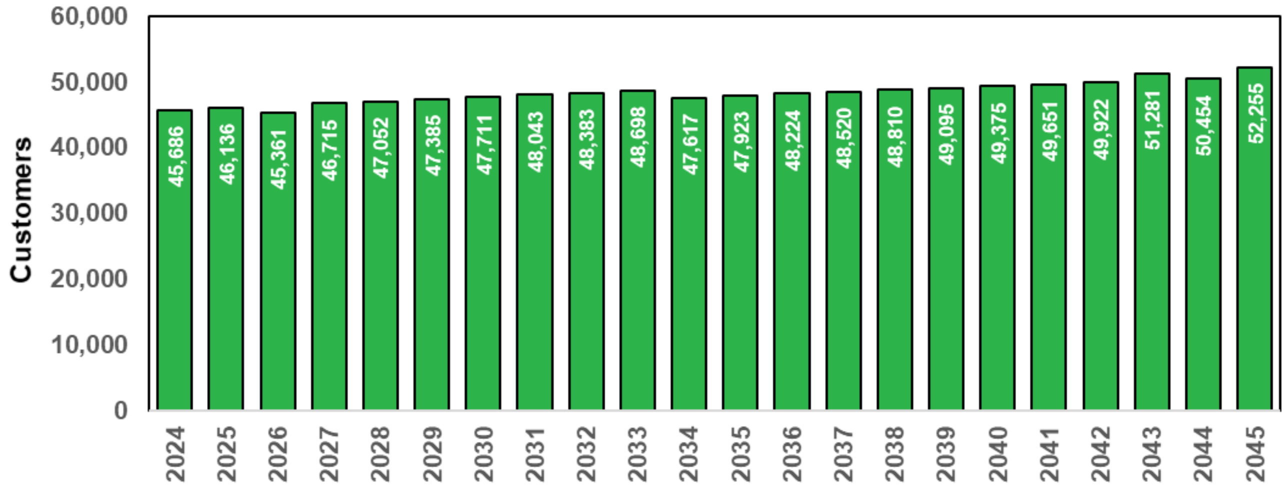
- The number of households with energy burden exceeding 6 percent of income.
- Average excess energy burden.

To assess current and future energy burden, data for customer income, energy usage, and energy rates is required. Customer income data was derived from a spatial analysis of census and third-party income data and was matched with usage and bill amount data. Total energy burden includes all fuels, natural gas and electric, at a specific location.[14] Forecasting this CBI requires assumptions regarding individual customer income and usage along with the cost of non-electric household fuels. To forecast energy burden in this analysis, customers are grouped by income, electric energy usage, and whether customers are electric only vs electric and natural gas. Customer income is escalated using the 2001-2021 historical income growth rate for each income group and customer usage[15] is forecast using current energy use reduced by the amount of energy efficiency selected for a specific income group.[16] Lastly, the cost of the energy used by the customer is estimated using a rate forecast based on the resources selected with the IRP forecast. The analysis does not consider energy assistance other than assistance provided by the development of a low-income community solar facility.

The first metric illustrates the forecast of the number of customers with excess energy burden (see Figure 10.4) over the planning horizon. These customers have a combined energy bill between electric and natural gas exceeding 6 percent of their income to be included in this metric. Customers can fall into this metric due to high usage or low income. The absolute number of customers with an energy burden increases by 6,569 by 2045, though the percent of energy burdened customers is essentially flat at 20 percent. Avista expects to increase the amount of energy assistance participation for those customers through increased outreach and targeted programs.

[13] At this time separate tracking on a forecasted basis for known low-income and Named Communities cannot be completed until additional data is gathered. Avista intends to have this information available for the CEIP Progress Report.
[14] Currently the only non-electric household fuel expense included is natural gas. Estimated costs for other fuels such as fuel oil, propane, and wood should be included, but are not available at this time.
[15] This analysis does not include EV load in the energy usage calculation as it would unfairly place higher electric costs on the customer without considering other transportation costs not included in the calculation.
[16] Typical increases to energy usage (i.e., adding new technology and devices) for this purpose is being ignored.

Figure 10.6: Washington Customers with Excess Energy Burden (Before Energy Assistance)



Avista will have approximately 280,000 Washington electric residential customers in 2023 and approximately 20 percent of these customers exceed the 6 percent threshold as shown in Figure 10.6 in 2024. Avista continues to refine this metric for historical baseline purposes, and it will be included in the Biennial CEIP update.

The last customer energy burden metric is the amount of dollars per year of energy assistance the customer would need to reduce their energy burden to the 6 percent level. Excess energy burden growth is shown in Figure 10.7 and Figure 10.8 shows the average excess energy burden. This metric is expected to increase. Both the nominal and real (2024 dollars) values are increasing, though the real increase is modest in comparison to the nominal increase. The difference between the two demonstrates the impact of inflation compared to the impact of rate increases.

