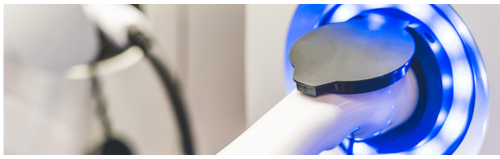
2023

Electric Integrated Resource Plan



Safe Harbor Statement

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

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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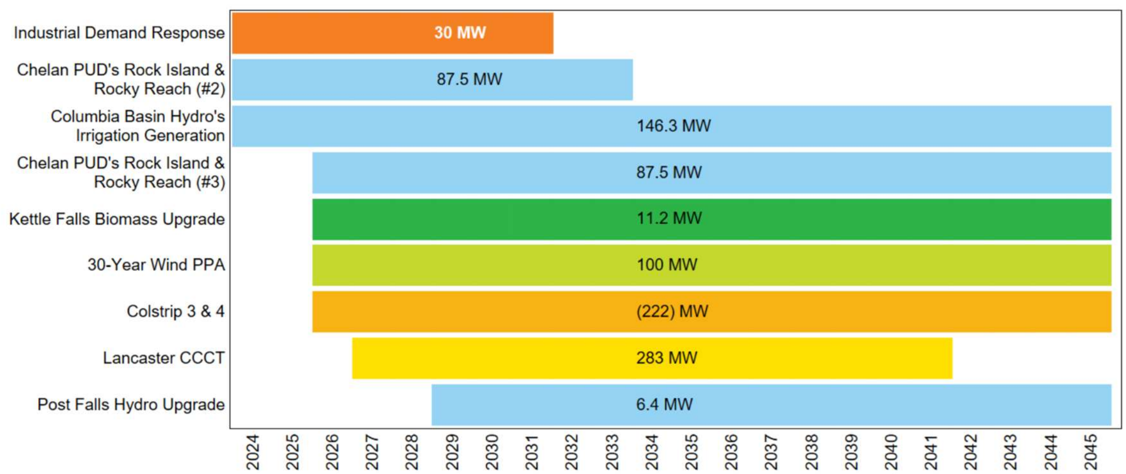
2023 Electric IRP
Executive Summary

Avista has a 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.

Avista secured several new supply contracts since the 2021 IRP including additional slices of Chelan PUD's Rock Island and Rocky Reach hydro facilities, Columbia Basin Hydro Power's irrigation generation facilities, planned upgrades to Avista's Kettle Falls and Post Falls generation facilities, a 30-year wind PPA[1], and an extension of the current agreement for output from the Lancaster Combined Cycle Combustion Turbine (CCCT). These resources, as summarized in the figure below, will meet Avista's expected energy and capacity needs through the middle of the 2030s. In addition to resource acquisitions, Avista agreed to end its use of coal by transferring ownership of Colstrip Units 3 & 4 to Northwestern Energy at the end of 2025.

Announced Resource Changes (MW)



The 2023 Integrated Resource Plan (IRP) updates Avista's load forecast, distributed energy resources (DER) including an energy efficiency and demand response assessment, supply-side resource options cost and generic operating characteristics, and the load-resource position. It includes a Preferred Resource Strategy (PRS) summarizing a mix of planned resource types to meet future customer demand and state energy goals.

[1] Avista will identify this project at a later date.

2023 IRP Highlights

Major changes from the 2021 IRP include:

- Progress on Washington's Clean Energy Implementation Plan's (CEIP) Customer Benefit Indicators (CBIs) especially those relevant to resource modeling. A forecast of new projects funded by the Named Community Investment Fund (NCIF) is also included.
- Increased load forecast from higher expectations for transportation and building electrification.
- Reduced energy efficiency targets due to lower avoided costs and lower potential opportunities with stronger codes and standards.
- Incorporates future hydro and temperature conditions based on the Representative Concentration Pathways (RCP) 4.5 forecast.

Preferred Resource Strategy

Avista estimates customer loads will increase 0.86% annually, but winter and summer peak demand will grow by 1.16% and 1.24% respectively. With the resource additions above, Avista's resource strategy focus for the next 10 years is to continue investing in energy efficiency meeting 27% of future load growth and reducing loads by 85 aMW through 2045. Avista will achieve equitable outcomes for its Washington service area by engaging disadvantaged communities through the Company's NCIF, with potential programs such as community solar, energy storage, and targeted energy efficiency. The company will also leverage demand response pilots such as Time of Use Rates (TOU), Peak Time Rebate (PTR), and water heater direct control programs to determine the programs most valuable to our customers.

Avista refines its resource selection by selecting resources for Idaho and Washington separately to meet monthly energy and capacity targets. The table below outlines the complete list of new generating and storage resources required to meet future resource deficits. For Washington loads, beginning in 2030, the plan calls for investing in 400 MW of wind followed by long-duration storage resources beginning in 2036 using renewable liquid fuels such as ammonia and/or green hydrogen, as well as iron-oxide storage technologies. For Idaho, the plan calls for natural gas peaking resources beginning in 2034 to replace resource retirements and meet load growth, along with a small amount of long duration storage beginning in 2043.

With these resource additions, the energy system is capable of generating 92% of the load with clean energy resources and will meet 100% of Washington's load with clean resources on average for each month. Also, by 2045, greenhouse gas emissions are 80% lower than the 2021 levels.

2023 IRP Preferred Resource Strategy

Resource	Time Period	Jurisdiction	Capacity (MW)	Energy Capability (aMW)
NW Wind	2030	WA	200	63
Montana Wind	2032	WA	200	97
Natural Gas CT	2034	ID	90	86
Renewable Fueled CT	2036	WA	88	31
Long Duration Storage (>24 hr)	2039	WA	52	-1
PPA Wind Renewal	2041	WA	140	53
Renewable Fueled CT	2041	WA	74	26
Natural Gas (ICE)	2041	ID	46	46
PPA Wind Renewal	2042	WA	105	36
Renewable Fueled CT	2042	WA	186	65
Natural Gas CT	2042	ID	102	97
Long Duration Storage (>24 hr)	2043	WA/ID	68	-1
NW Wind	2044	WA	100	31
Long Duration Storage (>24 hr)	2044	WA/ID	50	-1
NW Wind	2045	WA	200	63
Renewable Fueled CT	2045	WA	348	122
Natural Gas (ICE)	2045	ID	65	65
Short Duration Storage (<8 hr)	2045	ID	25	0
		Total New Resources	**2,139**	**878**

The new resource choices will result in above average inflation of the retail rate. In Washington, projected rates increase at 3.4% per year on average, but 6.41% per year in the last 5 years of the study ending at 23.4 cents per kWh. For Idaho, projected rates grow at a slower pace of 2.7% per year and 4.2% in the last 5 years of the plan for a 2045 rate of 18.5 cents per kWh.

Alternative Resource Strategies Analysis

Avista studied 17 alternative resource portfolio scenarios to test higher levels of renewable energy for Idaho, additional transportation and building electrification load, resource adequacy requirements, and the impacts of resource strategies only focusing on customer impacts other than cost. Some of the result highlights include:

- Transitioning 100% of Avista's resource portfolio to clean energy by 2045 would increase Idaho's rates by 40% adding 7.5 cents per kWh, vastly exceeding the 2-5% increase customers indicated by survey they are willing to pay for carbon reductions.
- A study where Washington electrifies 80% of the natural gas distribution system with high levels of transportation electrification results in 33% higher rates by 2045 due to the incremental resource need and upgrading the transmission and distribution system. Distribution system upgrades alone results in a 4 cent/kWh increase.
- A scenario to identify resource choice changes using social impacts to Idaho resulted in higher renewable energy selection with a 1.8% rate increase, well within the customer tolerance. Although the most interesting result of this scenario shows Washington's 100% transition goals increase customer rates by more than the societal benefits.
- Avista found moving to the Western Resource Adequacy Program (WRAP) planning margins will not substantially change the resource strategy. Depending on the amount of level of Qualifying Capacity Credits (QCC) the WRAP assigns our resources will impact the strategy by changing the required duration of energy storage needs.

IRP Process

Each IRP is a thoroughly researched plan using a robust data-driven approach identifying a PRS that meets customer needs while balancing costs and risk measures with environmental goals and mandates. The 2023 IRP cycle included nine public meetings with Avista's Technical Advisory Committee (TAC) and one public meeting, where Avista presented assumptions, methodologies, and results of planning analyses for public review and comment. Participants in the public process include customers, academics, environmental organizations, government agencies, consultants, utilities, elected officials, state utility commission stakeholders, and other interested parties.

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1. Introduction

Avista is a multijurisdictional utility serving electric customers in Washington and Idaho. Both states have rules and regulations 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. Avista was able to adjust its filing date for the 2023 Electric Integrated Resource Plan (IRP) in Idaho to June 2023 due to finalizing the 2022 All-Source Request for Proposal. In addition, Avista also filed an IRP progress report in its January 2023 Washington Progress Report filing to meet a separate filing requiring, which did not include all resources acquired from the RFP. As such, this is an update to the prior filing progress report filing.

The energy planning requirements between Avista's two jurisdictions could not be more different. In Idaho, the focus is on reliability and serving customers with the lowest cost resources. In Washington, energy policy focuses on the Clean Energy Transformation Act (CETA). This act 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 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.

In Washington there are now 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.

This chapter discusses the IRP requirements, the process used to develop it, changes from the 2021 IRP, how resources obtained through 2022 All-Source RFP are included in the 2023 IRP and concludes with an overview of the chapters and appendices included.

IRP Process

This IRP 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 IRP. 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 to serve future needs. Besides the technical meetings, there are also public meetings for customers and others to hear about the plan and provide comments.

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 – March 8, 2023	• Recorded Presentation • Daytime Comment and Question Session • Evening Comment and Question Session
TAC 9 – April 25, 2023	• All-Source RFP Update • 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 IRP. Table 1.2 lists organizations participating in the 2023 IRP TAC processes.

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

Washington Progress Report Requirements

This IRP satisfies the Progress Report requirement defined in WAC 480-100-625 and is due two years after each utility files its IRP. Avista filed its first Progress Report in January 2023, but this IRP is an update to that report. The Progress 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."

Table 1.3: Washington Progress Report Requirement Discussions

Progress Report Requirement	IRP Chapter Discussion
Load Forecast	Chapter 2 – Economic and Load Forecast
Demand-Side and Conservation Potential Assessments	Chapter 5 – Distributed Energy Resources
Resource Costs	Chapter 6 – Supply-Side Resource Options
Portfolio Analysis and Preferred Portfolio	Chapter 9 – Preferred Resource Strategy Chapter 10 – Scenario Analysis

Washington Clean Energy Implementation Plan (CEIP) Coordination

The IRP, 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. Avista has included the inputs used and approved in the development of the 2021 Clean Energy Action Plan (CEAP) 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 IRP. The following assumptions were used to develop the clean energy requirements for 2030 and 2045 CETA requirements.

- 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 Public Utility Regulatory Policies Act (PURPA) generation constructed prior to 2019 *plus* voluntary renewable energy programs.
- Customer voluntary Renewable Energy Credits (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 with deliveries before 2022,
  - All wind, solar, and biomass generation. Nonpower attributes associated with Idaho's share may 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.
- 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.

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 the Progress Report. The following six conditions, listed by their original number issued in Order 01 from the WUTC, are covered in the 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 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 Equity Advisory Group (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 Clean Energy Transformation Act (CETA) goals with a choice between an Idaho allocated existing renewable resource at market price (limited to Kettle Falls, Palouse Wind, Rattlesnake Flat, 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 Distribution Planning Advisory Group (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 EEAG 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 Clean Energy Implementation Plan (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 as well as the extension of the existing Lancaster Purchase Power Agreement (PPA).

(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 11 outlines how each CBI is relevant or not 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 (WPP) 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 vehicles (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.

Idaho Regulatory Requirements

The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 25260. Order 22299 dates back to 1989; this order outlines the requirement for the utility to file a "Resource Management Report [(RMR)]". This report *recognize[s] the managerial aspects of owning and maintaining existing resources as well as procuring new resources and avoiding/reducing load*. *[The Commission's] desire is the report on the utility's planning status, not a requirement to implement new planning efforts according to some bureaucratic dictum*. *We realize that integrated resource planning is an ongoing, changing process. Thus, we consider the RMR required herein to be similar to an accounting balance sheet, i.e., a "freeze-frame" look at a utility's fluid process.*

The report should discuss any flexibilities and analyses considered during comprehensive resource planning such as:

1. Examination of load forecast uncertainties
2. Effects of known or potential changes to existing resources
3. Consideration of demand- and supply-side resource options
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead-time, reliability, risk, etc.) as future events unfold.

Avista outlines the order's requirements below for ease of readability for each of the Commission's requirements.

Existing Resource Stack

Identification of all resources by category below;[1] including the utility shall provide a copy of the utility's most recent U.S. Department of Energy Form EIA-714 submittal and the following specific data, as defined by the NERC, ought to be included as an appendix:[2]

a) Hydroelectric;
   i. Rated capacity by unit;
   ii. Equivalent Availability Factor by month for most recent 5 years;
   iii. Equivalent Forced Outage Rate by month for most recent 5 years; and
   iv. FERC license expiration date.
b) Coal-fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
c) Oil or Gas fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
d) PURPA Hydroelectric;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
e) PURPA Thermal;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
f) Economy Exchanges;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
g) Economy Purchases;

[1] Resources less than three megawatts should be grouped as a single resource in the appropriate category.
[2] FERC Form 714 can be on-line at https://www.ferc.gov/docs-filing/forms/form-714/data.asp

  - I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
  - II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.

h) Contract Purchases;
  - I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
  - II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.

i) Transmission Resources; and
  - I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

j) Other.
  - I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

Load Forecast

Each RMR should discuss expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. For each appropriate market, the discussion should:

a) identify the most recent monthly peak demand and average energy consumption (where appropriate by customer class), both firm and interruptible;
b) identify the most probable average annual demand and energy growth rates by month and, where appropriate, by customer class over at least the next three years and discuss the years following in more general terms;
c) discuss the level of uncertainty in the forecast, including identification of the maximum credible deviations from the expected average growth rates; and
d) identify assumptions, methodologies, data bases, models, reports, etc. used to reach load forecast conclusions.

This section of the report is to be a short synopsis of the utility's present load condition, expectations, and level of confidence. Supporting information does not need to be included but should be cited and made available upon request.

Additional Resource Menu

This section should consist of the utility's plan for meeting all potential jurisdictional load over the 20-year planning period. The discussion should include references to expected costs, reliability and risks inherent in the range of credible future scenarios.

- An ideal way to handle this section could be to describe the most probable 20-year scenario followed by comparative descriptions of scenarios showing potential variations in expected load and supply conditions and the utility's expected responses thereto. Enough scenarios should be presented to give a clear understanding of the utility's expected responses over the full range of possible future conditions.

- The guidance provided above is intended to ensure maximum flexibility to utilities in presenting their resource plans. Ideally, each utility will use several scenarios to demonstrate potential maximum, minimum and intermediate levels of new resource requirements and the expected means of fulfilling those requirements. For example,
    - A credible scenario requiring maximum new resources might be regional load growth exceeding 3% per year combined with catastrophic destruction (earthquake, fire, flood, etc.) of a utility's largest resource (i.e., Bridger coal plant for IPCo and PP&L, Hunter coal plant for UP&L and Noxon hydro plant for WWP).
    - A credible scenario causing reduced utilization of existing resources might be regional stagflation combined with loss of a major industry within a utility's service territory. Analyses of intermediate scenarios would also be useful.
- To demonstrate the risks associated with various proposed responses, certain types of information should be supplied to describe each method of meeting load. For example,
    - If new hydroelectric generating plants are proposed, the lead time required to receive FERC licensing and the risk of license denial should be discussed.
    - If new thermal generating plants are proposed, the size, potential for unused capacity, risks of cost escalation and fuel security should be discussed and compared to other types of plants.
    - If off-system purchases are proposed, specific supply sources should be identified, regional resource reserve margin should be discussed with supporting documentation identified, potential transmission constraints and/or additions should be discussed, and all associated costs should be estimated.
    - If conservation or demand side resources are proposed, they should be identified by customer class and measure, including documentation of availability, potential market penetration and cost.
- Because existing hydroelectric plants could be lost to competing companies if FERC relicensing requirements are not aggressively pursued, relicensing alternatives require special consideration. For example,
    - If hydroelectric plant relicensing upgrades are proposed, their costs should be presented both as a function of increased plant output and of total plant output to recognize the potential of losing the entire site.
    - Costs of upgrades not required for relicensing should be so identified and compared only to actual increased capacity/energy availability at the unit, line, substation, distribution system, or other affected plant. Increased

maintenance costs, instrumentation, monitoring, diagnostics, and capital investments to improve or maintain availability should be quantified.
- Because PURPA projects are not under the utility's control, they also require special consideration. Each utility must choose its own way of estimating future PURPA supplies. The basis for estimates of PURPA generation should be clearly described.

Other provisions from Order 22299

- Because the RMR is expected to be a report of a utility's plans, and because utilities are being given broad discretion in choosing their reporting format, Least Cost Plans or Integrated Resource Plans submitted to other jurisdictions should be applicable in Idaho.
    - Utilities should use discretion and judgement to determine if reports submitted to other jurisdictions provide such emphasis, if adding an appendix would supply such emphasis, or if a separate report should be prepared for Idaho.
    - The project manager responsible for the content and quality of the RMR shall be clearly identified therein and a resume of her/his qualifications shall be included as an appendix to the RMR.
- Finally, the Resource Management Report is not designed to turn the IPUC into a planning agency nor shall the Report constitute pre-approval of a utility's proposed resource acquisitions.
- The reporting process is intended to be ongoing-revisions and adjustments are expected. The utilities should work with the Commission Staff when reviewing and updating the RMRs. When appropriate, regular public workshops could be helpful and should be a part of the reviewing and updating process.
- Most parties seem to agree that reducing and/or avoiding peak capacity load or annual energy load has at least the equivalent effect on system reliability of adding generating resources of the same size and reliability. Furthermore, because conservation almost always reduces transmission and distribution system loads, most parties consider reliability effects of conservation superior to those of generating resources. Consequently, the Commission finds that electric utilities under its jurisdiction, when formulating resource plans, should give consideration to appropriate conservation and demand management measures equivalent to the consideration given generating resources.
- Therefore, we find that the parties should use the avoided cost methodology resulting from the No. U-1500-170 case for evaluating the cost effectiveness of conservation measures. The specific means for comparing No. U-1500-170 case avoided costs to conservation costs will initially be developed case-by-case as specific conservation programs are proposed by each utility. Prices to be paid for conservation resources procured by utilities are discussed later in this Order.
- Give balanced consideration to demand side and supply side resources when formulating resource plans and when procuring resources.

- Submit to the Commission, no later than March 15, 1989, and at least biennially thereafter, a Resource Management Report describing the status of its resource planning as of the most current practicable date.

Order 25260 Requirements

This order documents additional requirements for resource planning including:

- Give full consideration to renewables, among other resource options.
- Investigate and carefully weigh the site-specific potential for particular renewables in their service area.
- Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in general rate case or other proceeding in which the issue is noticed.

Summary of Changes from the 2021 IRP

Avista made several material changes to the methodology of the analysis since the 2021 IRP. The major changes are the capacity and energy position methodology, updated energy efficiency and demand response potentials, 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 WPP'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 (for early years only) and accounting metrics.
- The energy risk metric for energy planning now includes risks from load, hydro, and Variable Energy Resources (VERs), prior plans did not include VERs within the calculation.
- Load and hydro forecasts use the Representative Concentration Pathway (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 Company's Transportation Electrification Plan.
- Recent resource acquisitions are included in this forecast from Chelan PUD, Columbia Basin Hydro, a 30-year wind PPA, the extension of the Lancaster PPA, and upgrades to Kettle Falls and Post Falls.

Energy Efficiency and Demand Response

- NEIs are included on an individual measure basis rather than a single value for all programs for Washington programs.

[3] RCP 4.5 is defined in Chapter 4.

- The Named Community Investment Fund (NCIF) sets a threshold for additional low-income energy efficiency targets beyond cost effective measures for Washington.
- 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 renewable fueled (ammonia) turbines.
- The Inflation Reduction Act tax incentives are reflected in resource cost.
- An NEI study for new resources is reflected in the resource selection for Washington resources.
- WRAP QCCs are used for new resource selection but discounted over time[4] to reflect changes in regional generation mix.

Market Analysis

- A new regional resource forecast is updated to reflect best available information utilizing Energy Exemplar's latest Western Electricity Coordinating Council (WECC) database.
- 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 hourly simulations due to enhanced modeling logic for storage resources increasing run times.

Portfolio Optimization Analysis

- Monthly level energy positions rather than annual are used 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 positions 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 CBI results are included within the PRiSM model for Washington.
- The NCIF creates thresholds distributed energy resources to address state policy choices.

[4] For wind, solar, energy storage and demand response.

Modeling and Assumption Updates to January 2023 Progress Report Filing

1. Reflect all 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 in Washington.
3. Include any available information regarding the functionality of Washington's CCA.
4. Include stakeholder feedback for improvement in the analysis or the report.
5. Include portfolio scenario analysis and market risk impacts on scenarios.

2023 IRP Chapter Outline

The 2023 IRP consists of 12 chapters.

Chapter 1: Introduction, Stakeholder Involvement and Process Changes

This chapter introduces the IRP, covers requirements and details public participation and involvement in the process used to develop it, as well as significant assumption, modeling and process changes between the 2021 and 2023 IRPs.

Chapter 2: Economic and Load Forecast

This chapter covers regional economic conditions, Avista's energy and the peak load forecasts, including scenarios with different load projections.

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 and demand response potential assessments, and 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 Planning & Distribution

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: Preferred Resource Strategy

This chapter details the Preferred Resource Strategy (PRS) selection process used to develop the 2023 PRS and resulting avoided costs.

Chapter 10: Scenario Analysis

This chapter presents alternative resource portfolios and shows how each scenario performs under different energy market conditions.

Chapter 11: 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.

Chapter 12: Action Plan

This chapter discusses progress made on Action Items in the 2021 IRP. It details the areas Avista will focus on between publication of this plan and the 2025 IRP.

2023 IRP Appendices

Appendix A: TAC Presentations

This appendix includes the presentations for the nine TAC meetings and meeting notes plus the public presentations.

Appendix B: IRP Work Plan

This appendix includes 2023 IRP Work Plan outlining the process Avista's used to develop its 2023 Electric IRP for filing with the Washington and Idaho Commissions by June 1, 2023.

Appendix C: AEG Conservation and Demand Response Potential Assessments

This appendix includes the conservation (energy efficiency) and demand response potential assessment studies.

Appendix D: DNV Non-Energy Impact Studies

This appendix includes NEI Studies from DNV for supply-side and energy efficiency resources.

Appendix E: Transmission Designated Network Study

This appendix includes the transmission study results for this IRP.

Appendix F: Inputs and Results

This appendix includes all the IRP data assumptions, such as cost and operating characteristics for generic resource types, as well as the modeling results.

Appendix G: Distributed Energy Resources Scope of Work

This appendix includes the scope of work for the upcoming study of feeder level potential of distributed energy resources for the Washington service territory.

Appendix H: Confidential Historical Generation Operation Data

This appendix includes actual monthly data for PURPA generation and forced outage data for Avista's resources.

Appendix I: New Resource Table for Transmission

This appendix approximates the location of new resources for transmission planning.

Appendix J: Confidential Inputs and Models

This appendix including the Aurora model and ARAM models.

Appendix K: Resource Portfolio Summary

This appendix includes the resources selected by year for each of the portfolio scenarios discussed in Chapter 10.

Appendix L: Public Comments

This appendix includes written comments from the public and advisory group members.

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2. Economic & Load Forecast

Avista's loads and resources are an integral component of the Integrated Resource Plan (IRP). 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 0.85% per year, higher than the 0.24% annual growth rate in the 2021 IRP. Higher growth largely reflects higher residential and commercial electric vehicles (EV) forecasts and new building electrification.
- 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 1.16% in the winter and 1.24% 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% of both Avista's customers (i.e., meters) and load. The remaining 30% 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% in 2007 to

[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.

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

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

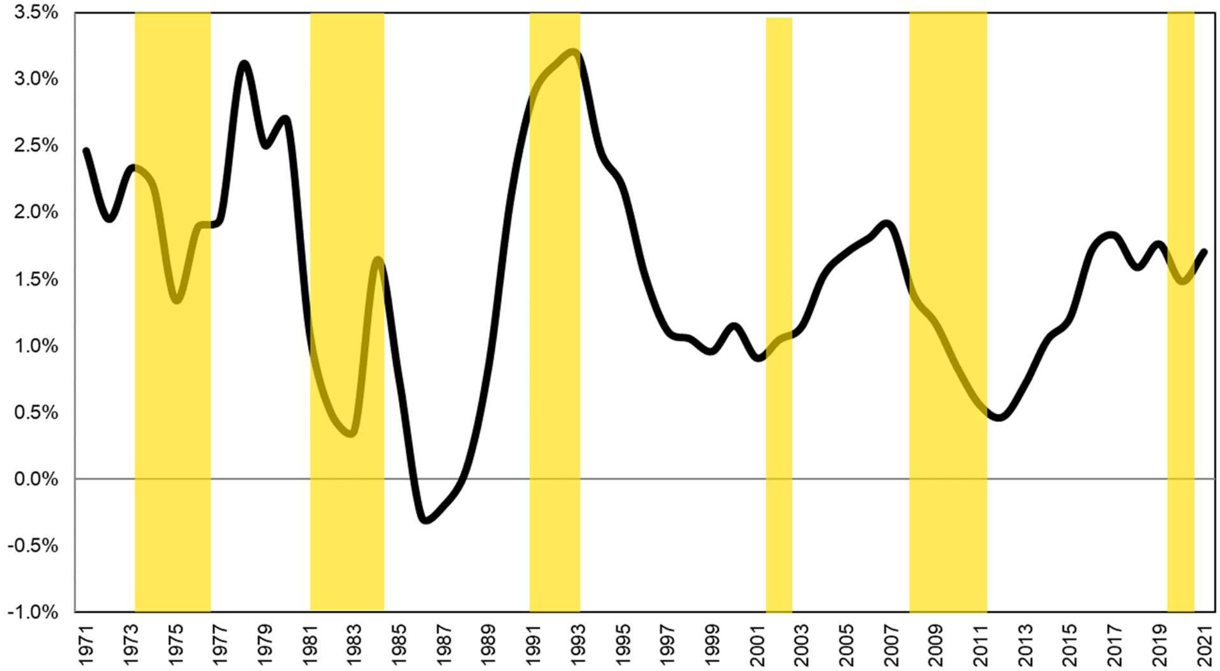
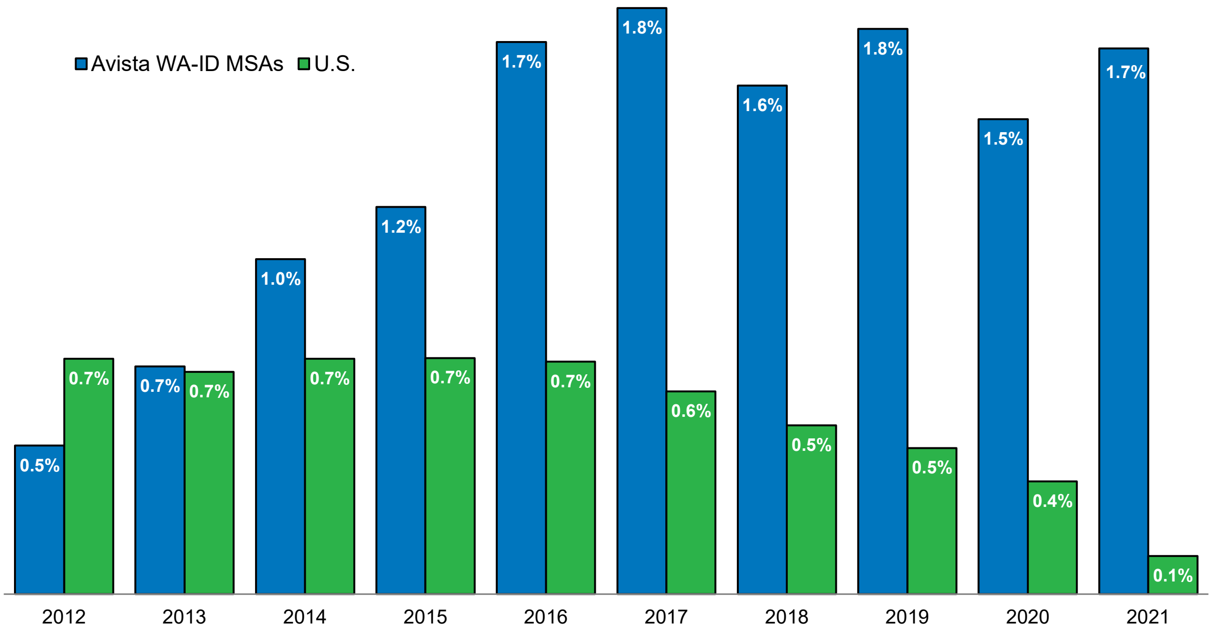


Figure 2.2 shows population growth since 2012.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; however, it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service 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% increase in service area employment growth is associated with a 0.4% 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.

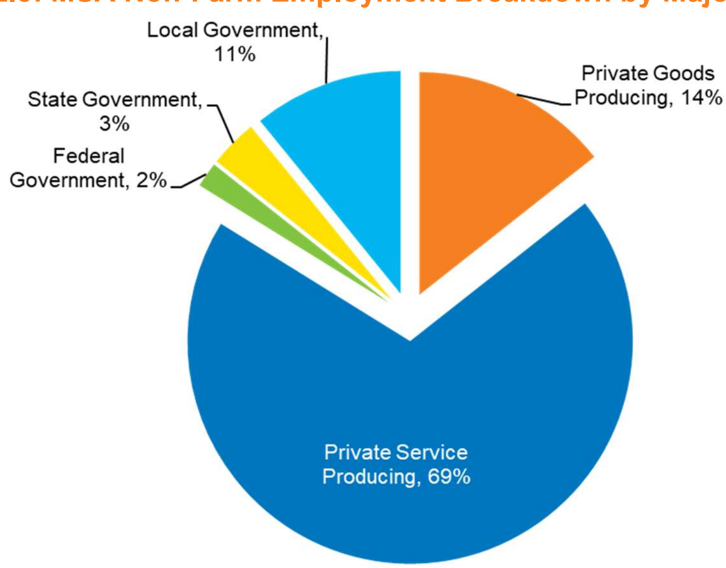
Figure 2.2: Avista and U.S. MSA Population Growth, 2012-2021



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% of employment in the three MSAs is in private services, followed by government (16%) and private goods-producing sectors (14%). Farming accounts for 1% 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 2012 to 2021.

Figure 2.4: Avista and U.S. MSA Non-Farm Employment Growth, 2012-2021

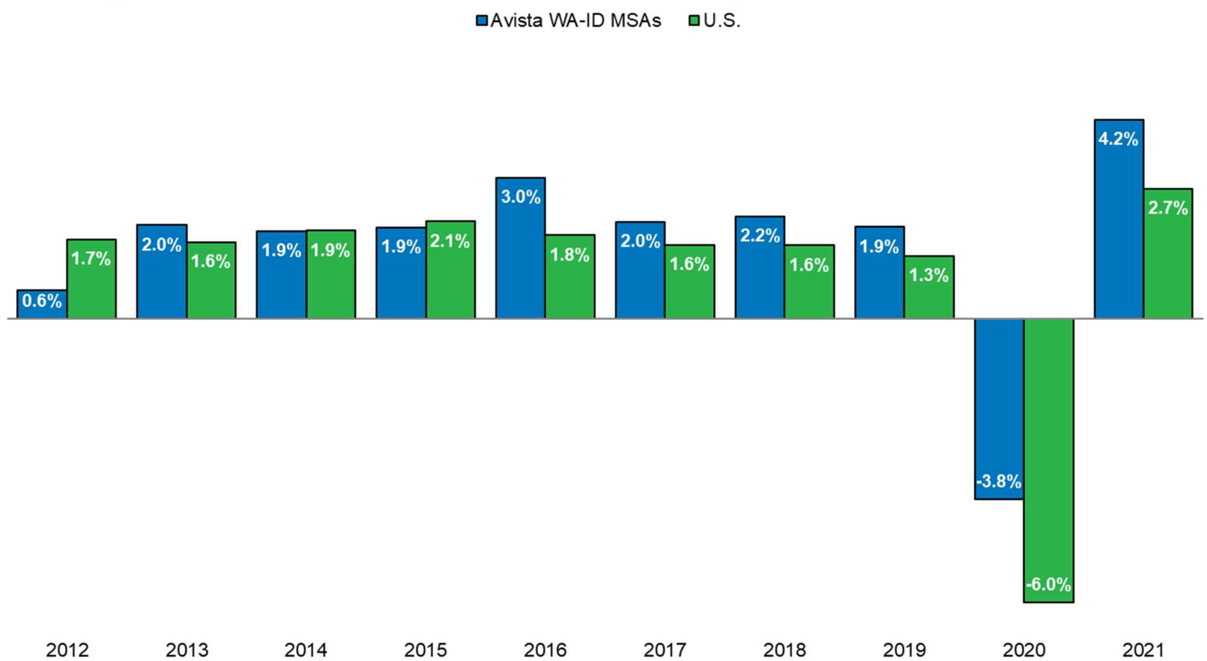


Figure 2.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[5] Regular income includes net earnings from employment, and investment income in the form of dividends, interest, and rent. Personal current transfer 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% of the local economy. The income share of transfer payments has nearly doubled over the last 40 years to 27%. Although 56% 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 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% in the 1970s to around 85% by the mid-1990s. The income ratio has not recovered.

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

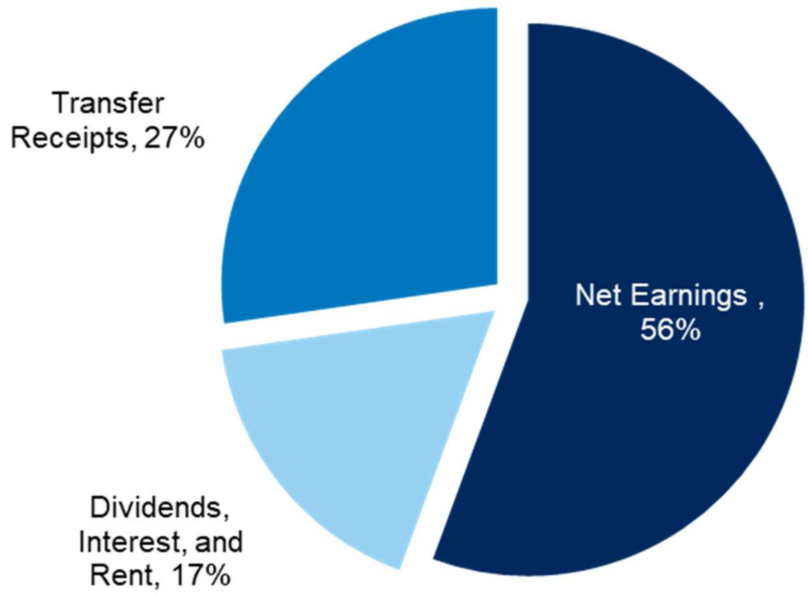
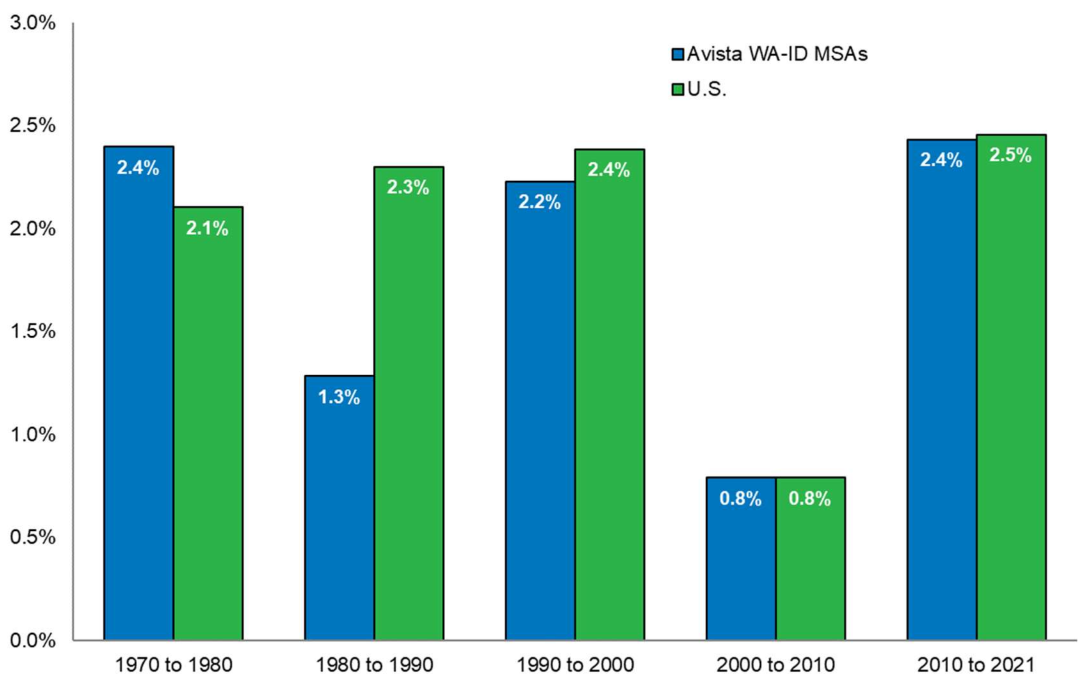


Figure 2.6: Avista and U.S. MSA Real Personal Income Growth by Decade, 1970-2021



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:

- $\mathrm{F}(\mathrm{kWh}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $\mathrm{F}(\mathrm{kWh}/\mathrm{C}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = the UPC forecast.
- $\mathrm{F}(\mathrm{C}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = 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 rate 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

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[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 (ARIMA) “transfer function” model such that $\epsilon_{t,y} = \text{ARIMA}\epsilon_{t,y}(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the (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 rate 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, are in a long-run steady decline, or are 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. The 10- and 15-year moving averages 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, the temperature is assumed to increase after 2026 based on temperature modeling from an ensemble of global climate models analyzed as part of the Columbia River Management Joint Operating Committee

[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.

(RMJOC) II Climate Change Analysis using the Relative Concentration Pathway (RCP) 4.5 forecast. In other words, the 20-year moving average of weather is used until 2026. Starting in 2027, changing HDDs and CDDs are built in using the RMJOC II RCP 4.5 forecast. The 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% from 2027 to 2029; and then increase 1.5% 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%, 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 and assumes macroeconomic factors flow through the 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

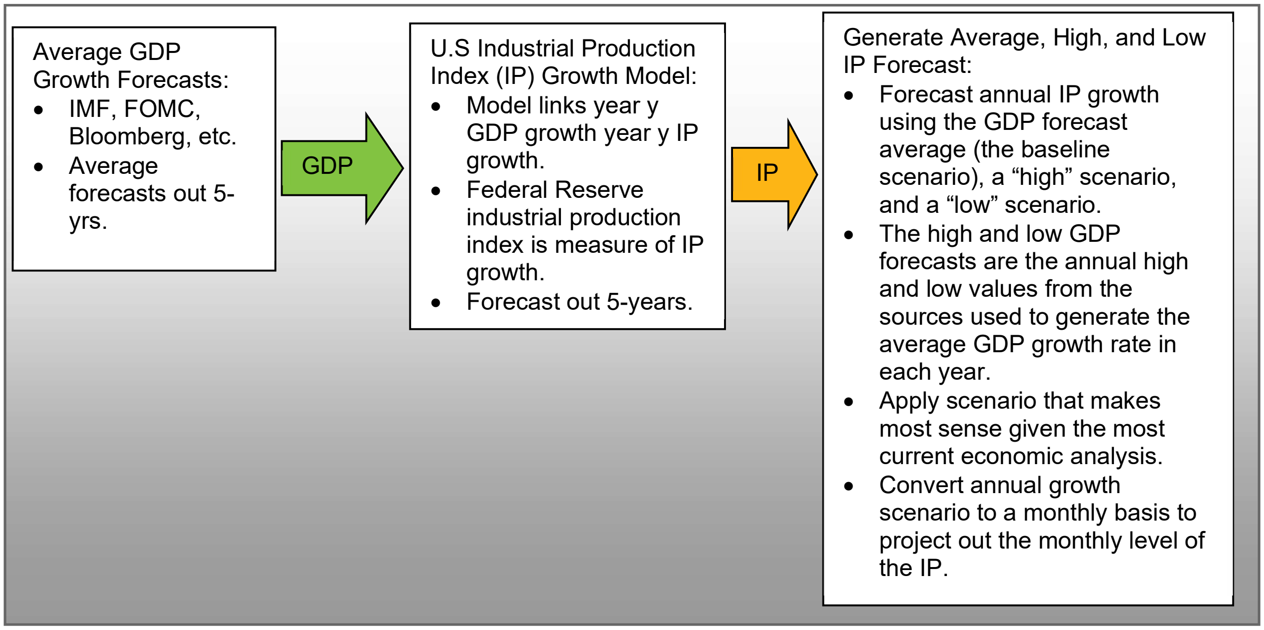
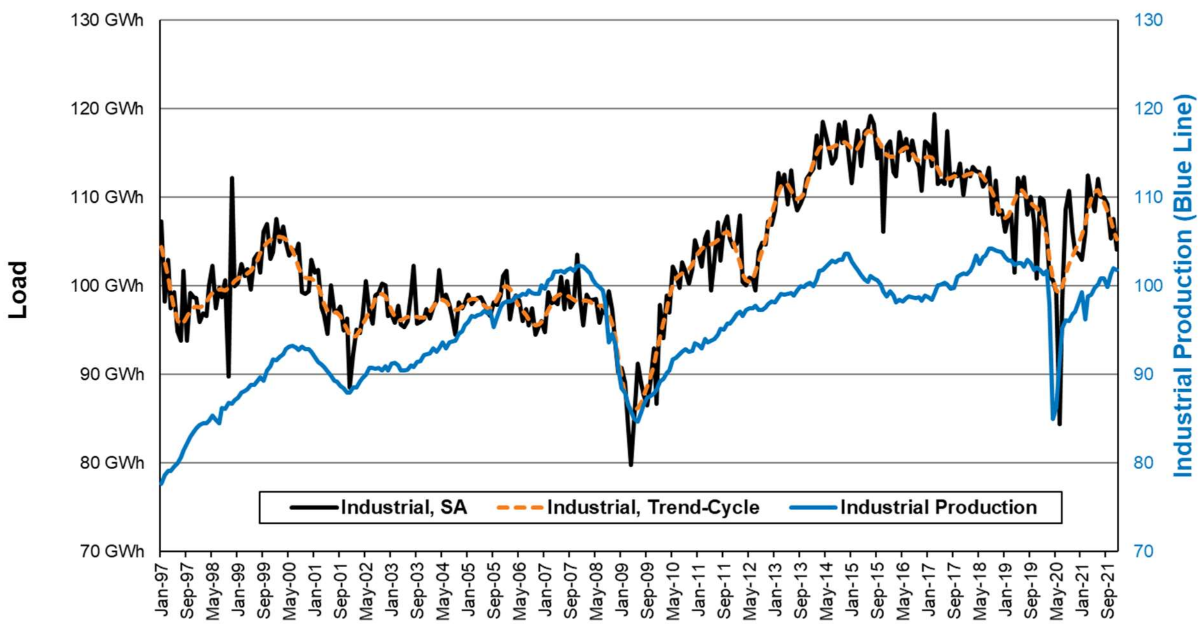


Figure 2.8: Industrial Load and Industrial (IP) Index



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 with 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

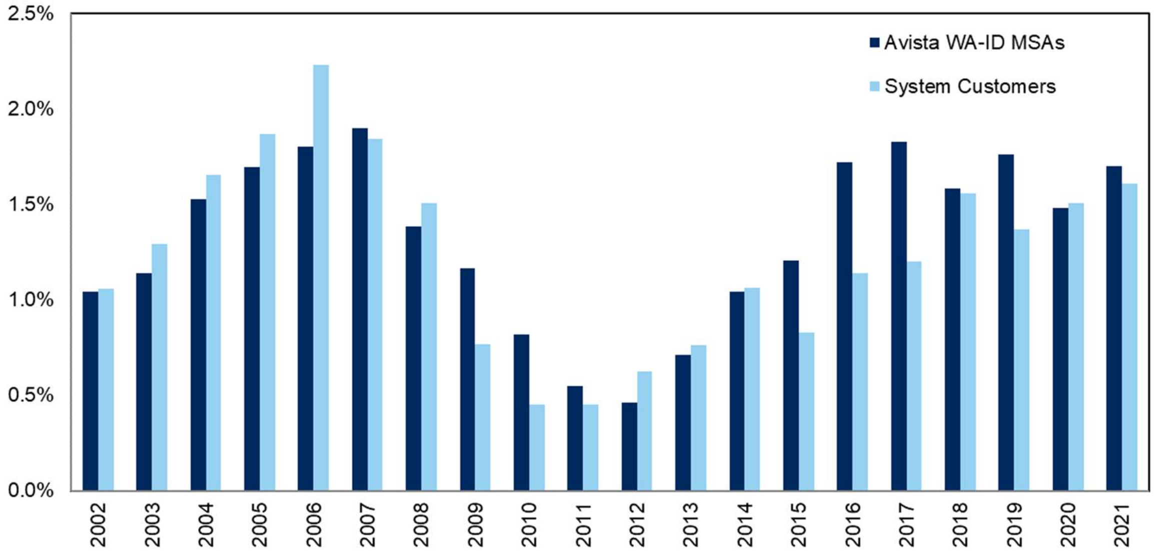
Figure 2.9 shows the relationship between annual population growth and year-over-year customer growth.[12] Customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs over the last 20 years. Population growth averaged 1.3% over the 2000-2021 period and customer growth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

Figure 2.9 demonstrates how population growth is the primary driver of customer growth. As a result, forecasted population growth 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.

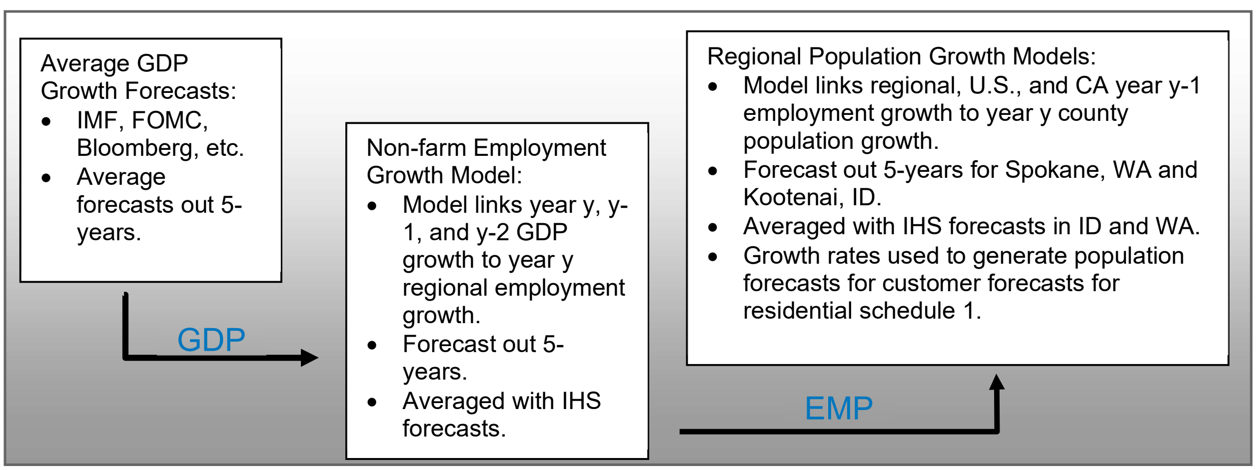
[12] Data Source: Bureau of Economic Analysis, U.S. Census, Washington State OFM, and Avista records.

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. **Load Growth by Revenue Class**
   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%, 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%. Average annual industrial customer growth rate over 2023-2045 is -1.0%, 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.

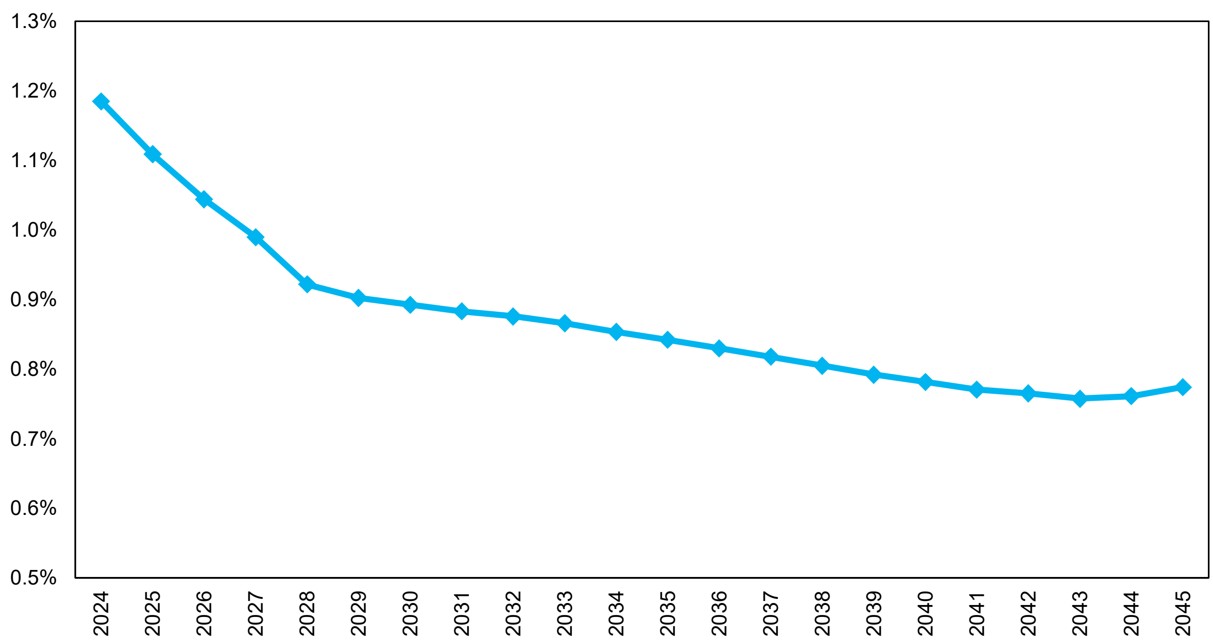
2. **Flat Streetlight Growth**
   Consistent with historical behavior, industrial and streetlight load growth projections do not correlate with residential or commercial load. Average annual industrial load

[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.

growth is -0.3% over the forecast horizon. This reflects the assumption that the annual -1.0% decline in industrial customer growth is not offset by UPC growth 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 0% over the forecast horizon to reflect the assumption of slow customer growth being offset by the impact of LED lighting.