Figure 10.7: Percent of Washington Customers with Excess Energy Burden

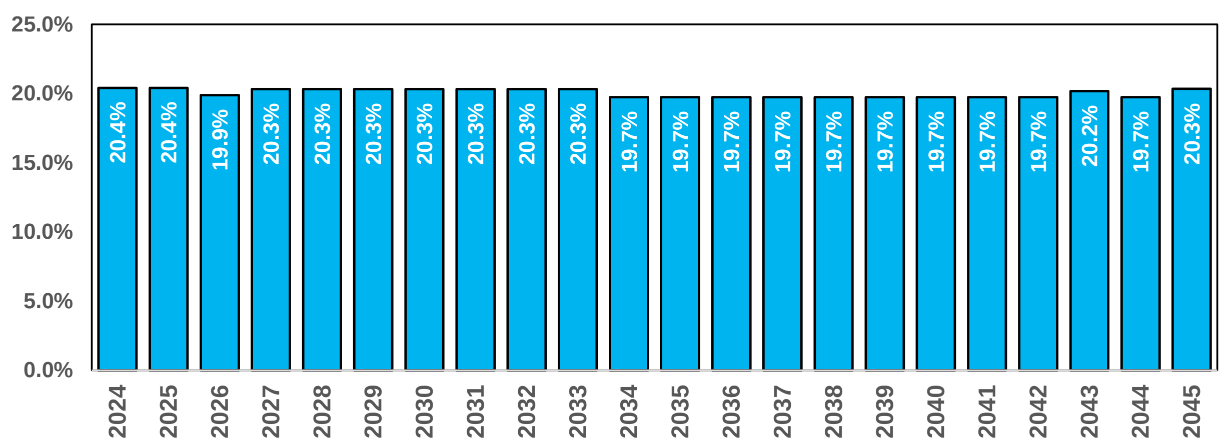
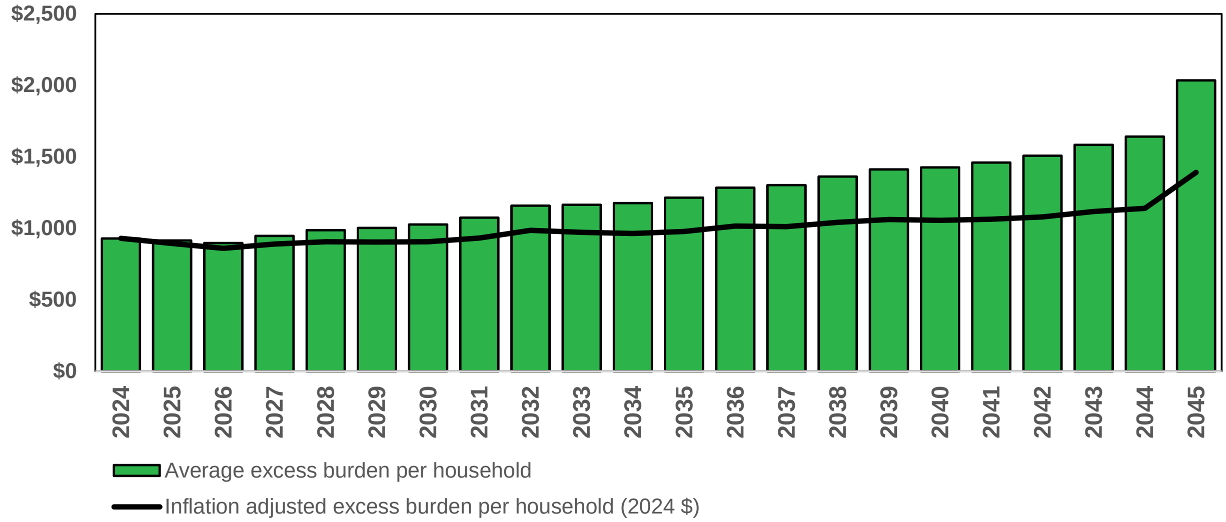


Figure 10.8: Average Washington Customer Excess Energy Burden



CBI No. 5 – Named Community Clean Energy

This CBI monitors and prioritizes investments in DERs under 5 MW; specifically, generation and storage resource opportunities in Named Communities. This CBI has three metrics:

- Energy produced from DERs.
- DER energy storage capability.
- Number of projects in Named Communities.