3. **Real Average Energy Price Annual Increase**
   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% annually between 2026 and 2029; and then increase 1.5% 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%, based on long-term estimates from the academic literature (See also footnote 11).

Figure 2.11: Long-Term Annual Residential Customer Growth



4. **Electric Vehicles Growth Rates Increase**
   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. This is an average annual growth rate of 23% between 2024 and 2045. 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% of all residential light-duty vehicle sales by 2030 and 38% by 2045. Based on the assumption of approximately two vehicles per residential customer (based on U.S. Census data for Avista’s service

area), the LDEV penetration rate is forecasted to rise from 0.5% of residential customers in 2023 to just over 27% 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%. The forecast assumes each MDEV averages 12,700 kWh per year and MDEVs will constitute 0.02% of all commercial light-duty vehicle sales by 2030 and 24% by 2045. The MDEV penetration rate is forecasted to rise from near 0% of commercial vehicles in 2024 to just over 13% by 2045 for a total load of 23 aMW. The current data on commercial MDEV in Avista's 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. Rooftop Solar Installations Increase

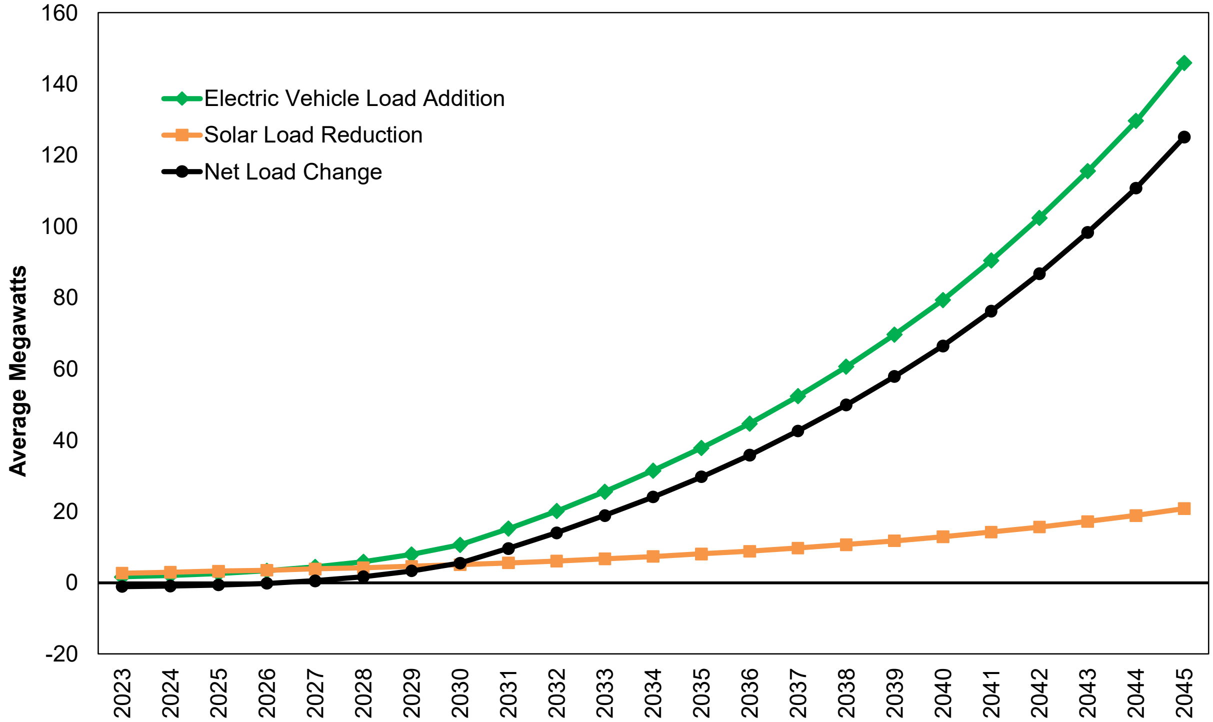
Residential rooftop solar penetration, measured as the share of residential solar customers to total residential customers, continues to grow at present levels in the forecast. The starting average PV system size is set at 7 kW (DC) with a 14% capacity factor, or about 8,500 kWh per year per customer. These values reflect current Company data on customer installation size and system efficiency. The forecast assumes the starting system size will increase 1% annually to about 10,900 kWh per year per customer in 2045, with the capacity factor remaining constant at 14%. 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% in 2024 to about 4.0% in 2045. This accumulation can be approximated by an exponential growth function. The baseline model assumes residential solar penetration will grow approximately 9.0% 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% 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% annually to about 38,500 kWh per year per customer in 2045, with the capacity factor remaining constant at 14%. 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% in 2024 to about 0.6% 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% 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 Avista's service area. First, urban and rural forests surround many of the owner-occupied structures. 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.

6. **Natural Gas Customers Decline**

Washington State's restrictions on using natural gas as a heating fuel and lowering natural gas connection incentives is reflected by assuming no additional commercial gas customers after 2023. This assumption means natural gas penetration will experience a steady decline over the forecast horizon, reflecting a shift towards electric 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's restrictions on using residential natural gas as a primary heating fuel and lowering connection incentives is reflected by assuming 80% of potential new natural gas customers will have heat pump heating systems with natural gas as the back-up source for temperatures below 40 degrees, the remaining new customers will be 100% electric. All new customers assume the use of an electric heat pump water heater.

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

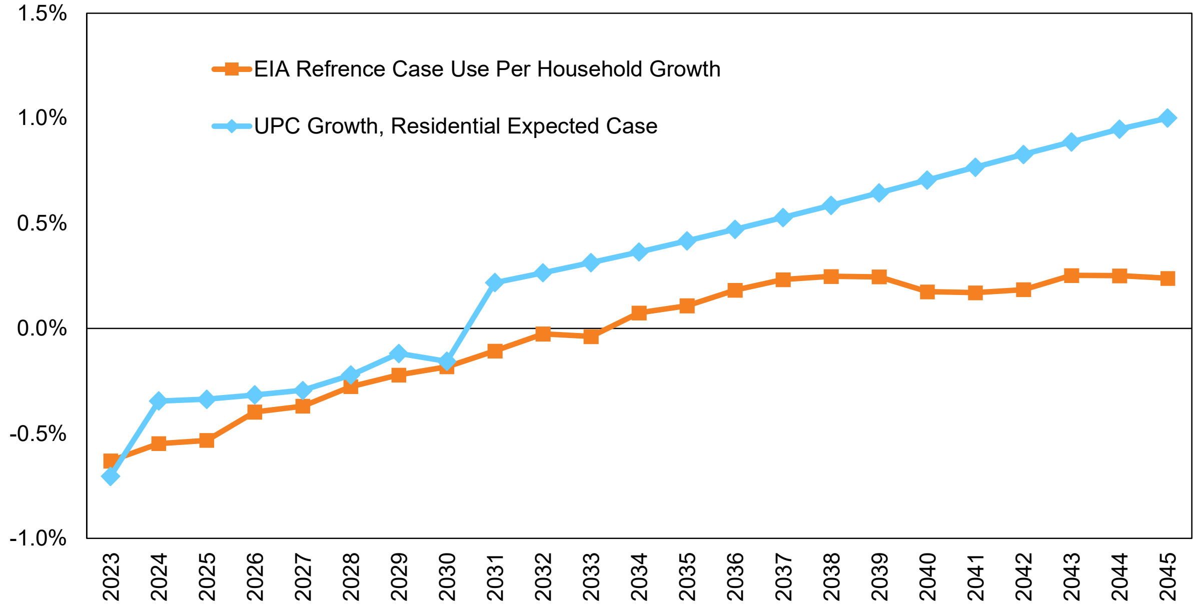
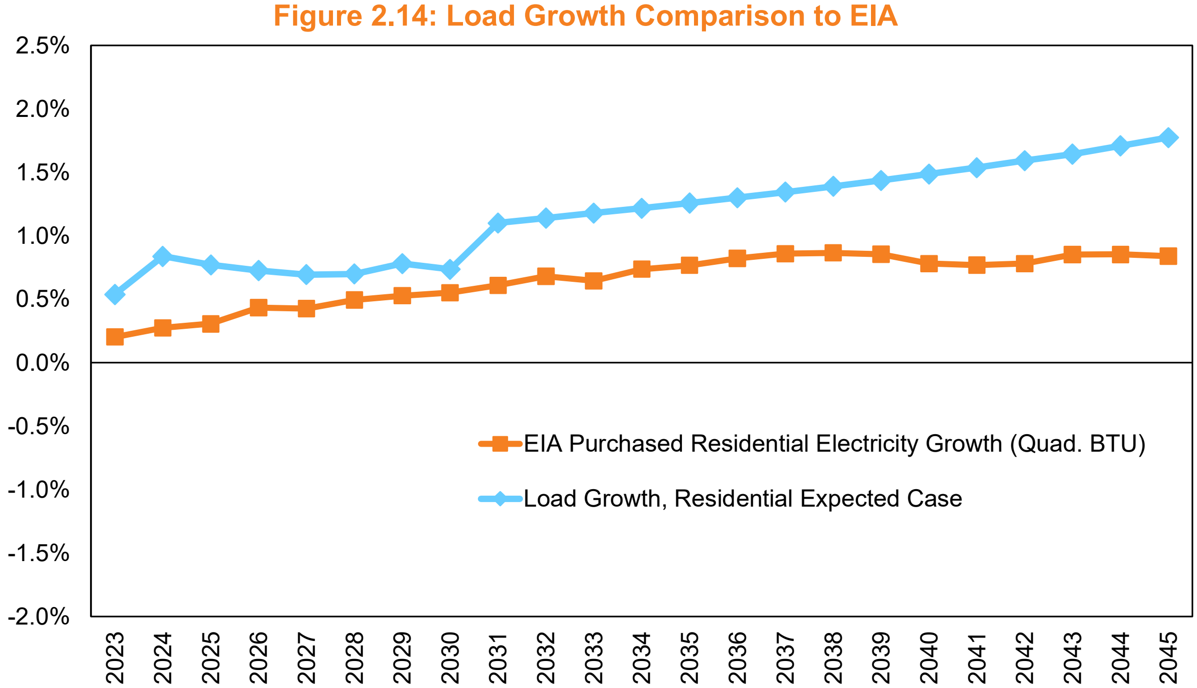


Figure 2.14 shows EIA and residential load growth forecasts. Avista's forecast is higher over the entire period, reflecting the assumptions for rapid EV adoption and a service area population growth that will exceed the U.S. average. The higher population forecast for Avista's service area is consistent 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. Figure 2.16 shows 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

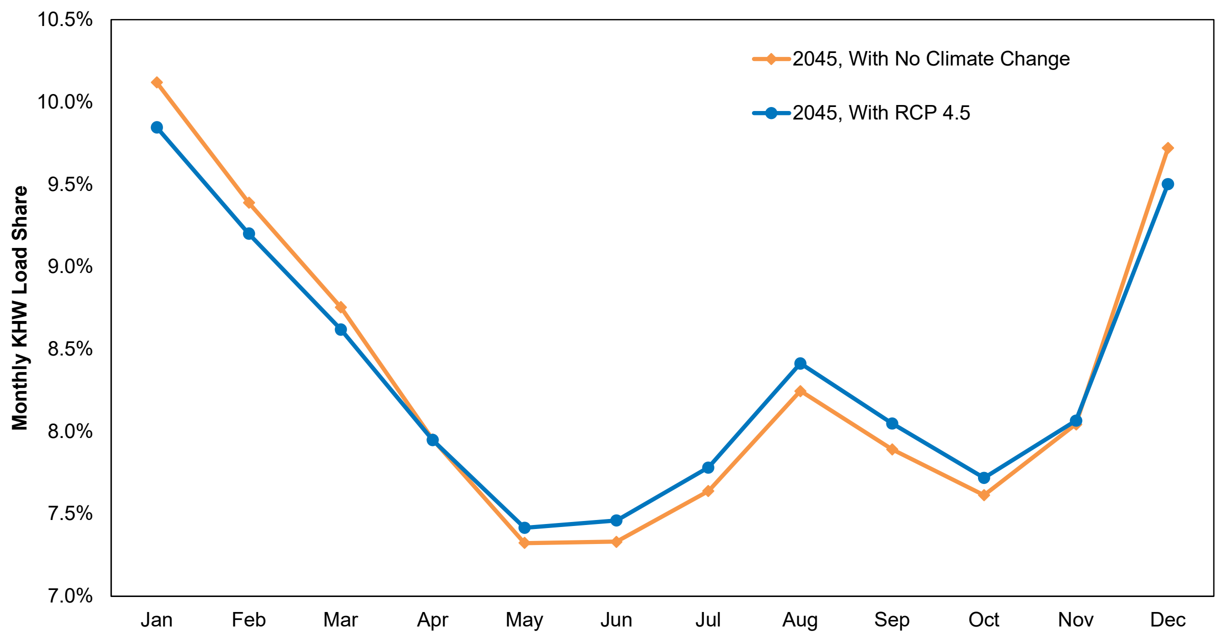
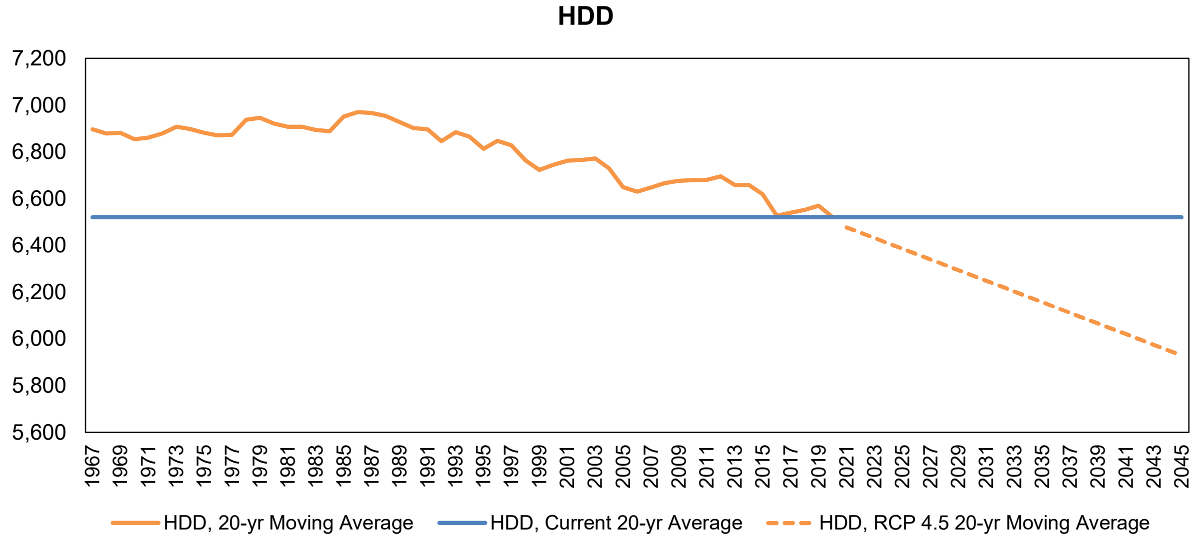
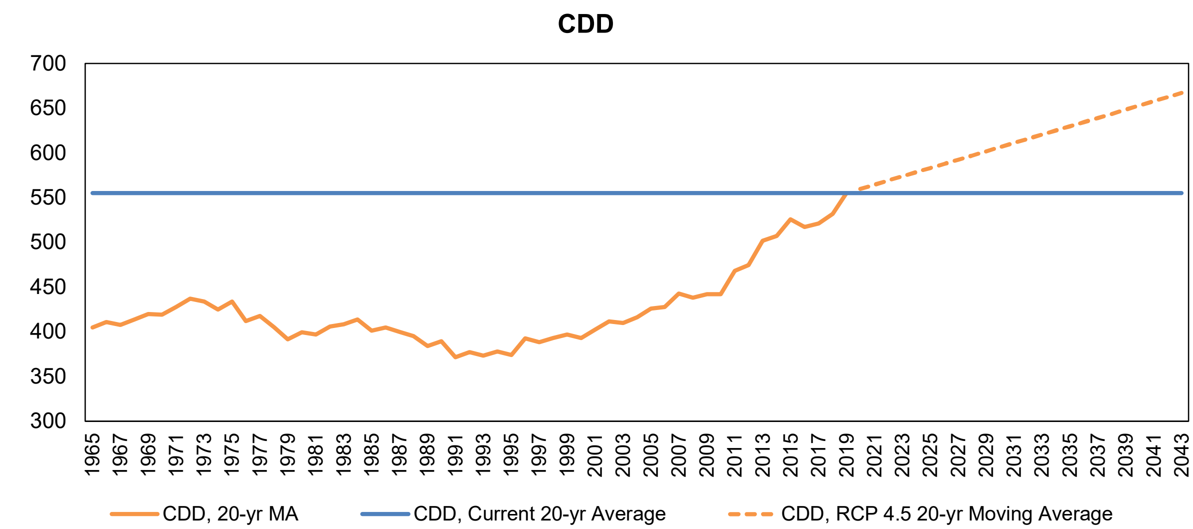


Figure 2.16: Load Share Comparison Due to Temperature Assumptions





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. Future 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 2.4 shows the current peak load regression model.

Equation 2.4: Peak Load Regression Model

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2$$
$$+ \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1}$$
$$+ \phi_2 (D_{SUM} \cdot GDP_{t.y-1}) + \phi_3 (D_{WIN} \cdot GDP_{t.y-1}) + \boldsymbol{\omega_{WD} D_{d,t,y}} + \boldsymbol{\omega_{HD} D_{d,t,y}}$$
$$+ \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 200} \quad + \epsilon_{d,t,y} \ for\ t, y = June\ 2004 \uparrow$$

Where:

- $\mathrm{hMW}_{\mathrm{d,t,y}}^{\mathrm{netpeak}}$ = 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.
- $\mathrm{HDD}_{\mathrm{d,t,y}}$ and $\mathrm{CDD}_{\mathrm{d,t,y}}$ = heating and cooling degree days the day before the peak.
- $(\mathrm{HDD}_{\mathrm{d,t,y}})^2$ = squared value of $HDD_{d,t,y}$.$\mathrm{HDD}_{\mathrm{d-1,t,y}}$ and $\mathrm{CDD}_{\mathrm{d-1,t,y}}$ = heating and cooling degree days the day before the peak.
- $\mathrm{CDD}_{\mathrm{d,t,y}}^{\mathrm{HIGH}}$ = maximum peak day temperature minus 65 degrees.[14]
- $\mathrm{GDP}_{\mathrm{t.y-1}}$ = 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 2.4 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 is still possible. In other words, although average winter temperatures have risen in the Company's 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 seen in the peak load forecast with RCP 4.5, and with the 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 2.4. 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% 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	Summer
Including Economic Growth, Large Industrial Customers, and adders for EVs, Solar, and WA Gas Restrictions	1.16	1.24
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

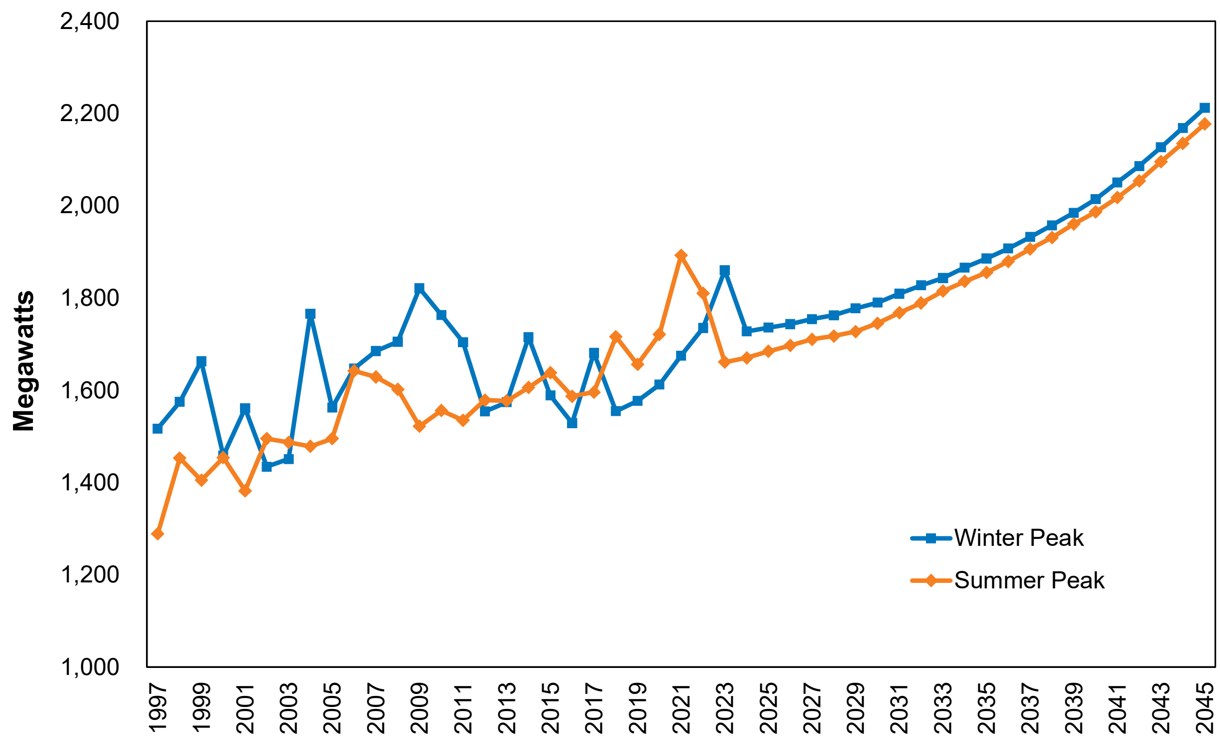


Figure 2.18: Peak Load Forecast with 1-in-20 High/Low Bounds

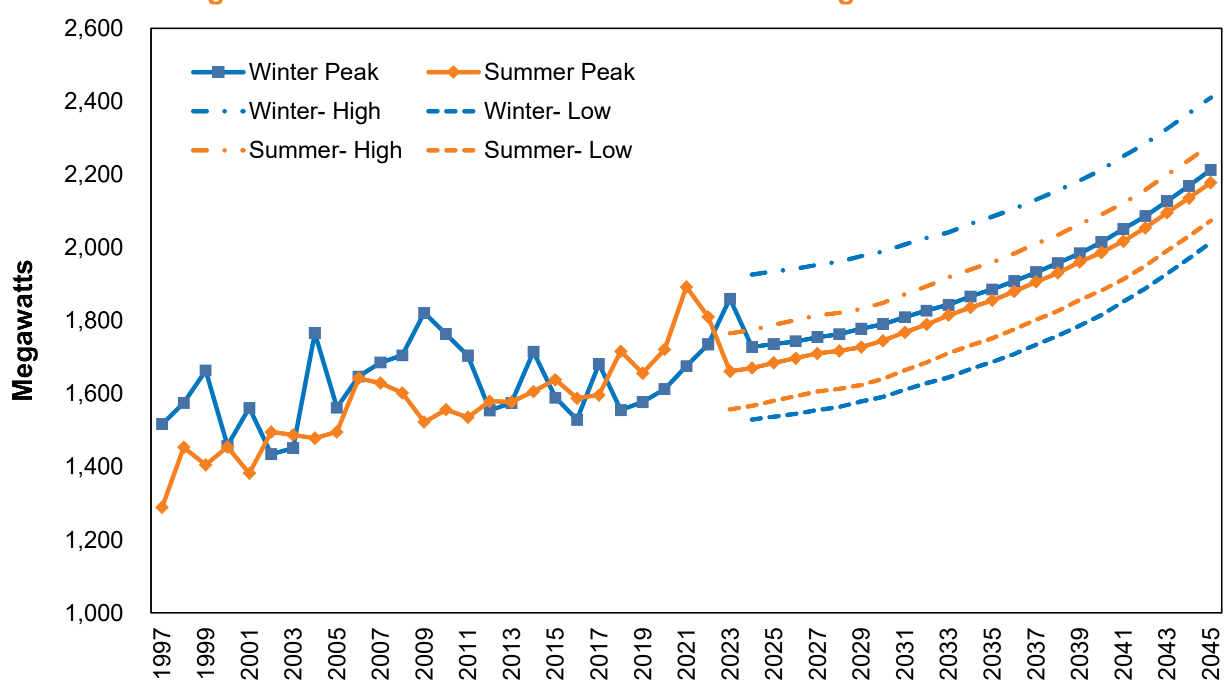


Table 2.4: Energy and Peak Forecasts

Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
2023	1,113	1,718	1,661
2024	1,121	1,728	1,670
2025	1,126	1,736	1,684
2026	1,132	1,743	1,697
2027	1,140	1,754	1,710
2028	1,147	1,762	1,717
2029	1,154	1,778	1,727
2030	1,161	1,790	1,745
2031	1,169	1,809	1,768
2032	1,179	1,828	1,789
2033	1,187	1,843	1,815
2034	1,197	1,866	1,836
2035	1,207	1,886	1,855
2036	1,218	1,907	1,879
2037	1,228	1,932	1,906
2038	1,239	1,957	1,931
2039	1,251	1,984	1,960
2040	1,265	2,014	1,986
2041	1,277	2,050	2,017
2042	1,292	2,086	2,054
2043	1,307	2,126	2,095
2044	1,325	2,168	2,135
2045	1,342	2,212	2,177

Scenario Analysis

Native Load Scenarios with Low/High Economic Growth

The load forecast for this IRP also considers futures with higher and lower loads due to higher or lower economic growth. The high and low load scenarios use the GDP growth and population growth assumptions shown in Table 2.5. The GDP growth assumptions are used to forecast long-run industrial production growth. Then growth is used to forecast the long-run growth rate in industrial customer UPC. The population growth assumptions are used to forecast residential customer growth. This assumption is then used to forecast long-run commercial customer growth. The forecasts are based on underlying regressions using annual data to estimate the long-run sensitivity of (1) U.S. industrial production growth to GDP growth; (2) industrial customer UPC growth to U.S industrial production growth; (3) changes in residential customers to changes in population; (4) changes in commercial customers to changes in residential customers.

Underlying the high/low range of GDP forecasts is the following long-run and well-established relationship: U.S. GDP growth is equal to U.S. population growth plus U.S. labor productivity growth. The U.S. Census forecast for average annual U.S. population growth over the IRP's forecast horizon is 0.5%. Given long-run demographic realities in the U.S., this will not likely vary significantly so it is held constant as a source of GDP variability. This leaves labor productivity as the primary driver of long-run GDP growth.

Given a 0.5% annual population growth, the Expected Case of 1.8% GDP growth implies labor productivity growth of 1.3%; this is in line with the annual productivity growth observed since the end of the Great Recession. The high case of 2.4% GDP growth implies annual productivity growth of 1.9%; this level is near pre-Great Recession growth. The low case of 1.2% GDP growth implies only 0.7% annual productivity growth. This level is low by all historical standards, but not improbable given the productivity slowdown being observed in most developed economies.

The high and low GDP growth cases are simultaneously paired with high and low regional population growth. As noted in Figure 2.1, periods of higher (lower) economic growth tends to be associated with higher (lower) service area population growth, especially through in-migration. To help identify reasonable high/low population growth ranges, Equation 2.5 is applied.

Equation 2.5: Population Growth Long-Run Forecast Relationship

$$POPG = (0.005 + a_1 0.005_{US} + a_2 EMPG_{SPK}) \cdot W + (0.005 + b_1 0.005_{US} + b_2 EMPG_{KOOT}) \cdot (1 - W)$$

Where:

- POPG = predicted population growth rate for the combined Spokane-Kootenai metro area.
- a = the estimated regression coefficients from the Spokane metro population growth forecast equation used for the medium-term forecast. These reflect the sensitivities of a change in U.S. employment growth (a_1<0) and Spokane metro employment growth (a_2>0) on Spokane metro population growth. Note that 0.005 is the Bureau of Labor Statistics' (BLS) forecast for long-run annual U.S. employment growth and $EMPG_{SPK}$ is the assumed high/low growth rate for Spokane metro.
- b = the estimated regression coefficients from the Kootenai metro population growth forecast equation medium-term forecast. These reflect the sensitivities of a change in U.S. employment growth (b_1<0) and Kootenai metro employment growth (b_2>0) Kootenai metro population growth. As before, 0.005 is the BLS's forecast for long-run U.S. employment growth and $EMPG_{KOOT}$ is the assumed high/low growth rate for the Kootenai metro area.
- 0.005 = the intercept term replacing the original intercept from the medium-term regression equations. It reflects the long-term U.S. Census forecast for annual U.S. population growth (0.5%) over the IRP's forecast period. The assumption here is as annual service area employment growth gets closer to U.S. employment growth, the incentive for people to migrate to the combined metro region for economic reasons declines to the neighborhood of national population growth.
- W = the share of population in the Spokane metro as a share of the total population the combined Spokane-Kootenai metro area. This provides a weight to produce a combined area population growth rate.

Using the historical regression relationship between U.S. GDP growth and service area employment growth (see Figure 2.19), Equation 2.5 can be used to identify population growth rates that are consistent with long-run GDP growth rates in the neighborhood of 2.4% and 1.2% holding long-run U.S. employment growth constant. The high and low population ranges identified using this method are similar to calculating the approximate 75th and 25th percentiles of annual population ***growth changes*** since the early 1990s, and then adding those percentile changes to the expected population growth case.

Table 2.5: High/Low Economic Growth Scenarios (2027-2045)

Economic Growth	U.S. GDP Growth (%)	Annual Service Area Population Growth (%)
Expected Case	1.8	0.8
High Growth	2.4	1.1
Low Growth	1.2	0.3

Figure 2.19: Average Megawatts, High/Low Economic Growth Scenarios

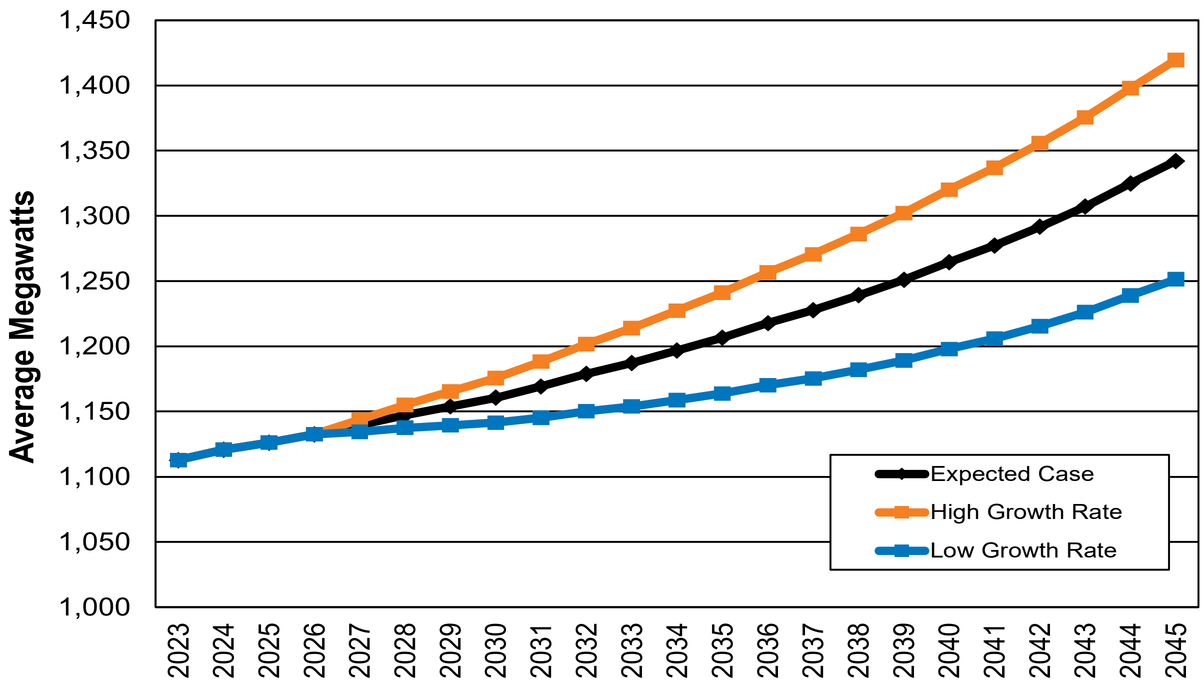


Table 2.6 shows the average annual load growth rate over the 2021-2045 period. Compared to the 2021 IRP, the last IRP assumed a low growth scenario with slightly negative growth of the 2025-2041 timeframe, this IRP shows positive load growth in all cases. This reflects the impact of a more aggressive EV forecast and commercial gas restrictions in Washington.

Table 2.6: Load Growth for High/Low Economic Growth Scenarios (2023-2045)

Economic Growth	Average Annual Native Load Growth (%)
Expected Case	0.85
High Growth	1.11
Low Growth	0.53

In the sections that follow, four alternative scenarios are considered. Each of these scenarios are compared against the Expected Case for both energy and peak. These scenarios are (1) Full building electrification in Washington; (2) Building electrification in Washington with natural gas as a backup; (3) high electric vehicle (EV) adoption throughout Avista's Washington and Idaho jurisdictions; and (4) a transformative scenario that reflects scenarios (1) and (3) combined with much higher solar adoption in Washington.

Washington Building Electrification (Full Electrification)

In this scenario, Expected Case is altered by assuming that all existing and new natural gas customers will gradually move to electric only service - there are no additional gas connects for new customers and existing customers gradually switch to electric only service. Solar and EV accumulation are assumed to be the same as the Expected Case. The results are shown in Figures 2.20-2.22. The first graph in the figure shows energy compared to the Expected Case, the second shows winter peak compared to the Expected Case; and the third shows the summer peak compared to the Expected Case.

Figure 2.20: Full Building Electrification – Energy Impact

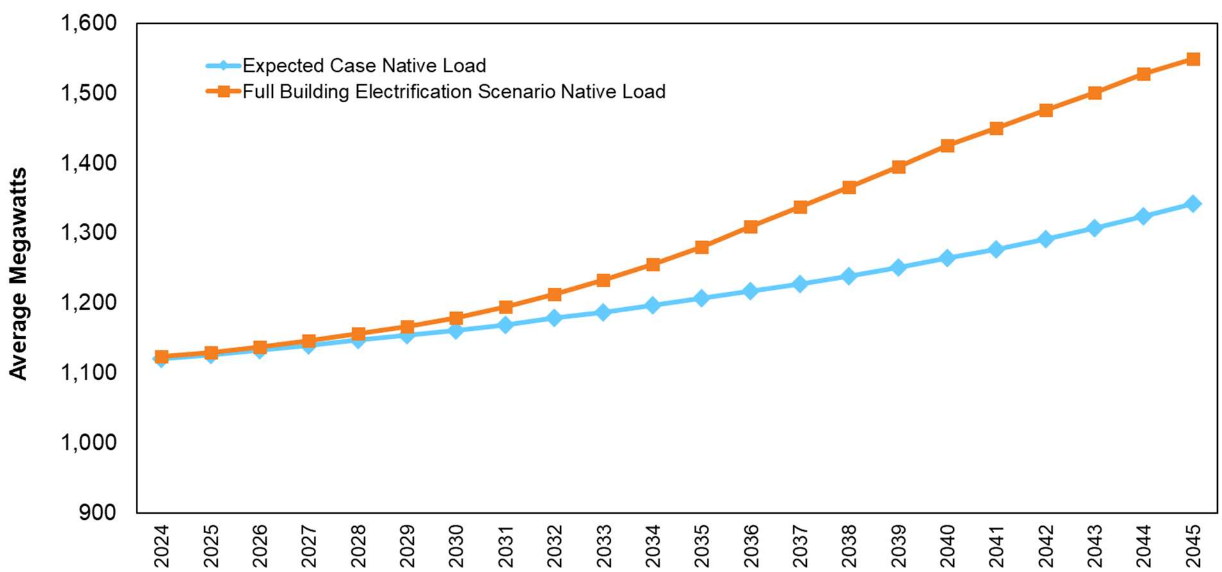


Figure 2.21: Full Building Electrification – Winter Peak Impact

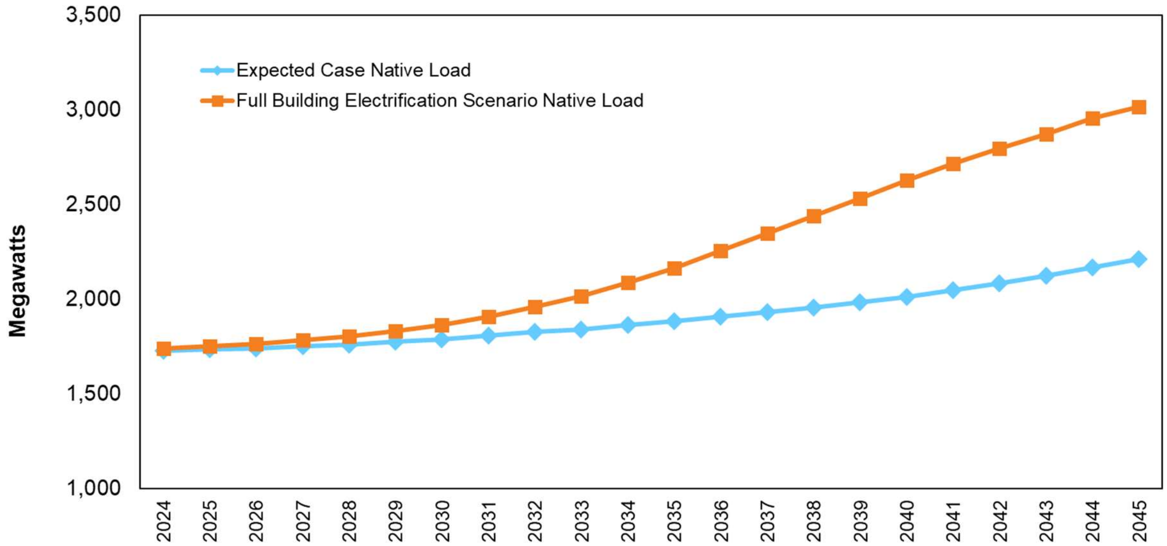
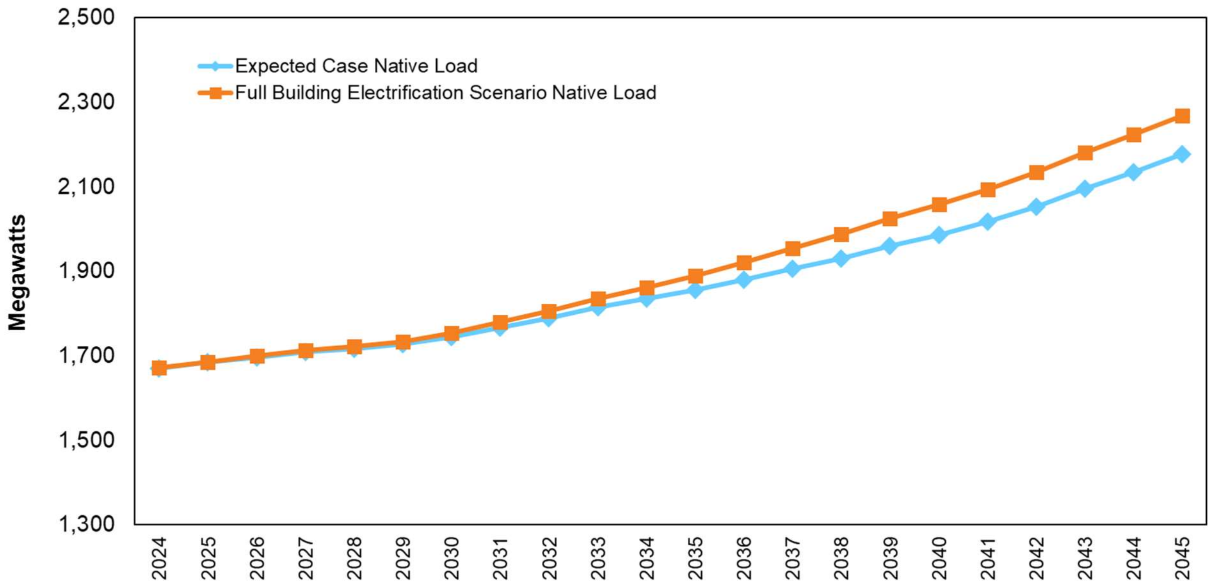


Figure 2.22: Full Building Electrification – Summer Peak Impact



Washington Building Electrification (Electrification w/ Natural Gas Backup)

In this scenario, the Expected Case is altered by assuming that all existing and new natural gas customers will gradually move to electric service with natural gas as a backup during temperatures below 40 degrees. New customers will add gas only as a backup and existing gas customers gradually switch to electric with gas only as a backup. Solar and EV accumulation are assumed to be the same as the Expected Case. The results are shown in Figure 2.23-2.25. The first graph in the figure shows energy compared to the Expected Case, the second shows winter peak compared to the Expected Case; and the third shows the summer peak compared to the Expected Case.

Figure 2.23: Hybrid Electrification – Energy Impact

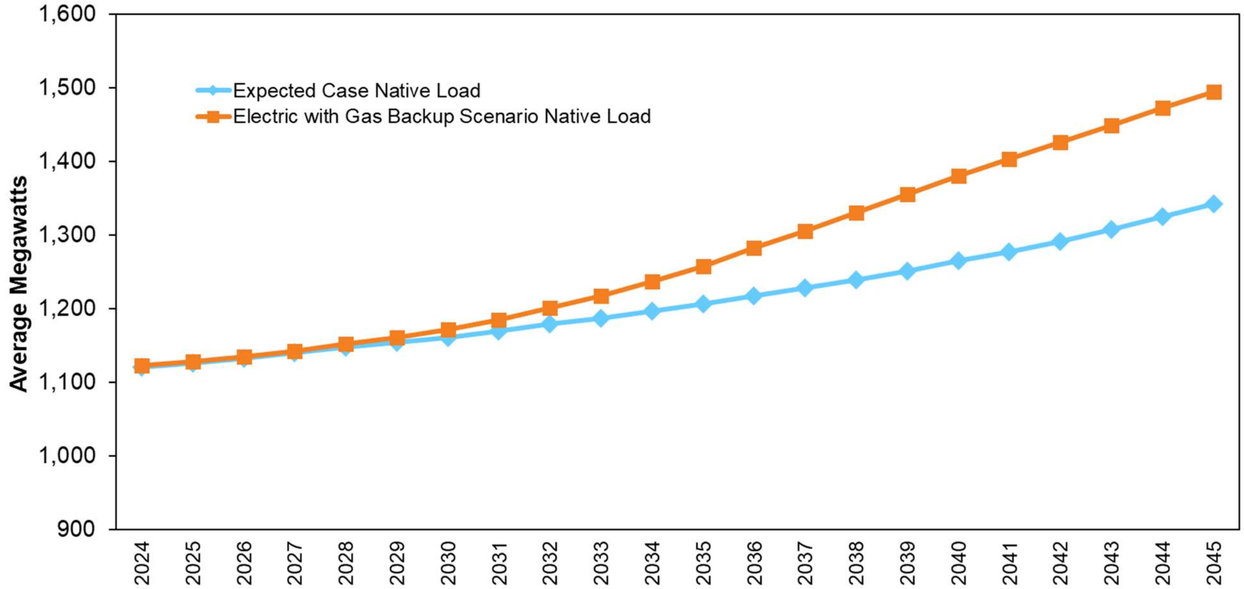


Figure 2.24: Hybrid Electrification – Winter Peak Impact

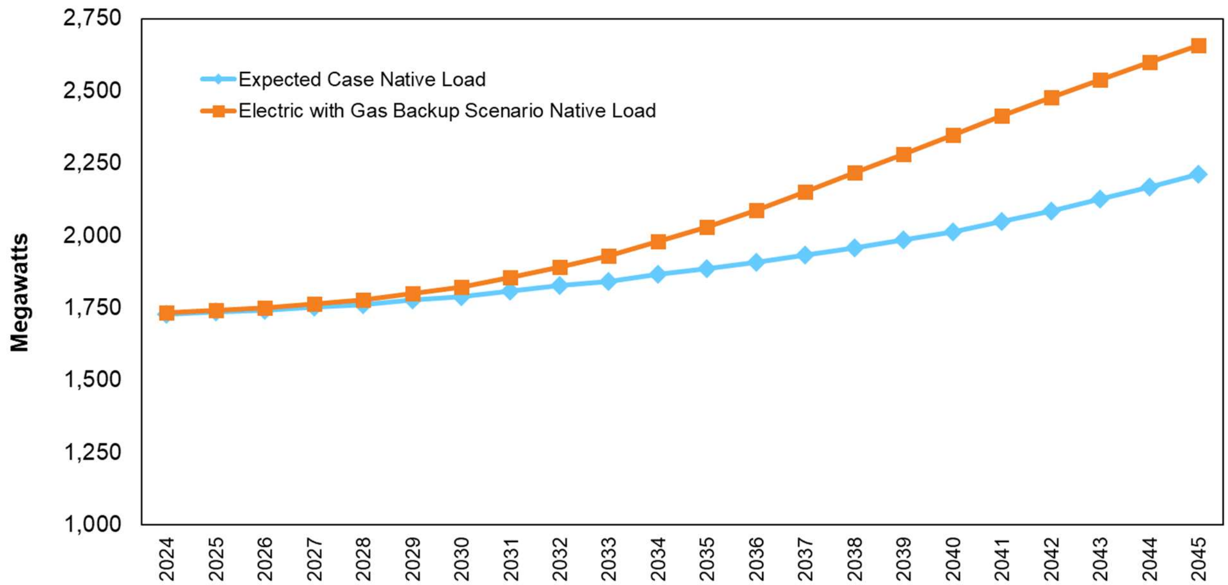
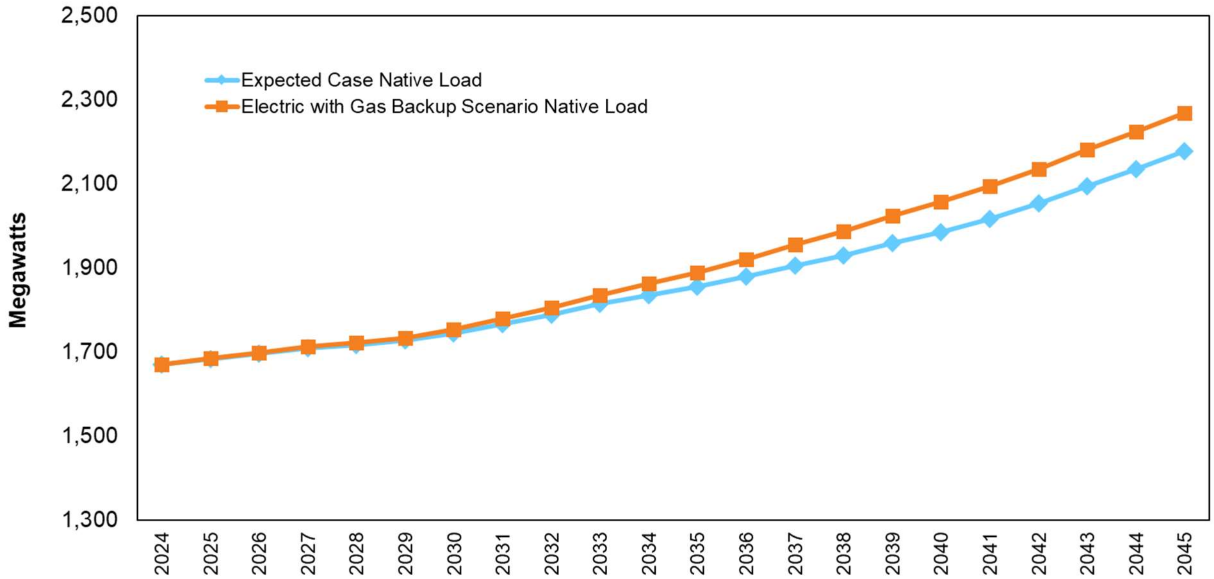


Figure 2.25: Hybrid Electrification – Summer Peak Impact



High Electric Vehicle Adoption

In this scenario, the Expected Case is altered by only changing the assumption of the accumulation of light and medium duty EVs. Table 2.7 shows the change in assumption between the Expected Case and the scenario. The 2050 date is used because this is the year frequently quoted as the goal-year for state-level policy statements regarding EV targets as a percent of sales. For example, along with several other states, Washington has a target of 2050 for LDVs to be 100% of new car sales.

Table 2.7: EV Percent of Sales Comparison between Expected and Scenario

Jurisdiction	LDV Expected Case, Percent of Vehicle Sales by 2050	LDV Scenario, Percent of Vehicle Sales by 2050	MDV Expected Case, Percent of Vehicle Sales by 2050	MDV Scenario, Percent of Vehicle Sales by 2050
Washington	50%	100%	50%	95%
Idaho	41%	75%	50%	75%

The results are shown in Figure 2.26-2.28. The first graph in the figure shows energy compared to the Expected Case, the second shows winter peak compared to the Expected Case; and the third shows the summer peak compared to the Expected Case.

Figure 2.26: High EV Adoption – Energy Impact

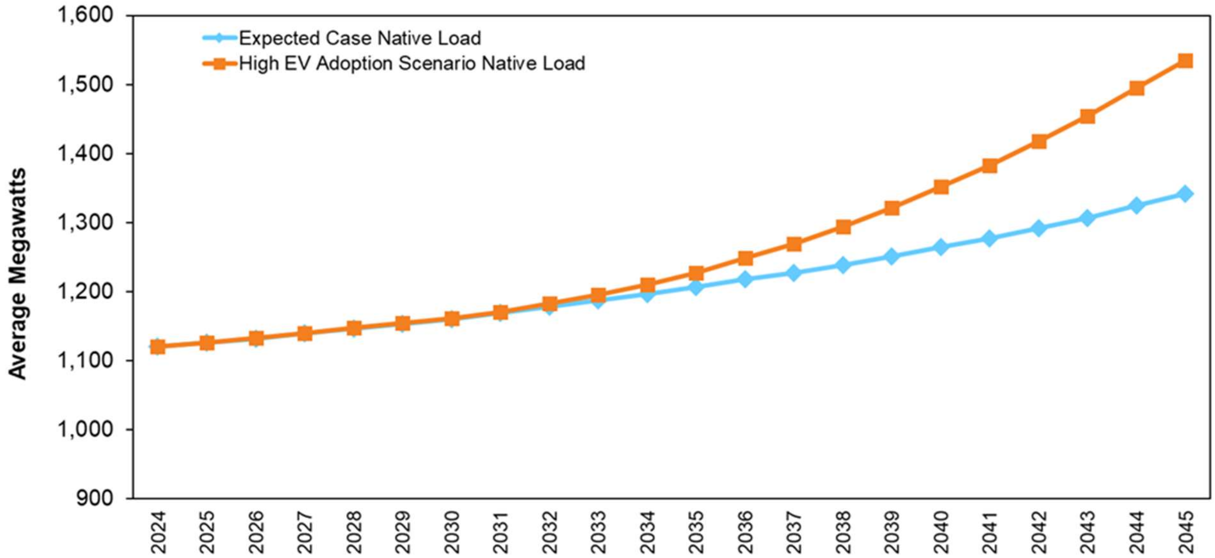


Figure 2.27: High EV Adoption – Winter Peak Impact

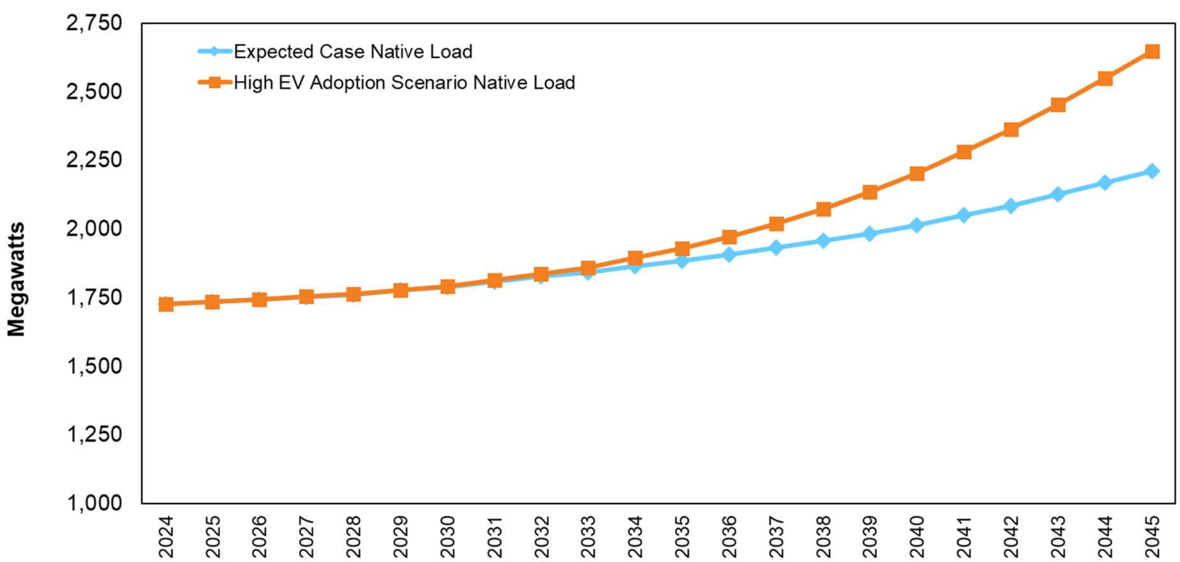
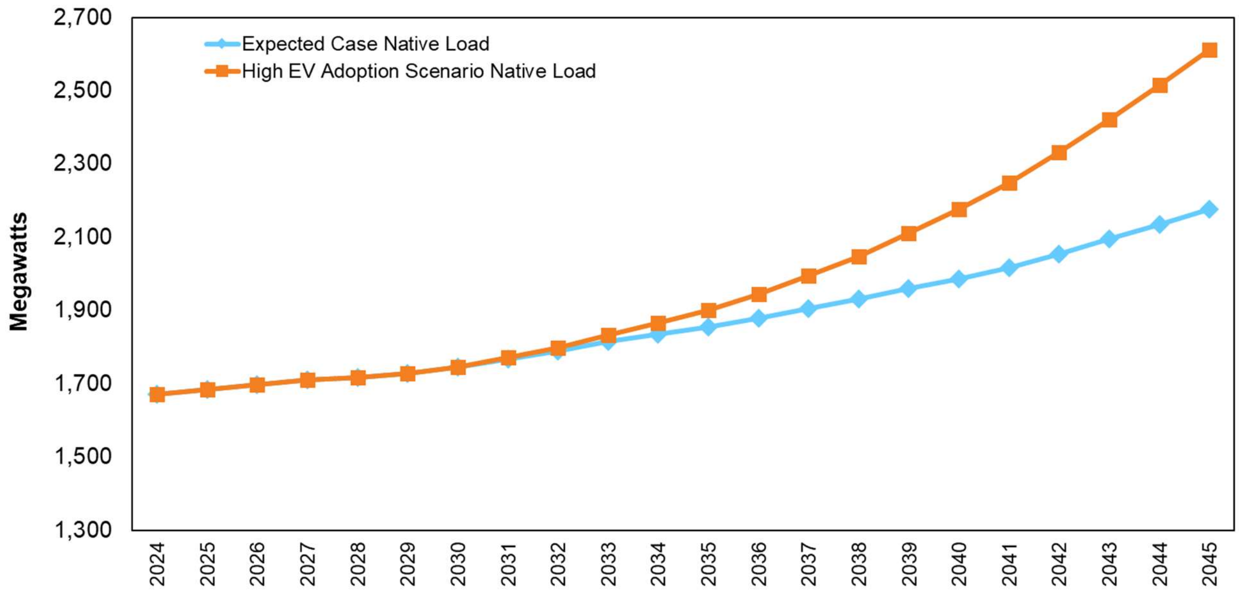


Figure 2.28: High EV Adoption – Summer Peak Impact



Washington Energy Transformation

In this scenario, the Expected Case is altered by using the scenarios for full electrification of buildings and high EV sales in conjunction with a more aggressive assumption of residential and solar penetration in Washington. The higher solar penetration is shown in Table 2.8.

Table 2.8: WA Solar Percent of Customer Comparison between Expected and Scenario

Jurisdiction	WA Residential Expected Case, Percent of Customers by 2045	WA Residential Scenario, Percent of Customers by 2045	WA Commercial Expected Case, Percent of Customers by 2045	WA Commercial Scenario, Percent of Customers by 2045
Washington	6%	20%	0.8%	5%

The results are shown in Figure 2.29-2.31. The first graph in the figure shows energy compared to the Expected Case, the second shows winter peak compared to the Expected Case; and the third shows the summer peak compared to the Expected Case.

Figure 2.29: Full Electrification and High EV and Solar Adoption – Energy Impact

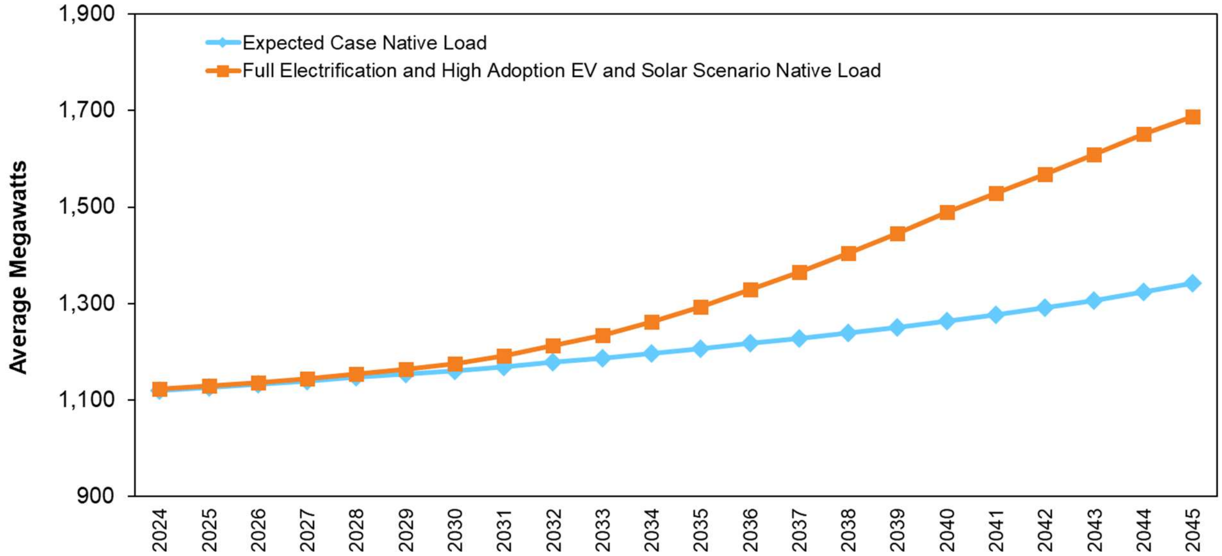


Figure 2.30: Full Electrification and High EV and Solar Adoption – Winter Peak Impact

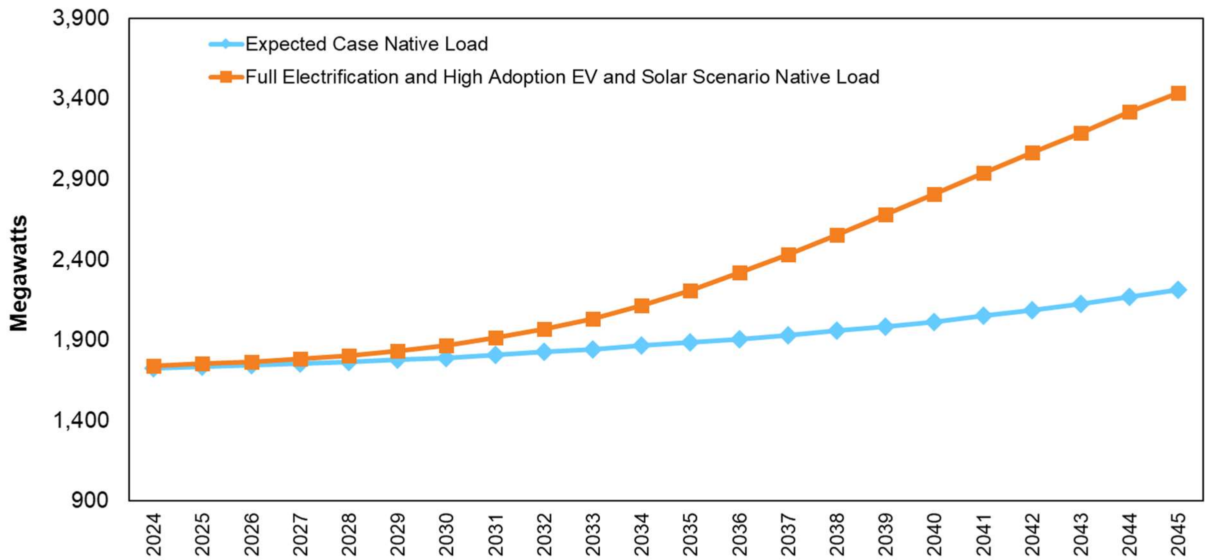
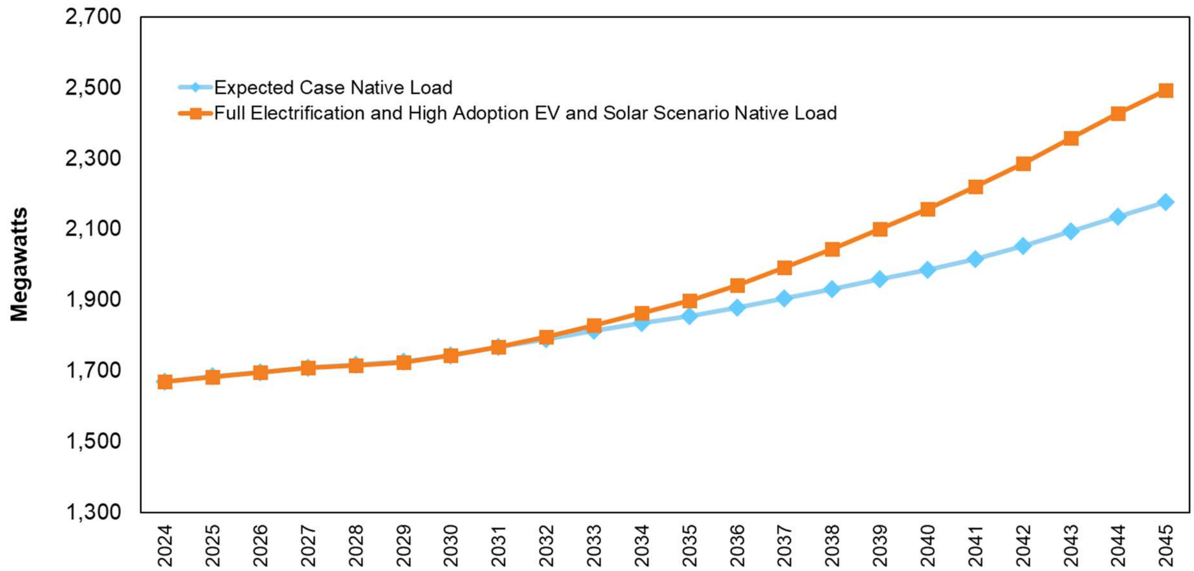


Figure 2.31: Full Electrification and High EV and Solar Adoption – Summer Peak Impact



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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.
- Avista agreed to transfer ownership of Colstrip 3 & 4 to Northwestern Energy on January 1, 2026.
- Recently signed hydro agreements with Chelan PUD and Columbia Basin Hydro are included within the plan.
- Avista plans to upgrade Kettle Falls Generating Station and Post Falls Hydroelectric Development.
- The Lancaster PPA is extended through 2041 as a result of the recent RFP process.

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%, followed by natural gas-fired resources at 37%. On an annual basis, natural gas-fired generation can produce more energy (45%) than hydro (31%) 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

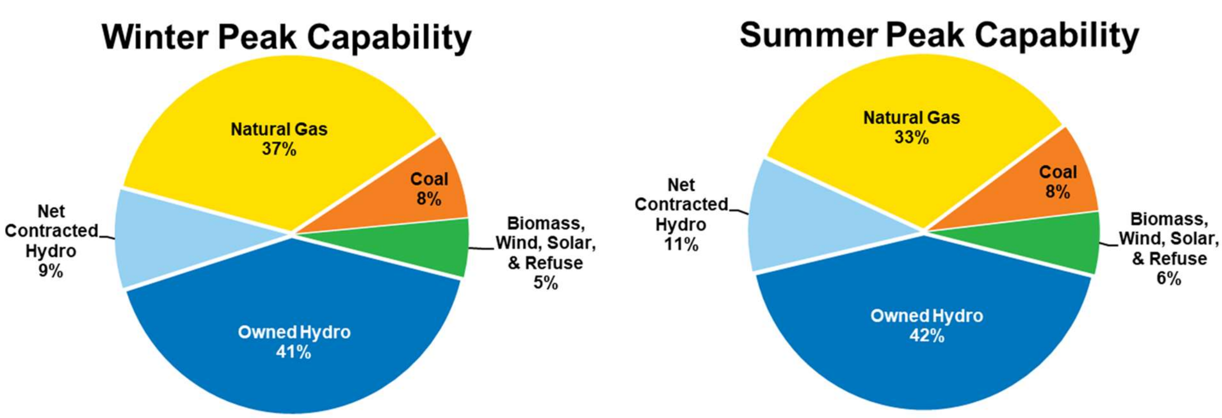
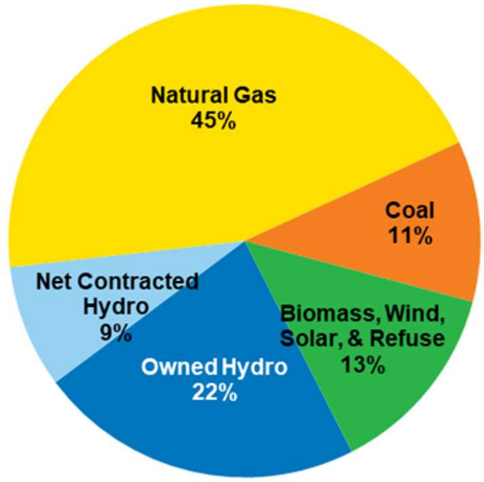
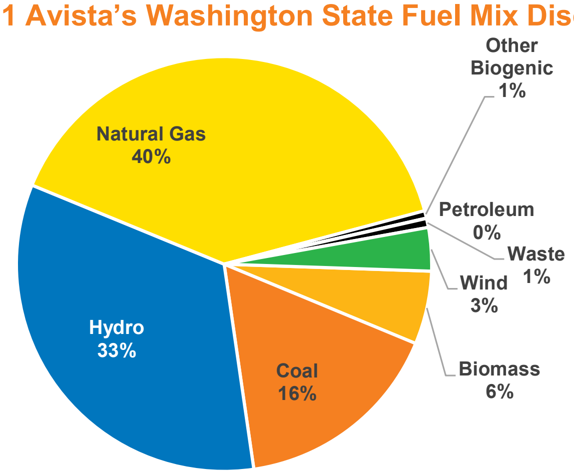


Figure 3.2: 2024 Annual Energy Capability



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, it also adds estimates for regional[2] unassigned market purchases and Avista-owned generation minus net renewable energy credit (REC) sales. Figure 3.3 shows the draft Avista's 2021 Fuel Mix Disclosure. The Idaho fuel mix is nearly identical to Washington's except for its allocation of Public Utility Regulatory Policies Act (PURPA) generation. Each state receives RECs based on their current authorized share of the system (approximately 65% Washington and 35% 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: 2021 Avista's Washington State Fuel Mix Disclosure



[1] 11A-Utility-Fuel-Mix-Market-Summary-23.5.2-1.pdf from Dep. of Commerce.
[2] For 2020, the region is approximately 55% hydroelectric, 13% natural gas, 11% unspecified, 10% coal, 4% nuclear, 5% wind and 1% 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 one 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 favorable operating conditions, although Avista uses 555 MW for planning purposes.

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.

[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. This may be adjusted for the next IRP with Colstrip leaving Avista's portfolio at the end of 2025.
[7] There is no remaining book life but there are seven years of remaining tax depreciation impacts to customers.

Energy moves across both segments of the transmission line under a long-term wheeling arrangement. Talen Montana, LLC operates the facilities on behalf of the six owners (see Table 3.4). Avista currently owns 15% 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 December 31, 2025, ownership of Colstrip will be transferred to Northwestern Energy and therefore will no longer serve Avista customers. NorthWestern will assume all of Avista's Colstrip ownership along with its related interest in the plant, plant equipment, rights, and obligations. Under the Agreement, Avista retains its existing remediation obligations and enters into a vote sharing agreement with NorthWestern to retain voting rights in regard to any decisions made with respect to remediation activities. In addition, while NorthWestern will have the right to exercise Avista's vote with respect to capital expenditures between now and 2025, the Agreement is structured such that Avista's contribution to those expenditures is limited to its pro rata share between the date of the expenditure and 2025, and to the least-cost alternative available, thereby ensuring that the costs directly benefit Avista customers and don't, in and of themselves, extend the life of the plant. The Agreement also preserves Avista's rights in the Colstrip transmission system.

Table 3.4: Current 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. 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.

Colstrip finished converting to dry ash storage in 2022. The master plan for site wide ash management is filed with the MDEQ-AOC[8] and additional information on CCRs is available at Talen's website[9]. 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.

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.

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[8] http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation.

[9] https://www.talenenergy.com/ccr-colstrip/.

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.[10] 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. A memo of understanding was signed with Myno Carbon ("Myno") who will provide Kettle Falls with steam from a biochar process. This steam adds 13 MW[11] 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.

[10] 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.

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

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 3.5: 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**

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.

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 3.6 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 3.6: Mid-Columbia Capacity and Energy Contracts[12]

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[13]	Oct-2018	Dec-2028	23.8	12.2	-6.2

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 3.7 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. This summer capacity solves the Avista's future summer capacity needs consequently, less solar is selected in the preferred resource strategy.

Table 3.7: 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**

[12] 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.
[13] 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 47 MW in exchange for 10% of the Wells project.

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 3.8 accumulating to 139.9 MW, but fully net metered from customer load are shown in Table 3.9 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 3.8: 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[14]	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	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 3.9: 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**

[14] Energy estimate is net of the City of Spokane's pumping load.

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.

The Lancaster resource was bid into Avista's 2022 All-Source RFP and was selected as a least cost resource through third-party evaluation. This agreement extends the existing agreement through December 31, 2041.

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.

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.

30-Year Wind PPA

In January 2023, Avista reached an agreement to acquire approximately 100 MW of wind energy through a 30-year purchase power agreement. Avista will provide more information once both parties agree to make the project public.

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% 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 3.10 describes Avista's other contractual rights and obligations.

Table 3.10: 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	2041	283.0	231.0	218.0
Palouse	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[15]	-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**

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 1,442,413 dekatherms per day based on the average of the top five historical natural gas burn days of 2019, 2022 and 2023, as shown in Table 3.11.

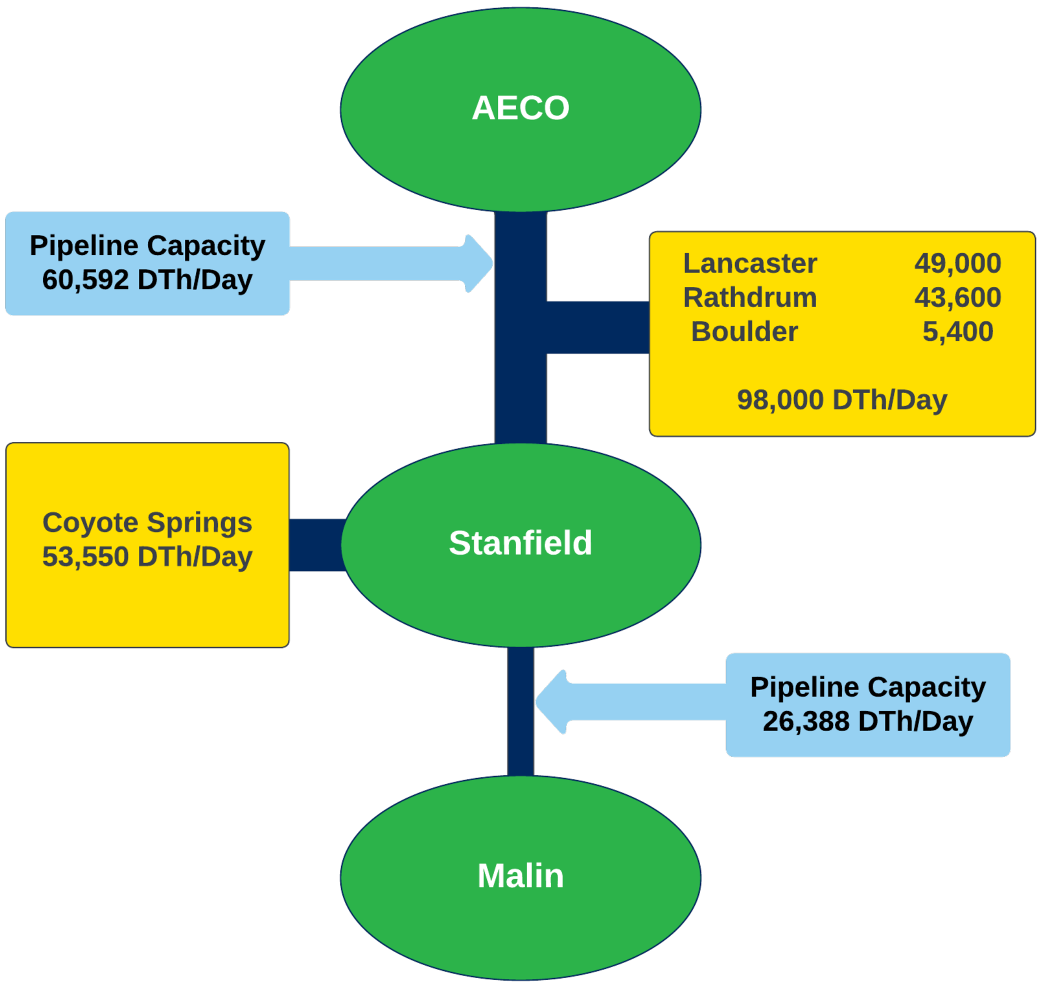
As discussed above, Avista does not have firm transportation rights for the entirety of its natural gas generation capacity. Avista relies on short-term transportation contracts to meet needs above Avista's firm contractual rights. Adequate surplus transportation has historically been available because 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.

[15] 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.

Table 3.11: Top Five Historical Peak Day 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
11/10/2022	5,401	50,371	46,700	40,305	142,777	60,592
12/21/2022	5,505	50,591	43,826	43,898	143,819	60,592
1/30/2023	4,571	51,567	48,206	44,441	148,785	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 3.12 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 3.12: 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. On May 11, 2023, the EPA issued draft rules regarding large stationary coal and natural gas fired resources. Avista is awaiting final rules prior to making any adjustments to its resource plan.

Climate Change - State Legislation and State Regulatory Activities

Washington State enacted Senate Bill 5116, CETA. As stated elsewhere in this IRP, 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% 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% 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% 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.

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 includes resources acquired from the 2022 All-Source Request for Proposals (RFP). Notwithstanding future resource changes, there are several fundamental changes to Loads & Resources (L&R) since the 2021 IRP. The following developments have occurred since the 2021 IRP:

- Additional long-term capacity and energy acquired from Chelan PUD, Columbia Basin Hydro, a 30-year wind Power Purchase Agreement (PPA), and plans to upgrade Kettle Falls Generating Station and Post Falls;
- The Lancaster PPA is extended through 2041;
- The Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP) entered the first stage of non-binding program implementation and its program metrics now guide some of Avista's resource adequacy planning;
- Future temperature changes are incorporated into Avista's base hydro and load forecast;
- 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 (CEIP) are approved.

Section Highlights

- Avista's Planning Reserve Margin requirement is 22% in the Winter and 13% in the summer until the WRAP is a binding program.
- Avista's first capacity and energy resource deficiency begins in January 2034.
- 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 Clean Energy Transformation Act (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% for predominately thermal systems and 10% for predominately hydro systems,[1] but does not provide an estimate for energy-limited hydro systems like Avista's.

In the prior IRPs, Avista used a planning reserve margin of 16% in the winter months and 7% in the summer months.[2] 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% of the simulations, or a 5% loss of load probability (LOLP). Avista then included operating reserves in addition per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 3% for balancing of area load and 3% 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% in the winter months and 15.6% in the summer months.

To align its planning reserve margin (PRM) with the WRAP methodologies, Avista simplified its approach for this IRP. First Avista now uses a 22% PRM in the winter and a 13% in the summer for this IRP. In addition to these values Avista also includes an adjustment to cover regulation and reserves for non Avista loads and resources within the balancing area. This amount equals approximately 21 MW in the winter and 20 MW in the summer and escalates with load growth. In addition to these changes to the PRM, Avista also is using the WRAP's methodology for resource capacity accounting, also known as Qualifying Capacity Credit (QCC). The combination of the new QCC values and the new PRM values effectively do not change the Avista planning requirements from the 2021 IRP net position. This is due to the QCC values for resources lowering the amount of capacity as compared to Avista's prior methodology.

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

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

[2] Excludes operating reserves and other flexibility requirements

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 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.[3]

To demonstrate compliance with the Forward Showing Program, participants must demonstrate its 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.

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

Table 4.1: Avista 2023 Summer and 2023-2024 Winter 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

Avista joined 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 (NPCC) is also evaluating the creation of new resource adequacy metrics beyond traditional Loss of Load Probability Expectation (LOLE). These metric covers frequency, duration, and magnitude of outages. Avista will follow this process to see if it should develop a metric beyond what is required in the WRAP.

Using the PRM and QCC methodologies previously discussed in this chapter, 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 2034 there is a winter capacity need and starting in 2036 there is a summer capacity need. The deficiencies increase over the planning horizon due to load growth, resource retirements and contract expirations.

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

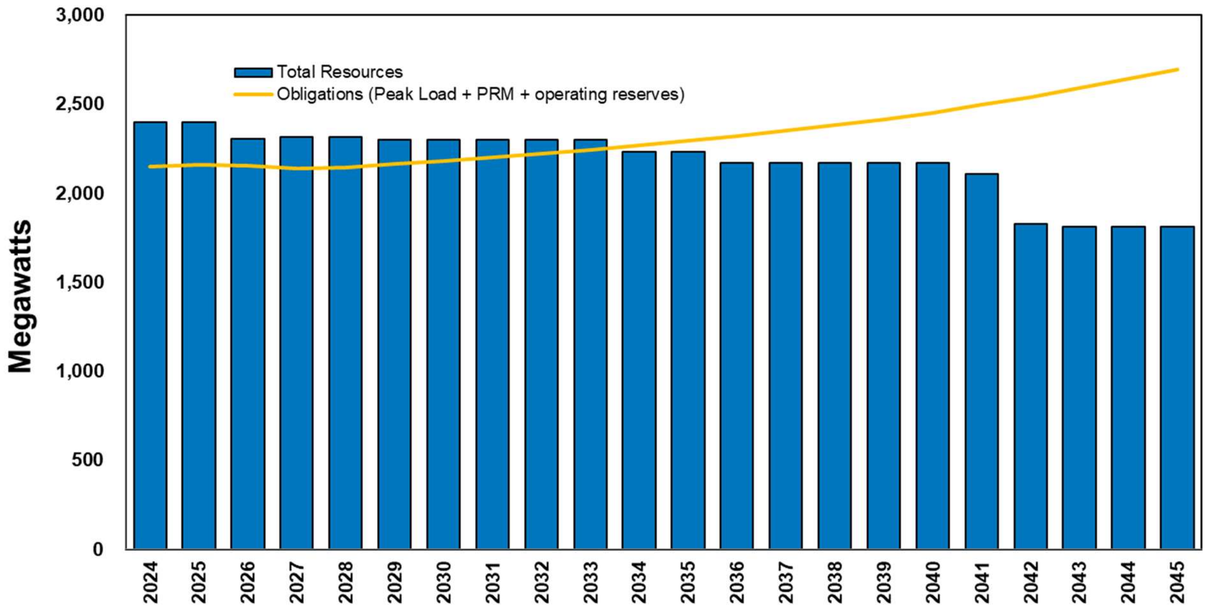
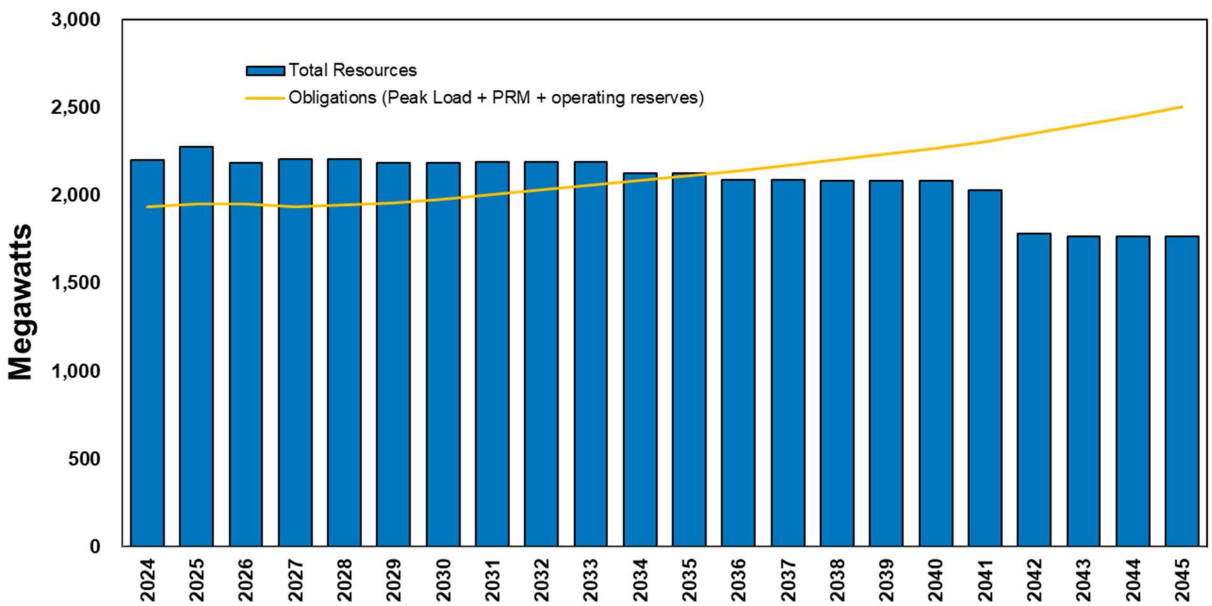


Figure 4.2: Summer One-Hour Peak Capacity Load and Resources Balance



Energy Requirements

In contrast to peak planning, energy planning determines the need based on customer demand with a time element. Avista evaluates energy planning on a monthly target basis for meeting customer demand, renewable targets, and evaluating generation risks. In previous IRP's Avista only monitored energy requirements on an annual average basis. Avista found this methodology worked in the past when traditional thermal unit such as natural gas generation was the resource choice in IRPs, but with a transition to renewable energy resources with differing energy delivery time periods, Avista is now using monthly energy requirements to ensure Avista do not acquire too much energy in certain periods such as spring and not enough in high load months such as August or January.

The monthly energy analysis requires additional steps beyond capacity planning to take into account what may happen to a resource's operations. 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 IRP 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.

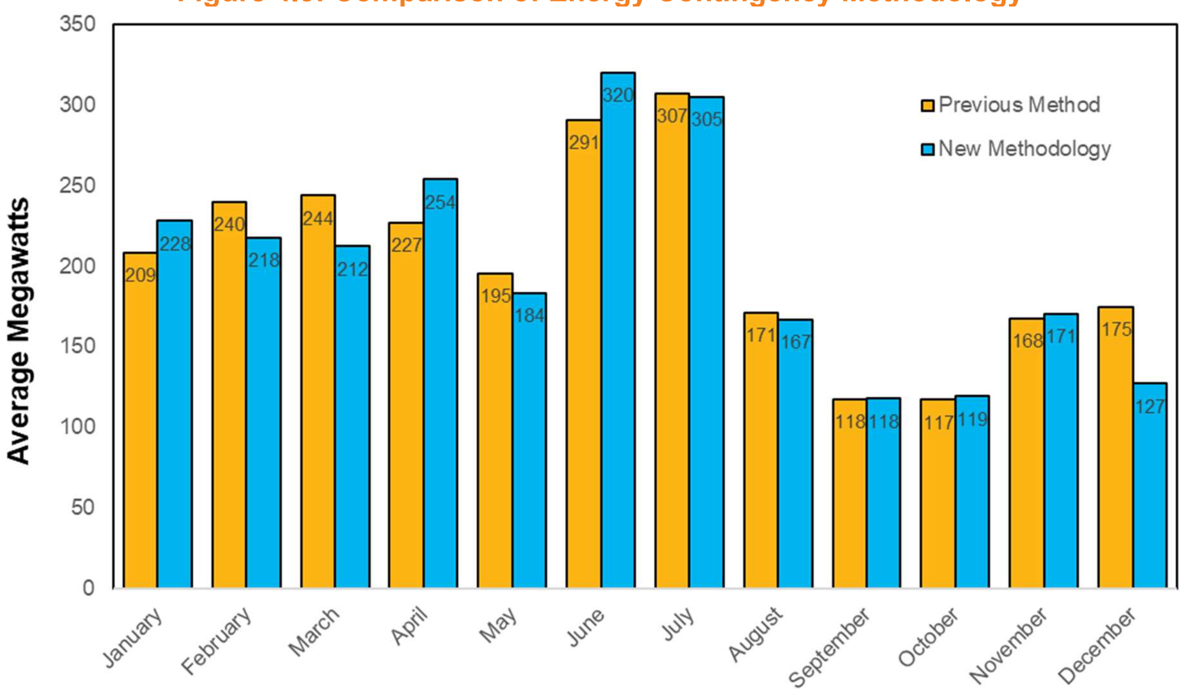
Energy Risk Evaluation

Energy planning is based on average conditions. The load forecast utilizes 20-year average weather while the hydro generation estimates are based on the median over a

30-year period. There is a risk the load can be larger and/or hydro generation 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% confidence interval added to the difference between monthly median hydro generation and the 10th percentile hydro generation. A new methodology is 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 95th 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. Table 4.3 presents net monthly energy positions for 2025, 2030, 2035, 2040, and 2045.

Table 4.3: Net Energy Position

Month	2025	2030	2035	2040	2045
January	218	109	35	-3	-829
February	216	76	27	-26	-823
March	375	260	210	168	-603
April	551	427	360	311	-326
May	691	604	540	486	-17
June	737	621	540	447	-175
July	395	240	200	104	-672
August	266	135	59	-8	-766
September	339	222	176	135	-603
October	346	218	148	81	-677
November	261	116	27	-20	-818
December	297	147	69	-17	-851

Forecasted Temperature & Precipitation Analysis

Projected temperature increases will impact hydro generation, 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 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 model 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 4.4 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 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.

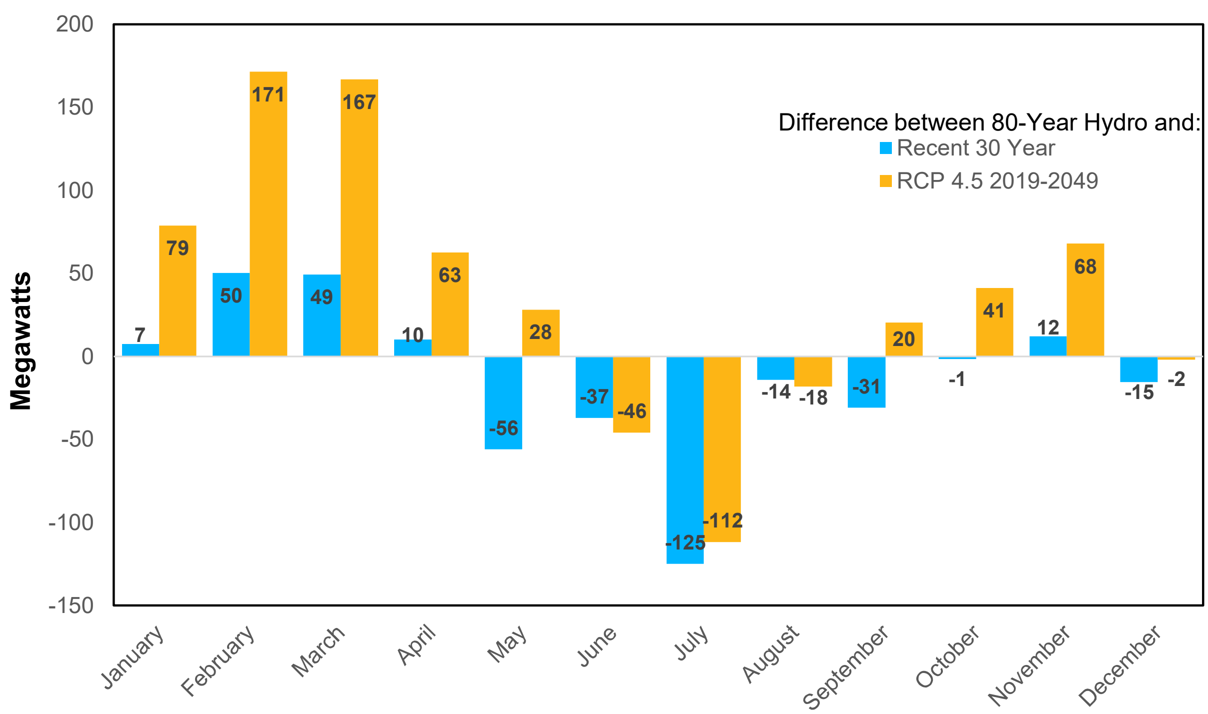
Prior IRPs used monthly hydrogeneration by estimating hydrogeneration occurring under current operating parameters for each water year from 1929 to 2008 (80-year hydro record) and taking the median value for each month for each facility. In this analysis, Avista changed the methodology to use the median 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 4.4 present the differences between the 80-year hydro record, the recent 30-year record resulting from the RCP 4.5 analysis. Annual hydro generation is similar between the 80-year hydro record and recent 30-year record, as it is projected warming temperatures will increase annual hydro generation. On a monthly basis there is an increase in hydro generation 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 snow fall and an earlier snow pact melt.

Table 4.5: 80-Year, Recent 30-Year, and RCP 4.5 Hydro Generation Forecast Comparison

	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

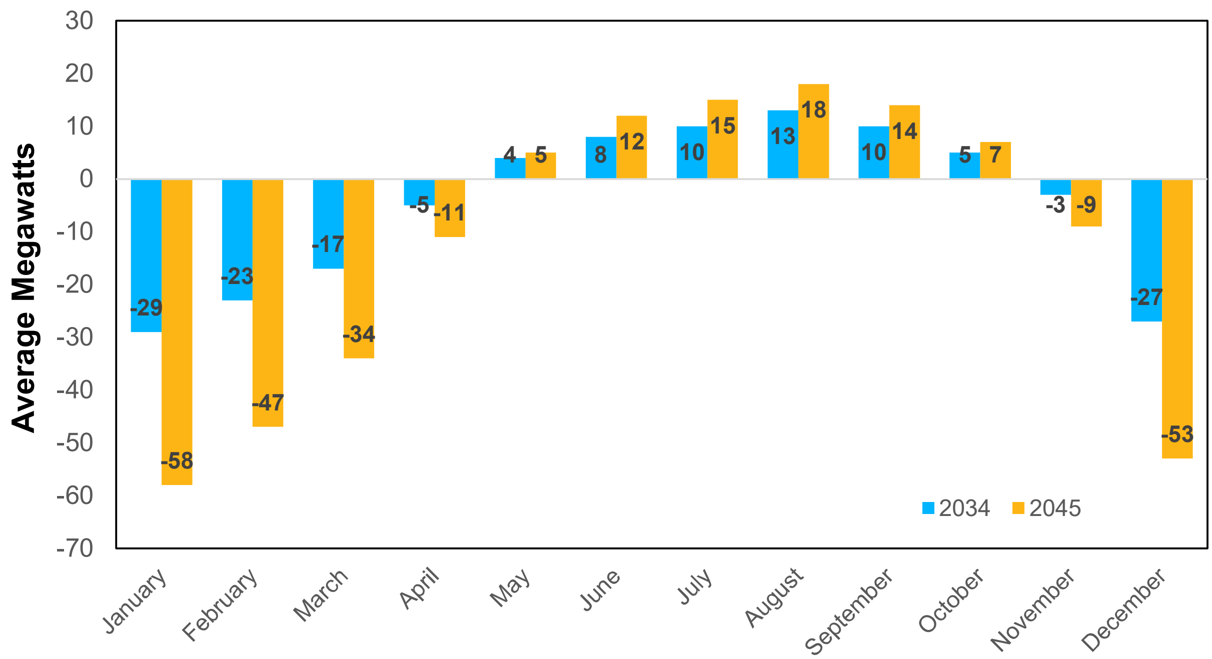
Figure 4.4: Comparison of Recent 80-Year, Recent 30-Year, and RCP 4.5 Generation



In addition to impacting hydro generation, 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 and are 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 4.5 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 4.5: 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[4] projects and both qualify for EIA and Clean Energy Transformation Act (CETA) compliance. The 30-year wind PPA acquisition and planned upgrades to the Kettle Falls Generating Station project in 2026 and Post Falls in 2029 will add additional qualified generation.

Table 4.6 shows the forecasted renewable energy credits (RECs)[5] 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 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
30-year Wind PPA[6]	-	-	41.9
Net Renewable Position (before rollover RECs)	**62.3**	**59.3**	**117.8**

[4] Adams Nielson can be used for the EIA after the voluntary Solar Select program ends in 2028.
[5] These RECs are qualifying RECs within Avista's system. For state compliance purposes Avista may transfer RECs between a state's allocation shares at market prices. Avista may also sell excess RECs to reduce customer rates.
[6] Online 1/1/2026, however, there is an option be on-line earlier.

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 is assumed to decrease in five percent steps to zero by 2045 in this plan.

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 incomplete, Avista through its Clean Energy Implementation Plan (CEIP), has compliance targets approved by the WUTC for the period 2023-2025. 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 2026-2029 or 2030-2044 periods. 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 Target Assumpions

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 4.6.

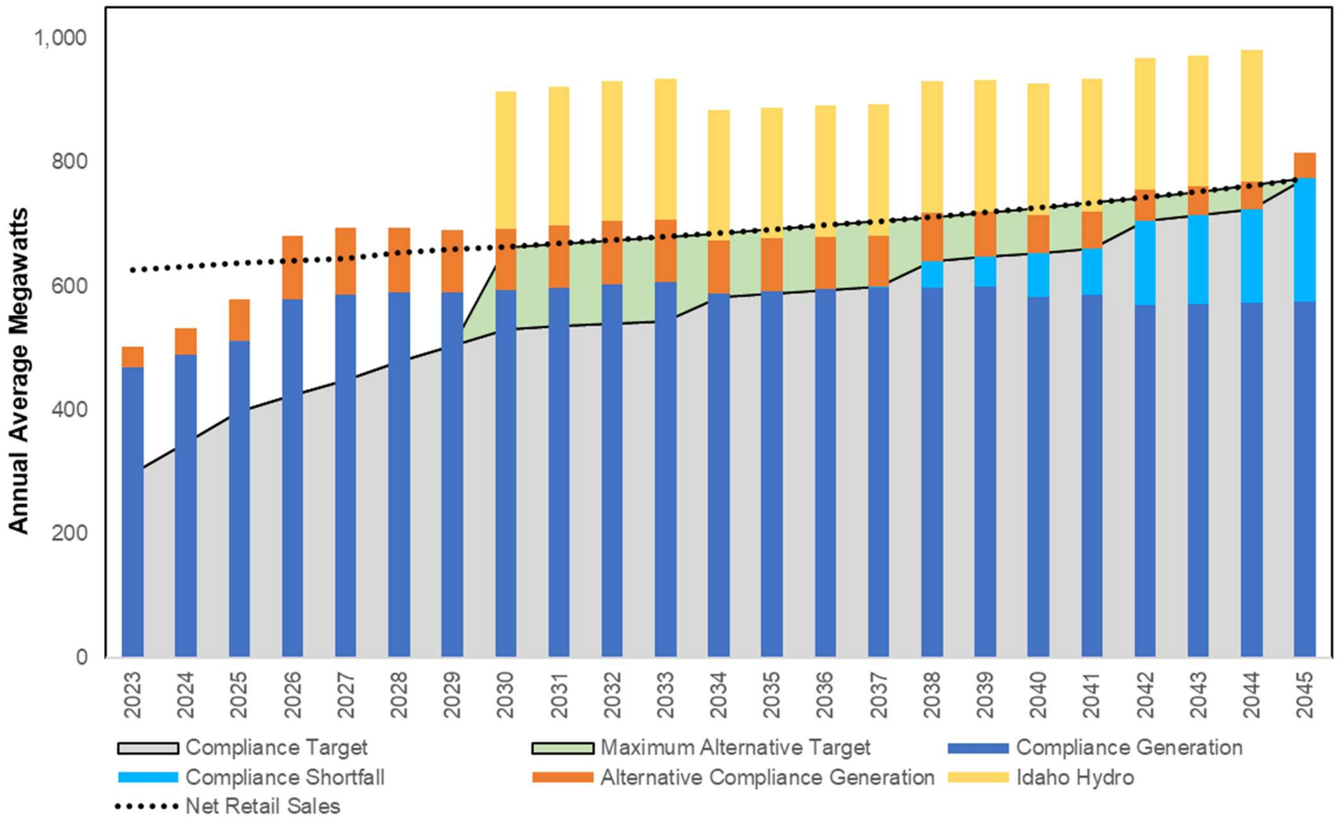
- Qualifying clean energy is determined by procurement and delivery of energy to Avista's system.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary customer programs such as Solar Select.
- Voluntary customer REC programs, such as Avista's My Clean Energy™ program, do not qualify toward the CETA standard.
- Compliant compliance generation includes:
    - Washington's share of hydro generation operating or contracted before 2022 (legacy hydro),
    - All wind, solar, and biomass generation with Avista portfolio. Nonpower attributes associated with Idaho's portion of generation according to the established production transmission (PT) ratio will be purchased by Washington at market rates if used for compliance,
    - New acquired (post 2019) 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 is not planning to use Idaho's share of legacy hydroelectric prior to 2030, however actual compliance may include them due to variability in clean resource availability (e.g., for a low water year). Avista includes these hydro resources toward alternative compliance if it is economic to acquire the renewable energy attributes.
- 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 4.6. The analysis demonstrates Avista has enough qualifying resources to meet compliance targets through 2033 using this methodology.

2045 Planning

This IRP plans to a monthly energy target for CETA compliance, including 2045. Given direction to plan for 100% clean energy in 2045, Avista seeks additional guidance on how to plan for this future. For example, should utilities plan to be 100% clean energy in all future conditions, thus requiring additional generation capacity and energy. How will market transactions be treated (i.e. how will we know if clean energy is available on a short hour or know how unspecified power will be treated) or should the utility plan on being an energy island with high planning margins and energy risk adders? While there are other issues likely develop, Avista requests guidance from the WUTC on these issues.

Figure 4.6: Washington State CETA Compliance Position



Resource Adequacy Risk Assessment

Future planning of resource adequacy requires consideration of many risks. Avista is utilizing the risks identified by the November 2020 paper *Implications of Regional Resource Adequacy Program on Utility Integrated Resource Planning*[7] as a framework to present how Avista manages these risks. While Avista's current resource deficit is projected for the mid-2030s, the risks outlined below will impact the ultimate resource need.

Peak Demand Forecast

Avista uses a 1-in-2 peak load forecast, meaning half of the time the load will be above and half the time load will be below the peak forecast. The forecast is based on historical and forecasted future weather conditions. While weather is considered in the unknown nature of future loads, there are also other load risks Avista considers in scenario analysis specifically related to electrification. Avista developed several potential outcomes of building and transportation electrification to understand potential impacts. The load forecast scenarios are discussed in Chapter 2 and the resource strategies to solve higher load is within Chapter 10.

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[7] Implications of a regional resource adequacy program on utility integrated resource planning https://www.westernenergyboard.org/wp-content/uploads/11-2020-LBNL-WIEB-regional-resource-adequency-and-utility-integrated-resource-planning-final-paper.pdf.

Since the last IRP, Avista is participating in the currently non-binding development of the Western Resource Adequacy Program (WRAP) with the intent of leveraging the diversity of regional loads and generation across the WECC. This enables individual utilities to reduce the need to carry the full burden of supplying for adequate capacity for their systems. During this non-binding interim as Avista transitions to WRAP methodology, a hybrid approach is being used for capacity planning. This approach incorporates the 2021 PRMs for summer and winter periods but uses the WRAP's Qualifying Capacity Credit (QCCs) values assigned by the WRAP's forward showing program.

Demand-Side Resource Contribution

Avista includes demand-side resources as options when determining the amount and type of resources needed to meet future demand, but demand side resources may also impact the net demand of the system prior to this inclusion- such as customer adoption. Chapter 5 discusses each of the distributed energy resource (DER) option included in the IRP, including energy efficiency, demand response, and distributed generation/energy storage.

The focus of DER modeling within the IRP is to ensure supply side resources are not over built. For example, roof top solar may reduce Avista's summer energy needs, but have limited impact on winter loads. To address this risk, Avista includes an estimate of incremental customer owned generation in its load forecast and includes scenario analysis to understand impacts at higher levels. The greatest risk to uncertainty regarding demand-side resources is whether they will impact winter peak load requirements and given today, most additions are solar, this risk is low. If customers begin to install a winter load impacting resources, Avista will need to reconsider the risk at that time.