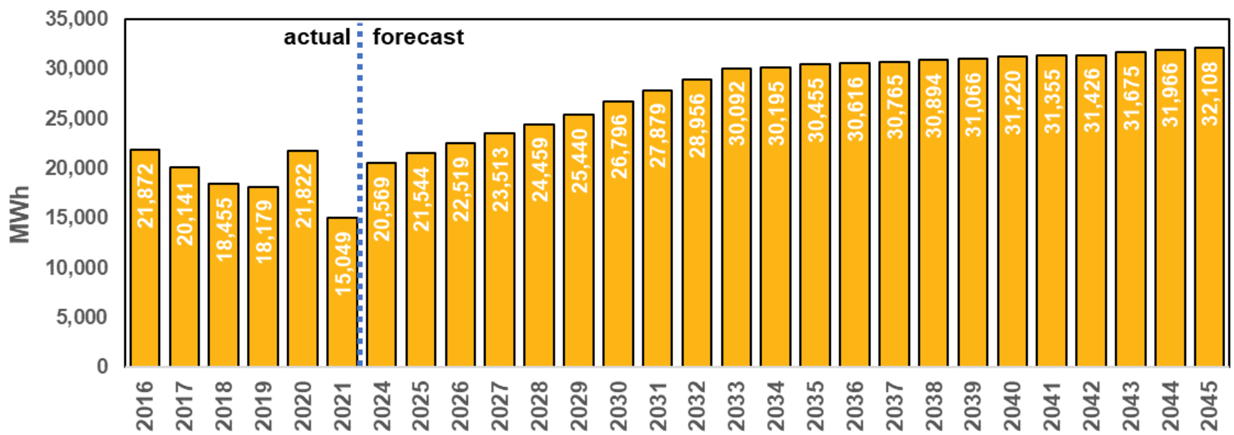
The Progress Report forecast includes DER production and capacity, but the number of projects is outside the planning scope and cannot be accurately forecasted. There are three methods these resources are brought to the system. The first is PURPA development. Historically, this method has brought the most energy to Avista from developers building resources and selling the output to Avista using the federal regulation requiring utilities to purchase the output from qualifying facilities at published avoided cost. The second method is from customers participating in Avista's net metering program. These resources are behind-the-meter customer resources where the energy produced is netted against customers' consumption.[17] The amount of these resources is outside utility control and is based on whether the customer chooses to own their own generation. The last category is small generation owned or contracted by Avista, typically this includes community solar projects, but could include other investments from the NCIF or cost-effective resource additions typically selected through an RFP process.

The historical and forecasted Named Community DER generation is shown in Figure 10.9. Most of the historical generation is from hydro-based generation and incremental additions are projected to be from community solar projects funded by state incentives

[17] Net metered generation in a Named Community was not available at the time of this report.

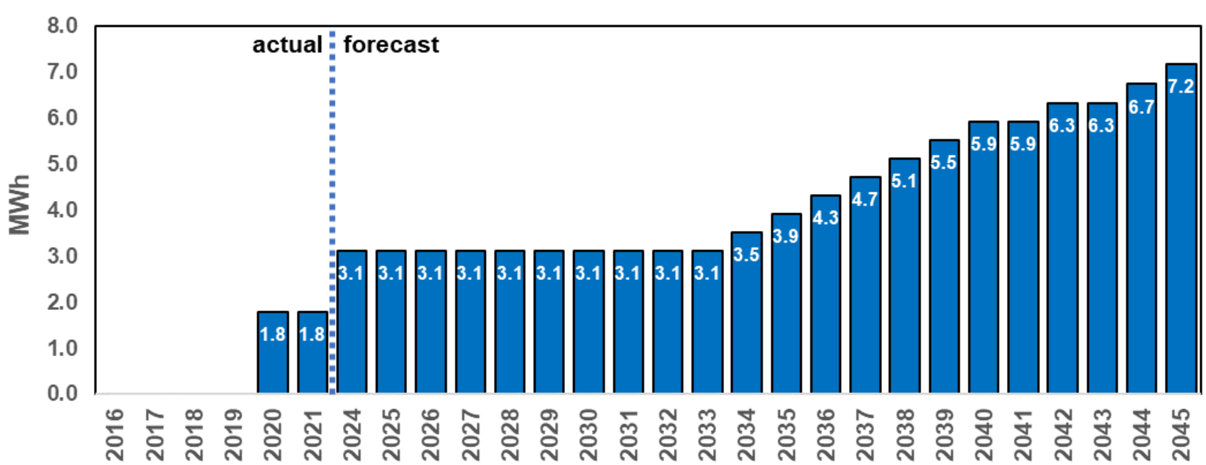
and the NCIF. This plan includes expected storage related DERs to be added to Named Communities to enhance distribution systems and provide system peak capacity. The DER additions described above are shown in Figure 10.10.

Figure 10.9: Total MWh of DER in Named Communities



Avista partnered with the Department of Commerce in Washington on two Clean Energy Fund Projects, each include the installation of DER energy storage in Named Communities. In 2020, 1.8 MWh of storage was installed as part of a microgrid project in Spokane. An additional 1.3 MWh will be installed as part of the eco-district project and it is expected to be online in April 2023. Each of the DER energy storage projects are co-located with solar assets and are equipped with control systems to operate the assets in coordination with each other and the grid. In addition to solar and energy storage, the eco-district site includes thermal energy storage (both water and phase change) designed to provide electric load shifting for the eco-district central energy plant. The design estimated MWh equivalent storage is approximately 0.6 MWh during summer months and 4.5 MWh during winter months.