Power Plant Retirement

Since the last IRP, Avista has announced that it will transfer ownership of its share of Colstrip end of December 2025. Avista also plans for plant retirements for each of its existing natural gas peaking generators and has proposed end dates for its Combined Cycle combustion turbines (CTs). This resource adequacy risk in this IRP is whether the resources do not operate until the proposed end date. Avista does see this risk for two of its plants; Northeast and Kettle Falls CT. Although Avista's capacity length compared to its load can withstand the capacity loss of these two facilities from a reliability perspective.

Renewable Contribution

Increasing renewable penetration will impact the reliability of the power system if utilities estimate their contributions too high. Avista found in the 2021 IRP it needed additional resources to maintain the 5 percent LOLP when relying on renewable resources to meet its peak loads. This IRP utilizes QCC values from the WRAP to identify the contributing capacity for variable energy resources (VERs), although Avista identifies significant risk associated with relying on VERs and uses a declining QCC value for these resources in this IRP (see Chapter 6) to protect against over reliance on these resources for resource adequacy. Avista also uses declining QCC values for energy storage resources as well. Avista anticipates understanding QCC values in high renewable penetration scenarios will be estimated by the WRAP in the future. Lastly, Avista did conduct a scenario analysis to understand how the portfolio may change with higher levels of QCC values for these same resources.

Storage Efficiency

Avista sees two risks for storage efficiency. The first risk is similar to the renewable QCC contribution described above where short duration resources may help reliability in small increments, but the reliability benefit is reduced as more storage is added to the system due to the need to recharge the storage device after use. The second risk of energy storage is the efficiency to recharge the device. Not all storage technologies have the same recharging capability based on energy losses and time to recharge; therefore, each of these considerations should be included in determining each device's credit toward meeting peak demand.

Avista's resource strategy includes new energy storage technologies using renewable fuels, such as green hydrogen and/or ammonia. These technologies protect against declining efficiencies found in today's battery technology and offer longer durations periods. But these resources have other risks including technology risk (these are new and relatively unproven in large scale) and they require significant energy to produce the fuel whereas the round trip efficiency is 20 to 25 percent.

Market Availability

In previous IRPs, Avista found market availability to be the greatest risk in resource adequacy absent a resource adequacy market or program. Avista's previous resource adequacy studies developed resource strategies to not exceed 330 MW of market reliance. With development of the Western Power Pool's WRAP program and once operational with binding requirements, Avista will likely increase its market reliance threshold by adopting lower PRM values compared to those used today. Avista is confident this market reliance is acceptable due to the fact by participating in the program enforces all utilities to procure adequate capacity to ensure the greater system is reliable to allow utilities to rely on each other when one may have higher loads.

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5. Distributed Energy Resources

Prior IRPs included Distributed Energy Resources (DERs); however the documentation had been placed 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% 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.

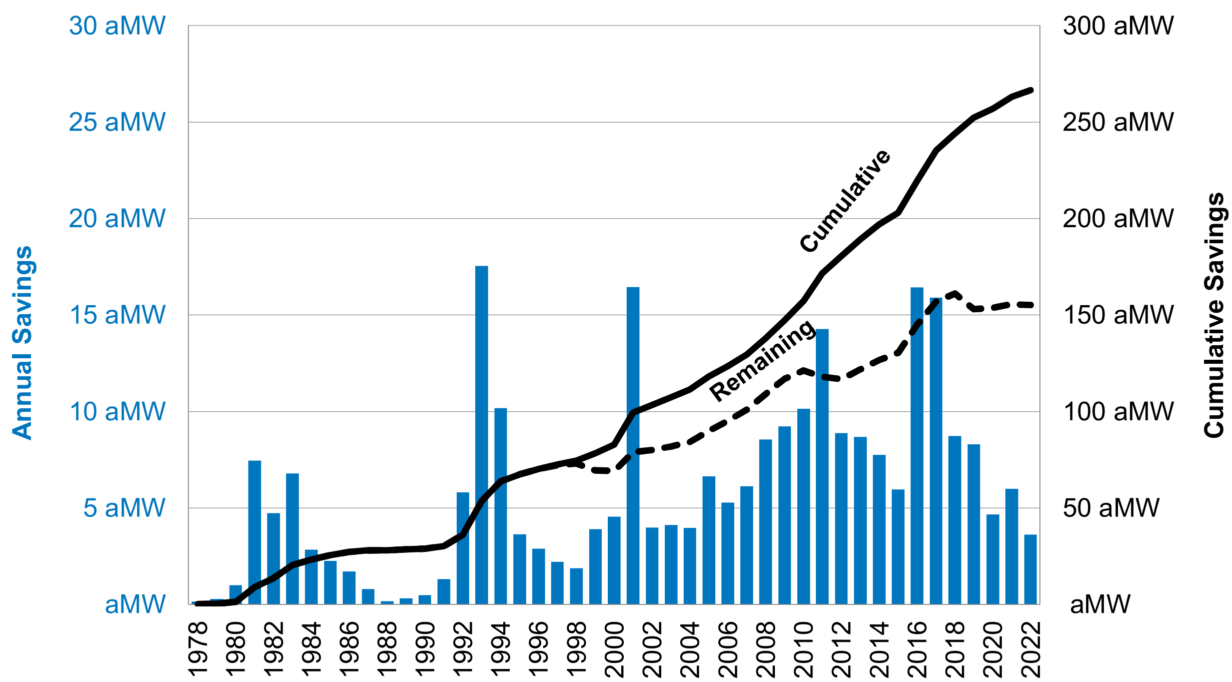
Energy Efficiency

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 11.2 percent of 2022 customer 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)

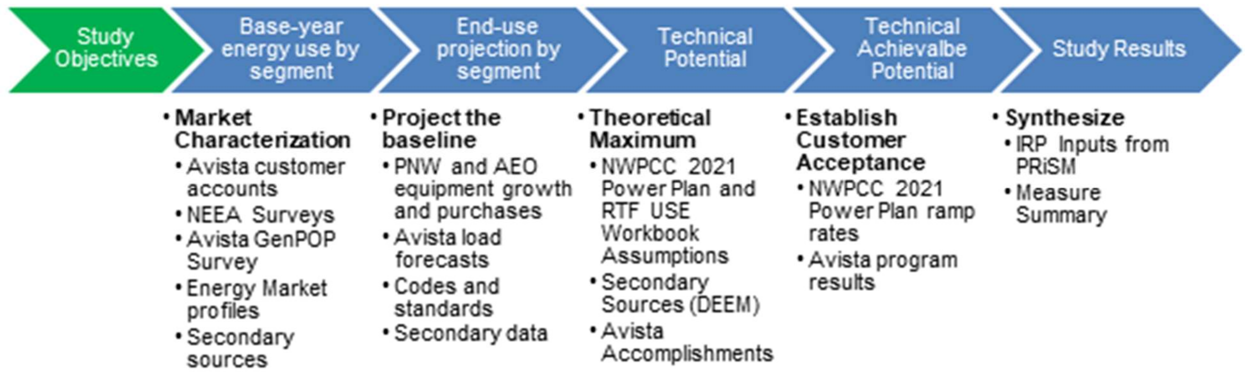


The Conservation Potential Assessment

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 for Washington customers only.

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.

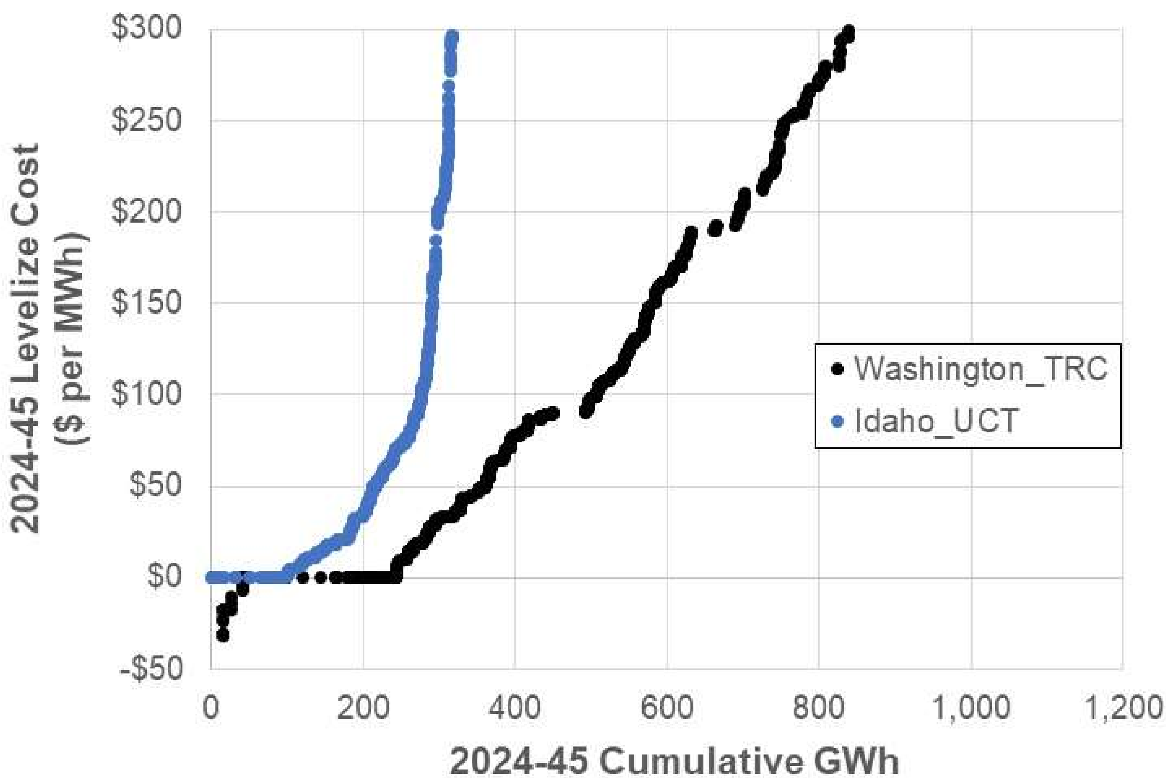
[2] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan.

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 cost using the Utility Cost Test (UCT) method 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 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 or 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.

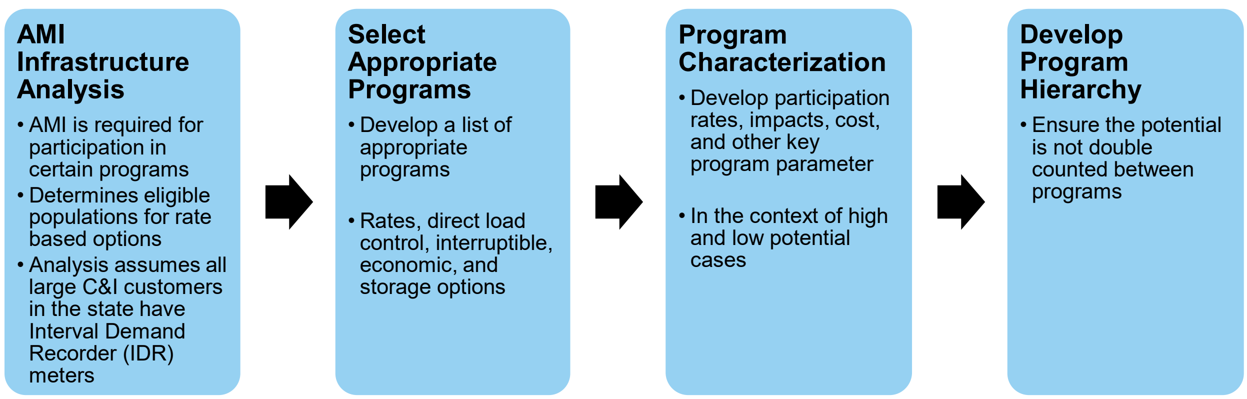
[5] https://www.smartgrid.gov/files/OE0000190_Battelle_FinalRep_2015_06.pdf.

[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 2024 and a three-year ramp rate for full deployment, finishing in 2027.

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.

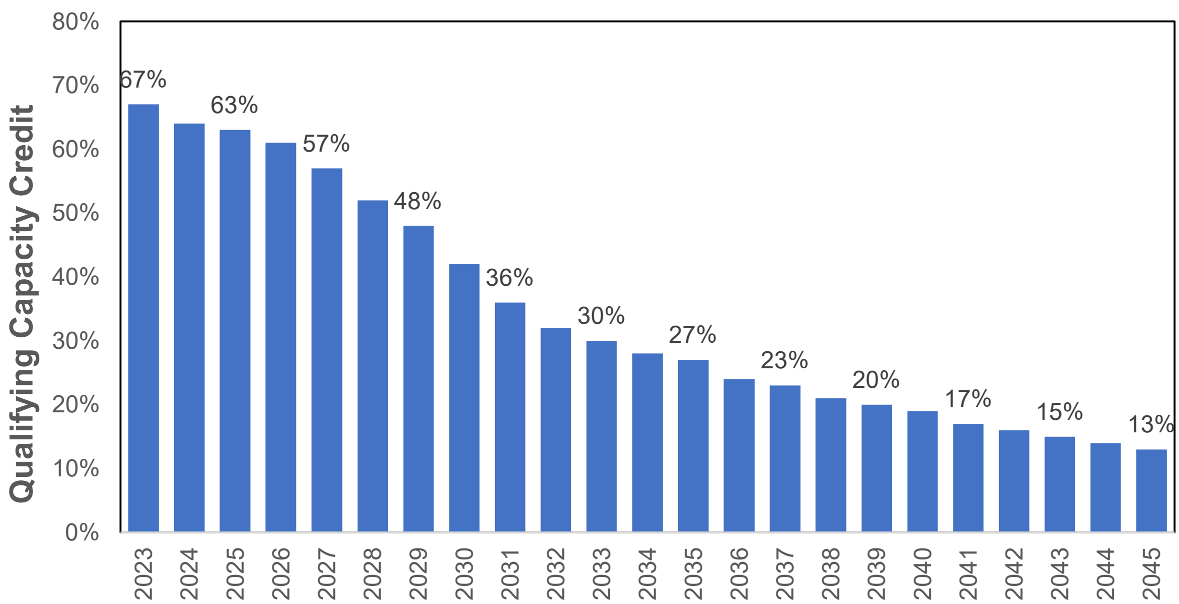
Table 5.4: System Program Cost and Potential

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 8 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

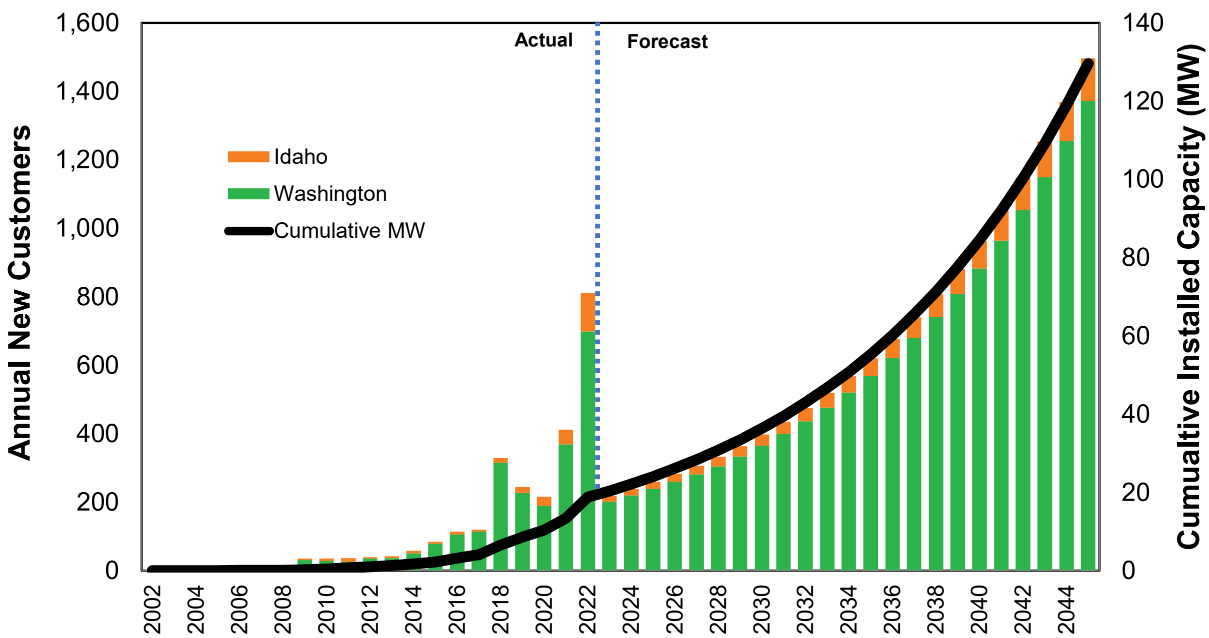


Distributed Generation Resources

Customer-Owned Generation

Avista has 2,602 customer-installed net-metered generation projects on its system as of 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 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

[9] The 2022 results are through September.

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	22.91	40.28
New res. building solar	6 (17 sites)	148	323	-	-
New res. building solar with storage	6 (17 sites)	148	323	21.61	37.72
Com. building solar	200	124	186	-	-
Com. building solar with storage	200	124	186	26.49	39.06
Utility owned solar array	100	63	65	-	-
Utility owned solar array with storage	100	63	65	14.20	16.35
Stand-alone energy storage (4hr)	500	-	-	15.55	18.92
Stand-alone energy storage (8hr)	500	-	-	27.58	32.25
Low-income Community Solar Program	100	25	n/a	-	-

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

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.

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.

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

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

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 (Applied Energy Group) with experience conducting such an analysis. 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 5.8: 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 IRP 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 $1,315 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.

[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	101.8	48.3	180
7F .04 CT Frame Greenfield (Washington)	62.3	104.3	50.0	
Reciprocating Engine (ICE) Machine (Idaho)	61.5	152.4	43.6	185
Reciprocating Engine (ICE) Machine (Washington)	63.4	156.2	45.0	
NG CCCT (1x1 w/DF) (Idaho)	57.6	183.3	36.1	312
NG CCCT (1x1 w/DF) (Washington)	59.2	187.1	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)	822	5.2	10,040	3.10	180	155
7F .04 CT Frame Greenfield (Washington)	845					159
Reciprocating Engine (ICE) Machine (Idaho)	1,315	5.2	8,190	5.93	185	244
Reciprocating Engine (ICE) Machine (Washington)	1,349					251
NG CCCT (1x1 w/DF) (Idaho)	1,315	30.5	6,820	4.75	312	410
NG CCCT (1x1 w/DF) (Washington)	1,349					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.

[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	1,201	1,460	1,649	5,535
2030	1,026	1,283	1,494	5,697
2035	1,092	1,359	1,594	6,021
2040	1,161	1,435	1,697	6,447
2045	1,231	1,512	1,804	6,954

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	33.51	42.35	32.69	124.42
2030	20.17	30.64	23.07	120.87
2035	43.81	60.80	53.59	151.69
2040	44.30	59.99	53.59	155.03
2045	43.89	57.17	52.08	157.64

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	13.5	8.6	4.8
2040	13.7	8.8	4.8
2045	13.7	8.8	4.6

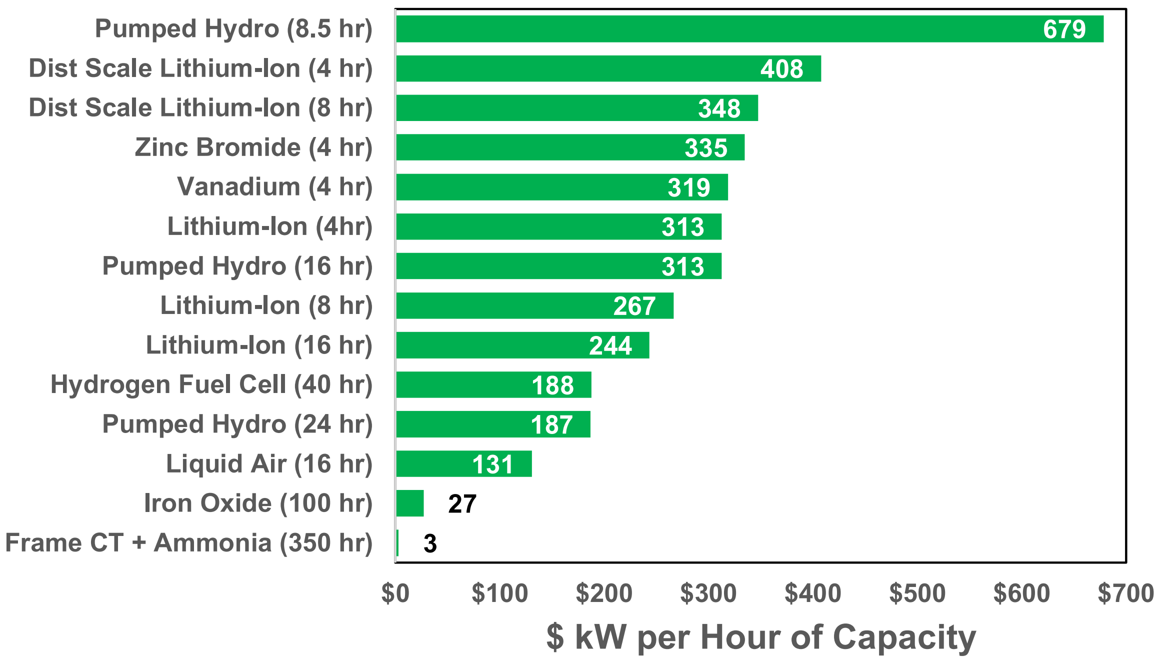
Stand-Alone Energy Storage

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	45.66	39.89	36.03
2030	50.94	44.50	40.20
2035	56.80	49.62	44.82
2040	63.33	55.32	49.97
2045	70.61	61.68	55.71

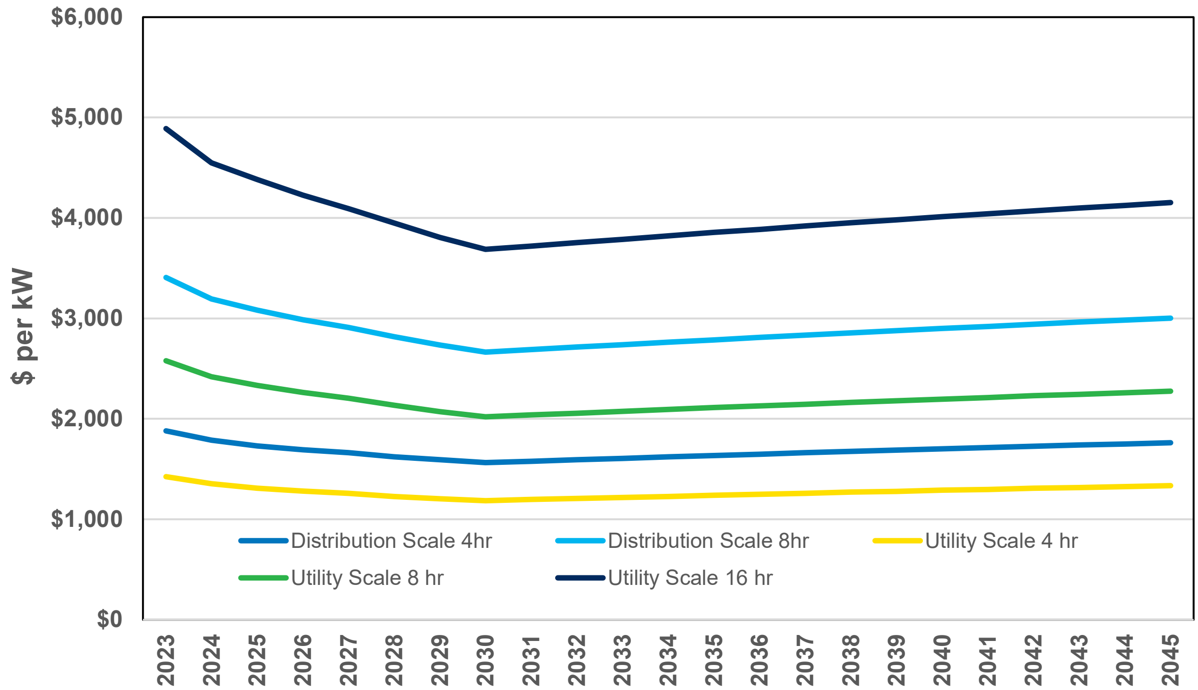
Lithium-Ion Batteries

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	11.57	20.47	38.26
2030	10.74	18.31	33.44
2035	14.82	24.67	45.07
2040	15.05	24.69	45.09
2045	14.99	24.23	44.25

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 $14.40 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 $248.21 per kW ($20.68 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: Storage Levelized Cost ($kW-Month)

Year	Vanadium	Zinc Bromide	Iron Oxide	Liquid Air
2025	15.91	17.23	20.91	15.06
2030	16.05	17.43	21.44	16.80
2035	19.92	21.56	29.68	25.30
2040	20.85	22.62	30.35	28.20
2045	21.88	23.78	31.07	31.45

Renewable "Green" Hydrogen

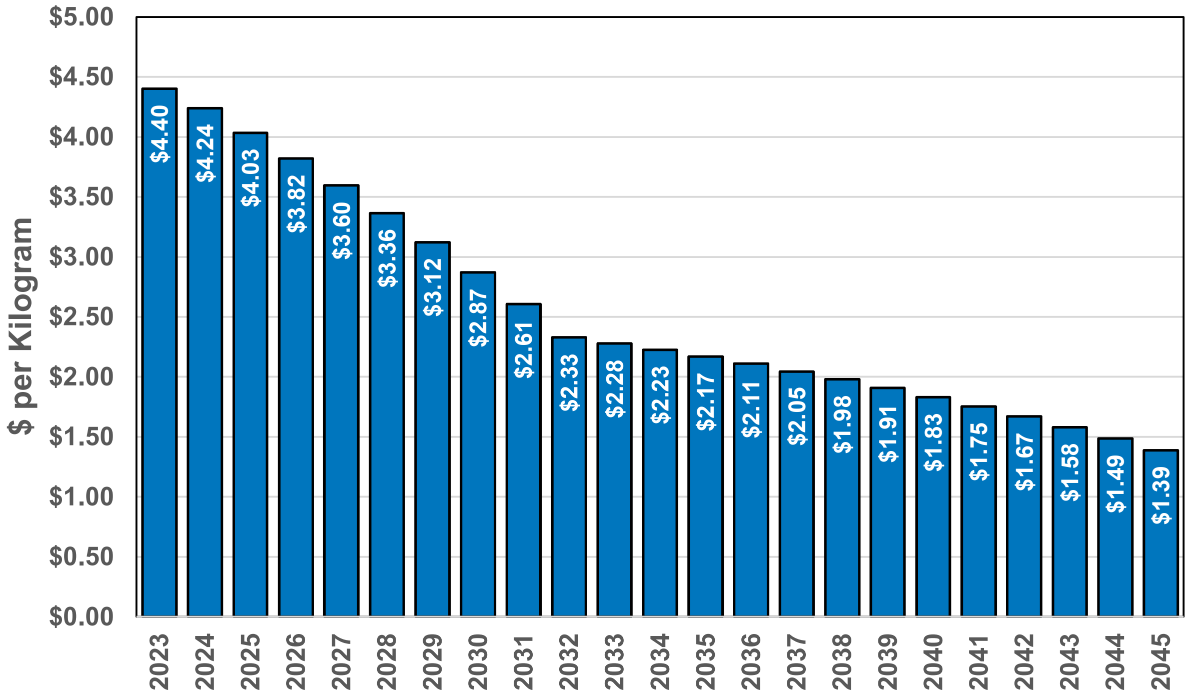
The idea of using green hydrogen using renewable energy to power an electrolyzer in the energy sector has been a perennial option for the distant future. This technology is an avenue for long-duration energy storage with the potential to store power to continuously run for up to several days. Hydrogen would be delivered by pipeline, truck, or rail and stored in tanks or underground caverns 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[7], 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.

[7] Current estimates require 2-3 gallons of water to create 1 kilogram of hydrogen.

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. Avista chose to use a fuel cell for hydrogen fuel rather then a CT, to allow for an air emission free resource and due to the likely limitations of storing the fuel required to operate a CT.

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[8]. Ammonia could be sourced from the same electrolysis process as green hydrogen, using either directly from a renewable energy source or from grid power and then can be transported and stored on the generation site similar the hydrogen fuel option above. Although, ammonia requires an additional step to the hydrogen process by adding nitrogen to hydrogen using the Haber-Bosch process. Current estimates taking into account the hydrogen electrolysis process estimate the round-trip efficiency of this technology with CT for power production at 13%[9], although with technology improvements the round-trip efficiency may reach 20%. The advantage of Ammonia as a fuel over direct hydrogen, is ammonia can be stored in larger volumes when in aqueous form and transported in larger quantities at a lower cost. Hydrogen storage in large quantities requires large geologic storage for hydrogen is not known to exist near Avista's service area.

For this resource option, two 74 MW capacity combustion turbines (148 MW) using a common 30,000 tonne 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, water, and power delivery costs. The resulting levelized fixed and operating cost are shown in Table 6.10.

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[8] Using ammonia a fuel is clean from a greenhouse gas perspective, but does emit NOx as part of combustion. Manufactures are currently working on SCR controls for these emissions, in the meantime, Avista assumes 0.015 lbs per mmbtu of combustion for this emission.

[9] This is based on the assumption 1 tonne of ammonia requires 13.9 MWh of power from the upstream process of electrolysis, desalination, pressure swing absorber, storage, and synthesis loops. Sagel, Rouwenhorst, Faria, Green ammonia enables sustainable energy production in small island developing states: A case study on the island of Curacao, 2022.

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	86.78	139.38	11.46	257.79
2030	96.80	105.60	12.78	198.47
2035	107.93	90.77	14.25	173.23
2040	120.33	83.35	15.89	161.49
2045	134.17	84.76	17.71	165.63

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 $647.95 per kW-year ($54.00 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 $54.03 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 $138.78 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[10] 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

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

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.

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 the Company’s 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 its 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.[11] To minimize cost and utilize ADSS, this is an iterative process between Energy Strategies

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

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 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

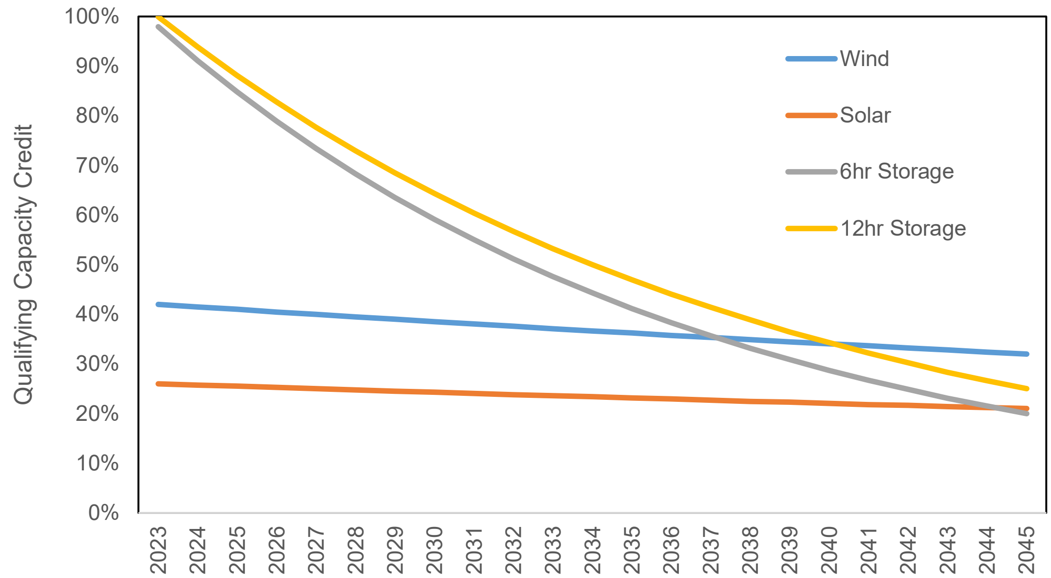
Resource	January (percent)	August (percent)
Northwest solar	3	24
Northwest wind	8	18
Montana wind	28	13
Off-shore wind	16	36
Storage 4- hour duration	83	83
Storage 8-, 16-, or 100-hour duration	98	98
Solar + Storage	25	100

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[12] for

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

this assumption investigating high renewable and energy storage penetrations. The resulting QCC forecast assumed in this IRP 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



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[13] 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.

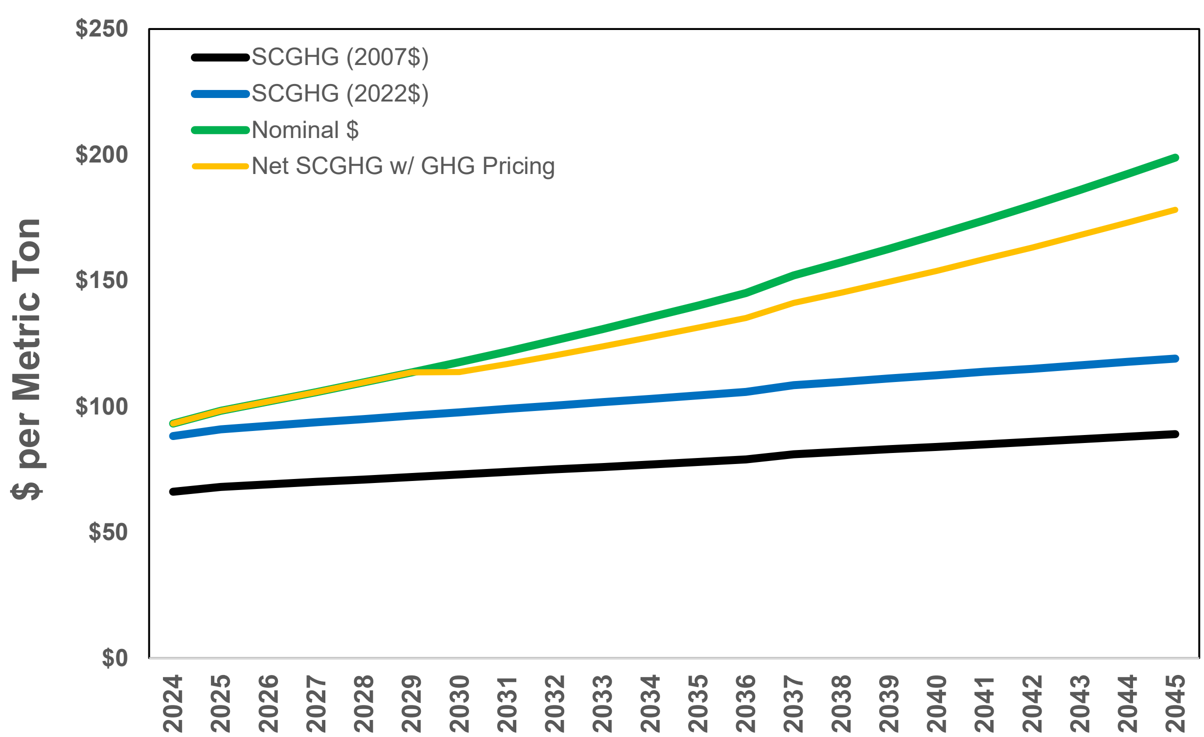
[13] The emission rate is from recent environmental impact studies for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility.

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.

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: IRP 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.

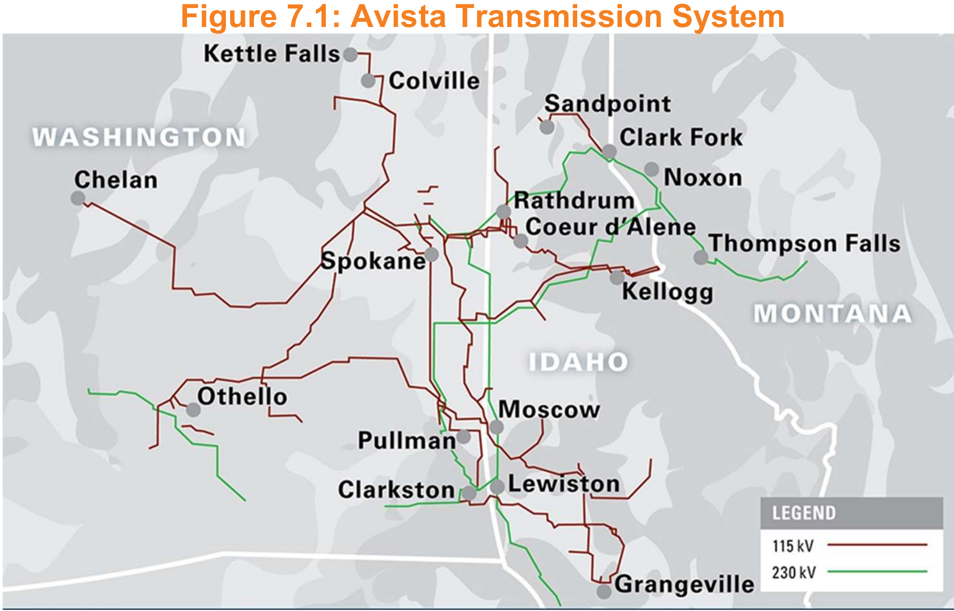
Section Highlights

- 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.
- Increasing electrical infrastructure to electrify both building and transportation in the Washington State service area is estimated to cost an additional 4 cents per kWh.

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

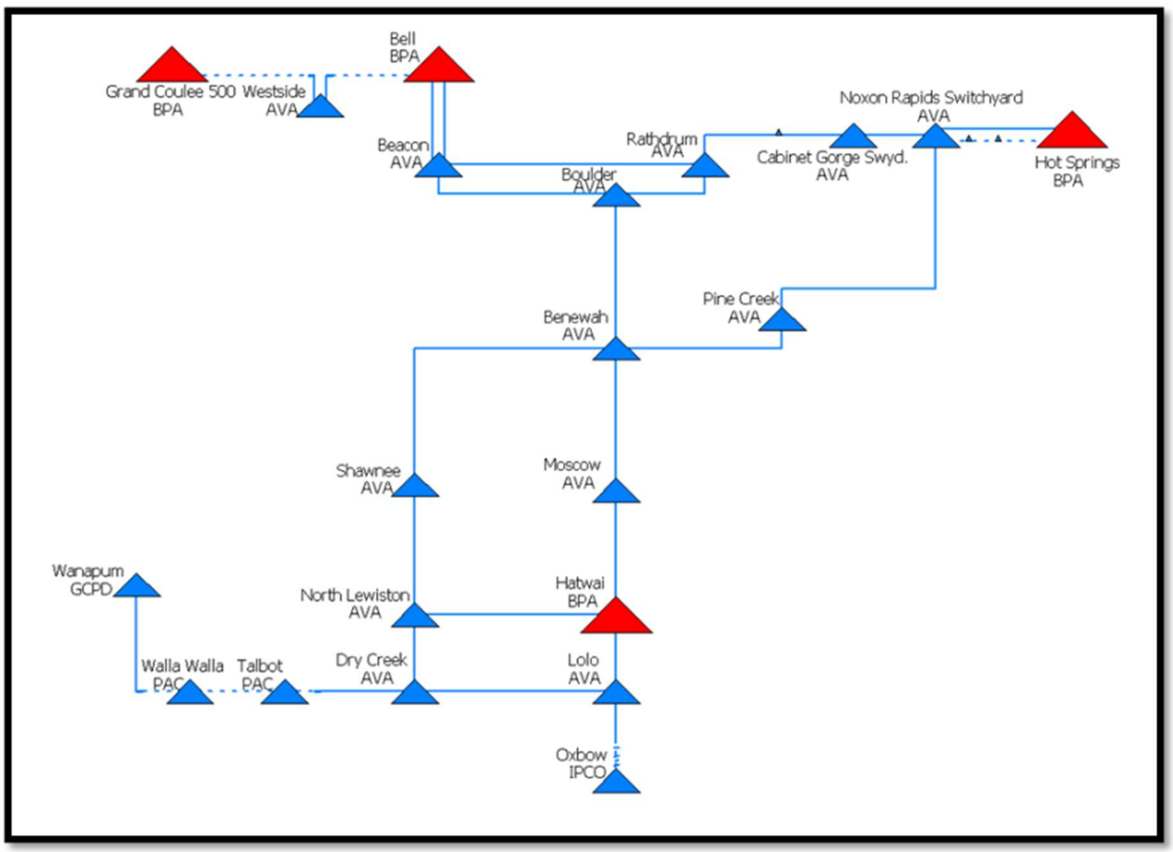


230 kV Transmission System

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.

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.

Figure 7.2: Avista 230 kV Transmission System



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.

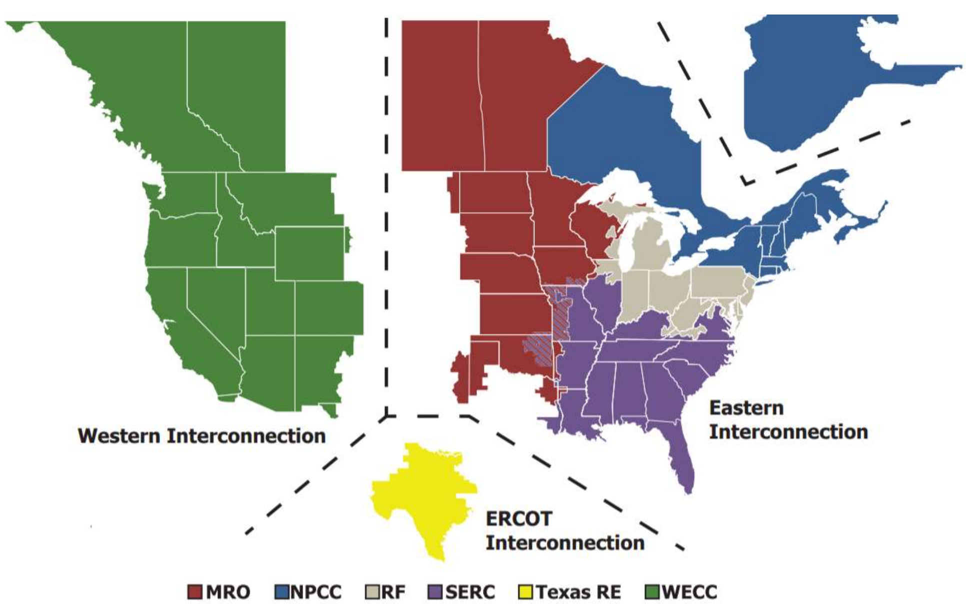
Western Electricity Coordinating Council

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



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

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 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 that are relating 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 completed Irvin 115 kV switching station adds 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

[2] Cost estimates are in 2022 dollars and use engineering judgment with a 50 percent margin for error.

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]

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

[3] https://www.oasis.oati.com/woa/docs/AVAT/

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 include 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 additional 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 amount of data and understanding it is a challenge. Early returns indicate a future without AMI would be challenging given policy directions for resource planning. 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 future resource and mitigation opportunities.

As part of CETA, Avista has started 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, 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 covers the spectrum from planning, to operations, to stakeholder engagement.[4] This work is being incorporated into the existing planning process. The development of a DER potential assessment (currently under contract) 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 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/or 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. For the 2023-2024 system assessment Avista will use tools and data previously unavailable in the last assessment. The additional clarity will facilitate the evaluation of DER's as mitigation options for any deficiencies identified.

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.

[4] Modern Grid Solutions® Work Product

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 than 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.

Electrification Impact Analysis

Avista's distribution system is not designed for a high penetration of electrification of existing customer's transportation and space/water heating loads. Many studies including this IRP and past IRP's concentrate on the power supply and transmission requirements of these new loads, but do not estimate distribution system costs. Traditionally, distribution planning is outside the scope of an IRP as the IRP focuses on the generation of the power supply not the delivery, but the cost to change the distribution system is informational to understand the full impacts of a major transition policy decision for Avista's customers.

This IRP contemplates four electrification scenarios for plausible Washington State load changes within IRP planning horizon (discussed in Chapter 10). The scenarios use alternative forecasts for higher electric vehicle (EV) adoption and a transition to using electric space and water heat of existing customers. Additional load requirements by existing customers will have an impact of the distribution system since the system was not designed for the additional load. The system changes and costs to integrate new loads will be a time-consuming exercise requiring assumptions for the impacts of each individual customer for each of the scenarios. To shorten the requirements for such a study, Avista chose to estimate the system impacts for the highest load forecast scenario and base its estimate on high level assumptions for system requirements based on known costs to construct system components. This analysis gives an approximate estimate to add to power and transmission cost estimates traditionally estimated in a resource plan.

There are two options to increase distribution capacity, one is to increase voltage of the system; this option requires replacing all distribution underground cable, line insulation, substation power transformers, voltage regulators, and numerous other equipment. The second option is using the same distribution voltage to split the existing system up into additional feeders by adding additional substations along with replacing targeted conductors. Both options will require replacement of service transformers and conductors from the transformer to the home. For this analysis the second option is used to estimate the system costs.

Avista then estimated the required replacement components based on the judgement of Avista's planning engineers and construction personnel. The high electrification scenario adds 1,225 MW of additional winter peak load by 2045, but for system planning purposes this is increased to 1,450 MW to account for higher loads due to the power supply planning metric based on a 1 in 2 weather event and the distribution system must plan for lower temperature events at 1 in 10 year lowest daily temperature. With the amount of new load known, the number of new feeders is estimated by assuming a new feeder can service 10 MW of new load. Then using an estimate of a new feeder substation can service four feeders is the basis for estimating the associated system components to service the new load without requiring a detailed study. Table 7.3 summarizes the total system cost estimates, these estimates include the required distribution system reconductoring, new transmission connections, and customer transformer and connection points. The total cost in 2023 dollars is $1.9 billion dollars or $57 million per feeder substation, when adjusting for inflation timing, the cost rises to $3.3 billion in total capital cost through 2045 (the current book value of the Washington distribution assets is approximately $1 billion as a comparison, Avista already adds approximately two feeders per year for load growth).

With this cost per substation forecast, a cash flow can be estimated based on spreading the required work between 2028 and 2045 and adjusting for inflating capital costs using a cost per feeder substation. Avista also estimates additional support employees will be required to facilitate the load growth. Avista estimates this to be an increase of 46 full time employees for support roles by 2045.

The combined new support labor force and capital investments using a 50-year life amortization results in a 2045 revenue requirement to Washington customers at $378 million. When dividing by 9,520 GWh of retail sales, the average rate is an additional 4 cents per kWh (the expected PRS average kWh rate is 23 cents per kWh in 2045). Although the incremental cost per additional kWh sales is 14.5 cents per kWh.

Table 7.3: T&D Requirements for the Combined Electrification Scenario (2023$ Millions)

Item	Units	Unit Cost	Total Cost
New Feeder Substations	36 Stations	$15.0	$542
Reconductor Distribution	163 Miles	$0.5	$81
115kV Transmission (Substation Integration)	72 Miles	$4.0	$289
Switching Station (230kV/115kV)	6 Stations	$75.0	$450
230kV Transmission (Switching Station Integration)	30 Miles	$2.3	$68
Service Transformers	32,000	$10k	$320
Reconductor Service Connections	1,910 miles	$62k	$118
Total Cost			$1,868
Cost per Feeder Substation			$57

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 (see Table 7.3). 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 7.4: 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

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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 of the Western Interconnect to optimize its resource portfolio options. Electric price forecasts are used to evaluate the net operating margin of each supply- and demand-side resources, including distributed energy resources (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 existing coal and natural gas plants retired or reduce dispatch.
- By 2045, this study assumes 94 percent of generation in the Pacific Northwest will be carbon free, up from approximately 70-80% today depending on hydro conditions.
- Greenhouse gas emissions (GHG) 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% 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 Integrated Resource Plan (IRP) 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 IRP planning; shown as Western Electricity Coordinating Council (WECC)[1] in Figure 8.1. The rest of the U.S. and Canada are in separate electrical systems. The Western Interconnect includes

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

the U.S. system west of the Rocky Mountains plus two Canadian provinces and the northwest corner of Mexico's Baja peninsula.

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.

Figure 8.1: NERC Interconnection Map

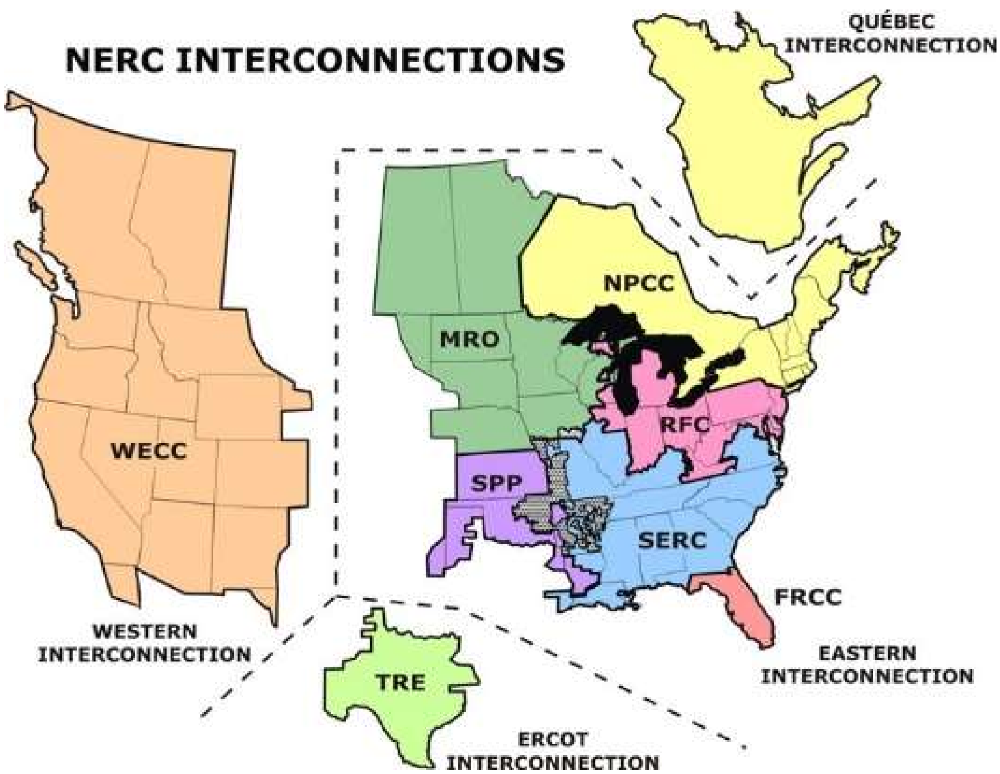


Table 8.1: AURORA Zones

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

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 resources 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 of the west for the 300 stochastic studies.

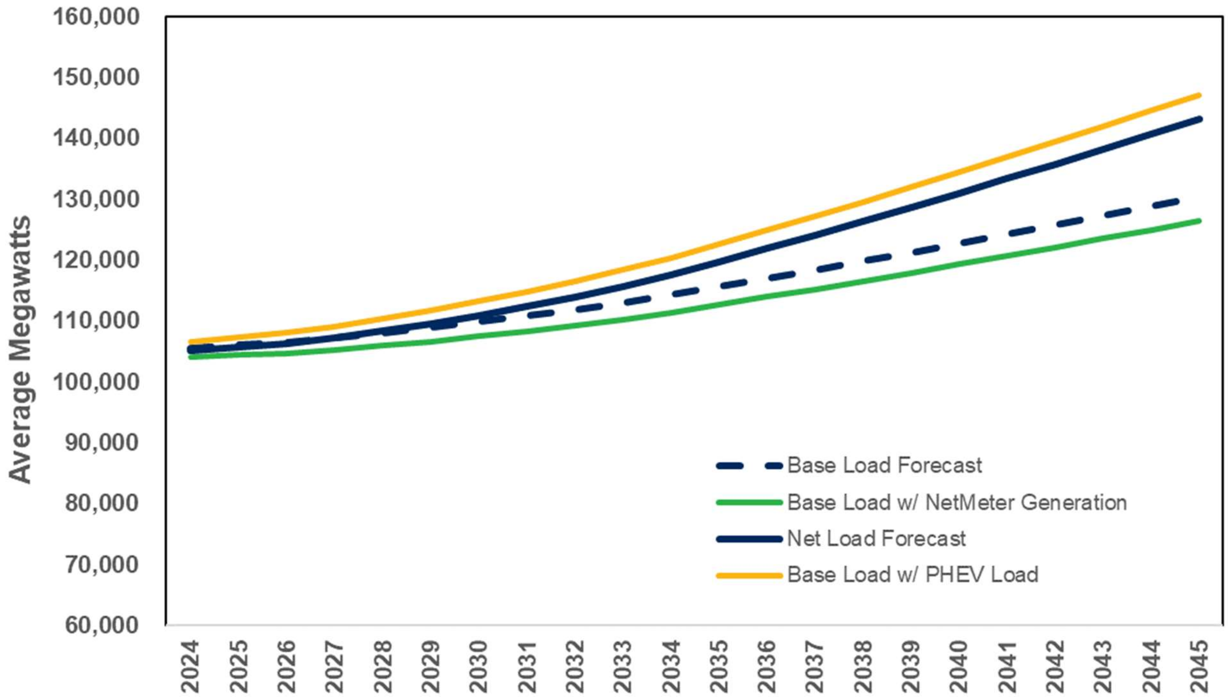
Western Interconnect Loads

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, varying state policies, population migration, and economic activity increase the complexity. While each of these drivers are important to the power pricing forecast, 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. The WECC 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 Federal Energy Regulatory Commission (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 use in meeting system variation.

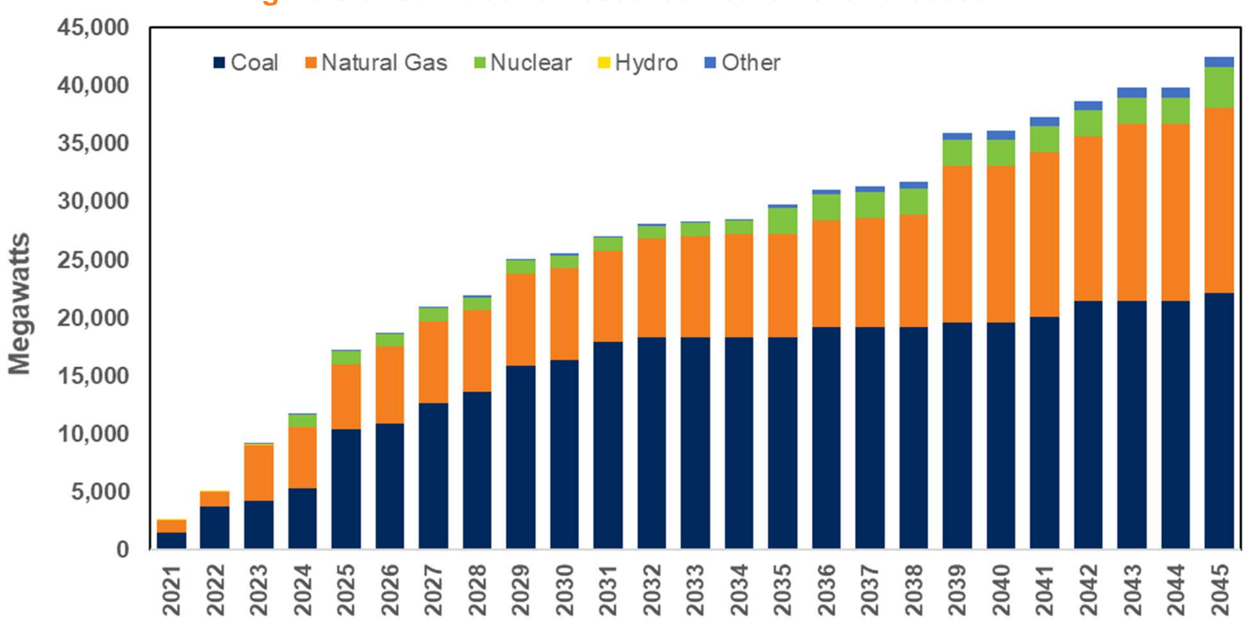
Generation Resources

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 becoming 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



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

New Resource Additions

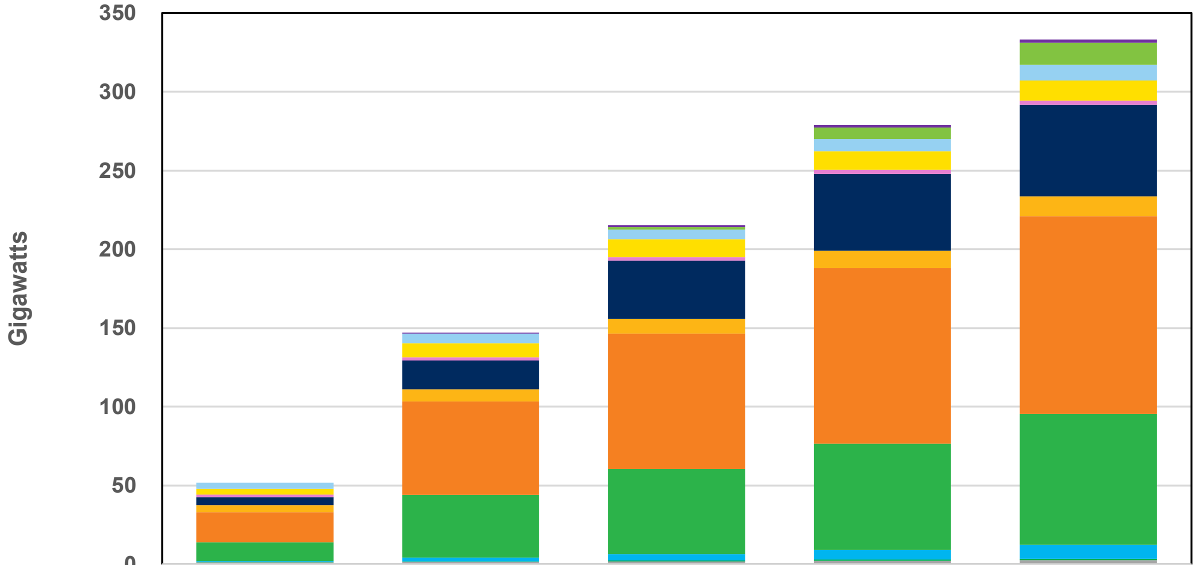
To meet future load growth, considering state clean energy goals and replacement of retired generation, a new generation forecast must include enough resources to meet peak load. Furthermore, some states include emission constraints or require emission pricing for new resource additions. Avista uses 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, 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 combustion turbines (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

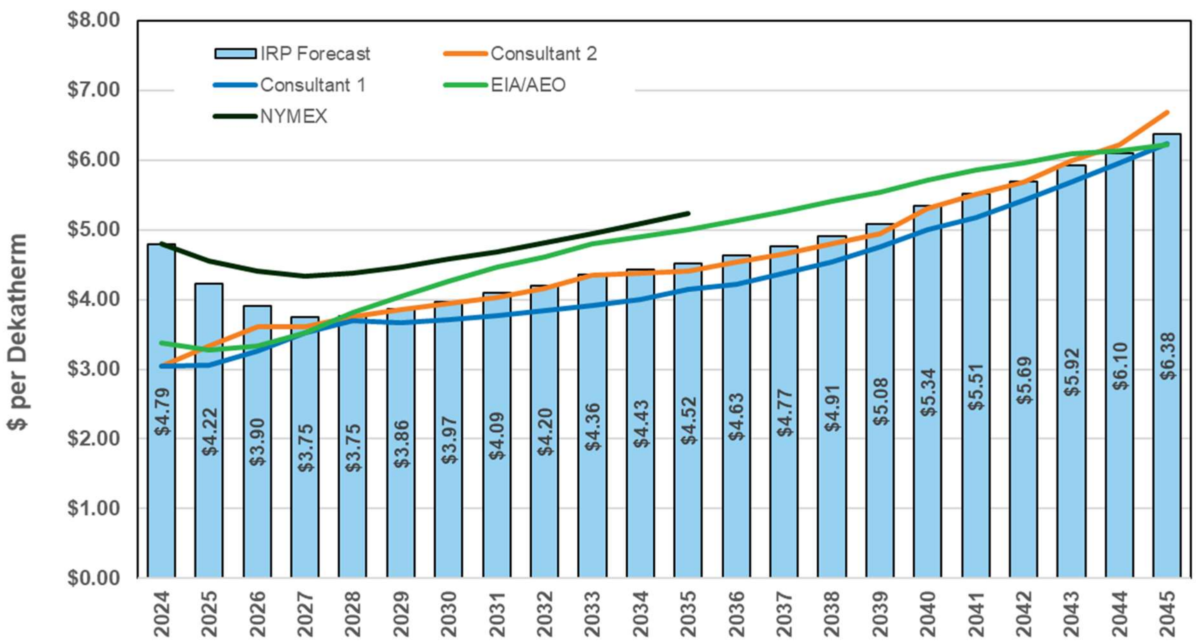
Several changes are made to the resources available to serve future loads to account for Avista's specific expectations, such as fuel prices, and to reflect potential variation of resource supply such as wind and hydro generation.

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 the selected basins.

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

[5] The natural gas pricing data is available on the IRP website within Appendix F.

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.

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**	**$4.27**	**$3.74**	**$3.55**	**$3.99**	**$4.20**

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 $3.98 per dekatherm. These values likely would converge with a sample size much larger than 300. The median price is lower at $3.91 per dekatherm. Another component of the stochastic nature of the forecast is the growth in variability. In the first year, prices vary 9 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

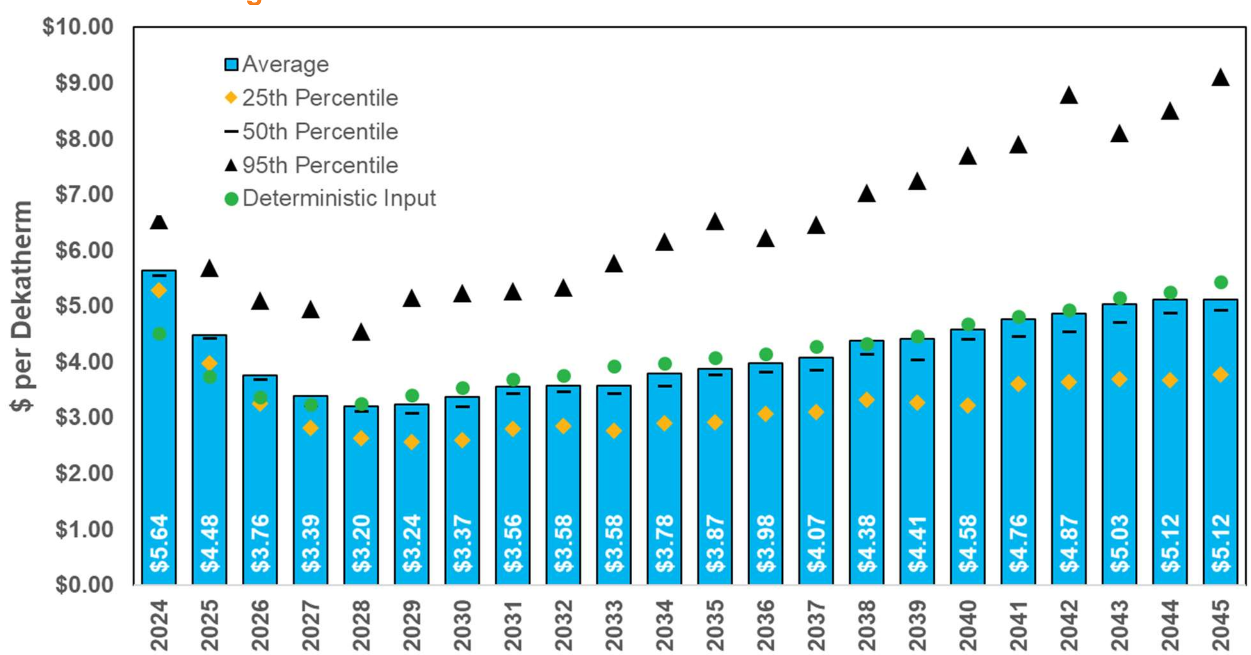
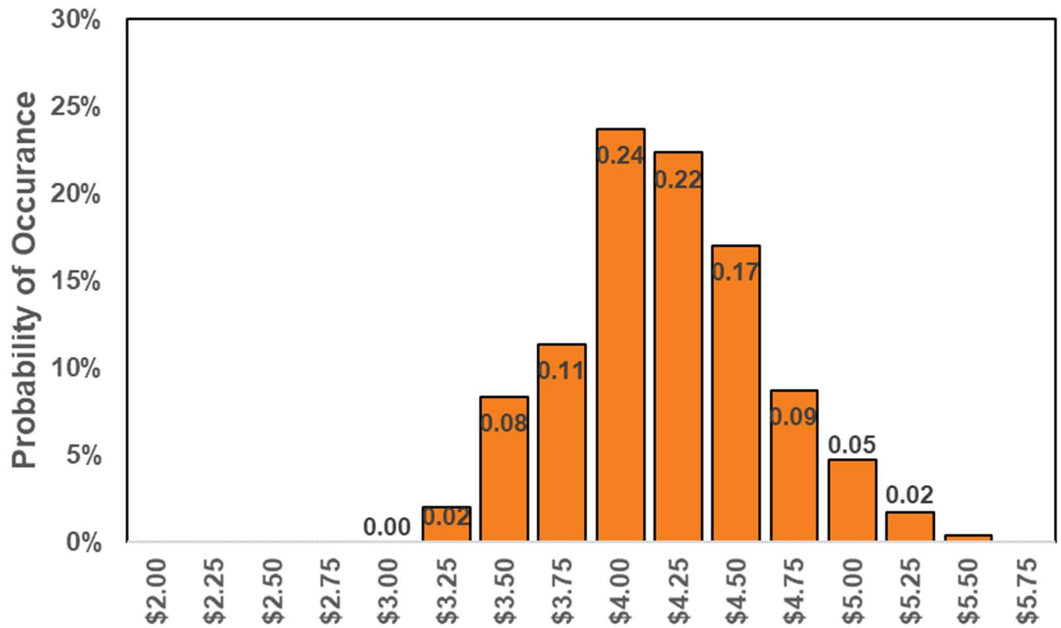


Figure 8.7 shows another way to visualize Avista's natural gas price forecast assumptions. This chart shows the 22-year nominal levelized prices for Stanfield as a histogram to demonstrate the skewness of the natural gas price forecast.

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 WECC loads, falling from 34 percent in 2001. Coal pricing is typically different from natural gas pricing, providing diversification thus 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.

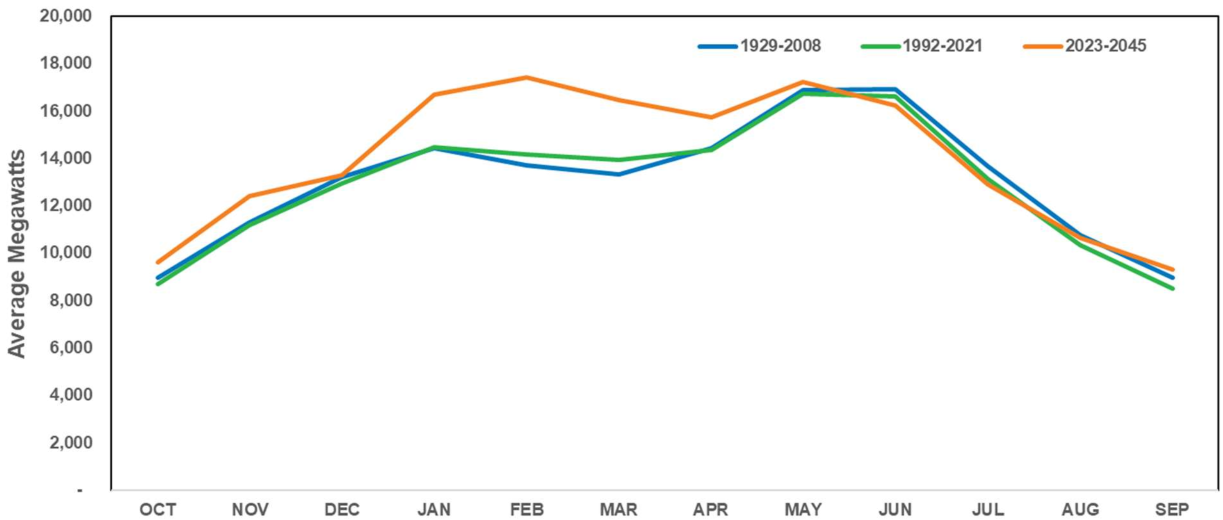
Coal price forecasts have uncertainty like natural gas prices, yet the effect on market prices is less because coal-fired generation rarely sets marginal prices in the Western Interconnect. While labor, steel, and transportation costs drive some portion of coal price uncertainty, transportation is its 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 incorporating the temperature change predictions in Representative Concentration Pathway (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.

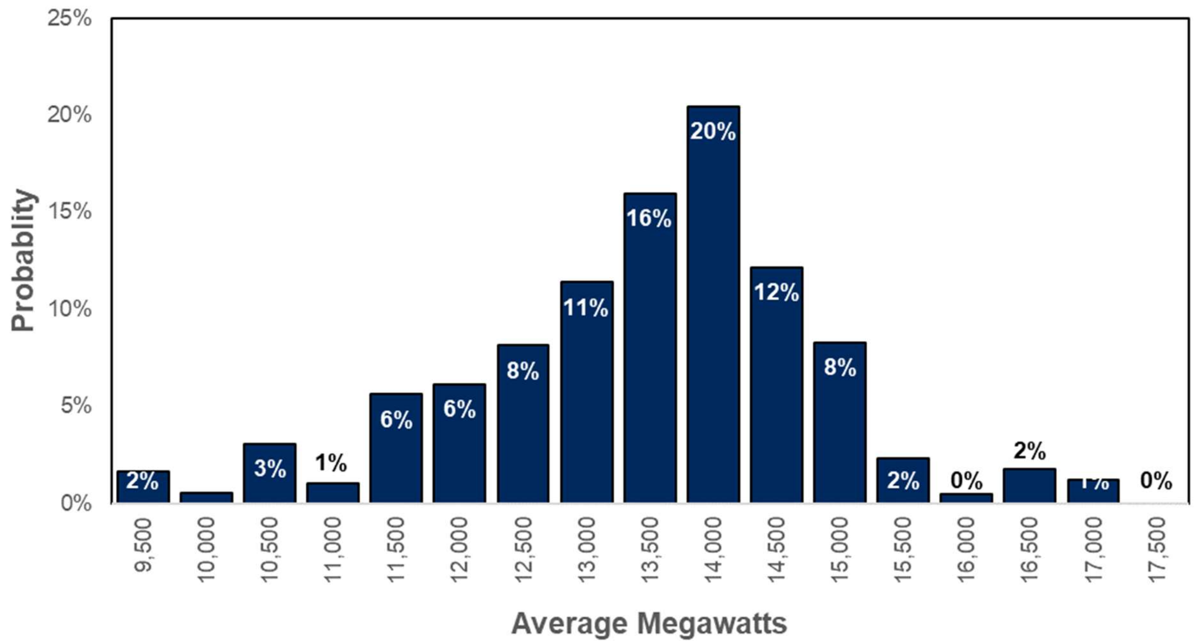
Figure 8.8: Northwest Hydro Generation Comparison



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 13,213 aMW (median 13,411 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 11,290 aMW (-15%) and a 90th percentile water year of 14,728 aMW (+11%).

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

Figure 8.9: Northwest Expected Energy



Wind Variation and Pricing

Wind is a growing generation source used 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 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 with multiple locations within an area. As solar continues to grow, additional data will be available and

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

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., Renewable Energy Credits (RECs)) or sale obligations. While hydro resources are dispatchable, they may not be able to dispatch off due to constraints of total dissolved gas 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 GHG 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).

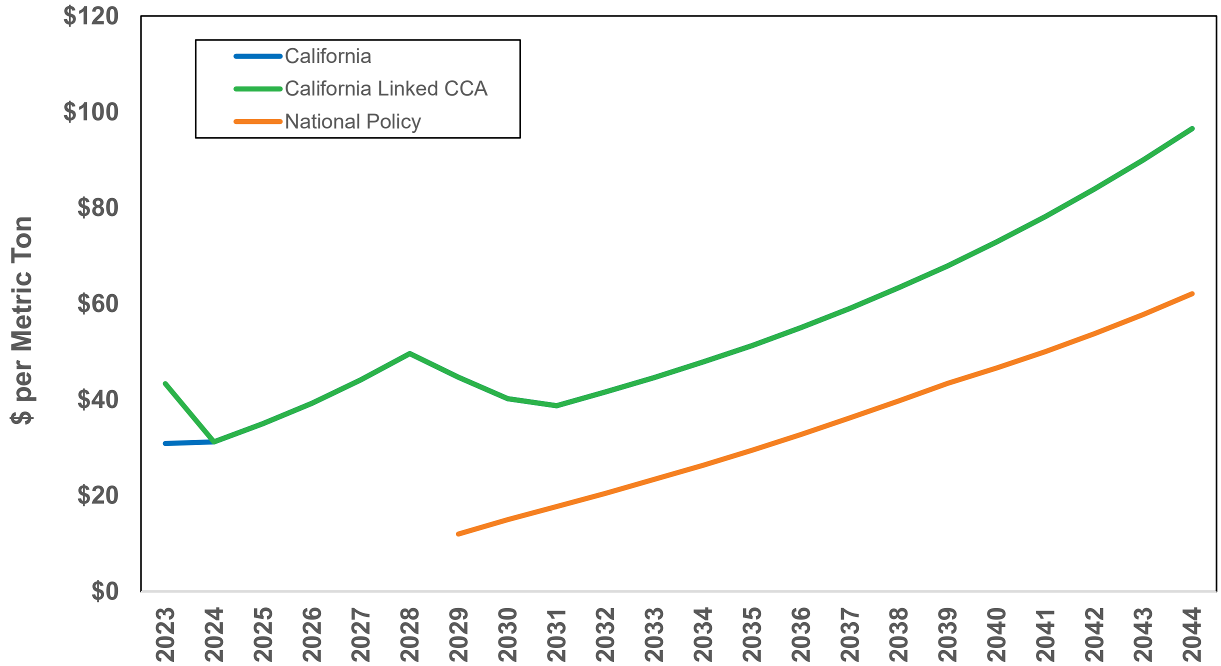
The Washington State Legislature passed the CCA in 2021 enacting the potential for carbon pricing on Washington generation resources beginning in 2023.[10] Final CCA rules were released only this past October 2022 and all regulated entities are still striving to comprehend its complete impacts. The regulatory 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 GHG 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% 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.[13] In 2022, 52 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 2022, 76 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.

[13] Forecast is for the average of the 300 simulations.

Figure 8.11: WECC Generation Technology History and Forecast

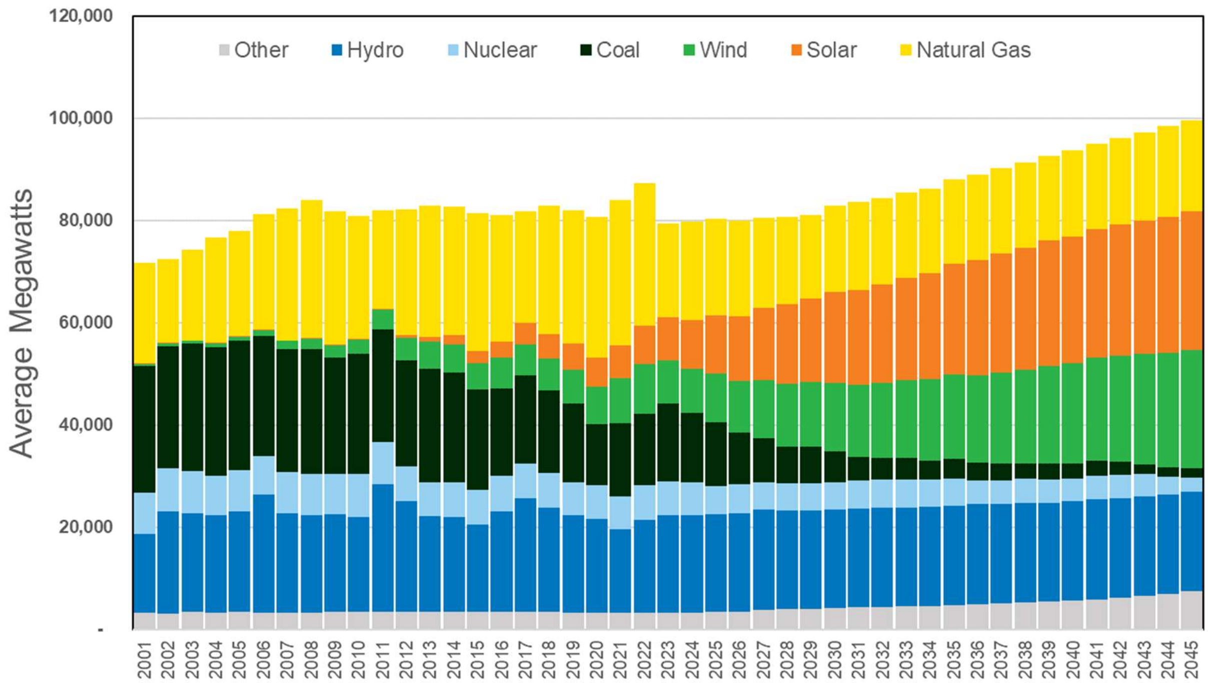
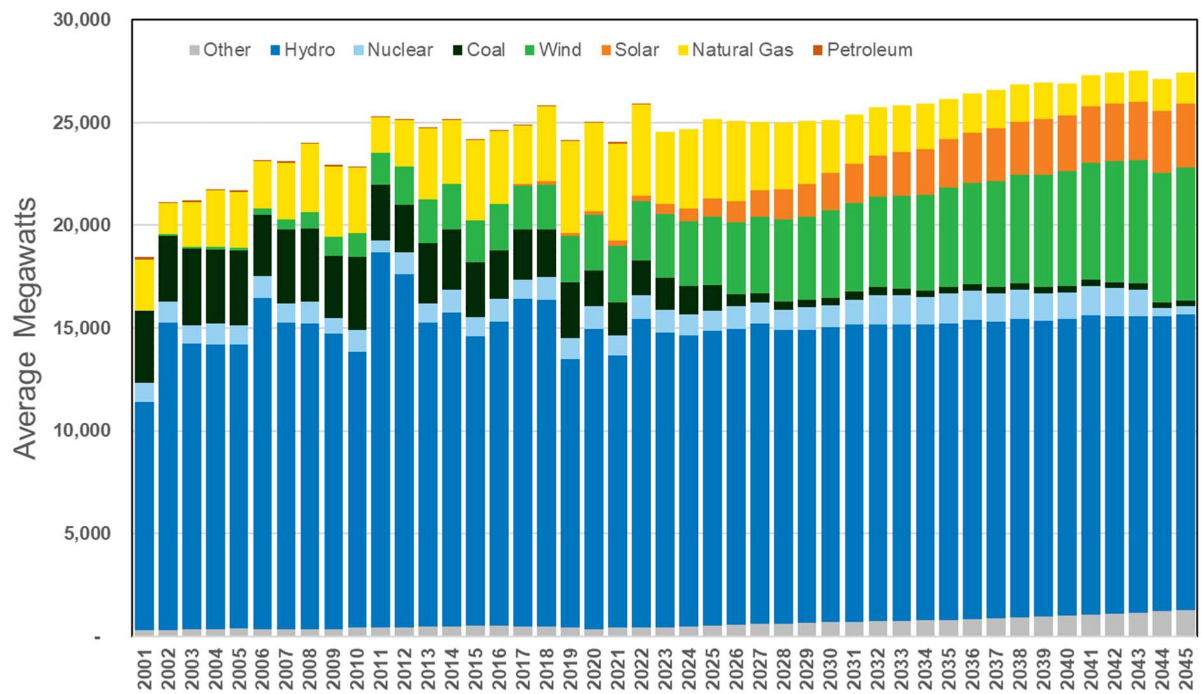


Figure 8.12: Northwest Generation Technology History and Forecast



Regional Greenhouse Gas Emissions

GHG 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 GHG 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 8.13 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 37 percent compared to 1990 levels as shown in Figure 8.14. All states will have a reduction in emissions in this forecast. The greatest reductions by percentage are Utah (89 percent), New Mexico (83 percent), Montana (77 percent) and Nevada (74 percent). The greatest reductions by tons are Utah (26 MMT), Wyoming (25 MMT), California (24 MMT), and New Mexico (22 MMT).

Figure 8.13: 2020 and 2045 Greenhouse Gas Emissions

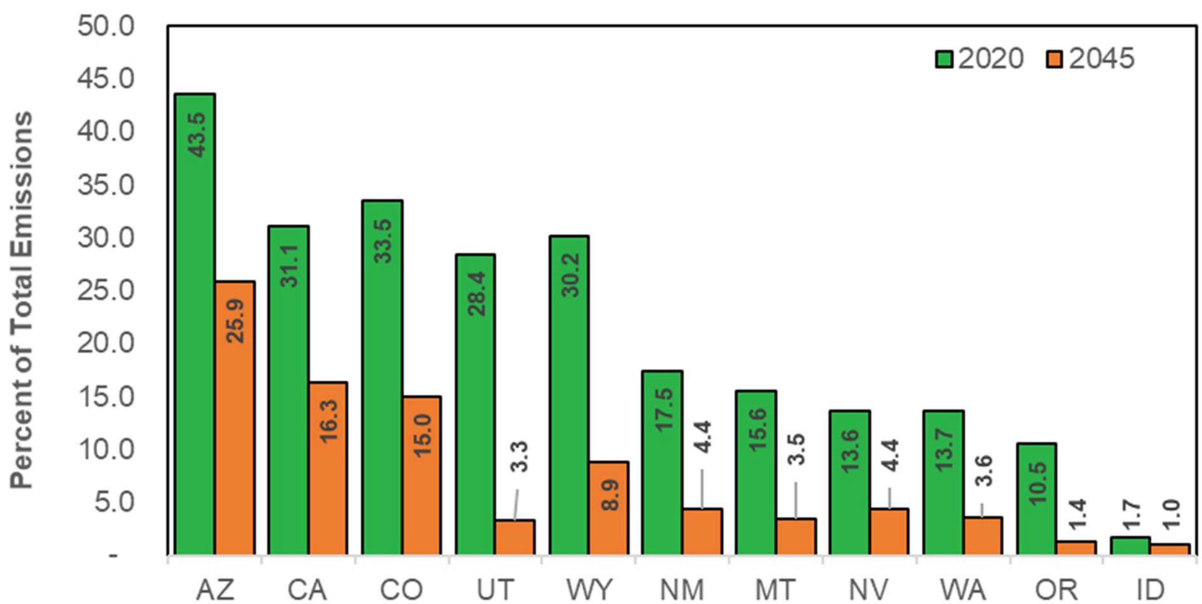
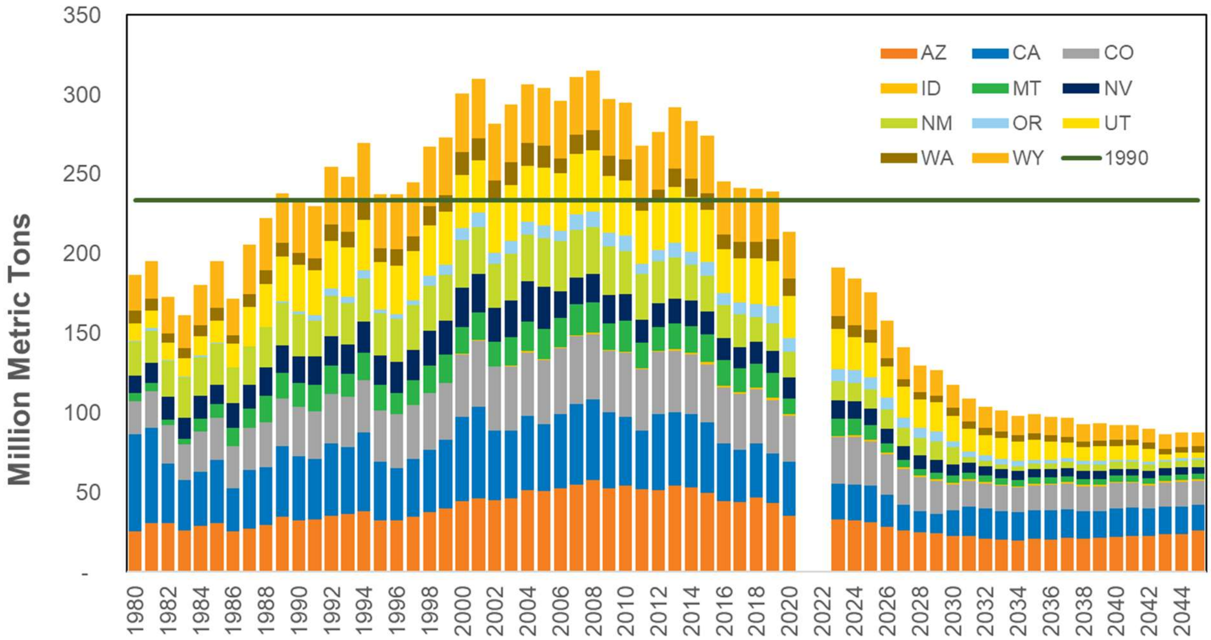


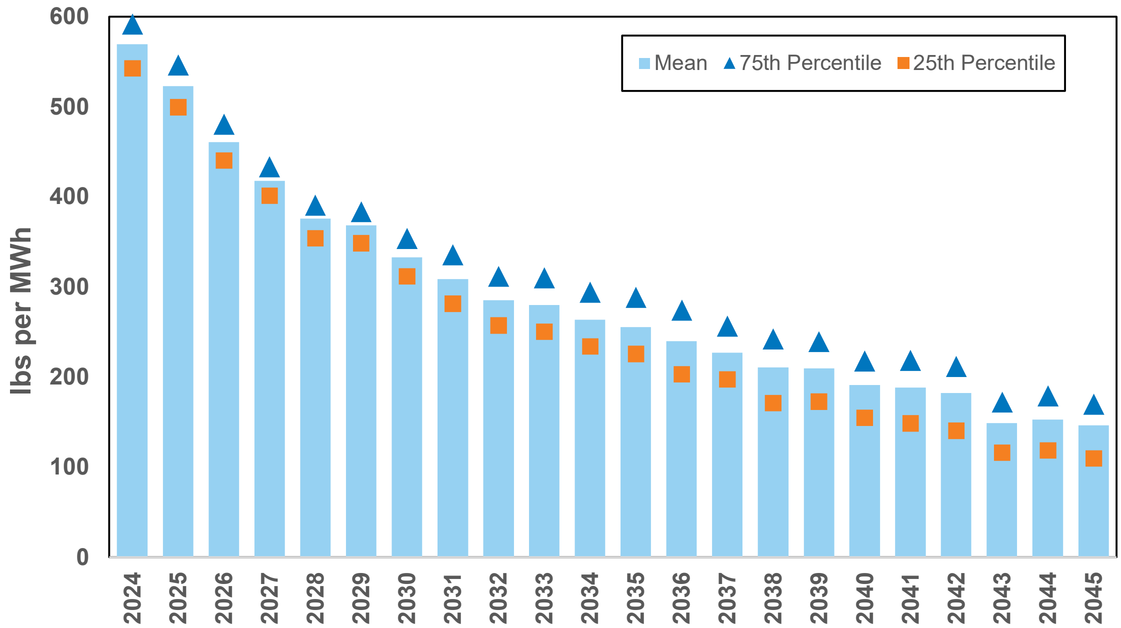
Figure 8.14: Greenhouse Gas Emissions Forecast



Regional Greenhouse Gas Emissions Intensity

To understand the GHG 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 8.15 for each of the 300 simulations. Figure 8.15 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 and natural gas retire or decrease dispatch, 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 8.15: 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 simulating 300 of the 22-year hourly studies. 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. 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 8.16. 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 $35.48 per MWh and $35.44 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 8.16: Mid-Columbia Electric Price Forecast Range

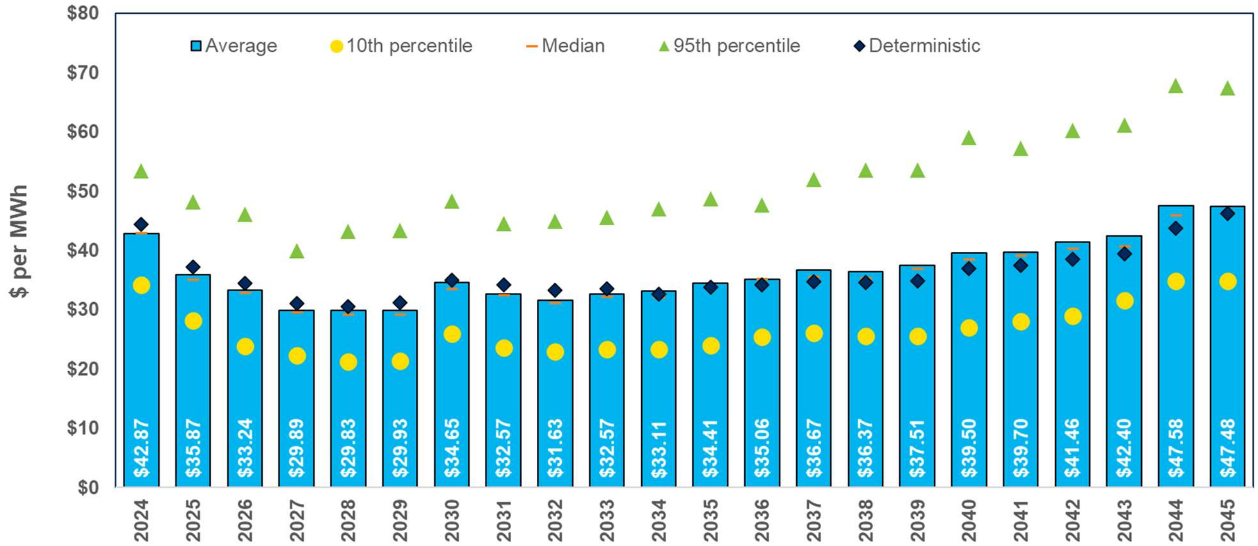


Table 8.3: Nominal Levelized Flat Mid-Columbia Electric Price Forecast

Metric	2024-2045 Levelized ($/MWh)
Deterministic	$35.48
Stochastic Mean	$35.44
10th Percentile	$31.94
50th Percentile	$35.29
95th Percentile	$40.84

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	$42.87	$38.56	$46.10	$60.15
2025	$35.87	$32.57	$38.33	$52.29
2026	$33.24	$30.80	$35.07	$49.22
2027	$29.89	$28.65	$30.82	$45.21
2028	$29.83	$29.74	$29.90	$44.89
2029	$29.93	$30.46	$29.52	$44.96
2030	$34.65	$35.97	$33.66	$51.48
2031	$32.57	$33.87	$31.59	$50.24
2032	$31.63	$33.33	$30.36	$48.71
2033	$32.57	$34.44	$31.17	$51.13
2034	$33.11	$35.14	$31.58	$51.97
2035	$34.41	$37.11	$32.40	$53.40
2036	$35.06	$38.03	$32.84	$54.60
2037	$36.67	$38.98	$34.93	$58.60
2038	$36.37	$38.76	$34.58	$59.06
2039	$37.51	$40.50	$35.26	$60.62
2040	$39.50	$42.02	$37.60	$66.68
2041	$39.70	$42.16	$37.85	$67.33
2042	$41.46	$42.99	$40.31	$72.16
2043	$42.40	$43.69	$41.44	$73.97
2044	$47.58	$48.76	$46.70	$81.89
2045	$47.48	$48.88	$46.42	$81.17
2024-2045	$35.44	$35.76	$35.20	$54.99

Figures 8.17 through 8.20 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 8.17: Winter Average Hourly Electric Prices (December - February)

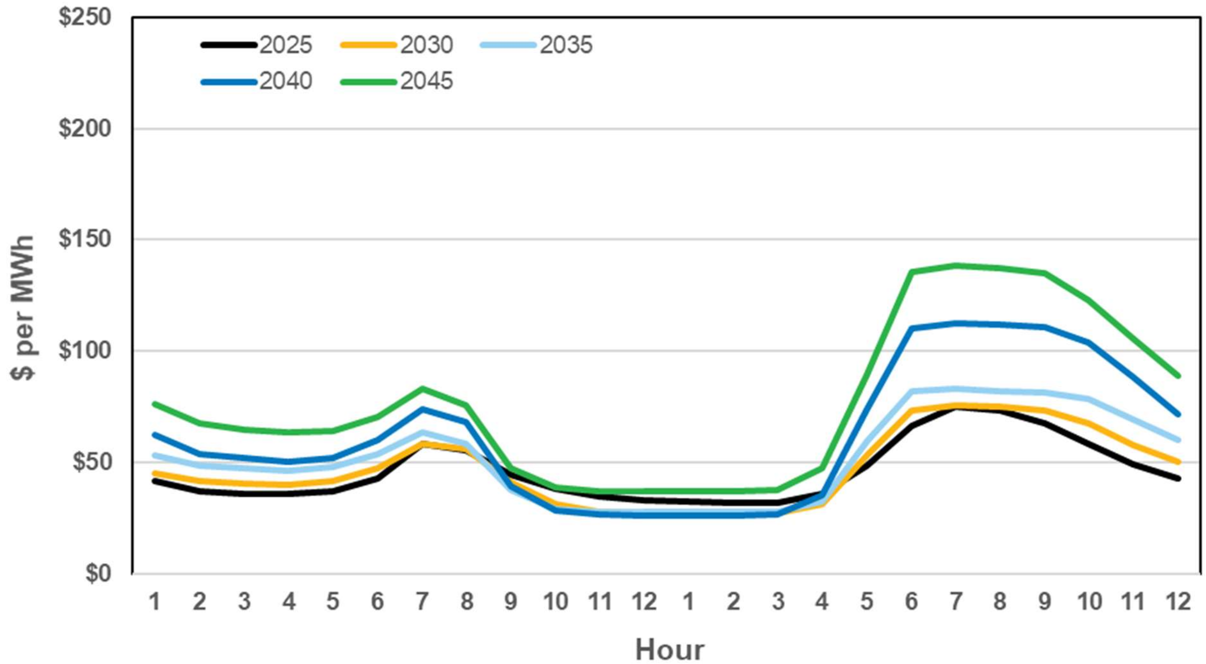


Figure 8.18: Spring Average Hourly Electric Prices (March - June)

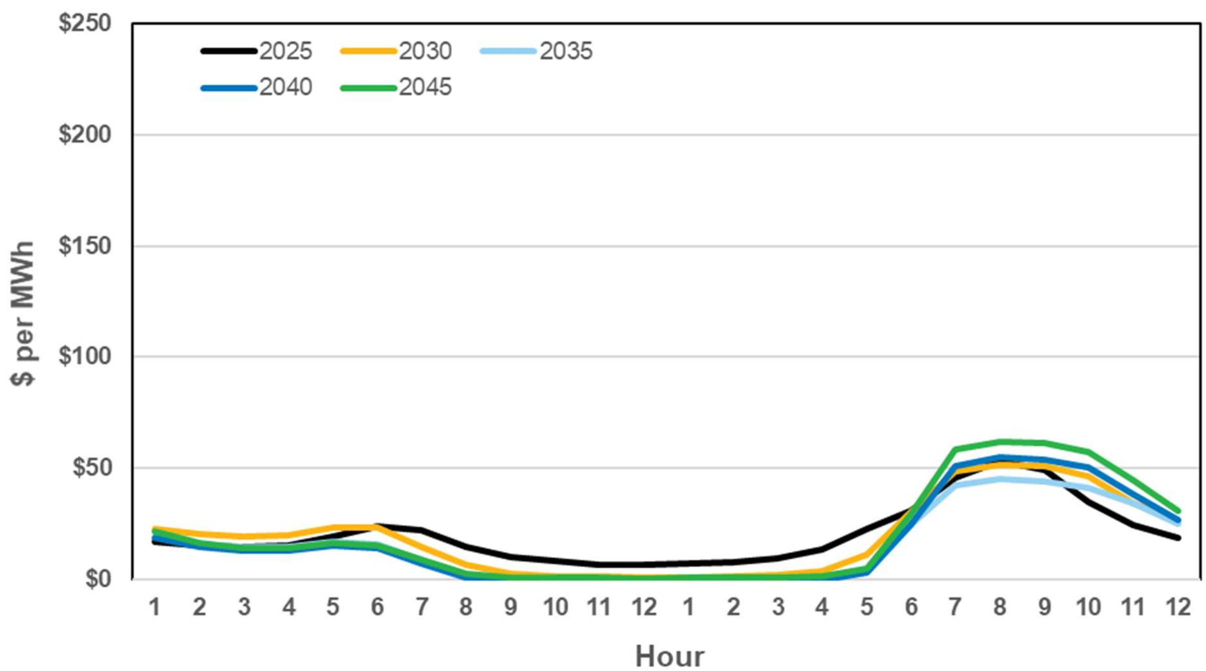


Figure 8.19: Summer Average Hourly Electric Prices (July - September)

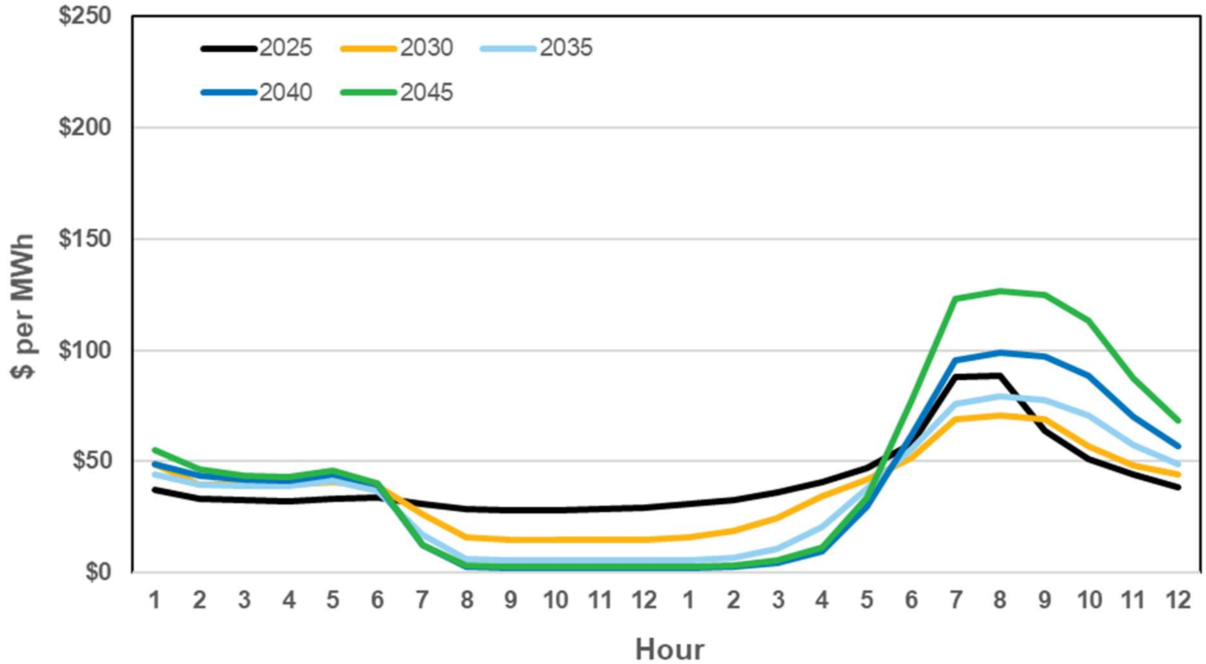
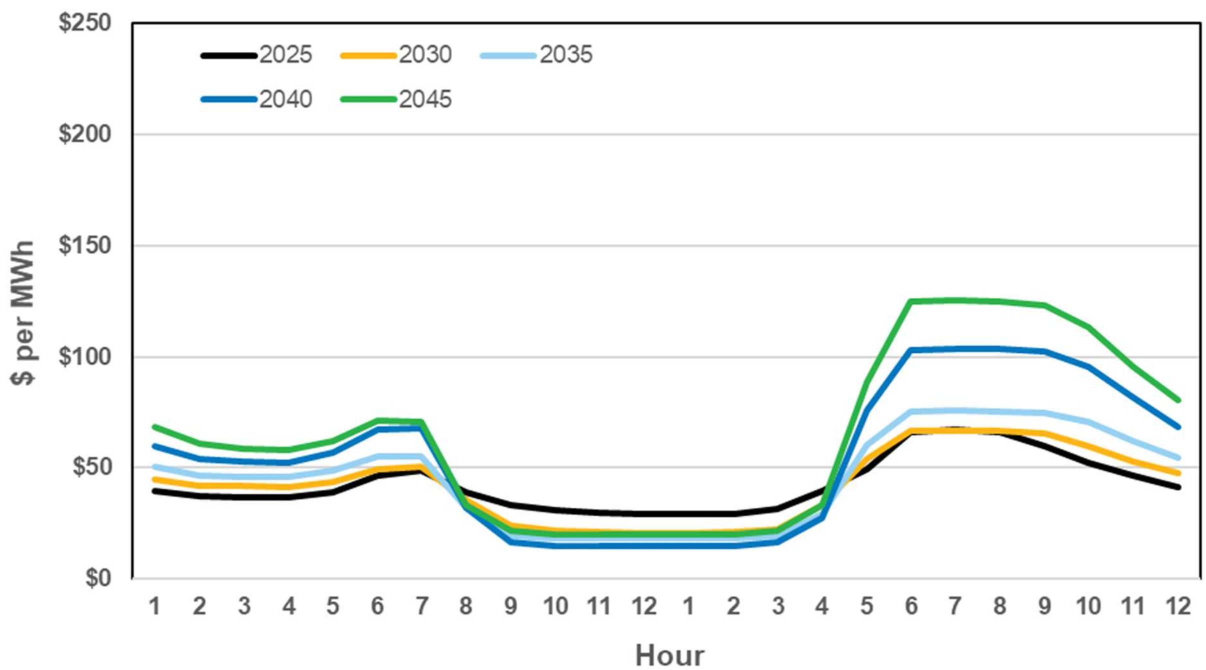


Figure 8.20: Autumn Average Hourly Electric Prices (October - November)



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9. Preferred Resource Strategy

Avista recently negotiated several resource acquisitions from its 2022 All-Source Request for Proposals (RFP) to meet customer energy and capacity needs into the mid-2030s. These acquisitions include both renewable resources and existing baseload natural gas from northwest energy suppliers. While large scale utility resources are meeting customer's needs, Avista will continue to invest in cost effective energy efficiency (EE) and other distributed energy resources (DER), pilot demand response (DR) programs, and invest in energy solutions in Named Communities (highly impacted communities and vulnerable populations). Avista also announced a plan to transfer out of its ownership of Colstrip by the end of 2025.