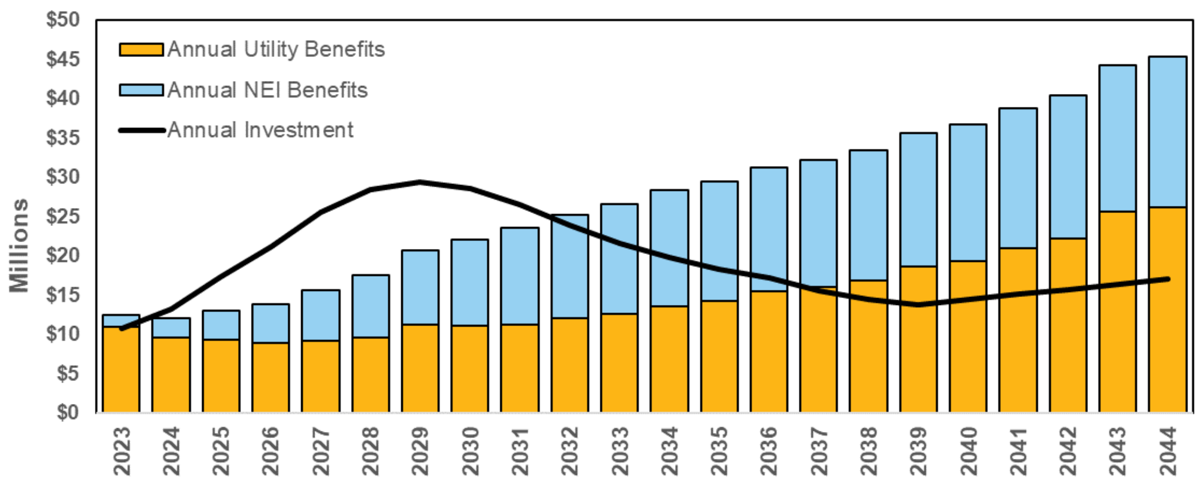
Figure 10.10: Total MWh Capability of Storage DER in Named Communities



CBI No. 6 – Investments in Named Communities

This plan includes high level estimates for investments and benefits in Named Communities. This illustration differs from the metric used for historical tracking and includes the annual utility invested cost of resources in this Progress Report and compares these values to the annual utility and non-energy benefits discussed earlier in this chapter. The resources are selected based on a cost-effective analysis including utility (energy/capacity) and NEI benefits, except for the minimum spending constraint from the NCIF. Figure 10.11 shows the projected investments and benefits. Resource selection choices are driven by high non-energy benefits for energy efficiency in low-income areas. Annual investment is driven by investments in energy efficiency. Investments peak in 2029 and then decrease through 2039 as there are fewer energy efficiency opportunities.

Figure 10.11: Total MWh Capability of Storage DER in Named Communities

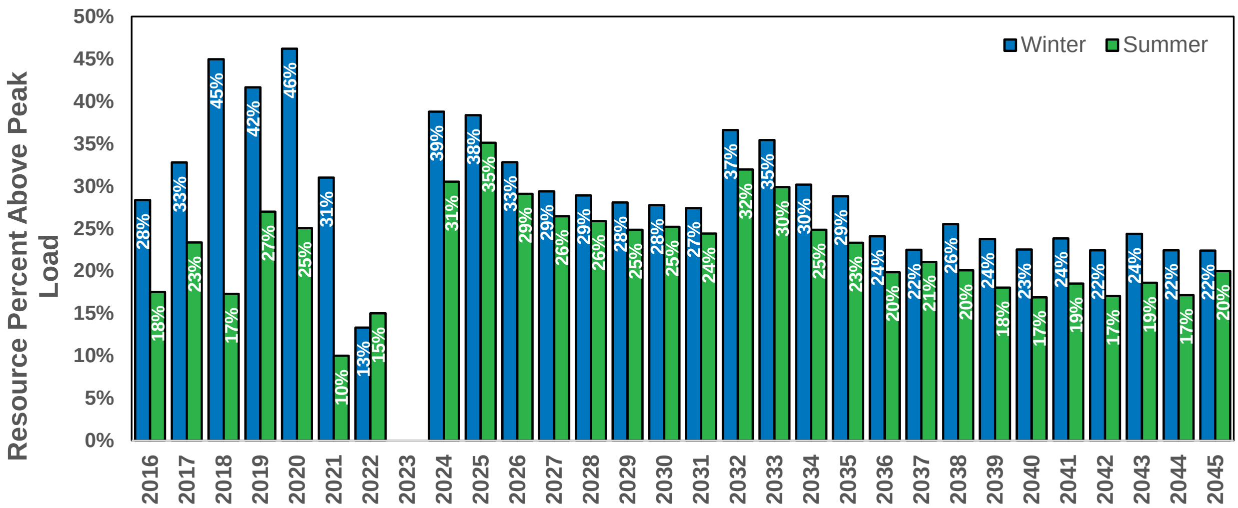


This CBI includes a third metric accounting for the number or sites and projects of future DERs. This forecast does not include this metric as the number of project sites will be determined during implementation.