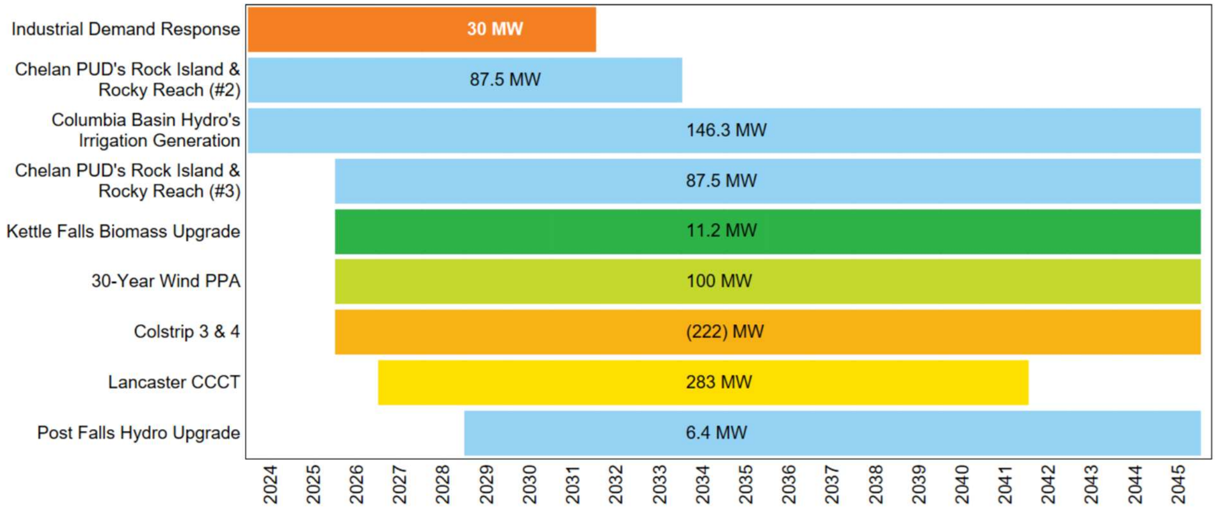
Section Highlights

- The 2022 All-Source RFP resource selections satisfy the customer's load and capacity forecast through the mid-2030s.
- Energy efficiency's impact on future load growth is slowing due to saturation.
- Named Community Investment Fund (NCIF) will increase distributed energy resources such as energy efficiency, small-scale renewables, and energy storage.
- Non-energy impacts are included to evaluate both demand- and supply-side resource selection for Washington resources.
- Avista needs long-duration storage to serve customers in peak hours after 2035 to achieve 100% clean energy targets.
- Greenhouse gas emissions fall by 80% by 2045 with the Preferred Resource Strategy (PRS).
- New transmission is needed to achieve Washington's 100% clean energy goals.

Background

Avista has announced several resource acquisitions and a divestiture since its 2021 IRP. These changes reflect one of Avista's biggest portfolio transformations since the early 2000s, beginning with the addition of two separate 5% purchases of Chelan PUD's Rocky Reach and Rock Island facilities from the 2020 Renewable RFP. The 2022 All-Source RFP then produced a 30-year Wind Purchase Power Agreement (PPA), an upgrade of the Kettle Falls Biomass Facility, and an extension of the Lancaster CCCT PPA through 2041. Announcements adjacent to the 2022 All-Source RFP include the acquisition of power from Columbia Basin Hydro's irrigation hydro generation fleet, 30 MW of industrial demand response, and the divestiture of Avista's 15% share of Colstrip Units 3 & 4 at the end of 2025. In previous IRPs and the 2021 Clean Energy Implementation Plan (CEIP) Avista has also indicated an intention to upgrade the Post Falls hydroelectric facility, currently projected for completion by the end of 2029.

Figure 9.1: Announced Resource Changes Since 2021 IRP



Resource Strategy Objectives

Avista needs reliable sources of power to meet peak planning requirements for both summer and winter peak loads to control enough energy to meet customers' normal demand and enough clean generation resources to meet Washington State's goals. Avista must also maintain system reliability, while meeting the regulatory and legal obligations of Idaho and Washington, including the Clean Energy Transformation Act's (CETA) requirement of serving Washington's retail loads with 100% non-emitting resources by 2045.

The acquisition strategy uses the best information available at the time of these analyses, including Avista's interpretation of CETA requirements. CETA rules are still in development for items 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 cost impacts specified by Washington's requirements for planning and including Non-Energy Impact (NEI) studies for alternative resources conducted by DNV.[1] Due to differing state Idaho and Washington policies, Avista separates the two jurisdictions for this analysis by creating an individual resource selection plan for each state and as a system where possible.

Avista's PRS describes the lowest reasonable cost resource mix given Avista's needs for new capacity, energy, and clean or non-carbon emitting resources for each state, while accounting for social and economic factors prescribed by state policies. The PRS includes supply-side resources, and DER options including EE and DR, to serve customer loads. The plan compares resource options to find the lowest-cost portfolio considering the non-power costs to meet capacity deficits in the winter and summer, annual energy and clean energy/CETA requirements. The analysis considers a minimum spending threshold for

[1] Available in Appendix D

using the Named Communities Investment Fund (NCIF)[2] monies available to enhance the equitable transition to clean energy in Named Communities in Avista's Washington electric service territory.

Resource Selection Process

Avista utilizes a mixed integer optimization model to select supply- and demand-side resources to meet customer energy and capacity needs. Avista developed Preferred Resource Strategy Model (PRiSM) 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 option's capability to serve energy, peak loads, and clean energy obligations. PRiSM then determines the lowest-cost mix of resource options meeting Avista's resource needs. The model can also measure and optimize the risk of various portfolio additions when informed by Monte Carlo data. For this analysis, Avista includes its forecast of 300 Monte Carlo market futures rather than a single forecast for its evaluation. PRiSM is publicly available in Appendix F.

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

[2] The NCIF was proposed in Avista's 2021 CEIP and commits to spend up to $5 million annually on specific actions in Named Communities.

[3] Resources can only be retired at the system level. PRiSM is not set up to "retire" a resource from serving only one state and transferring the output to the other state. Avista's PRS analysis "turns off" this feature and does not include additional model selected retirements beyond those discussed in this chapter.

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%, May through September)
    - Winter Planning Margin (22%, 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
    - Greenhouse Gas (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
    - Power Purchase Agreements
    - Peak contribution from Western Resource Adequacy Program (WRAP)/ E3 regional study
    - Generation levels
    - GHG emission levels for Climate Commitment Act (CCA)
    - Upstream GHG emission levels (WA only)
    - Construction and operating GHG emissions (WA only)
    - 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 (WA only)
    - 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 Greenhouse Gas + 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 monthly requirements
- Summer peak monthly requirements
- Annual energy monthly requirements
- Washington's clean energy monthly goals
- Named Community Investment Fund outlays (WA only)

Preferred Resource Strategy DER Selections

Currently there are three major energy policies in Washington impacting long-term resource strategies with major uncertainties. None of these policies are developed to a level needed to properly optimize resources. The current policy issues are: 1) CETA's determination of "use" for compliance with the 2030 primary compliance standard, 2) the Climate Commitment Act's (CCA) 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' 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 technologies 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 alternative options for Avista to consider. This IRP reflects Avista's decisions based on input from its TAC. The PRS includes several components: 1) required investments as part of Avista's commitment of NCIF monies, 2) demand response or retail rate pricing strategies, 3) energy efficiency, 4) supply-side resources, and 5) transmission needs.

Washington Named Community Investment Fund

This IRP includes projects from the NCIF approved[4] in Avista's first CEIP. This fund targets specific communities with additional investments beyond those traditionally used

[4] Docket UE-220350, Order 01

in least cost resource acquisitions to improve disadvantaged communities as the industry transitions to cleaner resources. The fund is approximately 1% of revenue requirement or $5 million. This IRP attempts to estimate resource decisions based on available funding with impacts to resource strategy. The NCIF targets spending for the following objectives of the total available funding:

- 40% or up to $2 million dedicated to supplement and support Avista's targeted energy efficiency efforts.
- 20% or up to $1 million dedicated to distribution resilience efforts.
- 20% or up to $1 million dedicated to incentives or grants to develop projects led by local customers or third parties.
- 10% or up to $500,000 for new targeted outreach and engagement efforts specifically for Named Communities. This is intended to reduce barriers to participation for Named Communities' access to clean energy.
- 10% or up to $500,000 for all other projects, programs, or initiatives.

The IRP focuses on ensuring enough energy or capacity is created to meet customer load at the right time. Specific NCIF projects are unknown and will be developed over time based on direction from the communities Avista serves. Due to the unknown nature of future projects, the IRP needs to be adjusted to account for these benefits and reduce acquisition targets for other resources. Therefore, actual decisions for funding may or may not impact overall resource needs and are subject to Avista's Equity Advisory Group's (EAG) recommendations 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 NCIF objectives. This is done by requiring the model to select an additional $2 million dollars of EE (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 8 MW of community solar using Department of Commerce funding for this planning horizon. After funding expires, the NCIF could add approximately 2 MW of additional locally distributed solar with 9 MWh of energy storage designed to directly benefit customers residing in Named Communities. The quantity of community solar is a direct result of state (Commerce) and NCIF funding covering 100% of the solar costs including land and administration costs. The total amount of solar added to benefit these communities will be directly related to available funding and project limitations. In addition to solar, Avista's energy efficiency targets are 2.25 GWh higher to reflect additional investments in Named Communities through 2045.[5] The following forecast of these specific resources is in Table 9.1. Both energy efficiency and solar decrease towards the end of the forecasted period. Solar decreases are due to the end of the state funding incentives. Energy efficiency savings beyond 2033 will be

[5] For energy efficiency, energy potential is estimated using low-income vs. non-low income and does not include geographic areas at this time.

insignificant as compared to prior years as most of the energy efficiency potential was achieved in the first 10 years.

Table 9.1: NCIF Resource Selection

Program	Distribution Level Solar	Distribution Level Storage	Energy Efficiency
2024-2033	791 kW per year	Not selected	222 MWh per year
2034-2045	150 kW per year	193 kW (773 kWh) per year	2.2 MWh per year

Demand Response Selections

Demand Response and/or retail rate load control programs could be integral to Avista's strategy to meet peak customer load requirements with non-emitting resources. Avista added 30 MW of industrial demand response since the 2021 IRP and agreed to pilot three DR programs (see Chapter 5). There is uncertainty in the treatment of DRs in the upcoming WRAP with regards to what amount will meet the planning reserve margin (PRM) due to the time duration limits and load snap back effects. Further, some programs using retail rates, such as Time of Use (TOU) are not dispatchable and are dependent on the customers' willingness to participate at the time of the DR event.

In this analysis, ***voluntary TOU rates*** in Washington State are the only cost-effective DR option in the PRS given the cost and benefit assumptions. Avista will pilot this project to determine if the program delivers the expected benefits. If the program is implemented post-pilot, it would begin in 2025 at the earliest for all Washington customers. The total estimated peak savings from TOU rates is nearly 7 MW by 2045.[6] This program is cost-effective over other programs due to significant energy savings assumed for the program rather than just its load reduction capability. Avista will also pilot Peak Time Rebate (PTR) and a water heater direct control program over the next two years. These pilots may result in additional cost-effective selections as the IRP assumptions will be updated based on information gathered in the pilot process. As for this IRP analysis, DR is not favored in this plan due to program cost, but on the ability to count on the resource to meet peak requirements (Qualifying Capacity Credit- QCC) .[7] This plan assumes QCCs for DR pilots will fall to 20% of its capability by the end of the plan, whereas if the QCC was 100% of the capability, 18 MW would be selected in Washington and 9 MW in Idaho. The additional programs selected in this scenario include PTR and Variable Peak Pricing (VPP).

Energy Efficiency Selections

Energy efficiency meets more than 27% of all future load growth, where prior IRP forecasts found EE met nearly 70% of future load growth. This decline is related to

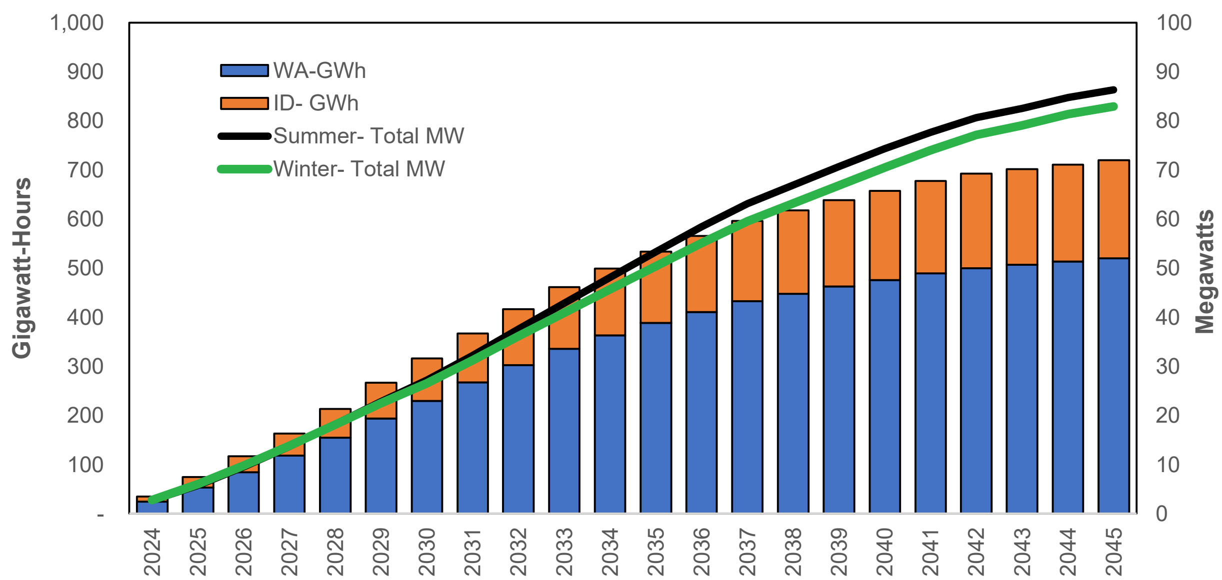
[6] AEG estimate a non-voluntary TOU program would yield 40 MW of savings by 2045.
[7] QCCs are further described in Chapter 4.

expectations of new load from electric transportation and building electrification using efficient appliances and market saturation of efficient technologies. Over 2,600 individual EE measures were studied in this IRP.[8] Avista models EE 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.

Avista's load forecast (described in Chapter 2) is net of future EE savings. This EE selection exercise is trying to determine the amount of EE and the specific cost-effective programs Avista should pursue. Avista adds the selected quantity of efficiency savings back to the load forecast through an iterative 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, 695 cumulative gigawatt-hours are saved through EE between 2024 and 2045. When considering transmission and distribution losses, loads are 85 aMW less with these programs. Figure 9.2 shows total energy and peak hour savings by state for both winter and summer. Winter peaks are reduced by nearly 80 MW and summer peaks are reduced by 84 MW. Over the IRP planning horizon, 29% of new EE comes from Idaho customers and 71% from Washington customers. Washington has more EE savings than Idaho relative to its share of load because of the higher avoided costs driven by CETA and other Washington regulations.

Figure 9.2: Energy Efficiency Annual Forecast



[8] Past IRPs included over 7,000 measures, to be more efficient this IRP combines similar programs to reduce the options.

Most EE savings are from commercial customers (58%), followed by residential customers (28%), with the remainder from industrial customers. The greatest sources of EE, at nearly 67%, are from lighting and space heating/cooling measures. Figure 9.3 shows the program type by share of the total savings by percentage through 2045.

Washington Biennial Conservation Plan

The amount of energy efficiency identified in the PRS will lead to specific program creation in Washington and Idaho. The IRP informs Avista's EE team in determining cost-effective solutions and potential new programs for business planning, budgeting, and program development to meet Washington's Energy Independence Act (EIA) Biennial Conservation Plan (BCP) targets. 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 Avista'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 9.4 shows the annual selection of new energy efficiency compared to the 10-year pro-rata share methodology.

Figure 9.3: Energy Efficiency Savings Programs by Share of Total

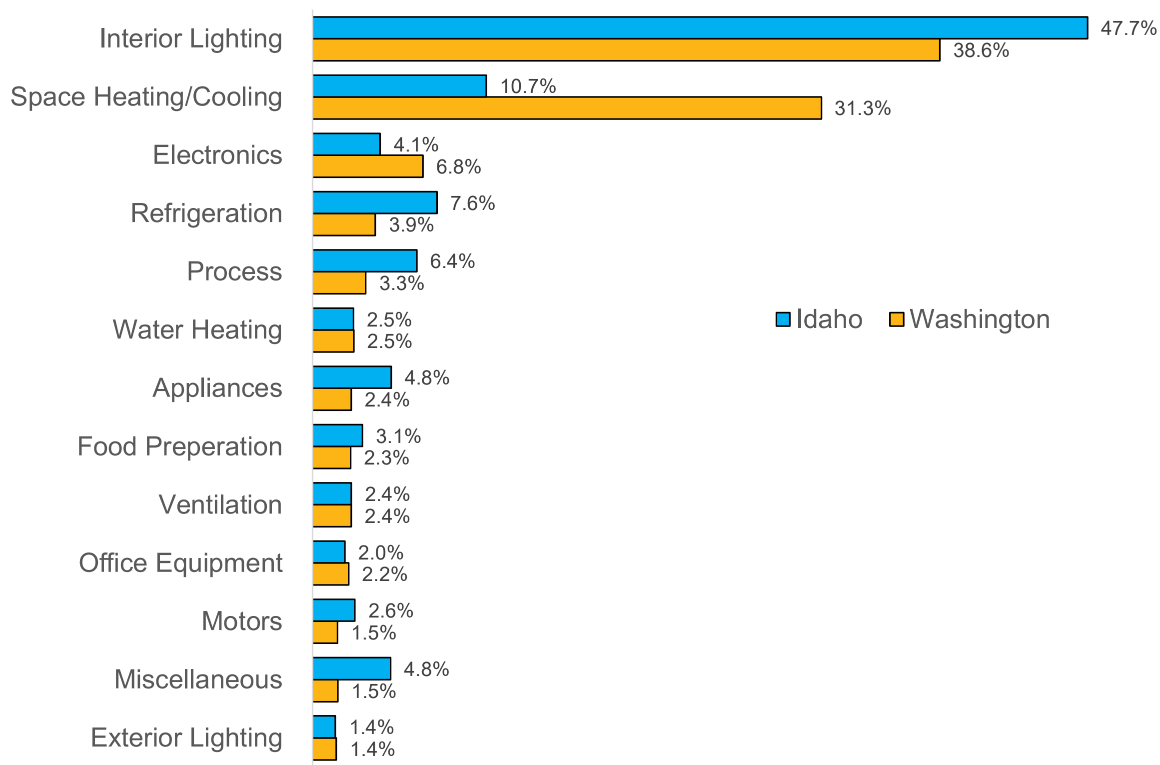
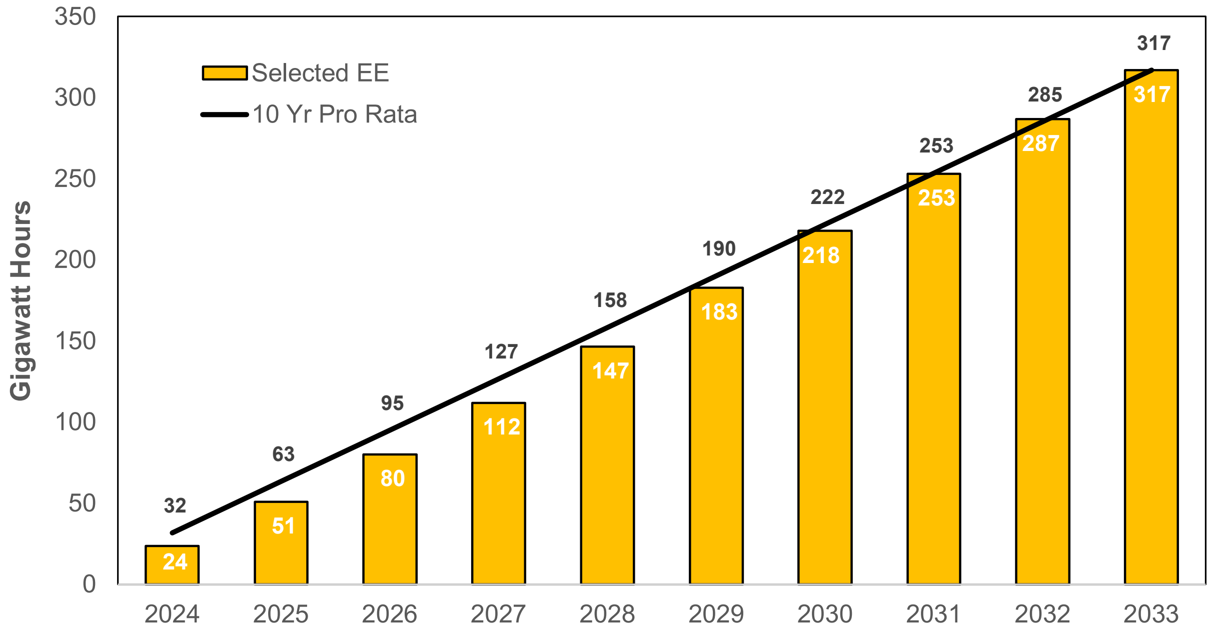


Figure 9.4: Washington Annual Achievable Potential Energy Efficiency (Gigawatt Hours)



For the 2024-2025 Conservation Potential Assessment (CPA), the two-year achievable potential is 50,899 MWh for Washington. The pro-rata share of the utility's ten-year conservation potential is 63,374 MWh and is used in the calculation of the biennial target. Table 9.2 contains achievable conservation potential for 2024-2025 using the PRiSM methodology. Also included below in Table 9.2 is the energy savings expected from the 2024 and 2025 feeder upgrade projects shown.

Table 9.2: Biennial Conservation Target for Washington Energy Efficiency

2024-2025 Biennial Conservation Target (MWh)	
CPA Pro-Rata Share	63,374
EIA Target	**63,374**
Decoupling Threshold	3,226
Total Utility Conservation Goal	**66,600**
Excluded Programs (NEEA)	-10,162
Utility Specific Conservation Goal	**56,438**
Decoupling Threshold	-3,226
EIA Penalty Threshold	**53,212**

Preferred Resource Strategy Resource Selections

The PRS is designed to meet resource needs described in Chapter 4 with generic new resources as described in the DER (Chapter 5) and supply-side resource (Chapter 6) chapters. Due to recent acquisitions described earlier, Avista will not need new resources until the beginning of the next decade. When Avista prepares to acquire these resources, an all-source RFP will be issued ahead of the need to find the best resource opportunity to meet the need rather than use specific IRP resource requirements. The resource strategy discussed here is based on the best available information for planning purposes and are a result of expectations of future loads and resource pricing. Due to uncertainty, Avista will study alternative portfolios discussed in Chapter 10 and will continue to revise this plan every two years.

Avista separates its two jurisdictions for IRP resource selection due to different state-level policy objectives and financial evaluation methodologies. To conduct this analysis, each state is separated by its load forecast along with its planning risk adjustments (totaling the planning obligation), then existing resources are netted against the obligation for each state, whereas each resource is split between states using the existing methodology to allocate resource costs (Production Transmission (PT) ratio) where 64.4% is assigned to Washington and 35.6% to Idaho.[9] Resources are then selected based on the objective function described on earlier in this chapter to fill any shortfalls.

Supply-Side Resource Retirement or Exits

The resource strategy includes retirement or exit of several resources to the existing power supply portfolio. The first resource leaving the system is Colstrip Units 3 and 4, at the end of 2025. These units provide 222 MW of generation capability. Following Colstrip are approximate retirement dates for several of Avista's natural gas peaking facilities. While these dates are subject to change, this plan uses these dates as placeholders to determine need for additional resources. These retirements include Northeast by the end of 2035, Kettle Falls combustion turbine (CT) and Boulder Park by the end of 2040, and Rathdrum by the end of 2044. With the Lancaster PPA extension concluding by the end of 2041, the last remaining natural gas facility is Coyote Springs 2. This resource does not have a planned retirement year for this IRP but is excluded from the resource stack for Washington beginning in 2045. Table 9.3 summarizes resource retirement and exit assumptions.

Table 9.3: Resource Retirements and Exits

Resource	Fuel Type	Year	January Capacity MW
Colstrip Units 3 & 4	Coal	2025	222.0
Northeast Units A & B	Natural Gas	2035	66.0
Boulder Park (1-6)	Natural Gas	2040	24.6
Kettle Falls CT	Natural Gas	2040	11.0
Rathdrum Units 1 & 2	Natural Gas	2044	176.0
		Total	**499.6**

[9] Under the current PT ratio methodology, the ratio would change each year if one state's load grows faster than the other. In this IRP, the PT ratio is left constant to illustrate resource need without one state gaining a larger share of the existing resource base.

Supply-Side Resource Selections (2024 to 2035)

Due to Avista's recent resource acquisitions, the first utility scale resource selection is 200 MW of Northwest wind in 2030 followed by another 200 MW of wind from Montana in 2032. The model selected these resources earlier than the forecasted actual need, as they are more cost effective to acquire before the current tax credits expire. These selections are also constrained by transmission interconnect limit expectations, whereas Avista estimates only 200 MW of on-system wind can be added to the system prior to transmission expansion and only 200 MW of Montana wind can be imported without expanded transmission from Montana. Due to these transmission limitations, the model selects the resource for Washington only to meet its clean energy targets. The resources would be economic for Idaho if there are additional low-cost transmission interconnect opportunities when the new wind is acquired.

The next resource addition before 2035 is a 90 MW natural gas CT for Idaho load requirements. The resource replaces the lost capacity of Northeast CT and positions the jurisdiction to overcome future natural gas retirements in 2040 while also meeting increased load obligations. Table 9.4 summarizes the capacity addition plan through 2035.

Table 9.4: Resource Selections (2024-2035)

Resource	Time Period	Jurisdiction	Capability (MW)	Energy Capability (aMW)
NW Wind	2030	WA	200	63
Montana Wind	2032	WA	200	97
Natural Gas CT	2034	ID	90	86
		Total New Resources	**490**	**245**

Supply-Side Resource Selections (2036 to 2045)

To meet aggressive clean energy targets for Washington by 2045 and replace aging natural gas resources while meeting higher load growth due to electrification preferences in Washington state, Avista expects substantial resource needs after 2036. Idaho needs follow load growth and natural gas resource retirements. Table 9.5 outlines the resource additions and the associated energy production from added resources between 2036 and 2045.

Table 9.5: Resource Selections (2036-2045)

Resource	Time Period	Jurisdiction	Capacity (MW)	Energy Capability (aMW)
Renewable Fueled CT	2036	WA	88	31
Long Duration Storage (>24 hr)	2039	WA	52	-1
PPA Wind Renewal	2041	WA	140	53
Renewable Fueled CT	2041	WA	74	26
Natural Gas (ICE)	2041	ID	46	46
PPA Wind Renewal	2042	WA	105	36
Renewable Fueled CT	2042	WA	186	65
Natural Gas CT	2042	ID	102	97
Long Duration Storage (>24 hr)	2043	WA/ID	68	-1
NW Wind	2044	WA	100	31
Long Duration Storage (>24 hr)	2044	WA/ID	50	-1
NW Wind	2045	WA	200	63
Renewable Fueled CT	2045	WA	348	122
Natural Gas (ICE)	2045	ID	65	65
Short Duration Storage (<8 hr)	2045	ID	25	0
Total New Resources			**1,649**	**632**

There are two primary technologies selected by the model to solve capacity shortfalls without using natural gas technologies – these are ammonia-based turbines labeled as "Renewable Fueled CT' in Table 9.5 and iron-oxide storage labeled as "Long Duration Storage (>24hr)". Both of these technologies are undeveloped at a commercial utility scale and can be substituted if the technologies do not materialize, although its substituted resource would require a new technology or requiring more lower duration storage resources at a higher cost. A significant risk to meet future load in Washington is the failure of storage technologies materializing, placing the 100% clean energy targets in significant jeopardy without compromising reliability or affordability.

The Idaho capacity additions are, for the most part, natural gas CT in 2042 and natural gas Internal Combustion Engines (ICE) in 2041 and 2045. Long- and short-duration energy storage fill smaller capacity needs during this period. In total, 280 MW of capacity are required for Idaho customers.

For Washington State, 1,370 MW of capacity is required to replace capacity resources and further develop additional clean energy to meet 2045 targets. Over the last decade of this plan, Washington customers, who represent 64% of existing load, demand 83% of the new capacity or 480% more generating capacity than Idaho customers. The plan outlines 545 MW of additional wind capacity, whereas 245 MW of this total could be met with extensions of existing wind PPAs. The other wind selections are from off-system resources to avoid building higher cost transmission on the Avista system. The remaining

824 MW are capacity resources additions are long-duration storage or renewable fuels, whereas renewable fuels are in fact long duration storage, but have a separate energy consumption intake.

Renewable Fuels

Avista estimates a need of 696 MW of renewable fueled CTs. This IRP assumes the fuel is purchased within a future hydrogen/ammonia fuel market. The renewable fuel will require substantial clean electrical energy production to meet the demand. For example, current ammonia round trip efficiency with a CT is approximately 13.4%, meaning for each MWh of ammonia power will require 7.5 MWh of a renewable resource to be created earlier in the process. Avista anticipates additional renewable resources beyond those identified in the PRS will need to be developed by the fuel supplier or will be buying power from either the wholesale market or a utility.

The amount of renewable production for the expected case of this study to satisfy the CT requirements is 376 aMW, but in a 95th percentile scenario (i.e. low water year) 953 aMW is required. To put this into perspective the fuel requirements is equal to 1,500 MW (AC) of solar for the expected case and 3,800 MW for the high scenario. Avista anticipates much of the fuel can be produced by a combination of electric market over supply, but it is likely additional renewable resources will be required. Due to the varying fuel requirements ammonia storage and transportation will be key to ensuring electrical reliability, at minimum four 30,000 tonne tanks would be required to ensure reliability for Avista's Washington demand.

System Overview

Figures 9.5 through 9.7 summarize the future resource additions by combining the existing portfolio of resources, with contracted additions, and future resource selections from this plan. As shown in Figure 9.5, the resource portfolio exceeds winter peak planning requirements through 2039, then is balanced once it must fill resource deficits from natural gas retirements and load growth with new resources. The end of the plan relies on storage and renewable fuels to satisfy winter peak requirements. The solid black line represents the planning load level, including the planning margin, and the dotted line is the expected peak load given an average coldest weather event.

The summer capacity position in Figure 9.6 is similar to the winter position where the portfolio has excess capacity, but in this comparison the portfolio should stay above peak needs as the winter peak position is the binding constraint for new resources. The solid black line represents the planning load level including the planning margin, and the dotted line is the expected peak load given an average hot weather event.

Avista's annual energy position (Figure 9.7) is long compared to annual average needs due to two factors: 1) excess energy in the springs months from hydro runoff creates an extreme long position in one quarter compared to others, 2) Avista plans its system to peak load requirements and if the generation used to serve peak requirements creates energy it will be excess to the average need, but can be sold to benefit customers if the resource is economic to operate. The solid black line represents the planning load level including the risk of load exceeding expected average weather conditions and/or renewable energy such as hydro, producing less generation than anticipated in a normal year. The dotted line is the expected average load with normal weather conditions.

Figure 9.5: System Winter Capacity Load & Resources

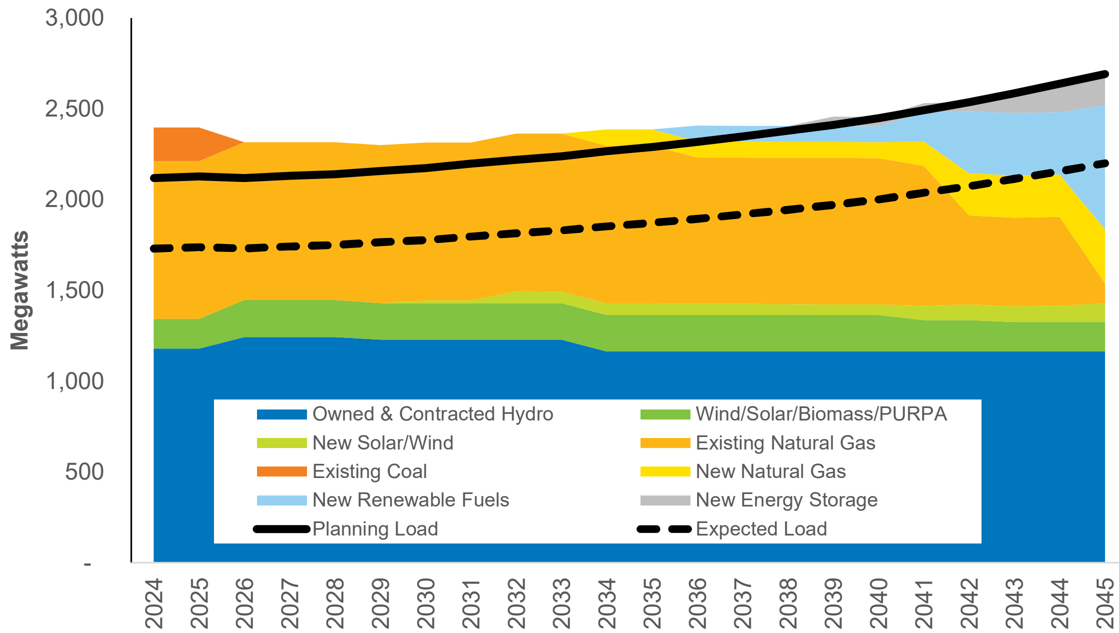


Figure 9.6: System Summer Capacity Load & Resources

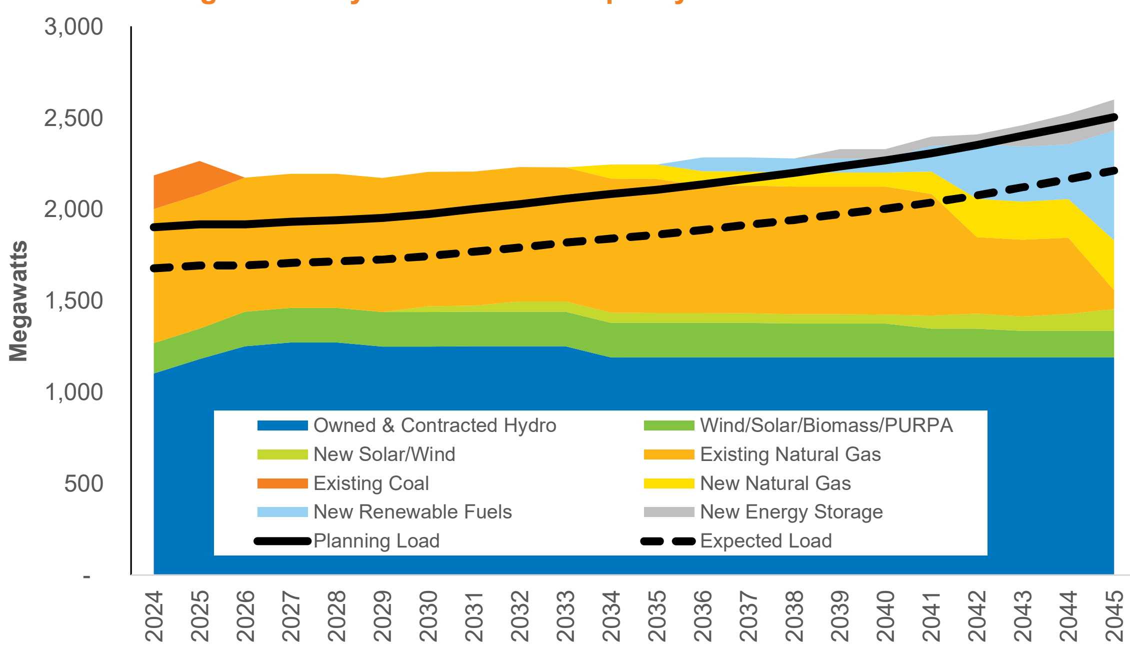
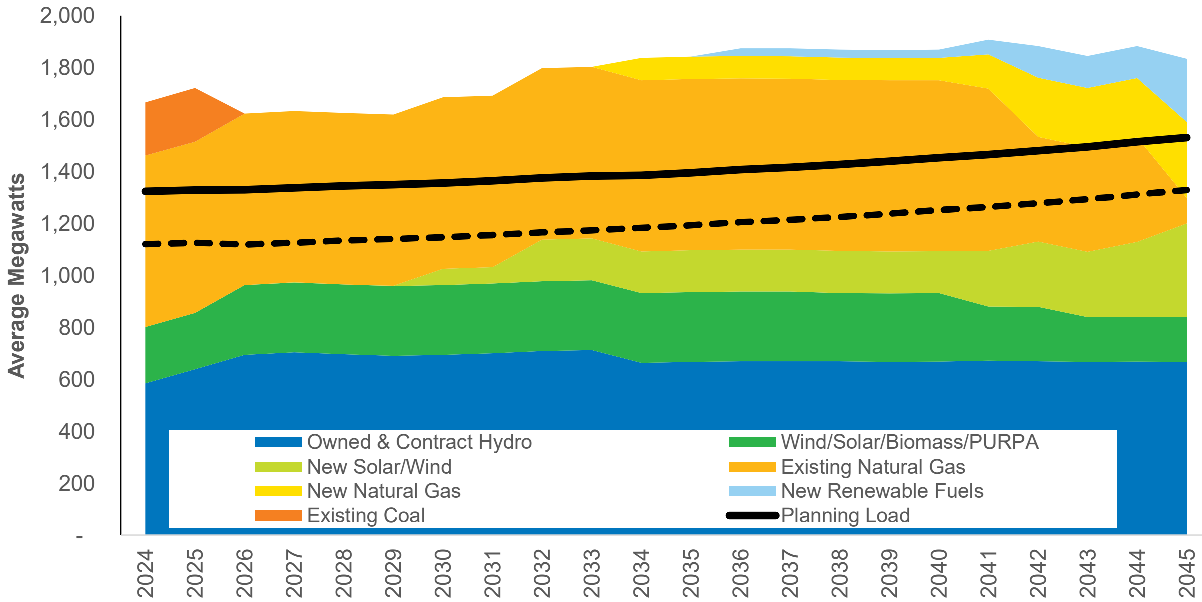


Figure 9.7: System Annual Energy Load & Resources



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 complex multi-year transmission needs. Without new transmission construction, some resource generation will just not be available for delivery to customers.

The PRiSM model estimates 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 but transmission congested areas, such as the Big Bend (Othello, WA) 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 will evaluate long-term system needs and begin permitting and land acquisitions as early as possible.

The PRS also identifies 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 greenfield or existing sites, but subject to area load growth, state policies, and capacity needs; additional reinforcement between North Idaho and Spokane will be needed if the resource is sited in these areas. Because of the urban nature of these areas, Avista's transmission group will need to investigate how 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, 200 MW of Montana wind[10] in the first half of the plan and 500 MW of Northwest wind in the second half 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 resources with Avista's system to their systems. Further, with the amount of variable energy resources (VER) (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 the excess generation without expanding existing transmission capacity or utilizing neighboring systems. 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 as well as the cost and benefits of an RTO. Avista plans to further analyze market related transmission needs in preparation of the 2025 IRP.

Market Risk Analysis

As discussed in Chapter 4, Avista has changed its approach to capacity planning. The 2021 IRP utilized a loss of load probability (LOLP) analysis to determine capacity additions necessary to achieve a 5% LOLP. In this IRP, Avista is utilizing metrics, called Qualifying Capacity Credits (QCCs), from the WRAP program and other regional studies to drive capacity additions in the PRS. Inherent in this approach is the potential for increased reliance within an organized energy market.

To understand market reliance throughout the year a modified version of the reliability model used in the 2021 IRP LOLP analysis was used. The model is a linear optimization dispatch model based in Excel using Lindo Systems' *What'sBest*. The model optimizes to serve load with a specified amount of generation from run of river facilities, contracts, and renewables. The balance is then met with dispatched generation from hydro with storage, thermal generation, batteries and market purchases and sales. The dispatch is linearly optimized to minimize costs from thermal generation and market purchases.

A risk evaluation is done by running the model repeatedly, each time randomly selecting a weather year driving load and renewable generation and a hydro year for hydrogeneration, both run of river generation and available water for dispatch of storage hydro projects. The model also integrates forced outages based on rates established for each generation resource. For each year, the model output includes any hours where load could not be met by generation, battery storage, or market purchases, thereby creating a loss of load event. The model output also includes the full hourly market

[10] Assumes transmission is available from other plant closures and new facilities will be constructed to integrate new wind resources to existing transmission.

purchases for each year. Market prices were taken from the Aurora stochastic price analysis described in Chapter 8.

Four scenarios were run for this analysis: 1) 2030 PRS with an hourly market purchase limit of 330 MW, 2) 2030 PRS with an hourly market purchase limit of 1,000 MW, 3) 2045 PRS with an hourly market purchase limit of 330 MW, and 4) 2045 PRS with an hourly market purchase limit of 1,000 MW. Each scenario was run 1,000 times. Historically, Avista used the 330 MW market limit to set thresholds for reliability, but with the development of the WRAP and its resource sharing benefits during peak events, this threshold is moved to 1,000 MW to understand market dependance during peak events.

Results were evaluated by averaging the market purchases for each hour of the day for each month. Both all hours of the year and potential market constrained hours were analyzed. Market constrained hours are those days that the daily average temperature is below 2 or above 83 degrees Fahrenheit. Those days are considered market constrained hours because at these temperature conditions many utilities in the region would be experiencing above average load and market liquidity would be reduced.

2030 PRS 330 MW Market Purchase Limit

The LOLP for this scenario was 0.40%, with only two simulations resulting in unserved energy. The matrix below shows the average market hourly purchase for each month by hour. Market purchases are driven by market price, available hydro, and renewable production. As shown in Figures 8.17 through 8.20 from Chapter 8, prices are lower during the mid-day and highest during hours 18-24. Market prices in 2030 were generally lower than the model price for thermal generation, therefore the model selected market purchases during low-cost hours rather than thermal generation. This does not reflect a market reliance, rather optimization based on market prices and the cost of thermal generation. Average market purchases during the mid-day are near the modeled max of 330 MW, but do not reach that level as show in Table 9.6. During May and June market purchases are less than 30% of the model max due to the abundance of hydro energy. During periods of a regionally constrained market, the limit of 330 MW was reached during mid-day and neared the market limit in all other hours in all months except for March, April, and May. Generally speaking hours 7, 8 and 18 are the highest load hours during winter months and hours 16 to 18 are the highest in the summer months. As shown in the lower Table 9.6 chart, the model shows market reliance toward the market cap in summer months, but winter months appears to not reach the maximum allowable market in these hours.

Table 9.6: 2030 Average Market Purchases with 330 MW Market Limit (aMW)

All Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	77	105	117	125	119	74	36	46	144	235	271	278	279	277	274	250	56	3	3	3	4	10	22	48
2	84	116	131	138	124	59	27	68	221	298	314	316	315	313	310	297	155	4	1	1	2	4	18	48
3	87	112	125	122	80	38	65	229	306	320	323	323	323	321	320	310	245	27	5	5	5	10	25	55
4	39	48	51	44	23	18	121	230	273	286	289	288	286	283	279	258	184	16	2	1	2	4	10	22
5	8	11	12	9	5	5	35	66	83	87	88	88	87	87	82	61	25	2	0	0	0	0	2	11
6	19	23	23	21	15	18	52	80	89	90	90	91	89	80	61	37	15	5	2	1	1	1	8	23
7	33	40	38	40	38	71	201	260	270	275	278	282	279	257	219	150	88	50	18	11	11	21	32	36
8	46	56	59	62	51	67	212	282	292	296	298	302	302	290	265	203	138	65	11	8	8	20	35	43
9	29	35	35	34	28	25	131	260	277	281	283	285	286	284	264	177	86	25	9	8	10	19	24	27
10	42	50	50	48	35	21	51	220	276	286	287	286	283	280	271	195	42	6	5	6	8	16	25	35
11	64	83	92	99	89	47	33	161	276	301	302	301	297	297	287	204	19	4	4	3	4	10	22	42
12	56	82	88	99	100	72	30	69	166	244	271	274	273	269	266	196	23	2	2	2	3	9	21	38

Regional Market Constraint Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	297	304	311	317	325	316	300	317	330	330	330	330	330	330	330	330	301	273	286	271	262	275	247	268
2	330	319	330	317	319	273	330	303	330	330	330	330	330	330	330	330	330	298	246	213	253	265	280	286
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	325	325	330	330	330	330	330	330	330	327	325	321	327	330	282	243	206	234	214	171	112	155	123	328
7	276	308	295	312	328	310	330	330	330	330	330	330	330	330	330	328	321	287	216	218	238	238	279	287
8	265	252	283	300	286	309	330	330	330	330	330	330	330	330	330	330	330	297	208	184	212	250	238	196
9	165	117	205	196	209	297	330	330	330	330	330	330	330	330	330	330	330	330	248	250	241	189	330	246
10	153	188	252	164	176	231	330	330	330	330	330	330	330	330	330	330	330	140	154	95	207	113	207	264
11	323	327	329	330	330	325	330	330	330	330	330	330	330	330	330	330	316	315	313	330	330	293	319	330
12	266	292	304	307	317	319	313	324	330	330	330	330	330	330	330	330	291	237	229	203	215	211	242	264

2030 PRS 1,000 MW Market Purchase Limit

The LOLP for this scenario is 0%. The only difference between this scenario and the previously described scenario was the modeled maximum was increased from 330 MW to 1,000 MW. This suggests the two loss of load events in the previous scenario were alleviated by market availability. The market purchase pattern is similar to the previous scenario, but the values are greater, though not reaching the model maximum of 1,000 MW as shown in Table 9.7. This illustrates the difference between market price and the cost of thermal generation. Given the low prices in the middle of the day and system flexibility, Avista is able to shift its energy storage at its hydro system to minimize capacity purchases during the highest load in hour 18. During periods of a regionally constrained market there is an increase in purchases across all hours of the day in comparison to the "all hours" scenario, though in most instances did not reach the model maximum of 1,000 MW. It is noteworthy when comparing these results to the 330 MW market limit, the summer month's peak hours use more market during high low hours, this is likely due to pricing arbitrage to take advantage of mid-day lower prices.

Table 9.7: 2030 Average Market Purchases with 1,000 MW Market Limit (aMW)

All Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	74	107	127	140	130	71	36	52	223	425	528	554	554	544	531	457	58	2	2	2	2	8	18	44
2	64	103	126	140	125	50	24	88	396	622	707	725	712	695	669	590	216	3	1	1	1	3	12	35
3	59	87	103	102	56	23	74	382	604	683	704	698	684	657	629	559	354	23	3	3	4	7	13	35
4	21	28	29	23	9	8	105	274	380	423	428	418	409	384	364	300	166	12	2	1	2	3	6	14
5	7	10	10	7	4	2	25	67	96	106	108	108	106	108	99	67	21	1	0	0	0	0	3	14
6	16	19	19	17	12	9	42	88	113	119	121	127	127	113	84	44	14	4	2	1	1	0	9	26
7	18	23	20	20	17	39	187	346	399	434	464	500	516	464	373	232	123	69	24	9	9	18	25	26
8	35	43	43	45	32	49	238	429	495	531	554	590	607	572	491	328	195	82	13	9	8	19	31	36
9	28	36	36	33	23	19	168	423	478	493	505	514	526	528	474	268	113	32	8	7	10	22	27	30
10	48	60	59	56	33	16	61	397	547	574	575	563	545	525	499	317	45	6	5	6	8	18	29	41
11	62	89	106	119	95	37	30	265	570	668	673	670	652	643	601	352	18	3	3	3	4	9	18	39
12	44	70	81	98	95	55	25	77	252	422	500	515	511	498	487	315	23	2	2	2	3	8	19	35

Regional Market Constraint Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	228	276	331	363	361	240	268	328	522	665	773	785	774	749	726	641	277	221	250	188	175	174	151	190
2	303	379	396	390	434	271	352	499	819	922	969	981	977	972	952	943	509	145	140	92	99	245	226	195
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	322	318	251	260	266	350	425	457	508	427	338	299	304	318	240	222	196	231	209	172	155	129	131	503
7	302	312	275	258	268	294	454	612	696	777	839	882	919	886	764	633	533	395	293	193	210	210	421	382
8	285	277	275	304	285	306	502	677	772	846	894	958	979	950	856	639	552	440	270	486	424	262	190	244
9	86	135	203	193	158	167	492	923	968	895	912	907	916	920	919	527	346	109	38	22	20	166	335	143
10	88	263	247	234	113	102	236	945	913	833	834	836	832	820	812	564	350	0	0	0	81	172	238	299
11	369	394	418	479	444	329	420	818	994	1000	1000	1000	999	987	982	841	341	288	265	274	198	239	223	345
12	174	249	276	313	315	254	280	407	598	708	756	756	753	707	713	506	278	185	179	147	162	202	200	183

2045 PRS 330 MW Market Purchase Limit

The LOLP for this scenario is 0%. Market purchases follow a similar pattern as the 2030 scenarios with the most significant market purchases occurring in the mid-day when prices are low. In the 2045 scenario the cost of thermal generation is increased largely due to the addition of higher cost renewable fueled (ammonia) turbines. This high-priced fuel increases the use of market purchases leading to the maximum market purchases as shown in Table 9.8, but available during high stress hours. In market constrained hours the market max of 330 MW is used in most hours except during the months March, April, and May.

Table 9.8: 2045 Average Market Purchases with 330 MW Market Limit (aMW)

All Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	312	324	323	323	323	314	260	252	314	329	330	330	330	330	330	330	308	194	203	189	176	230	298	317
2	311	318	318	319	317	289	211	247	325	330	330	330	330	330	330	330	324	178	165	147	118	138	237	296
3	279	293	296	295	264	205	213	313	329	330	330	330	330	330	330	330	326	211	112	112	96	109	187	252
4	75	87	91	79	44	36	173	279	305	310	313	313	314	314	314	309	260	47	12	9	9	11	25	46
5	13	16	15	12	7	3	31	63	79	83	86	88	90	91	86	65	32	21	17	9	7	6	4	13
6	24	28	27	25	17	23	70	106	116	118	119	122	125	117	97	76	60	60	48	29	16	13	12	23
7	125	131	114	113	107	158	269	303	311	315	318	321	322	318	302	268	231	195	114	83	64	84	118	138
8	205	202	188	184	170	199	292	314	320	323	325	326	327	327	326	321	309	265	111	89	91	178	249	251
9	197	183	158	157	152	161	268	313	318	320	321	322	324	325	323	317	291	136	88	86	88	137	207	223
10	244	236	219	217	211	208	260	320	327	328	328	328	328	328	328	323	286	82	87	85	95	163	238	262
11	303	303	301	303	300	282	261	315	329	330	330	330	330	330	330	326	235	134	142	132	133	190	267	297
12	315	316	312	314	315	311	272	284	324	329	329	330	330	330	330	327	251	171	181	169	163	204	279	311

Regional Market Constraint Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
2	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	315	324	318	296	330	330	330
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	307	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	271	305
7	330	325	316	303	311	307	320	327	330	330	330	330	330	330	330	330	326	326	316	305	311	311	326	330
8	330	329	328	322	320	313	330	330	330	330	330	330	330	330	330	330	330	330	312	318	324	330	330	330
9	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
10	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
11	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
12	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330

2045 PRS 1,000 MW Market Purchase Limit

The LOLP for this scenario is 0%. It follows a similar pattern to the previous scenario with market purchases highest during the mid-day hours, and less market purchases during months with increased hydro production. During market constrained hours the market maximum was reached during mid-day hours and there was an increase of use across all hours, except during the months of March, April, and May as shown in Table 9.9.

The conclusion of this study indicates with expensive variable cost units (Renewable Fueled CTs), the Avista system will be able to optimize lower cost market power (if transmission allows) and utilize the CT capacity for reliability. Given the desire of the model to maximize the allowable market purchases indicates a need to ensure transmission is available to future energy markets.

Table 9.9: 2045 Average Market Purchases with 1,000 MW Market Limit (aMW)

All Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	496	534	530	538	534	440	211	247	576	835	902	918	929	932	936	933	533	156	177	145	111	175	334	463
2	306	347	358	367	347	211	101	246	693	877	919	929	936	937	938	940	706	158	141	118	81	83	146	244
3	167	212	229	222	135	63	151	566	823	877	889	891	898	896	893	892	753	201	82	82	67	74	91	122
4	32	38	36	28	10	10	123	337	472	517	535	541	553	550	543	520	319	38	10	7	8	8	13	23
5	14	16	14	11	7	1	25	68	95	104	110	114	120	124	117	83	33	21	16	9	6	5	5	18
6	21	23	21	18	11	9	60	126	151	161	169	182	194	180	138	89	60	63	51	30	16	12	15	29
7	64	71	57	56	49	107	302	452	505	556	599	662	713	709	646	519	381	289	136	82	59	80	101	92
8	171	162	142	138	112	159	385	533	591	640	679	727	775	793	781	731	654	433	111	74	70	172	276	253
9	175	176	139	143	128	127	352	523	572	583	608	632	669	691	690	640	503	185	100	93	96	160	206	219
10	274	279	243	242	205	159	322	634	731	735	731	735	740	735	739	685	407	78	92	89	102	167	238	298
11	362	394	393	415	375	268	237	648	861	898	894	902	906	906	905	809	234	112	128	106	92	146	239	330
12	464	499	483	502	502	435	232	376	687	852	890	901	909	912	919	827	278	121	142	116	93	137	266	414

Regional Market Constraint Hours

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	790	833	845	872	878	806	630	588	935	994	1000	1000	1000	1000	1000	1000	892	327	345	317	268	379	679	797
2	755	836	883	918	888	740	323	659	969	1000	1000	1000	1000	1000	1000	1000	932	341	365	342	283	250	334	605
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	533	566	564	487	526	622	613	631	642	759	691	652	756	732	509	532	484	561	408	358	356	326	226	156
7	429	400	370	345	319	384	530	657	747	843	892	951	979	990	966	892	755	595	421	330	319	322	341	488
8	506	398	359	352	303	347	589	748	842	927	979	997	1000	1000	1000	995	980	698	254	195	205	469	715	605
9	346	398	472	417	471	521	544	744	893	905	952	972	1000	1000	993	991	906	355	387	381	169	974	722	696
10	451	523	630	503	658	626	409	770	913	953	985	972	973	980	991	998	952	151	311	267	511	904	723	644
11	844	902	906	941	966	867	846	1000	1000	1000	1000	1000	1000	1000	1000	1000	653	366	376	299	284	450	726	885
12	730	756	766	793	824	780	691	852	969	984	991	1000	1000	997	992	983	547	279	306	262	262	370	557	730

Environmental Impacts

Avista's recent changes to its resource portfolio significantly improves its environmental footprint. Transferring Avista's percent ownership of Colstrip Units 3 and 4 to Northwestern Energy at the end of 2025 will significantly reduce GHG and other air emissions. While this transfer does not retire the plant nor eliminate emissions, it does meet Washington's and Avista's own clean energy goals and will allow Montana to make their own decisions regarding coal. The additions of hydro, wind, and biomass power from recent RFPs increases Avista's percentage of clean energy on the system. Figure 9.8 illustrates the increases to clean energy by year and by jurisdiction. The chart compares total annual clean energy production for each state's allocated share of energy[11] compared to the load, whereas in Washington, Avista will need to produce more clean energy than its load to meet the 100% clean energy target. With its already high clean energy portfolio, the Idaho jurisdiction does not need to add additional energy due to cost constraints. On a system basis, the portfolio by 2045 could be 92% clean energy as

[11] This does not include potential transfers of clean energy between states to satisfy CETA requirements.

compared to load, although when comparing to retail sales Avista would be generating 97.3% clean energy compared to retail sales (not shown).

Figure 9.8: System Clean Energy Ratio Compared to Load (Select Years)

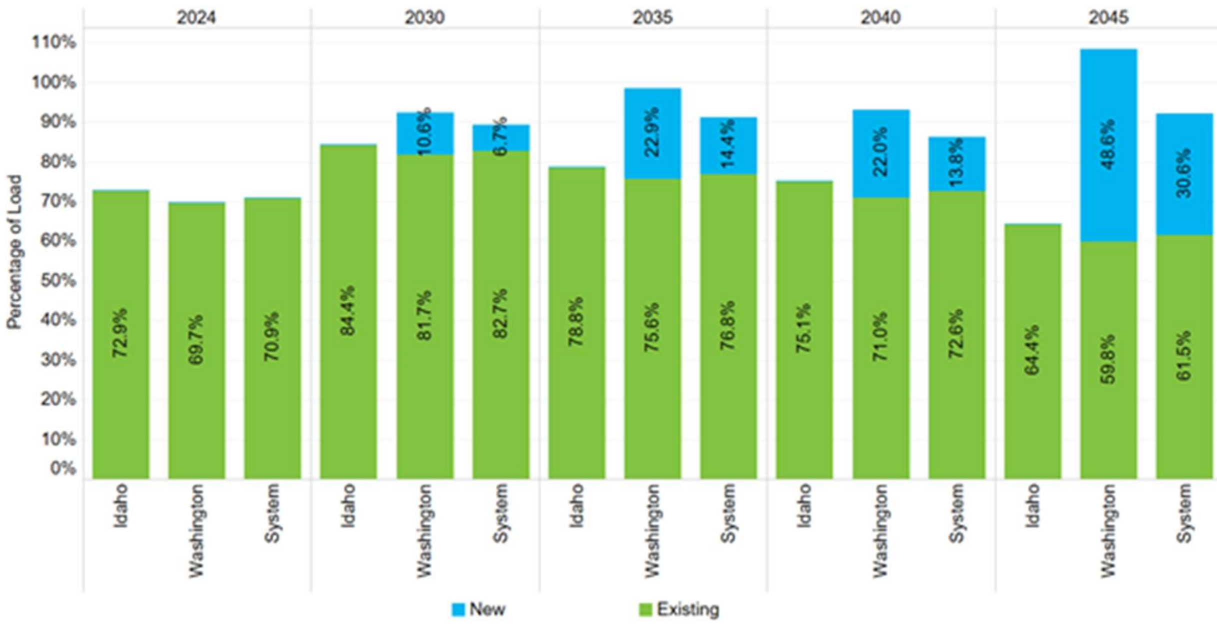
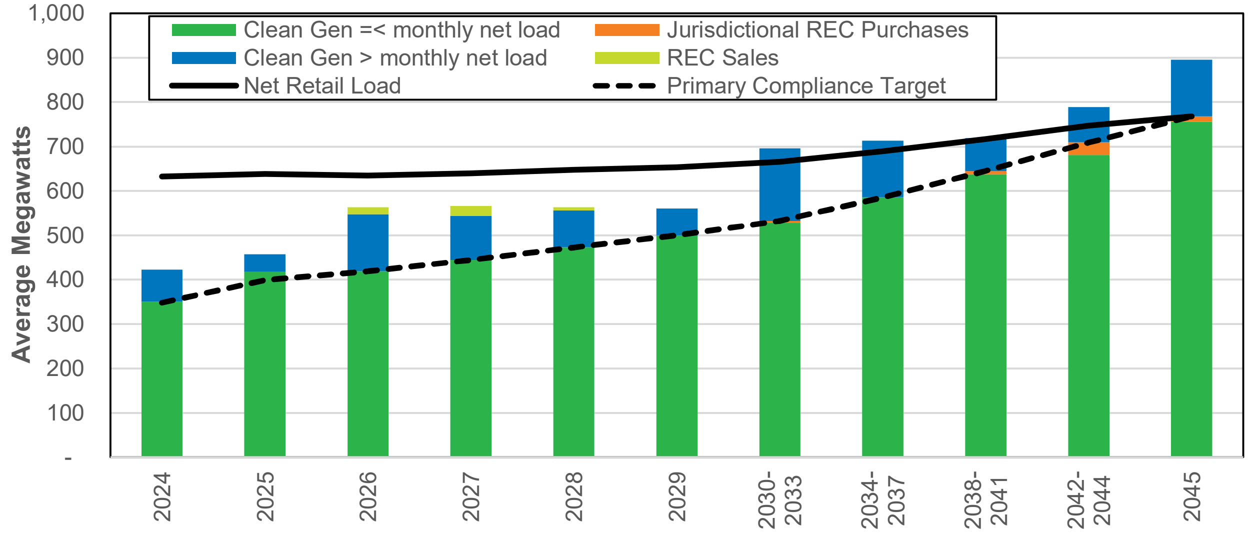


Figure 9.9 illustrates the results of the PRS portfolio compared to Avista's assumptions to meet the primary compliance target where specific CETA obligations prior 2045 are not known. The primary compliance target estimate is shown in the black dotted line and the solid line represents net retail load.[12] In this case, Avista must use clean energy to meet its primary compliance target after 2030 (green bars). Any clean energy generation exceeding load within a month counts towards alternative compliance.[13] As illustrated by Figure 9.9, Avista currently and will continue to create a significant amount of surplus clean energy as shown in the blue bars. The orange area shows where the model selects clean energy purchases from the Idaho jurisdiction and the lime area shows where excess Renewable Energy Credits (RECs) are sold. The PRiSM model limits REC sales to prevent the model from taking a market position where it could build resources to sell RECs, therefore REC sales are limited. Avista will sell excess RECs for the benefit of customers in actual operations. The 100% clean energy target in 2045 will require a significant amount of additional clean energy as compared with load due to clean energy production patterns differing from load patterns. Although this may allow the development of lower cost hydrogen used to create the ammonia to meet the peak load requirements of this portfolio.

[12] Net retail load equals retail sales minus Washington state PURPA resources and voluntary renewable resources such as the Solar Select Program.
[13] This is an IRP assumption as the actual methodology has not been decided by state rule.

Figure 9.9: Clean Energy to Retail Load Comparison (CETA Requirements)



To illustrate the reductions in greenhouse gas emissions, Figure 9.10 shows the 2021 emission level from Avista's facilities at nearly 3 million metric tons (red line). These amounts will fall to nearly 1.5 million metric tons after Colstrip leaves the portfolio at the end of 2025. Afterwards, emissions steadily fall due to reduced natural gas dispatch due to higher renewable penetration levels in the market and greenhouse gas market pricing (e.g., CCA impacts). The blue bars represent direct emissions from existing facilities, while the orange bars are from new natural gas facilities replacing retiring plants. In green, is the estimated emissions from either buying market power or selling excess power from the Avista system. The light blue represents emissions from Avista's generating plant operations and construction of new resources. By 2045, Avista anticipates an 80% reduction in greenhouse emissions as compared to the 2021 levels.

Another view of Avista's low GHG portfolio is through the emissions intensity. In this case, total emissions are compared to Avista's load. Figure 9.11 shows two methodologies for this comparison. The first method is taking only Avista's direct emissions (blue and orange bars from Figure 9.10) compared to load. The second accounts for market transactions (the green bars from Figure 9.10). The black line averages the two methodologies, where current GHG emissions intensity rates are nearly 600 lbs./MWh declining to 300 lbs./MWh after Colstrip exits the portfolio, and then continues to decline as natural gas plants dispatch less frequently or retire. It should also be noted that load is increasing while the GHG emissions intensity rate is decreasing, indicating a greater emissions decline than load increase until the mid-2040s.

Figure 9.10: System Greenhouse Gas Emissions

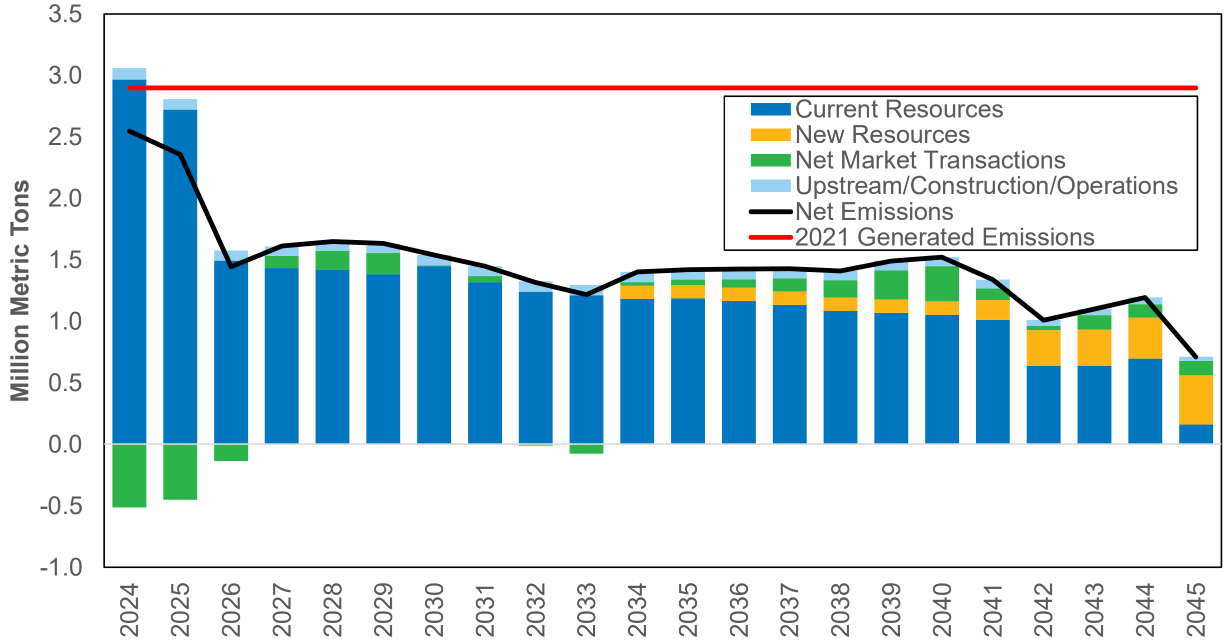
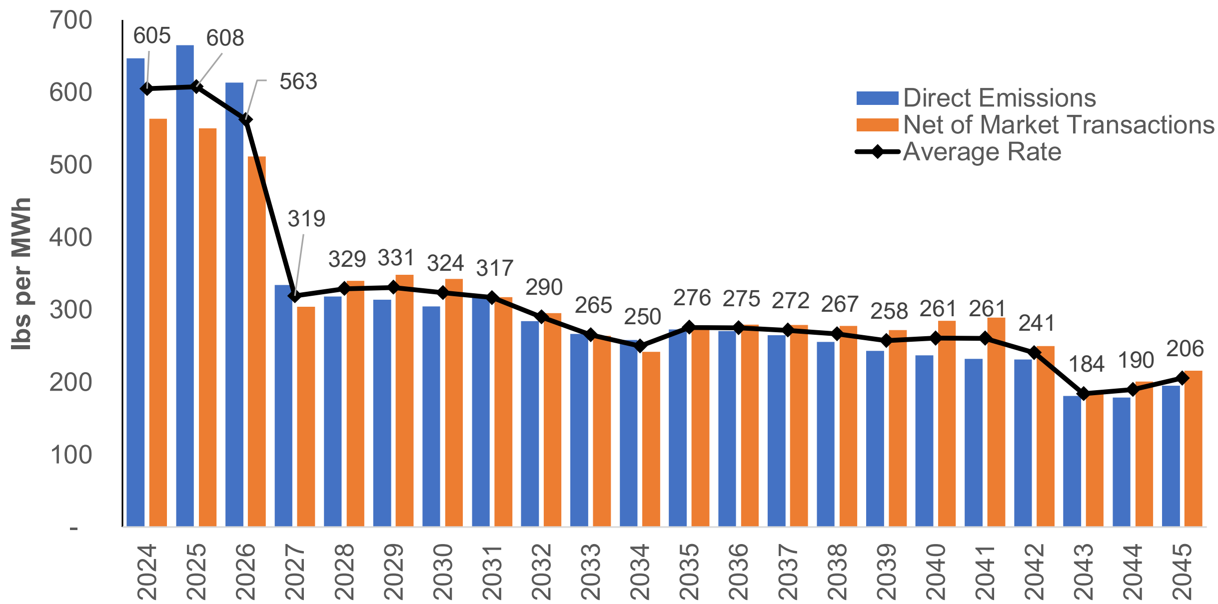


Figure 9.11: System Greenhouse Gas Emissions Intensity

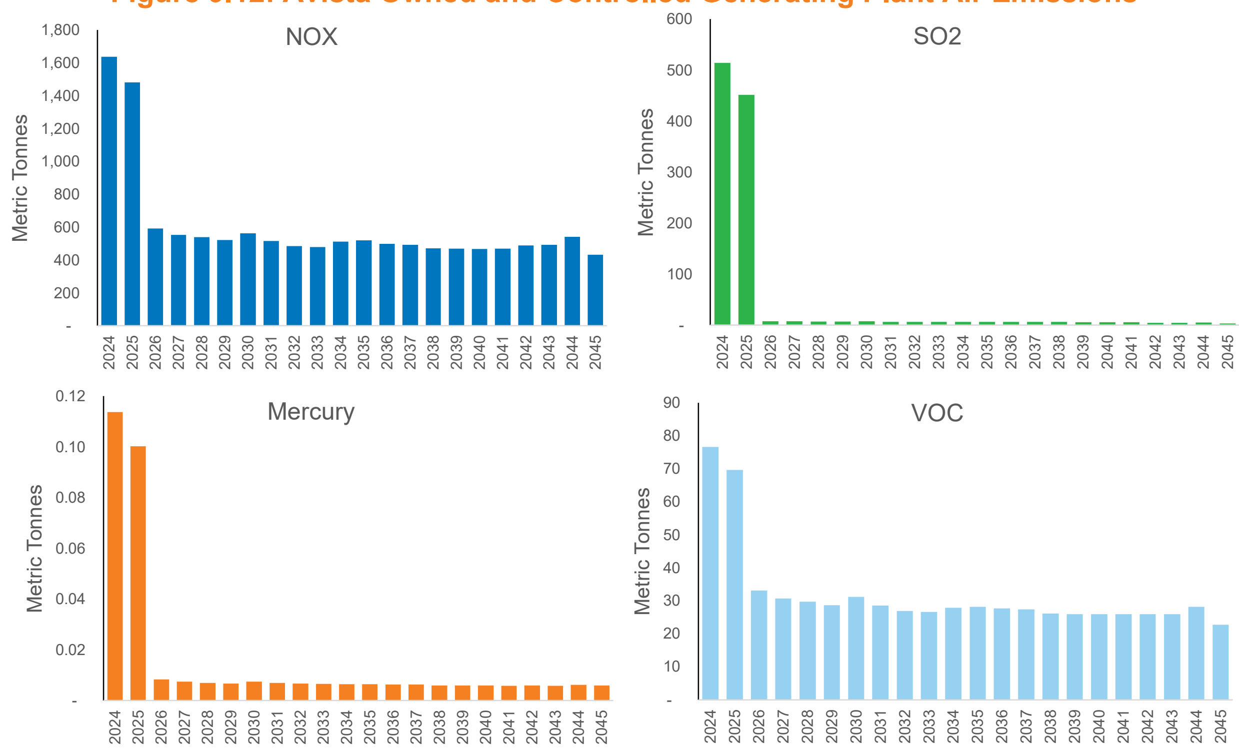


The last emission profiles concerning the resource portfolio includes other major air emissions from Avista's generation plants. These emissions are well below air quality standards set by the local air agencies and are controlled at the plant level with the best available technologies at the time of construction. Avista tracks four major air emissions in the IRP: Nitrous Oxide (NO_X), Sulfur Dioxide (SO_2), Mercury (Hg),[14] and Volatile

[14] Avista does not track mercury emissions at natural gas facilities since it is not a permit requirement, the emission beyond 2025 are for Kettle Falls based on historical intensity rates, although the most recent study

Organic Compounds (VOC) at the plant locations in Figure 9.12. The emissions shown here cover all Avista's owned facilities plus contracted plants where it has dispatch control rights. Emissions levels in all four categories fall over time, whereas the largest reductions are from Colstrip leaving the portfolio at the end of 2025. After 2025, the main source of air quality emissions will be from the Kettle Falls wood waste facility as Avista's natural gas generating facilities have limited emissions due to lower projected dispatch. Kettle Falls will see an improvement to air emissions intensity with the steam injection discussed earlier in the chapter. The selection of ammonia-based generation in the latter years of the portfolio could result in an increase in NO_X emissions from this technology due to the amount of NO_X emitted from the combustion. Since this is a new technology with the potential to mitigate the emission, the specific emissions levels are currently unknown. The expectation is that the NO_X will be mitigated in order for these plants to be able to obtain air permits.

Figure 9.12: Avista Owned and Controlled Generating Plant Air Emissions



Cost and Rate Projections

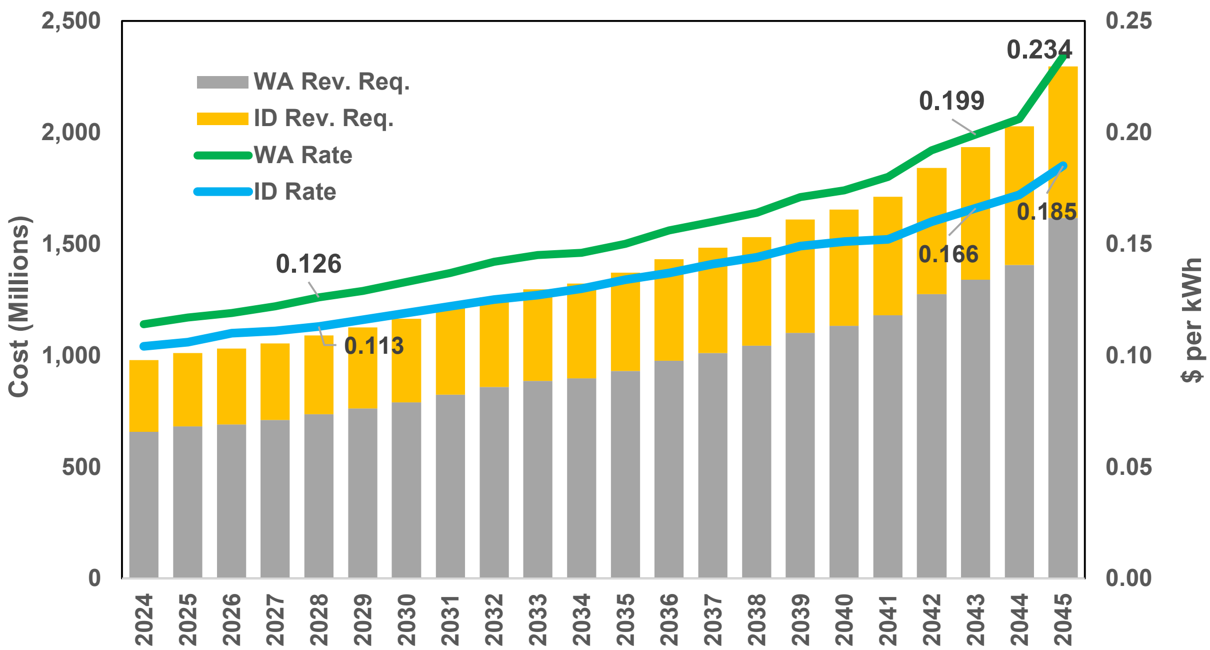
The IRP cost and rate projection does not include detailed transmission beyond specific generation acquisition, distribution, administrative, and Operations & Maintenance (O&M) recovery costs. Rather, the IRP focuses on energy supply costs. Avista assumes these non-generation costs increase by 3.8% per year to approximate an annual average customer rate estimate using historic non-power supply cost growth rates. Annual

conducted after the IRP modeling was complete, indicated a non-detect. For Colstrip, a default emission factor is used for mercury emissions.

projected rates and revenue requirements are shown in Figure 9.13. Rates are calculated by the total revenue requirement divided by retail sales and do not represent rate class forecasts. Also, as rates will be determined by actual investments, this analysis should only be used for comparative and informational purposes.

The Washington revenue requirement grows at 4.3% a year and rates increase 3.4% a year, although in the last five years of the study, revenue requirement and rates grow faster at 7.4% and 6.1% respectively. Cost and rates for Idaho are generally lower where the average revenue requirement grows at 3.5% each year and rates are less at 2.7% annually. Over the last five years, Idaho rates also increase at a faster rate due to resource retirements but have a 5.4% revenue requirement increase and 4.2% rates average increase).

Figure 9.13: Revenue Requirement and Rate Forecast by State



Incremental Cost Cap Analysis

Avista conducted an incremental cost analysis for Washington-related CETA costs using the incremental cost methodology provided by rule. The PRS 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 the exit of Coyote Springs 2 in 2045 for Washington customers. The difference in costs between these studies represents the annual incremental cost – this value is then compared to a 2% annual rate increase of the Alternative Lowest Reasonable Cost Portfolio cost. The analysis in Table 9.10 shows Avista does not reach the cost cap in any of the future 4-year compliance periods but is much closer in the last 2042 to 2045 window. Since it is unclear if 2045 would be covered in this four-year period, there is a strong likelihood given these assumptions, that exceeding the 2045 cost cap could be used as alternative compliance to meet the primary compliance requirement.

Table 9.10: 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	$139	$158	$180	$208	$248
Incremental Cost w NCIF spending	$19	$32	$41	$64	$166
Delta	$120	$126	$139	$144	$82

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 2% cost cap includes past higher cost resource acquisitions. One interpretation could be to exclude any resource acquisition made after 2020 meeting CETA clean energy requirements and let a capacity expansion model select resources to fill in those capacity/energy deficits or use a historically based model from a resource plan prior to CETA. 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 PRS cost to alternative portfolios. These calculations can be useful to evaluate new Public Utility Regulatory Policies Act (PURPA) agreements or other resource acquisitions. The calculations here are not used for setting Washington Schedule 62 rates but may inform its calculation.

Energy Efficiency

The Washington EIA requires utilities with more than 25,000 customers to acquire all cost-effective and achievable energy conservation.[15] Penalties could be accessed for utilities not achieving EIA targets, further, these targets are also used for setting efficiency requirements in Washington's CEIP. Avista uses the Total Resource Cost (TRC)[16] test plus non-energy impacts with a social cost of greenhouse gas savings to estimate its cost-effective energy savings. Idaho only uses the utility cost test. The estimated avoided cost of energy efficiency in Washington is shown in Figure 9.14 and Idaho's is shown in Figure 9.15. The total 20-year Washington energy avoided cost of energy efficiency is $68.94 per MWh and capacity is $118.44 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 whether the program has non-energy impacts.

[15] The EIA defines cost effective as 10% higher cost than a utility would otherwise spend on energy acquisition.
[16] See Chapter 5 for further information on the TRC and UCT methodologies.

Idaho avoided cost is less due to the exclusion of clean energy premiums, Power Act[17] preference, and avoidance of the social cost of greenhouse gas. Idaho energy avoided costs is $37.07 per MWh and capacity is $107.67 per kW-yr. Avista includes the savings of future transmission and distribution expenses and line loss savings in both states' avoided cost.

Figure 9.14: Washington Energy Efficiency Avoided Cost

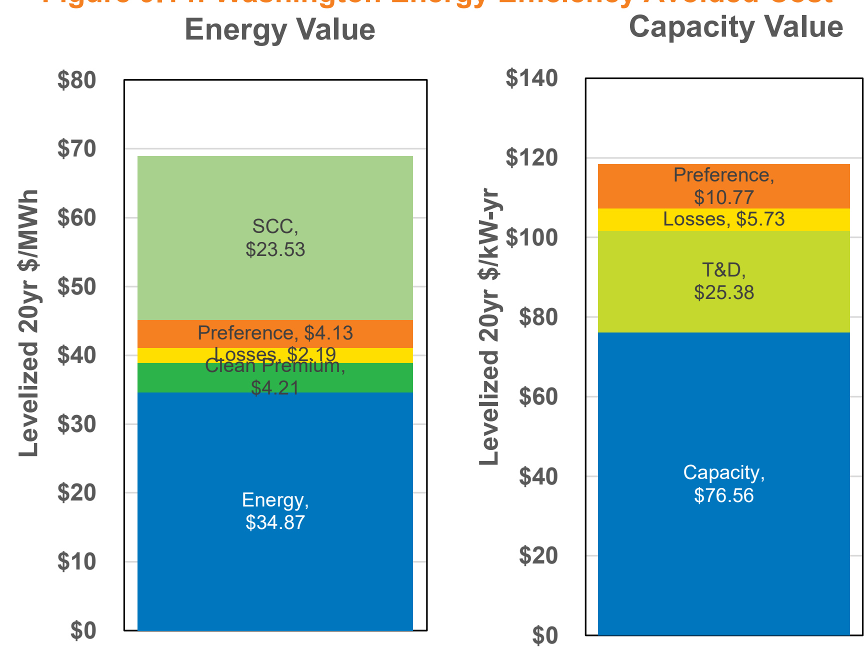
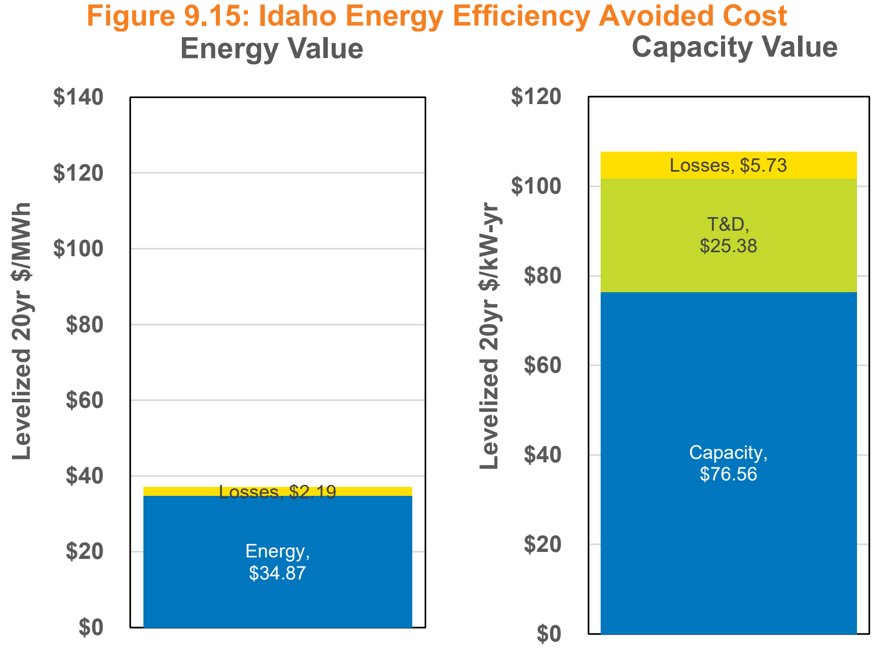


Figure 9.15: Idaho Energy Efficiency Avoided Cost



[17] Washington's Energy Independence Act requires a 10% cost advantage adder for energy efficiency to give this resource preference as required in the Northwest Power Act.

New Generation Avoided Costs

Avoided costs change as Avista's load and resource position changes, as well as with changes in the wholesale power market and new resource costs. Avoided costs are a best-available estimate at the time of this analysis. Specific project characteristics will likely change the value of a resource. The prices shown in Table 9.7 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 unspecified energy price shown in Table 9.7.[18] In addition to the energy prices, these theoretical resources would also receive capacity value for production at the time of system peak. This value begins in 2034.

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.[19] Avista uses these annual revenue requirement[20] differences to create annualized costs of capacity beginning in the first year of a major resource deficit. Recognizing cash flows fluctuate, the variability in annual values is levelized and tilted using a 2% 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.

New to this IRP is a second capacity value due to Washington requirements for a transition to clean energy. In this case, a clean capacity premium is offered for capacity reducing resources. Avista's greatest challenge in meeting the CETA targets is clean capacity rather than clean energy as demonstrated by the need for storage and renewable fueled CTs. The capacity premium was created by analyzing a portfolio with only clean capacity resources being selected in a similar way to the traditional capacity calculation discussed above. Due to cleaner resources having higher costs than natural gas CTs there is a higher avoided cost of this capacity. Historically, Avista included this cost within the clean energy premium, but has moved to a capacity value, as the capacity is a greater constraint than energy in this IRP.

Capacity pricing at the full capacity payment shown in Table 9.11 assumes a 100% QCC or Equivalent Load Carrying Capability (ELCC) in the winter. For example, solar receives a 2% QCC credit based on ELCC analysis and would receive 2% of the capacity payment compared with its nameplate capacity. Avista will need to either conduct an ELCC analysis or utilize the QCC value from the 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 than the summer for all future years of the planning horizon. However, a mild

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[18] Projects with undetermined energy production will need to be estimated based on the resource'
[19] Descriptions of each of these portfolios are including in Chapter 10.
[20] 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.

winter and hotter than expected summer could result in an actual summer peak greater than winter. Avoided costs are based on expected rather than actual costs.

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 expected in the PRS. 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 PRS to the same portfolio used to calculate the Clean Capacity Cost. Avista uses the annual revenue requirement differences to create an annualized cost of clean energy beginning with the first year of clean energy acquisition based on need for the resource (2034)[21] with an annual price adjustment of 2% 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 transitioning 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. The clean premium is significantly lower than the previous IRP due to lower renewable costs, higher traditional energy costs, and creating the clean capacity premium discussed above.

[21] Avista’s first selection of clean resource is prior to 2034 but is either due to the NCIF or taking advantage of expiring IRA benefits.

Table 9.11: New Resource Avoided Costs

Year	Flat Unspecified Energy ($/MWh)	Unspecified Capacity ($/kW-Yr)	Clean Energy Premium ($/MWh)	Clean Capacity Premium ($/kW-Yr)	Total Flat Clean Energy ($/MWh)	Total Clean Capacity ($/kW-Yr)
2024	$42.87	$0.0	$0.00	$0.0	$42.9	$0.0
2025	$35.87	$0.0	$0.00	$0.0	$35.9	$0.0
2026	$33.24	$0.0	$0.00	$0.0	$33.2	$0.0
2027	$29.89	$0.0	$0.00	$0.0	$29.9	$0.0
2028	$29.83	$0.0	$0.00	$0.0	$29.8	$0.0
2029	$29.93	$0.0	$0.00	$0.0	$29.9	$0.0
2030	$34.65	$0.0	$0.00	$0.0	$34.6	$0.0
2031	$32.57	$0.0	$0.00	$0.0	$32.6	$0.0
2032	$31.63	$0.0	$0.00	$0.0	$31.6	$0.0
2033	$32.57	$0.0	$0.00	$0.0	$32.6	$0.0
2034	$33.11	$93.0	$2.86	$63.3	$36.0	$156.3
2035	$34.41	$94.8	$2.91	$64.6	$37.3	$159.5
2036	$35.06	$96.7	$2.97	$65.9	$38.0	$162.6
2037	$36.67	$98.7	$3.03	$67.2	$39.7	$165.9
2038	$36.37	$100.6	$3.09	$68.6	$39.5	$169.2
2039	$37.51	$102.7	$3.15	$69.9	$40.7	$172.6
2040	$39.50	$104.7	$3.22	$71.3	$42.7	$176.1
2041	$39.70	$106.8	$3.28	$72.8	$43.0	$179.6
2042	$41.46	$108.9	$3.35	$74.2	$44.8	$183.2
2043	$42.40	$111.1	$3.41	$75.7	$45.8	$186.8
2044	$47.58	$113.3	$3.48	$77.2	$51.1	$190.6
2045	$47.48	$115.6	$3.55	$78.8	$51.0	$194.4
20-year Levelized	**$35.46**	**$50.91**	**$1.56**	**$34.68**	**$37.03**	**$85.59**
22-year Levelized	**$36.56**	**$56.68**	**$1.74**	**$38.62**	**$38.30**	**$95.31**

10. Portfolio Scenario Analysis

The 2023 Preferred Resource Strategy (PRS) is Avista's resource strategy to meet future load growth and replace aging generation resources through 2045. Because the future is often different from the IRP's Expected Case forecast, the future resource strategy needs flexibility to serve customers under a range of plausible outcomes. This IRP identifies alternative optimized resource strategies for different underlying assumptions. Resource decisions may change depending on how customers use electricity, how the economy changes and how carbon emission policies evolve. This chapter investigates the cost and risk impacts to the PRS under different futures the utility might face as well as alternative resource portfolios.

Section Highlights

- All portfolios studied include greenhouse gas emission reductions.
- Moving to 100% clean energy will have significant rate impact to Idaho customers toward the end of the plan.
- New and replacement natural gas peaking generation is cost effective for Idaho customers even when considering social costs and potential national greenhouse gas fees.
- The Western Resource Adequacy Program (WRAP) continues to provide small financial benefits to Avista in exchange for a more reliable energy marketplace.
- Electrification of either transportation and/or buildings will require significant amount of new generation, transmission, and distribution resources.

The portfolio scenarios are representative of studies requested by the Technical Advisory Committee (TAC) or required by regulation. Avista also developed several scenarios of based on potential future policies and ideas discussed at TAC meetings and the IRP public meeting. In addition to alternative portfolio choices, Avista tested a few portfolios under alternative market futures or sensitivities where resource choice differs from the PRS. These sensitivities show how the portfolios perform with a national carbon tax and with higher or lower natural gas prices.

Since Avista does not have significant resource needs until the 2030s, there is time to watch for industry changes to see how the future evolves. The most significant risk identified in this analysis is from higher load levels as a result of electrification of transportation and/or space and water heating. These changes will likely occur at a gradual enough pace to give the utility time to respond to electrification trends and not shock the power supply system. However, the new load scenarios are large enough to justify planning for long lead items as associated with transmission and distribution system upgrades, or a new large industrial load may require new generation at a faster pace.

Another risk identified in the scenario analysis occurs where Avista could change course from the PRS due to a clean energy requirement in Idaho. While natural gas remains a cost-effective option for Idaho customers, even when considering environmental costs; technology or public policies changes could require a reduction of natural gas-fired resources to serve Idaho customers. Based on the current political environment, this would most likely come from a federal policy change or a significant cost reduction in non-gas generation and storage from new technologies. Avista's customers, by way of survey (TAC 4 presentation in Appendix A) shows a preference for renewable energy options when the costs increases are manageable.

Portfolio Scenarios

In addition to the expected case, Avista studied 16 alternative portfolios to compare cost, risk, and emissions with the PRS for the Expected Case market forecast. Each portfolio changes an underlining assumption about the future and are then re-optimized to select the lowest cost portfolio for the requirements of the scenario. The PRS is Portfolio #1 on all tables and charts in this chapter. The summary of the resource selections for all portfolio scenarios is in Table 10.1 and Table 10.2. Appendix K includes a summary of resource selection by year by state for the expected case as well as each scenario addressed below.

Portfolio #2: Alternative Lowest Reasonable Cost Portfolio

The Alternative Lowest Reasonable Cost Portfolio is a Washington State required portfolio to determine whether a utility exceeds the Clean Energy Transformation Act (CETA) cost cap if the utility is using the method for compliance. This portfolio assumes no CETA clean energy requirements, nor does it include any Named Community Investment Fund (NCIF) investments but does include the Social Cost of Greenhouse Gas (SCGHG) for resource selection and continues to meet physical monthly capacity and energy requirements.

The study shows lower costs for Washington by $7.8 million per year levelized, while Idaho's cost changes are de minimis. The portfolio cost toward the end of the study horizon is $81 million lower in 2045 or 5% less cost per kWh. The reduction in cost is largely due to this portfolio continuing use of Coyote Springs 2 in 2045 for Washington customers, but results in fewer renewables (including renewable fueled Combustion Turbines (CTs)) and more long-duration storage and natural gas CTs.

Portfolio #3: Baseline Portfolio

This scenario represents resource choices based on the economic decisions without the SCGHG or CETA. Effectively this portfolio uses the same assumptions as Portfolio #2 but exclude SCGHG prices for Washington. This portfolio is important for developing the Avoided Costs discussed in Chapter 9 as it can separate portfolio costs by renewable and capacity premiums. This portfolio methodology (for the Washington portion) is similar to Idaho's assumptions for new resource selection, with non-energy impacts (NEIs) still included for Washington resource optimization.

By comparing the results of this portfolio with Portfolio #2, the impacts of the SCGHG assumption on resource selection can be quantified. In this portfolio, the amount of wind selected falls by nearly 600 MW for Washington and future resource needs are satisfied with natural gas turbines and energy storage. One curious modeling result is the selection of wind, additional storage, and demand response, while reducing the amount of natural gas CTs for the Idaho jurisdiction. This is likely a result of limited low-cost transmission, lowest cost resources spread between each jurisdiction and more resources selected as system resources rather than state specific.

As expected, this portfolio has a lower cost than the PRS and the Alternative Lowest Reasonable Cost portfolio. In this case, Washington costs are $13 million lower (levelized) and $203 million lower by 2045 (13% less per kWh) as compared to the PRS. For Idaho, costs changes compared to the PRS are again de minimis.

This portfolio is compared to Portfolio #4 for capacity avoided cost purposes resulting in $173.3 million Present Value of Revenue Requirement (PVRR) of additional cost to the system. When divided by the added capacity this creates a capacity cost of $93 per kW-year in 2034 with a 2% escalator for the lowest cost resource set to meet capacity needs. This portfolio can also be used to estimate the clean energy premium by comparing the PVRR to the PRS. The PRS includes a $16 million PVRR premium. Dividing this additional cost by the added energy results in a $3.80 per MWh clean energy benefit beginning in 2034 with a 2% per year escalator (see Chapter 9 for more information on Avoided Cost).

Portfolio #4: No Resource Additions

This portfolio is used to estimate the capacity premium for the Avoided Cost calculation. The portfolio does not include any resource additions other than it uses the same energy efficiency selections as the PRS. It also includes the same assumptions as the #3 Baseline Portfolio with the exception of using the market to meet all resource demands instead of acquiring additional resources. The costs are lower for this scenario as no new resources are required, but it is not a valid portfolio for cost comparisons other than for use in Avoided Cost calculations.

Table 10.1: Resource Selection Summary by Portfolio Scenario in MW (Washington)

Portfolio Scenario	NG CT	Solar	Storage Added to Solar	Wind	Storage	Hydrogen/ Ammonia	Other "Clean" Baseload	Existing Plant Upgrades	DR Capability	EE- Winter Capacity	EE- Summer Capacity
1- Preferred Resource Strategy	0	10	0	945	130	696	0	0	7	57	59
2- Alternative Lowest Reasonable Cost Portfolio	247	51	25	843	494	88	0	0	7	57	60
3- Baseline Portfolio	431	0	0	364	265	0	0	3	7	57	59
4- No Resource Additions	0	0	0	0	0	0	0	0	0	57	59
5- No CETA/ No new NG	0	0	0	400	795	79	0	0	7	55	59
6- WRAP PRM	0	11	1	1,028	365	578	20	6	7	57	60
7- WRAP PRM No QCC Changes	0	11	0	1,145	454	312	78	6	7	57	59
8- VERs Assigned to Washington	0	11	0	845	125	682	20	0	7	57	59
9- Low Economic Growth Loads	0	10	1	905	298	366	98	3	7	57	59
10- High Economic Growth Loads	0	11	1	1,045	209	646	20	3	7	57	59
11- High Electric Vehicle Growth	0	97	0	1,245	492	707	98	0	7	57	59
12- WA Space/ Water Electrification	0	11	0	1,545	935	890	98	0	7	57	60
13- WA Space/ Water Electrification w/NG Backup	0	161	1	1,345	569	767	98	0	7	57	60
14- Combined Electrification	0	11	0	1,545	1,231	712	447	3	7	58	60
15- Clean Portfolio by 2045	0	10	1	1,009	91	704	33	0	7	57	59
16- Social Cost Included for Idaho	0	84	37	905	123	682	20	0	7	57	59
17- WA Maximum Customer Benefits	0	827	1	845	591	228	40	3	7	58	60

Table 10.2: Resource Selection Summary by Portfolio Scenario in MW (Idaho)

Portfolio Scenario	NG CT	Solar	Storage Added to Solar	Wind	Storage	Hydrogen/ Ammonia	Other "Clean" Baseload	Existing Plant Upgrades	DR Capability	EE- Winter Capacity	EE- Summer Capacity
1- Preferred Resource Strategy	304	0	0	0	67	0	0	0	0	24	24
2- Alternative Lowest Reasonable Cost Portfolio	264	0	0	0	89	0	0	0	0	25	26
3- Baseline Portfolio	164	0	0	36	176	0	0	2	11	24	24
4- No Resource Additions	0	0	0	0	0	0	0	0	0	24	24
5- No CETA/ No new NG	0	0	0	0	350	0	0	0	0	22	21
6- WRAP PRM	302	0	0	0	87	0	0	4	0	24	26
7- WRAP PRM No QCC Changes	278	0	0	0	126	0	0	4	5	24	26
8- VERs Assigned to Washington	318	0	0	0	42	0	0	0	0	24	24
9- Low Economic Growth Loads	229	0	0	0	77	0	0	2	0	24	24
10- High Economic Growth Loads	349	0	0	0	112	0	0	2	7	24	24
11- High Electric Vehicle Growth	293	0	0	0	161	0	0	0	0	24	25
12- WA Space/ Water Electrification	267	0	0	0	135	0	0	0	0	24	24
13- WA Space/ Water Electrification w/NG Backup	272	0	0	0	149	0	0	0	0	26	25
14- Combined Electrification	283	0	0	0	167	0	0	2	0	26	26
15- Clean Portfolio by 2045	0	0	0	236	18	377	65	0	7	27	28
16- Social Cost Included for Idaho	203	0	0	0	36	115	20	0	0	24	26
17- WA Maximum Customer Benefits	271	0	0	0	85	0	0	2	0	24	24

Portfolio #5: No CETA/ No New Natural Gas

This portfolio identifies the clean capacity premium avoided costs. It is similar to the #2 Baseline Portfolio, except it does not allow new natural gas generation to be constructed, does not require the model to satisfy monthly energy targets and assumes Coyote Springs 2 is not available in Washington in 2045. This illustrates a portfolio without the specific CETA objectives but nearly eliminates greenhouse gas emitting resources by 2045. This portfolio does not meet general utility planning requirements as the utility is significantly short energy on an annual basis beginning in 2042. Given this portfolio is for avoided cost purposes only, the results should only be used in this context, a separate portfolio for achieving higher clean energy objectives is discussed later.

The resource selection in this scenario chooses long-duration energy storage over renewable fuel and natural gas CTs, these changes result in reduced amounts of wind generation. The reason for the significant resource selection changes compared to the PRS is due to the CETA requirements with primary versus alternative compliance and the monthly energy requirement being removed. Idaho sees significant resource decision changes in this portfolio as it no longer has natural gas CTs as a resource choice. As the model is not requiring energy goals to be satisfied, the natural gas CTs are exchanged for energy storage resources.

This portfolio is only used for Clean Capacity Avoided Cost purposes by comparing the cost and resource selection with the #4 No Additions Portfolio. The increase in total costs is approximately $300 million. When levelized against the added capacity, it results in a $156 per kW-year capacity premium with a 2% escalator. However, a $93 per kW-year could be associated with non-clean energy by comparing the #3 Baseline Portfolio to the #4 No Additions Portfolio, therefore the difference between these two values is the clean capacity premium of $63 per kW-year.

Portfolio #6: WRAP Planning Reserve Margins (PRM)

This portfolio scenario shows how the PRS might change once it adopts the Western Power Pool's WRAP's Planning Reserve Margin (PRM). Avista has chosen to use the WRAP's Qualifying Capacity Credit (QCC) values and Load and Resources (L&R) calculation methodology to determine resource need in this IRP but does not plan to implement lower PRM values until the program is fully binding. Table 10.3 compares the WRAP's PRM[1] values to those of the PRS, except for the shoulder month values in March through May and September, the PRM values are lower.

Table 10.3: Resource Selection Summary by Portfolio Scenario

Month	WRAP	2023 IRP
Jan	19.0%	22.0%
Feb	19.9%	22.0%
Mar	26.9%	22.0%
Apr	23.4%	22.0%
May	20.0%	13.0%
Jun	16.5%	13.0%
Jul	10.4%	13.0%
Aug	10.3%	13.0%
Sep	17.9%	13.0%
Oct	19.8%	22.0%
Nov	21.6%	22.0%
Dec	17.7%	22.0%

An interesting result of this portfolio scenario is the resource selection is not lower, and resource selection changed due to the seasonal differences in resource need. The model generally selected the same amount of natural gas CTs for Idaho, but Washington selection shifted from renewable fuel CTs to long duration storage, additional wind, and baseload renewables along with upgrading the existing Rathdrum CTs.

[1] The PRM values within the WRAP use the 2023 forward showing values and are subject to change. WRAP does not estimate PRM for shoulder months, they are estimated in this chart based on connecting months.

In the 2021 IRP, the WRAP scenario showed a cost savings to both Idaho and Washington. One of the reasons the model does not find as much savings as the 2021 IRP is due to binding constraints to meet monthly energy requirements. In the 2021 IRP, these constraints only had to be met on an annual average basis. While the savings in this IRP are not as high in the 2021 IRP, the WRAP is still an important market development to ensure the region is resource adequate and allows Avista to use the market during extreme peak conditions and discourages other utilities from being overly reliant on market resources to meet peak demand.