CBI No. 7 – Energy Availability

This CBI is designed to ensure Avista has a reliable system for all customers including Named Communities. This CBI measures three metrics related to customer reliability, but only one is related to resource planning. The other two are impacted by distribution system reliability from delivery system issues as discussed above. The item applicable to IRP planning is the Planning Reserve Margin (PRM) where the PRM is a minimum requirement for the amount of resource capability during peak events. This metric is one of a few applying to the full Avista system rather than just the State of Washington. Figure 10.12 shows the historic and forecasted expected peak hour resource capability versus load. For the historical periods, the metric shows the amount of actual generation or what could have been generated from Avista-controlled resources compared to actual peak load within the same hour resulting in an implied resource margin. After 2022, the PRM is a forecast comparing future peak loads and expected generation capability during peak hours using QCC values.[18] Future values exceed the current interim PRM of 22 percent in the winter and 13 percent in the summer throughout the planning horizon as additional resources are selected to address energy needs and the expectations of the QCC values of renewables and storage will fall.

Figure 10.12: Planning Reserve Margin

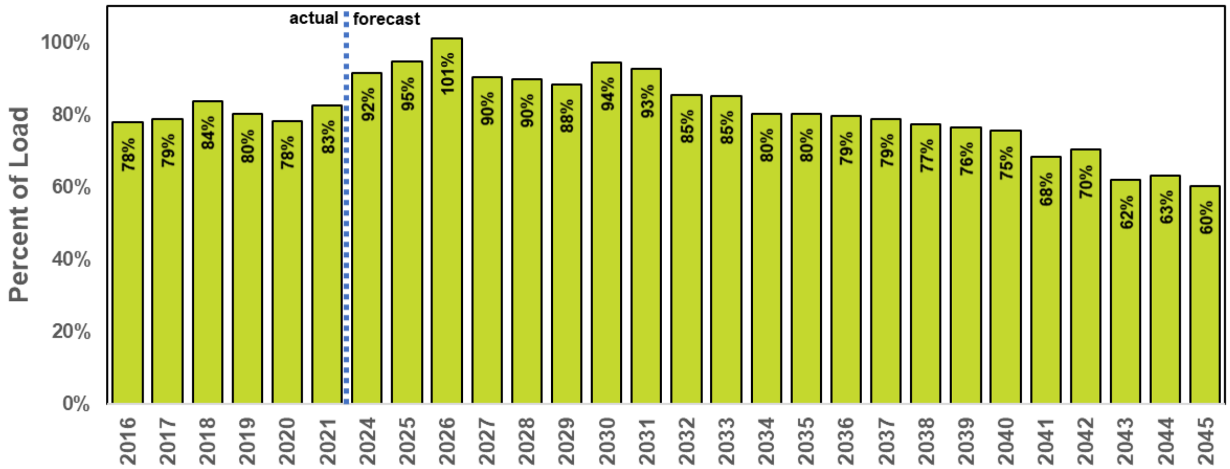


CBI No. 8 – Energy Generation Location

CETA encourages local resources and resources enhancing energy security. To address this benefit, Avista quantifies the amount of generation located within Washington State or directly connected to Avista's transmissions system used for system needs. Either of these location options should provide a greater reliability rate as potential disruptions are minimized by the proximality to load. This metric is energy agnostic on the type of energy used. Figure 10.13 shows the historical generation mix and resource selected mix of energy created in Washington or connected to Avista's transmission system. The amounts are shown as a percentage of customer loads. Avista's Washington and transmission connected resources will increase due to recent acquisitions from the Chelan PUD and Columbia Basin Hydro through 2026. In 2026, Avista will likely generate more local or connected generation than its load and export the surplus to other utilities. Avista's forecast shows lower connected resources due to selection of external resources being a lower cost than local resources due to system transmission upgrade costs. Economic benefits of local generation were included as a NEI, but these benefits are overcome by the high costs of new transmission.

[18] QCC values were derived by the Western Resource Adequacy Program with input from participating utilities and compilation by the program administrator – SPP.

Figure 10.13: Generation in Washington and/or Connected to Avista Transmission



CBI No. 9 – Outdoor Air Quality

As discussed above, Avista's resource air emissions are forecastable within an IRP. The impacts to unhealthy days within our communities are typically related to events outside of Avista's control and are after the fact calculations done by a 3rd party. The forecastable metrics include SO_2, NO_X, Mercury, and Volatile Organic Compound (VOC) emissions from Avista's Washington plants. These forecasts are based on emission rates per unit of fuel. These emissions are regulated by local air authorities and meet all local laws and regulations for air emissions and are found to be at a level safe for the local population. They are also tracked through Avista's public participation process, and associated NEIs to ensure air quality improvements are considered in resource selection.

The metric measures total annual emission levels for Washington State facilities including Kettle Falls Generating Station (KFGS), Kettle Falls Combustion Turbine, Boulder Park, and Northeast. All metric results decline over the IRP planning horizon due to lower thermal dispatch hours and increased efficiencies and controls at the KFGS with the addition of Myno's biochar co-gen facility supplying steam rather than direct combustion of woody biomass[19]. Figures 10.14 through 10.17 demonstrate the projected levels of emissions for each pollutant type. SO_2 and VOC have the largest forecasted changes which is due to the decrease in per unit emissions at Kettle Falls and its decreased dispatch over the planning horizon.

[19] If the ammonia combustion turbines were sited in Washington state, NO_X emission could increase subject to SCR controls and amount of required dispatch.

Figure 10.14: Avista Located Washington State Facility's SO_2 Emissions

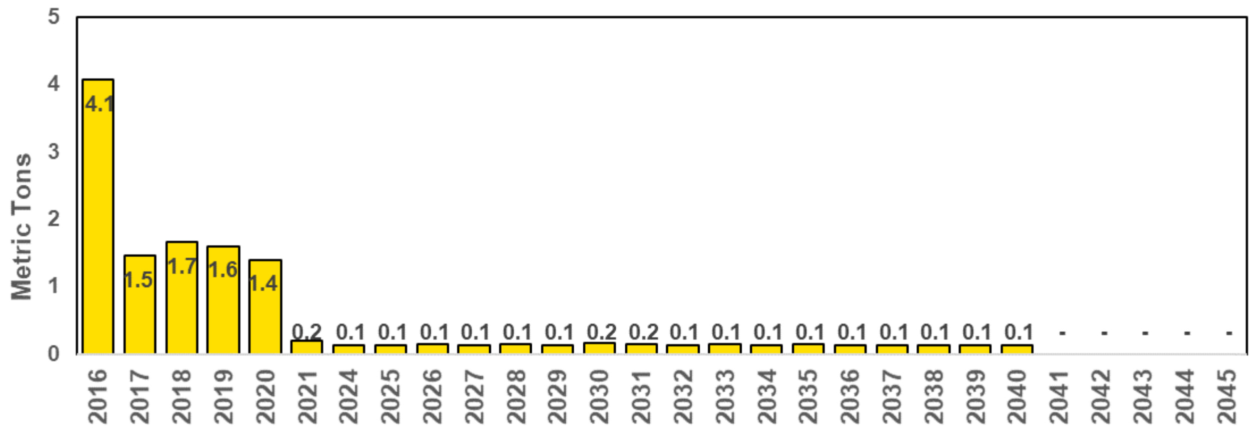


Figure 10.15: Avista's Washington State Facility's NO_x Emissions

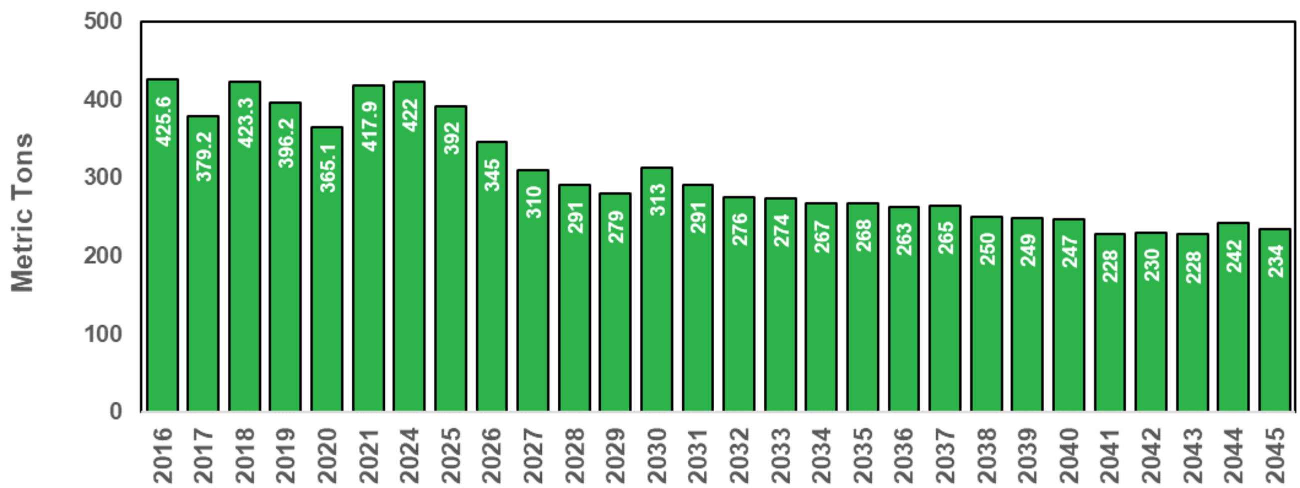


Figure 10.16: Avista's Washington State Facility's Mercury Emissions

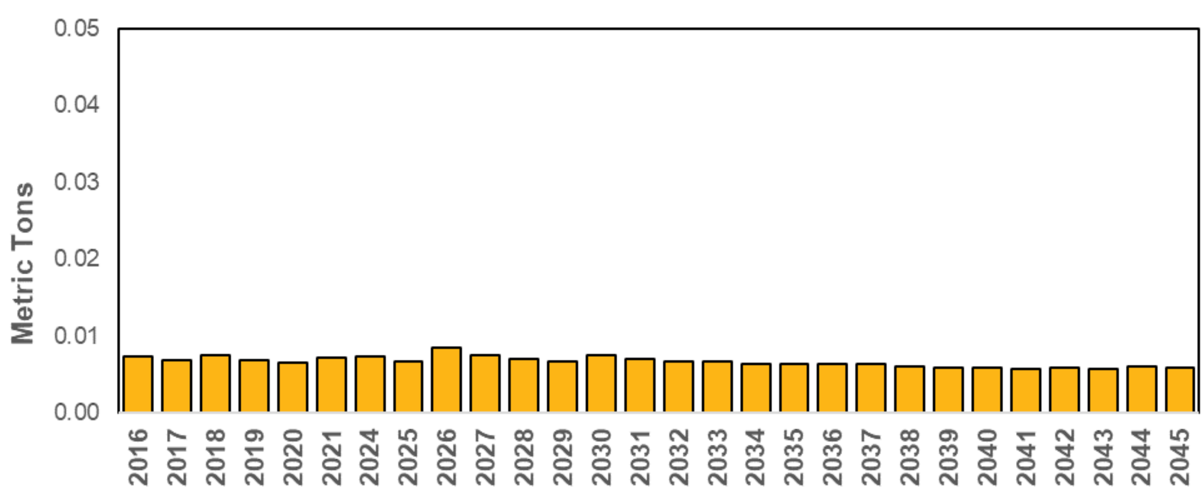
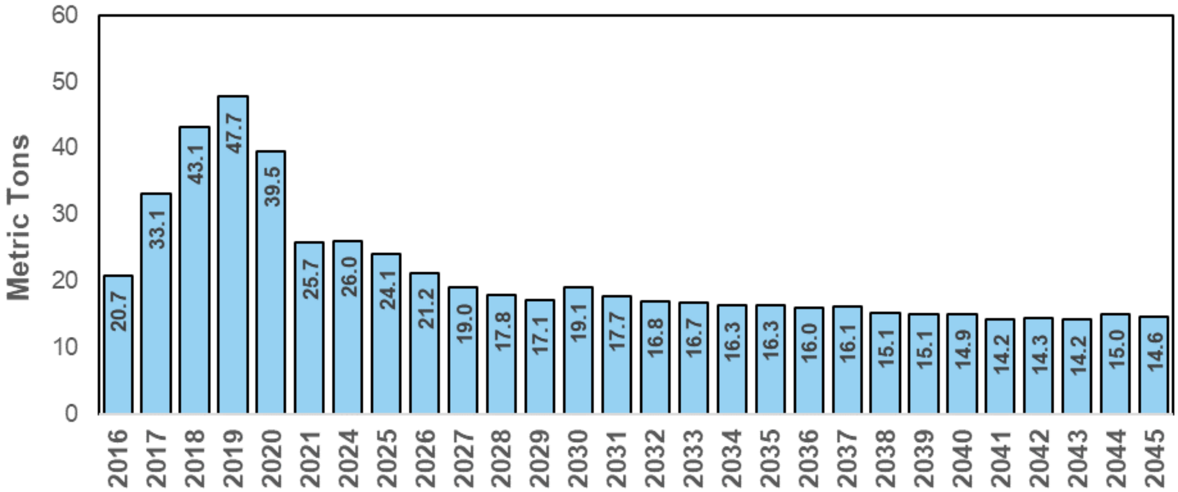


Figure 10.17: Avista's Washington State Facility's VOC Emissions



CBI No. 10 – Greenhouse Gas Emissions

This CBI forecasts total greenhouse gas emissions for the eastern Washington region as well as the amount from Avista's energy resources and purchased power. Two metrics are covered within this section; the first metric estimates the amount of direct emissions from Washington's share of power plant emissions and how those change considering market transactions (labeled as "net emissions"). Figure 10.18 shows direct greenhouse gas emissions rising until 2025 when Colstrip is required to exit Washington's portfolio. Emissions are expected to be higher in the short run as the current energy market needs additional dispatchable generation to meet loads with increasing levels of variable energy resources but should fall as additional clean energy resources are brought on the western system. Net emissions are lower than direct emission in the near-term as the calculation removes emissions related to power sold off the system. As time goes on system sales fall and Avista may need to purchase power and this forecast includes emissions associated with those purchases. Lastly, due to the Climate Commitment Act requirement of tracking emissions, this CBI may be modified to reflect the required methodology of reporting emissions.

One of the main purposes of CETA is to reduce state level greenhouse gases. Electric power specifically related to eastern Washington is small in relation to total emissions. The second greenhouse gas metric (shown in Figure 10.19) shows the direct utility emissions plus emissions from other sectors. Placing Avista emissions in the context of all emissions allows for a wholistic analysis of greenhouse gas reductions. This CBI estimates transportation emissions. If transportation is electrified, Avista will take on additional energy obligations and there would be no acknowledgment of the net greenhouse gas emissions savings if considered in isolation, but in conjunction with estimates of transportation emissions the benefit would be seen. The challenge with this metric pertains to items within the calculation which are outside of Avista's control and therefore only includes estimates related to either electrification included in Avista's load forecast for transportation and changes in natural gas usage from Avista's natural gas IRP. Currently, transportation emissions are flat rather than increasing due to uncertainly of electric vehicle adoption. Natural gas emissions are also nearly flat until the Avista Natural Gas Plan is finalized, but due to high costs to reduce emissions on this system reductions may require additional customer incentives directed by the state to adopt lower emitting fuels or electrification.

Figure 10.18: Washington Direct and Net Emissions

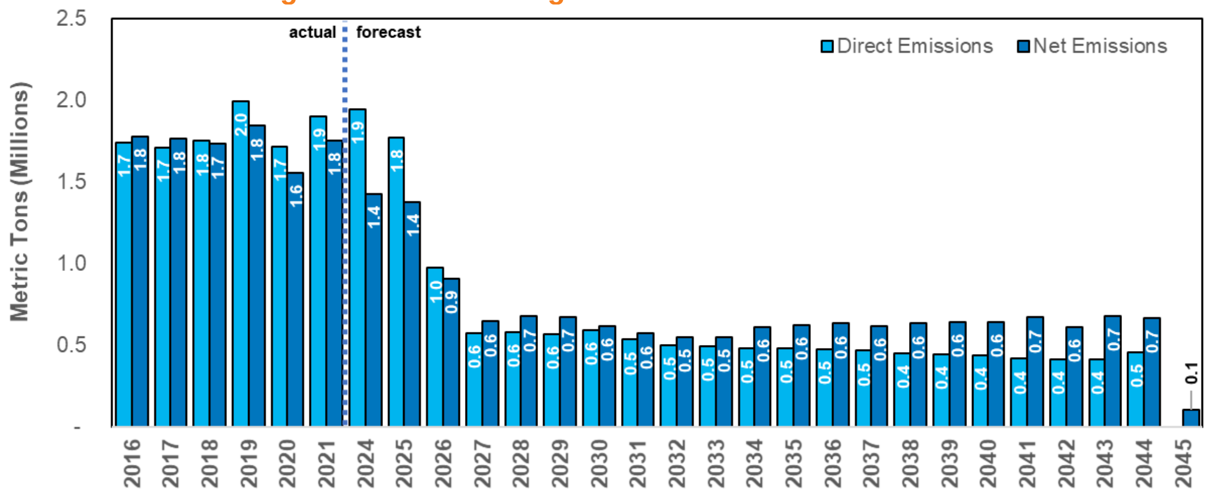
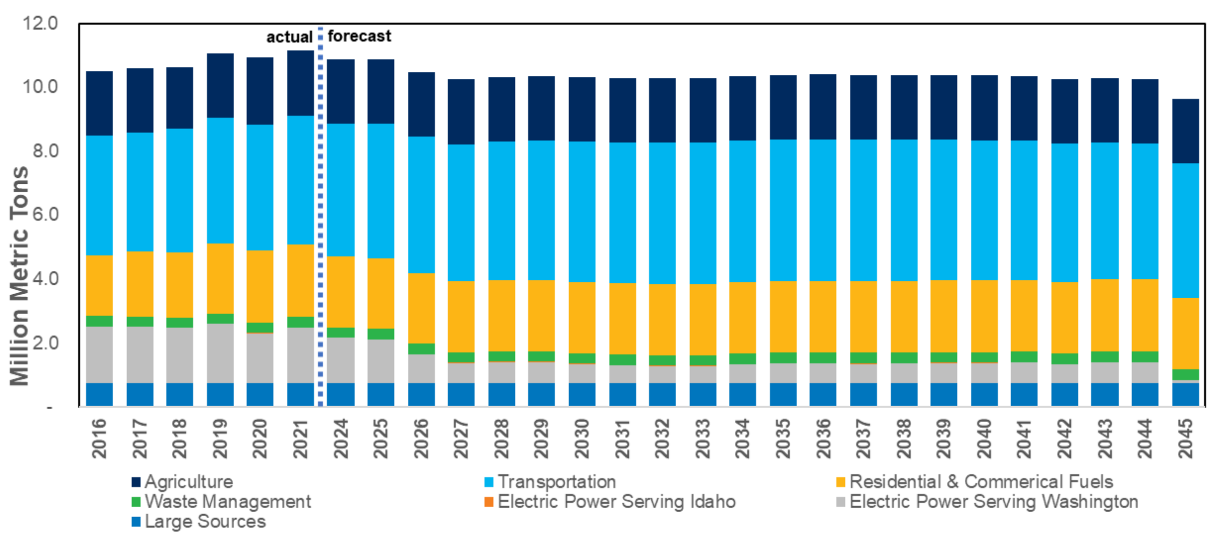


Figure 10.19: Washington Direct and Net Emissions



Future Customer Benefit Indicator Inclusion

The definition of equity and its various impact areas continues to be a topic of conversation. CBIs will continue to be measured to ensure all customers are equitably benefitting from the clean energy transition. CBIs are not intended to be static measures and will change throughout the duration of the transition to a cleaner energy future. The CBIs approved in the 2021 CEIP will remain until an update is required in the Biennial

CEIP. Where applicable, CBIs will be modified or added based on public feedback during implementation and in the development of the next CEAP/CEIP. The CBIs applicable to resource planning will be evaluated for each IRP, while outside the planning process, resource selection and implementation will continue to incorporate CBIs as they evolve.