Portfolio #7: WRAP PRM (No QCC Changes)

The WRAP creates QCC estimates used to determine how much an individual resource can be relied upon for winter and summer peak loads. Avista assumes these values will go down over the course of the study[2] for variable energy resources (VERs), storage resources, and demand response. This is due to the energy limitations of the resources and the inability to serve customer load for a duration of time and the high correlation of generation availability. For this IRP, Avista modified these QCC values based on a regional clean energy study from E3 (discussed in prior chapters). This portfolio scenario was developed to address TAC members concerns with the WRAP PRM assumptions as the WRAP has not yet conducted studies on these resources maintaining their QCCs with higher regional renewable and storage penetrations. This scenario uses the same WRAP planning margins as Portfolio #6, but the QCC values do not change over the time horizon of the study.

Higher peak generation capability or QCCs for renewable, storage, and demand response resources create a different resource strategy. For Washington, wind energy increases, and 4-hour energy storage replaces renewable fuel CTs needed for sustained high loads. Another significant change is the selection of baseload renewables such as geothermal and wood biomass. For the Idaho resource selection, the natural gas CT selection is slightly lower in favor of 4-hour duration energy storage and some limited demand response.

These assumption changes would effectively require the utility to rely more on the wholesale energy market for its energy needs than the PRS does for peak load periods. In exchange, it reduces cost as compared to the PRS, the PVRR is $106 million less or $9.2 million per year. Most of the total savings occurs after 2034 when Avista is short capacity. Since the resource strategy prior to 2034 is similar to the PRS, this period will allow time for further studies by the WRAP and other regional entities to determine how QCCs may change over the planning horizon.

[2] Southwest Power Pool (SPP), who administers the WRAP, acknowledges the QCCs will decline as more renewables are added to the system. They're in the process of conducting a study to quantify the impact of these increasing amounts of VER.

Portfolio #8: Variable Energy Resources Assigned to Washington

This portfolio uses the PRS's assumptions with one minor change, this change assigns all existing VERs to Washington rather than between states. The VERs include Palouse Wind, Rattlesnake Flat, and the new 30-year wind Purchase Power Agreement (PPA). This change allows energy produced from these facilities to be used for CETA without a transfer of the energy between states. The PRiSM model does allow these resources to be transferred within the PRS, but it may not, depending on the timing and cost of resource alternatives.

The goal of this study is to determine the amount and cost of new renewable generation avoided. This concept is similar to conditions in Washington's Clean Energy Implementation Plan (CEIP) to understand resource selection of new versus existing resources. Unfortunately, the PRiSM model was not designed to separate specific existing Power Purchase Agreement (PPA) resource costs between jurisdictions. This was a design choice in PRiSM to avoid specific resource price transparency due to the confidentially of PPA prices within agreements.

This study found Washington could reduce its renewable resource need by 100 MW of wind and minor changes in other resource selections. The results show the total system PVRR did increase by $29 million or 0.2%. Although this is likely due to a different set of resources selected to meet different capacity/energy deficits than the PRS. This portfolio should be studied in further detail in a future jurisdictional allocation conference setting if the states agree to discuss resource cost allocations.

Portfolio #9: Low Economic Growth Loads

This portfolio studies the effects of loads not materializing as forecasted due to low economic growth. A full description of the load scenario is in Chapter 2, but in this case, load grows at 0.53% instead of 0.85%. The load reduction impacts Idaho and Washington loads. As anticipated with lower loads, the resource strategy includes less wind, natural gas CTs, and renewable fueled CTs. Although the amount of storage and baseload renewables increases for both states.

The portfolio cost for both jurisdictions is lower, although disproportionately less for Idaho (-1.8% versus -0.9%). One interesting note, with less load and lower cost, the rate per kWh increases for both states. Absent non-power supply costs increasing, higher loads can reduce the average rate as it can dilute fixed costs for customers.

Portfolio #10: High Economic Growth Loads

This portfolio considers the effects to the resource portfolio if loads are higher than forecasted due to high economic growth. A full description of the high load scenario is in Chapter 2, but in this case, load grows at 1.11% instead of 0.85%. The load increase impacts both Idaho and Washington loads.

The higher loads results in more generation required than expected. Washington needs additional renewables and energy storage, and Idaho needs additional Natural Gas CTs, energy storage and demand response.

As with the low load growth scenario, the costs change as expected, but Idaho is impacted more than Washington, where its cost increase at 1.8% compared to 0.7% for Washington. Also, the average rate per kWh decreases due to higher loads absent fixed costs increasing to support the higher load.

Portfolio #11: High Electric Vehicle Growth

This is the first of several electrification scenarios studied in this IRP. Washington and Idaho loads increase in this scenario due to the electrification of more transportation than assumed in the PRS. Chapter 2 describes the specific load changes for both states, but generally this scenario assumes a more rapid accumulation of light duty vehicles (LDVs) and medium duty vehicles (MDVs) reflecting 100% LDV sales in Washington by 2050 and 75% for Idaho. For MDVs the assumption is for 95% by 2050 for Washington and 75% for Idaho. By 2045, this results in an additional 193 aMW of energy demand and peak loads increasing by 435 MW (20% higher than 2045 expected loads).

Due to higher loads, resource selection changes for both states. For Washington, PRS resource selections are higher with 300 MW more wind, 87 MW solar, 363 MW of energy storage, 98 MW baseload renewables and 10 MW of renewable fueled CTs. The change in Idaho is slightly less natural gas (-10 MW) and additional energy storage (+94 MW). This portfolio results in two additional transmission projects than the PRS with new transmission needed from 2044 to 2045 for new wind and import capability.

The increase in load has a greater effect on Washington costs than Idaho. Washington PVRR cost increases by 3.2% and Idaho 0.6%, but the Washington rates decline from a cost per kWh perspective. This does not include added costs to integrate this load on the distribution or transmission system. Avista hopes to estimate transmission and distribution (T&D) costs in the future. This will be discussed in future Distribution Planning Advisory Group (DPAG) meetings.

Portfolio #12: Washington Space/Water Heating Electrification

This portfolio scenario focuses on Washington building electrification, specifically if existing customers change their current natural gas fired appliances (space and water heating) to electric heat pumps with back up resistance heating and heat pump water heaters. This scenario’s load assumptions are described in Chapter 2. In summary, average annual loads increase by 208 aMW by 2045, but winter peak loads increase 805 MW (winter is 36% higher) and summer by 91 MW. This scenario creates significant load pressure on winter loads as moving the existing gas customers to electric will create significant peak winter loads due to resistance space heating loads. In addition, the current heat pump technology is limited in its ability to produce enough heat to satisfy building demand in extreme cold weather as seen in eastern Washington during peak load events.

The added load in Washington is served by an additional 600 MW wind, 805 MW energy storage, 194 MW renewable fueled CTs, and 98 MW base load renewable energy. Idaho sees small changes to its portfolio even though its load remains unchanged. These changes include 82 MW of energy storage and 32 MW fewer natural gas CTs and are largely due to changes in the shared resources selected in the PRS. This portfolio requires at least four large transmission projects to bring the new resources to serve load. The first must be online by 2036 and the other three between 2042 and 2044. The transmission would bring power from potential north Idaho plant locations to Spokane, integrate new wind in eastern Washington, and import power from outside of Avista's service area.

Washington costs and rates will increase significantly for this type of electrification as PVRR is 10.5% higher and the 2045 energy rates are 11% higher. These increases will be higher once transmission and distribution costs are factored into the analysis. Idaho's costs increase by 1.2% for PVRR and 5.7% for energy rates in 2045. In this case, Idaho's cost increases are mostly driven by how new transmission costs are allocated rather than resource changes. This scenario requires significant transmission to integrate the new resources for Washington, under the current cost recovery methodology, 34% of these costs would be directed to Idaho to pay its share of the costs as new transmission is a system benefit. If these costs were re-directed to Washington, Idaho would not see a rate impact and Washington's 2045 rate would be 13% higher.

Portfolio #13: WA Space/Water Heating Electrification w/ Natural Gas Backup

Due to the high load requirements and costs of Portfolio #12, this scenario reduces the winter peak load increase by using natural gas as a backup fuel. In this scenario, existing customers would not replace their natural gas furnace over time, but rather add a heat pump and use it for heating when temperatures are above 40-degrees. This scenario also assumes natural gas water heaters are replaced with electric water heater heat pumps. The result of these future load assumptions is an increase in annual energy loads by 152 aMW, but only 445 MW of winter peak load (compared to 805 MW in Portfolio #12- for a total of 20% higher loads than the 2045 expected case value), and summer peak loads are nearly the same as Portfolio #12.

This scenario still requires more resources than the PRS, but significantly less generation than Portfolio #12. In this case, 600 MW less wind, energy storage, and renewable fueled CTs are required compared to Portfolio #12, but 151 MW of solar is also selected. For Idaho, similar changes are made to the resource strategy as Portfolio #12. This portfolio results in two additional transmission projects in 2044 to 2045 for new wind and import capability.

With less load, the financial impacts to Washington customers are not as great as portfolio #12, as PVRR increases $574 million (5.6%) compared to the PRS and rates only are 4.1% higher in 2045. Though this scenario has similar impacts to Idaho rates as Portfolio #12, where Idaho rates are 5.1% higher in 2045.

Portfolio #14: Combined Electrification

This portfolio represents the extreme load growth scenario of what could be possible with all electrification policy choices in Washington State materializing by 2045. In this scenario the, High EV forecast from Portfolio #11 combines with the building electrification of Portfolio #12, plus an increase in roof top solar to offset some of this new load with 20% of residential customers and 5% of commercial customers having roof top solar by 2045. The net effect increases annual energy load by 345 aMW, winter peaks by 1,224 MW (55% higher) and summer peaks by 316 MW by 2045.

The increased load requires an additional 600 MW of wind, 1,100 MW of long-term energy storage, 58 MW of wood biomass, and 350 MW of nuclear capacity by 2045. In addition to these resources, transmission to interconnect these resources will need to be constructed with the first major project on-line by 2037 and three other major projects by 2045 subject to final generation location selection.

The cost increase to serve this additional load increases Washington's PVRR by 14% and its 2045 energy rate by 16.5% or 4 cents per kWh. If Washington must pay for the entire transmission costs as described in Portfolio #12 costs will increase even more. This scenario will also see additional costs to integrate the higher loads on the distribution system that are not factored into this cost estimate. Although early estimates (subject to change as discussed in Chapter 7) places this cost at $2.5 billion (total nominal dollars) of capital investment through 2045. This translates into an additional 4 cents per kWh of added load. The end result is a 33% higher average energy rate for Washington customers in this scenario versus the PRS. For Idaho, cost impacts have not been estimated, but are likely to be minimal.

Portfolio #15: Clean Portfolio by 2045

The Clean Portfolio would not have any greenhouse gas emitting resources after 2044. This includes retiring all existing natural gas generation by 2045 (including Coyote Springs 2) and not acquiring any additional gas facilities. This scenario has little impact on Washington as it is already required under CETA's policy goals. Although, Washington will not have the ability to use Idaho's share of clean resources to the extent it may require, and it will have to procure additional higher cost renewables to comply with the larger system-wide clean goal.

The portfolio changes in this scenario in Washington to include wind (+64 MW), energy storage (-39 MW), and baseload renewables (+33 MW). Idaho's portfolio is significantly different with 303 MW fewer natural gas CTs plus 236 MW of new wind and 378 MW of renewable fueled CTs along with a shift from energy storage to wood biomass from the PRS. Additional transmission is also required for this portfolio as compared to the PRS. Transmission projects to integrate eastern Washington wind and import off system resources would need to be available by 2044 in addition to the transmission required to bring capacity from North Idaho to the Spokane area.

For cost impacts, Washington sees marginal increases in PVRR of 0.1% and the 2045 energy rates are 2.6% higher. Idaho's cost impacts are far higher. The PVRR is only 2.5% higher, but the significant costs materialize toward the end of the plan where the 2045 energy rate is 40% higher or 7.4 cents per kWh. In this scenario, Washington has a 2045 energy rate of 24 cents per kWh and Idaho 25.9 cents per kWh. The Washington rate is slightly lower due to higher loads. Although, in this scenario the Production Transmission (PT) ratio (used to allocated cost to each jurisdiction) would likely change and the rates between the two states would likely land in between these two rate forecasts.

Portfolio #16: Social Cost Included for Idaho

The scenario attempts to include the non-energy impacts (NEI) of resource decisions into the resource selection process for Idaho. Specifically, this concept was suggested in the 2023 IRP public meeting process to understand whether the selection of natural gas turbines for Idaho can overcome these costs. In this scenario, the SCGHG and NEIs used for Washington's resource selection are used in Idaho. This portfolio shows what resources are truly economic when accounting for externalities and demonstrates the premium 100% clean energy policies may have exceeded what is actually economic even when considering social impacts.

This scenario repositions both states resource selections. Washington has a 74 MW increase in solar, 37 MW of energy storage, and 20 MW of geothermal, while wind, long-duration energy storage, and renewable fueled CTs fall. For Idaho, there is a 100 MW reduction in natural gas peakers replaced by a 116 MW renewable fueled CT. There is also a reduction in energy storage, replaced by a 20 MW geothermal unit. Another interesting impact of this scenario is the model generally prefers shared resources for energy storage and renewable fueled CTs. This portfolio does not require additional transmission beyond what is needed in the PRS.

The cost impacts to the system portfolio cost are minimal, Washington has only de minimis cost effects, but Idaho's PVRR increases by 0.4% and the 2045 rates only 1.8%. An important note is the premium Washington customers will pay for 100% clean energy over the economic value of the alternative choices. Washington's 2045 energy rate is 23.5 cents per kWh and Idaho's would be 18.8 cents per kWh. Given this, Washington would be paying a 25% premium over the social value of clean energy it is producing.

Portfolio #17: Washington Maximum Customer Benefits

The Washington State IRP rules require a Maximum Customer Benefits portfolio to understand the portfolio and cost impacts of additional Customer Benefit Indicators (CBIs). The portfolio is designed to take another step beyond the 2021 IRP to define what this portfolio future may look like. There are no specific rules guiding this portfolio but rather a set of assumptions to see how CBIs may improve. Avista expects to have more discussion with the TAC in the 2025 IRP cycle to refine this portfolio's assumptions.

For this IRP, the following assumptions based on the current CBIs were used. The model would not be able to select any renewable energy outside of the state (i.e., Montana Wind).[3] This increases the quantity of local generation CBI. The model cannot select renewable fueled CTs (i.e., ammonia turbines) due to additional NOx emissions, but can use hydrogen fuel cells. The amount of community solar increases beginning in 2034 for the benefit of Named Communities to lower the burden to low-income customers (solar selected directly offsets customer bills). No nuclear energy was allowed to be constructed. While this was not a CBI; it was added from TAC input on this scenario in the 2021 IRP.

These scenario assumptions add 817 MW of solar energy with 676 MW of the amount directly benefiting low-income customers. Since the model cannot select ammonia-fueled turbines, the resource selection uses green hydrogen fuel cells, energy storage, and geothermal to meet the remaining capacity requirements after the significant increase in solar energy. Idaho's portfolio is only modestly impacted. Due to the changes in resource selection, additional large transmission projects are still needed, but changes the specific transmission needs to only support new wind generation on and off the system, as long as the majority of the 676 MW of solar added to the system does not create transmission/distribution impacts. Avista's Distributed Energy Resource (DER) potential study for the 2025 IRP will determine if this amount of solar on a local level is possible.

There are cost impacts to Washington customers for these portfolio changes. The PVRR increases 3.7% and the 2045 energy rate increases 29% or 6.8 cents per kWh. In exchange for the higher rate, there are less air emissions (except those related to Kettle Falls Generating Station). The average excess energy burden of low-income customers falls from $2,035 per year in 2045 to $632 per year. DER MWh increase to 1 million MWh per year compared to 34,000 MWh and energy storage in Named Communities increase to 60 MWh compared to 12 MWh in the PRS.

Cost & Rate Impact Summary

The preceding portfolio summary gave contextual changes to each portfolio. This section provides tables and charts to summarize the results of the studies. Table 10.4 outlines each of the 17 portfolio PVRRs for each state, and the 2030 and 2045 energy rates per

[3] The PRiSM model is not designed to select the location of wind resources other than off-system, on-system or from Montana. For this study, off-system wind can still be selected as the northwest location is unknown.

kWh (excludes distribution adders discussed in the electrification scenarios). The yellow bars show the cost or rate of the category is within 3% of the PRS value, the green arrow up indicates the category exceeds a 3% increase compared to the PRS, and the red arrow down indicates a 3% reduction.

The costs of each portfolio are summarized by jurisdiction and are then sorted by total system cost impact in Figure 10.1. The higher cost scenarios include higher loads or higher clean energy objectives, while lower cost scenarios have less loads or renewables. Though the rank order does not reflect the additional load served by these scenarios, therefore Figures 10.2 and 10.3 show the rank of the energy rates for 2030 and 2045, sorted by 2045 rates. The 2030 rates do not materially differ since most resource decisions occurring after 2030.

Table 10.4: Jurisdiction Cost and Rate Summary

Scenario	WA- PVRR ($ Mill)	ID-PVRR ($ Mill)	TOTAL PVRR ($ Mill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)
1- Preferred Resource Strategy	10,213	4,783	14,996	0.133	0.234	0.119	0.185
2- Alternative Lowest Reasonable Cost Portfolio	10,122	4,778	14,900	0.132	0.222	0.119	0.181
3- Baseline Portfolio	10,064	4,789	14,852	0.133	0.205	0.119	0.184
4- No Resource Additions	9,966	4,713	14,679	0.133	0.194	0.119	0.169
5- No CETA/ No new NG	10,158	4,821	14,980	0.133	0.223	0.119	0.188
6- WRAP PRM	10,217	4,778	14,995	0.133	0.242	0.119	0.186
7- WRAP PRM No QCC Changes	10,126	4,763	14,889	0.133	0.233	0.119	0.179
8- VERs Assigned to Washington	10,205	4,819	15,024	0.133	0.234	0.120	0.184
9- Low Economic Growth Loads	10,119	4,697	14,816	0.134	0.243	0.120	0.192
10- High Economic Growth Loads	10,279	4,868	15,148	0.132	0.233	0.117	0.176
11- High Electric Vehicle Growth	10,541	4,812	15,354	0.133	0.227	0.119	0.186
12- WA Space/ Water Electrification	11,283	4,843	16,126	0.131	0.259	0.119	0.195
13- WA Space/ Water Electrification w/NG Backup	10,787	4,800	15,586	0.132	0.244	0.119	0.194
14- Combined Electrification	11,655	4,879	16,533	0.131	0.273	0.119	0.195
15- Clean Portfolio by 2045	10,227	4,902	15,130	0.133	0.240	0.119	0.259
16- Social Cost Included for Idaho	10,219	4,801	15,021	0.133	0.235	0.118	0.188
17- WA Maximum Customer Benefits	10,594	4,769	15,363	0.134	0.302	0.119	0.182

Figure 10.1: PVRR Summary

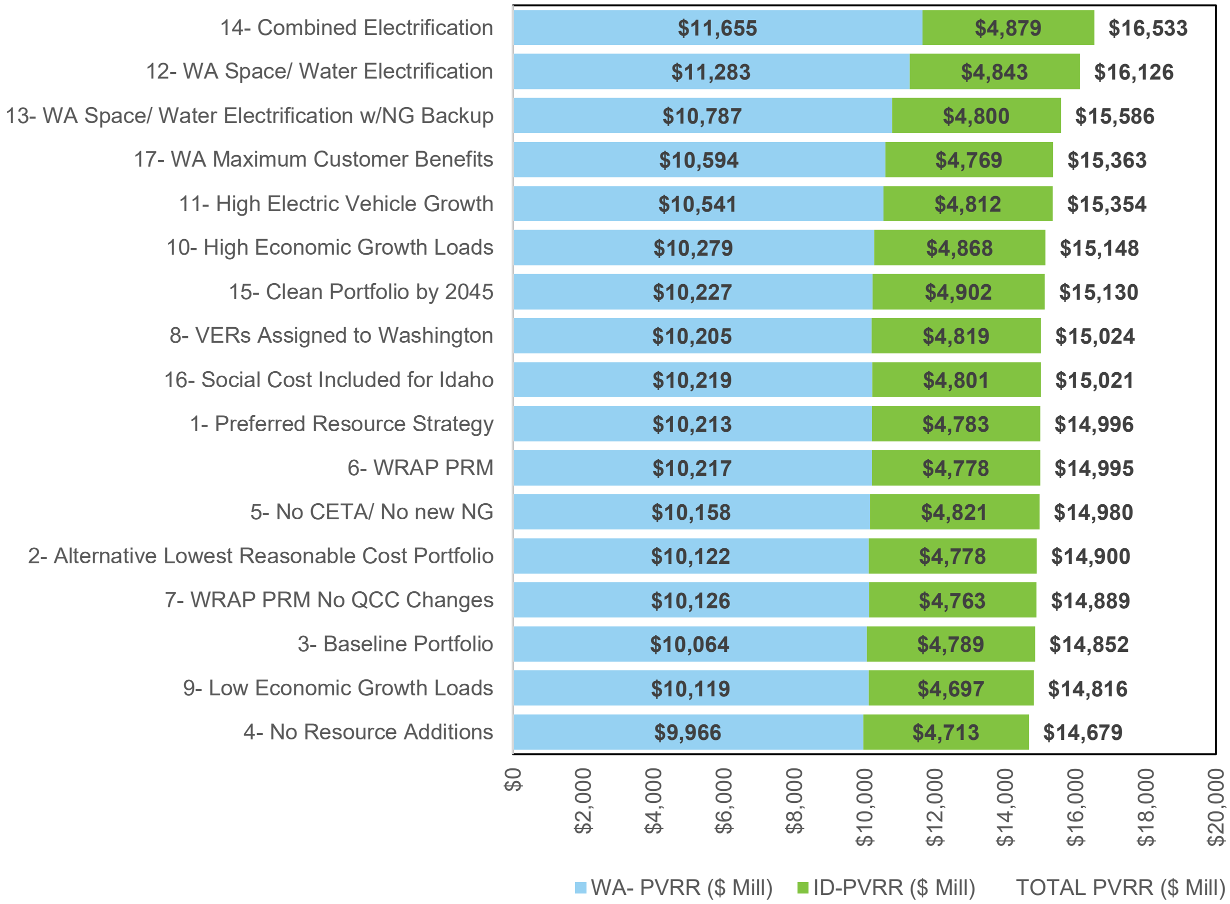


Figure 10.2: Washington Energy Rate Comparison

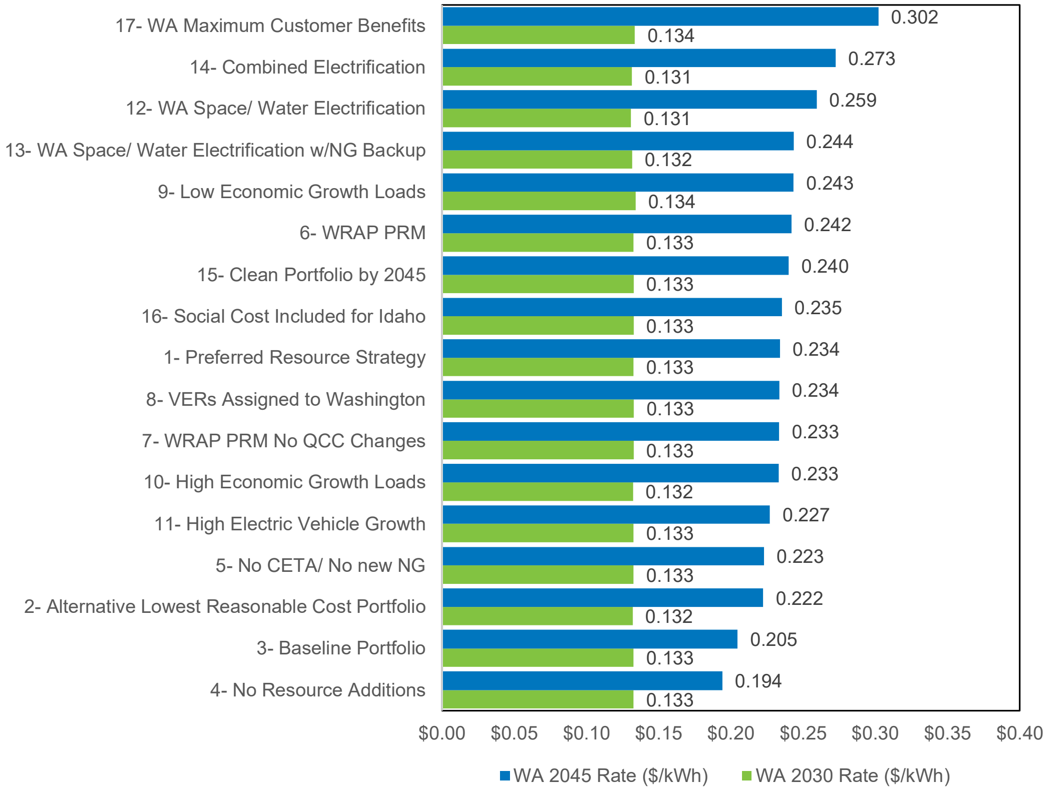
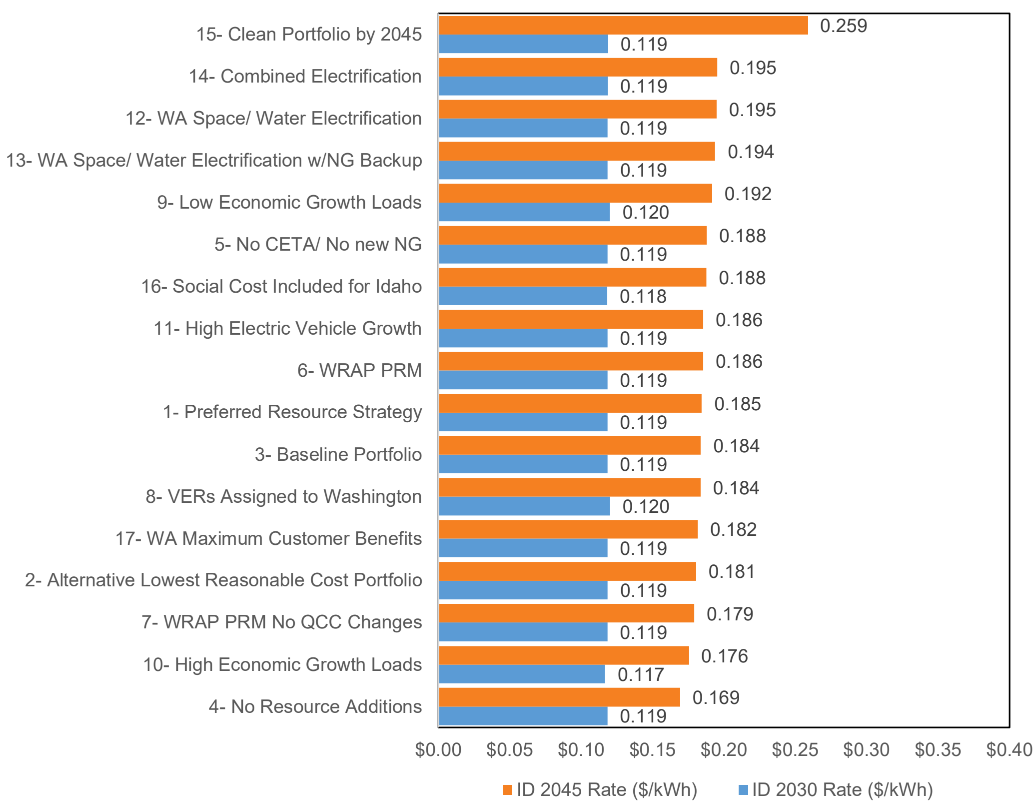


Figure 10.3: Idaho Energy Rate Comparison

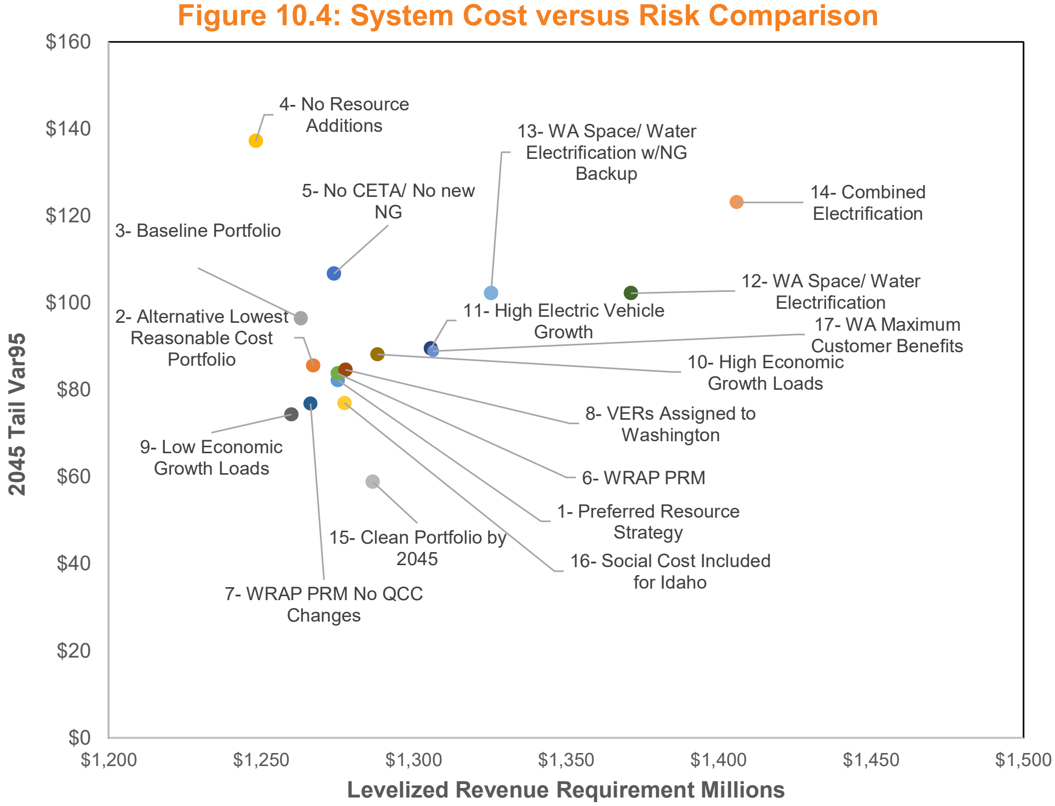


Market Risk Analysis

In addition to costs or energy rates, the IRP gives insights to the energy market risks of portfolios by showing how much the portfolio selection is impacted by changes in the wholesale electric market. Figure 10.4 compares the 2045 market risk to the PVRR of the portfolio cost (excludes additional distribution costs for electrification scenarios). The 2045 market risk used in this analysis is TailVar95 and calculated by the 95th percentile of portfolio costs subtracting the average portfolio cost for 300 simulations. The market risks included are from varying loads, natural gas prices, hydro conditions, and wind conditions. The portfolios with greater risk typically have a higher dependance on either natural gas resources, market power purchases, or higher risk due to added load.

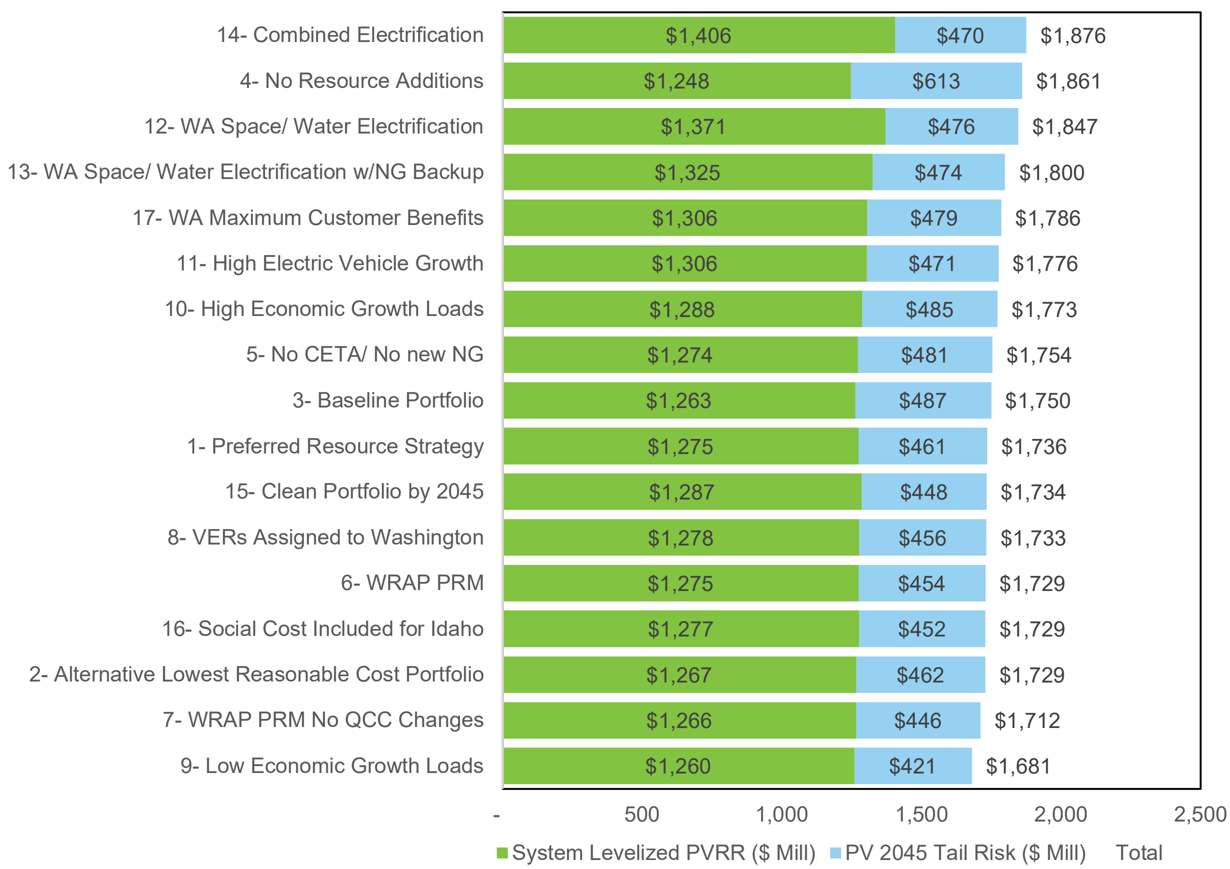
The only portfolios to further reduce market risk for the Idaho jurisdiction are those investing in additional renewable energy resources. As shown below, the lower risk comes at an added cost to the system. For example, in the #15 Clean Portfolio by 2045 scenario, the extreme market risk is $23 million or 28% lower, but the incremental cost to Idaho customers in 2045 is $267 million, reflecting a $0.075 per kWh premium or 40% higher. There is a point where additional cost can be justified by the risk savings, but this scenario may not justify the cost premium. The #16 Social Cost Included in Idaho Portfolio has a $5 million risk reduction at an $11 million premium. In this case, the social cost benefits would offset the difference in cost, but Avista will need guidance from the Idaho Public Utilities Commission (IPUC) if these social benefits are the correct valuation for Idaho customers.

Figure 10.4: System Cost versus Risk Comparison



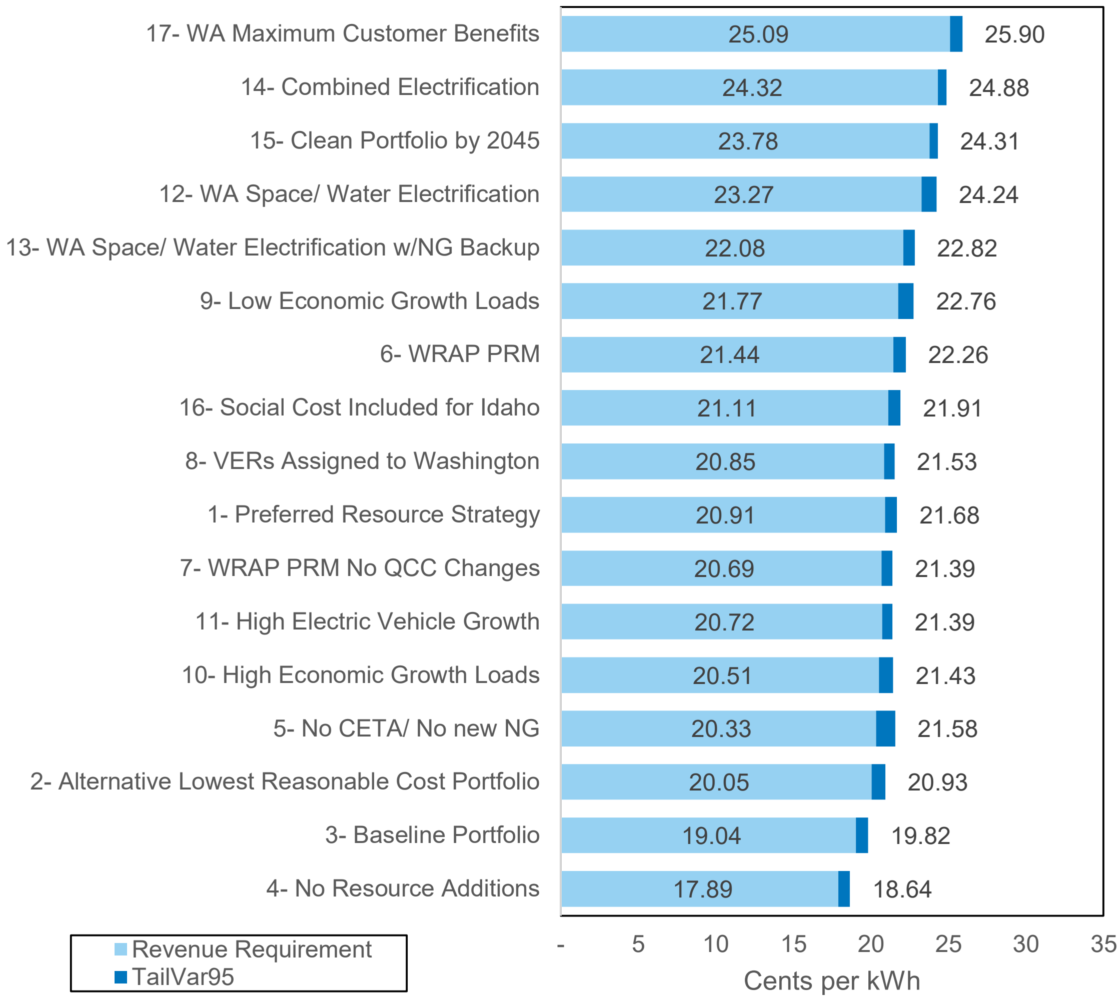
Another metric used to evaluate portfolio risk combines the PVRR and Tail-Var95 values. This is done by taking the present value of all future Tail-Var95 values and totaling this value with PVRR. These results are shown in Figure 10.5 and are sorted from the highest total cost to the lowest cost. Due to most of the resource acquisitions occurring toward the end of the plan and the differing amounts of load included in each of the portfolios, this metric is not as informative for scenarios with differing loads. Figure 10.6 was created for 2045 to address these concerns. In this case, the total cost of the year is divided by the load, then the TailVar95 risk value is added. The values shown in this figure are in cents per kWh. This methodology demonstrates each of the scenarios on a more equal footing. In this view, the risk additions compared to the total costs are low due to the overall size of the rate base of the total utility cost. In addition, most of the resources serving load have volumetric risk rather than natural gas price risk, except for the Idaho portion of load.

Figure 10.5: Portfolio PVRR with Risk Analysis



The 2045 analysis also shows the PRS compared to other portfolios is the least risk adjusted for costs where the portfolio meets reliability and regulatory objectives (Portfolios #2, #3, #4, #5, and #7). The only portfolios with lower risk adjusted costs are dependent on outcomes beyond Avista's control such as high load growth (#10, #11). The analysis also shows, as in other portfolio summary information, the added costs for the high electrification and higher clean energy requirements compared to the PRS. Since this analysis summarizes customer cost, the societal benefits should overcome these added customer costs to be a preferred resource strategy.

Figure 10.6: 2045 System Energy Cost w/ Risk

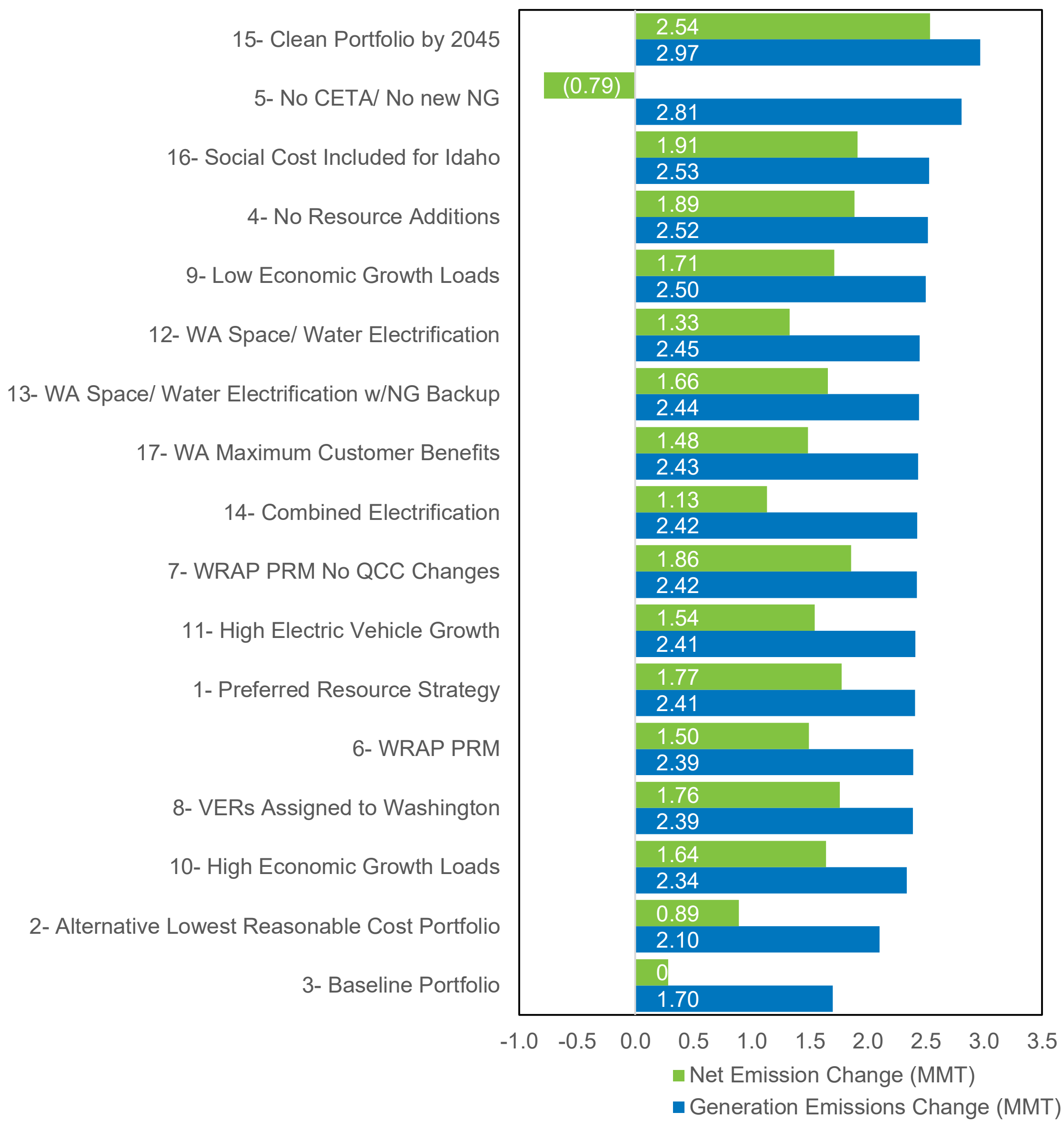


Greenhouse Gas Emission Comparison

All resource strategies going forward will have greenhouse gas emission reductions compared to current emissions. The reductions are largely due to Colstrip Units 3 & 4 leaving the system after 2025. Further reductions will be from reduced dispatch of existing natural gas facilities due to Washington's Climate Commitment Act (CCA) and Lancaster's PPA extension ending at the end 2041. While each portfolio has reductions, the reduced amounts are not all equal. Each portfolio's 22-year reduction levels are shown in Figure 10.7. The data used for this chart is the gross emissions from Avista's existing and selected controlled generating resources in blue and the green bars represent the net emissions when there are sales or purchases in the wholesale energy market. Market transactions include an emissions rate factor of 0.437 metric tonnes per MWh as defined by CCA, while market sales use the estimated emission intensity of the Avista facilities.

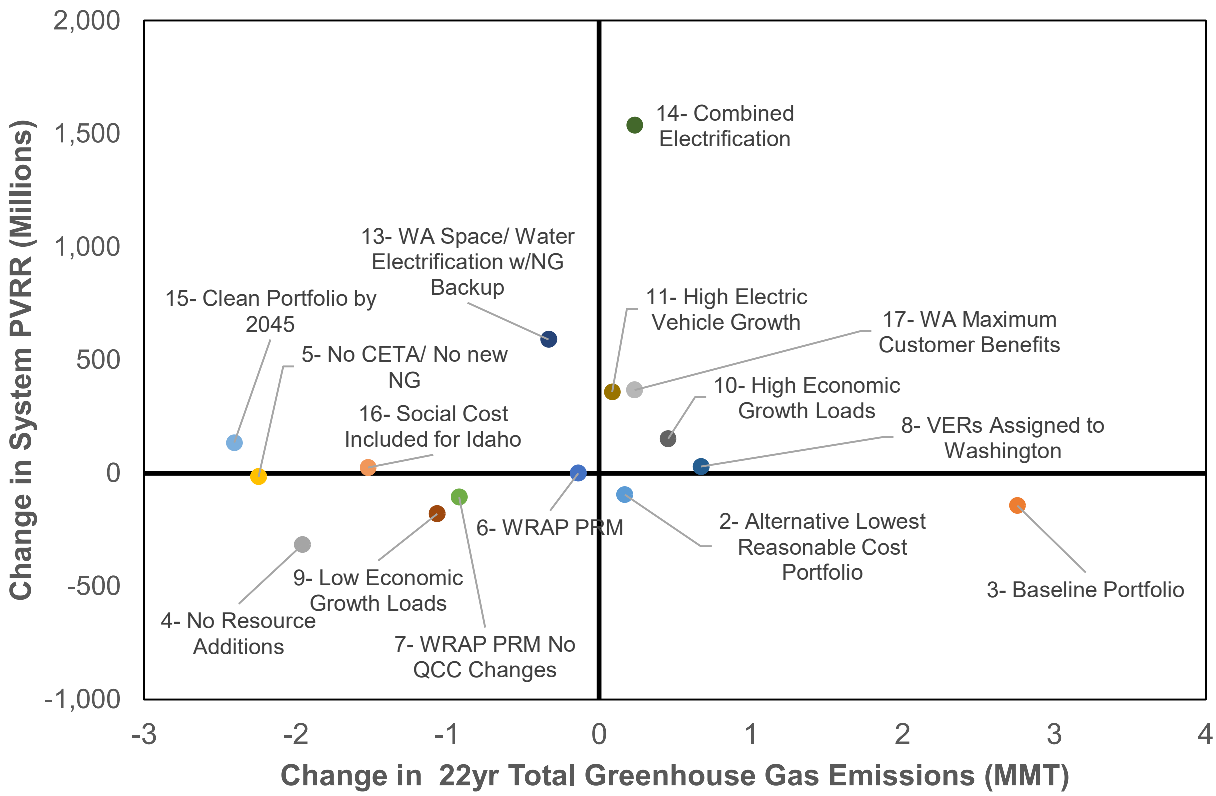
The #15 Clean Portfolio by 2045 has the greatest reduction levels using both metrics and the #3 Baseline Portfolio has the least reduction on a gross level. The only portfolio showing an increase is the theoretical portfolio #5 where the amount of market purchases creates a high-emissions total due to the 0.437 metric tonne per MWh assumption. It is worth noting the 0.437 intensity rate is an incremental rate and likely does not represent the average emission intensity rate of market purchases especially as the system decarbonizes.

Figure 10.7: Emission Reduction (Millions of Metric Tons (2045 compared to 2024)



The second metric for evaluating greenhouse gas emissions is the cost and emission reductions compared to the PRS. Figure 10.8 shows the added PVRR cost compared the PRS and to the total emissions changes over the 22-year study horizon - the emission quantification used is the gross emissions generated from Avista controlled facilities. For example, the #14 Combined Electrification Portfolio increases cost by $1.5 billion PVRR over the PRS and the Greenhouse Gas (GHG) emissions are 0.23 million metric tonnes. Portfolios in the bottom left quadrant have lower cost and lower emissions compared to the PRS. These portfolios do not meet current reliability or regulatory requirements.

Figure 10.8: Change in Emissions Compared to Portfolio PVRR



Market Price Sensitivities

This IRP considers three alternative market price sensitivities to understand the impact to the portfolio choices. These market sensitives are discussed in Chapter 8 including the specific assumption changes and the resulting market price effects. This section shows how portfolios with different resource selections perform these future market scenarios. Only portfolios with different resource choices for the same load objective are studied. These include the PRS, the #3 Baseline Portfolio and the #15 Clean Portfolio by 2045. For the National GHG Pricing sensitivity, a new portfolio demonstrates how Avista could best minimize cost if this future materializes.

The first set of analyses shows the change in system PVRR and emissions changes for the three portfolios in Table 10.4 compared to the Expected Case's market pricing. For emissions, the amounts measured in this analysis are the average emissions of the generation facilities over the period of the IRP.

The results for the High Natural Gas Price sensitivity show all portfolios have higher costs compared to using the Expected Case's market pricing, but the clean portfolio shows the greatest protection from higher costs. In the Low Natural Gas Price sensitivity, the opposite occurs where the #3 Baseline Portfolio has the most benefit, but all portfolios benefit by lower pricing. As the #3 Baseline Portfolio does not meet regulatory requirements for Washington, the PRS shows the best outcome. However, this analysis illustrates the resource choices in the PRS for Idaho provide the best outcome in low natural gas pricing environments. In all portfolios, higher natural gas prices lead to less emissions, while low prices lead to higher emissions. Although, if market related emission were considered the emission levels may not be different.

For the National GHG pricing scenario the PVRR is largely unchanged due to Avista's clean portfolio without coal generation and minimal natural gas, but the emissions are less in this scenario.

Given the differences in policy objectives between Washington and Idaho, a separate analysis was created for Table 10.5 to show how costs differ for the three portfolios. This analysis shows Washington has greater cost projection in high natural gas pricing environments compared to Idaho, but Idaho has greater cost protection in low natural gas pricing futures. As in a future with a National GHG price, Washington's portfolio will see a benefit to system cost, where Idaho may have a marginal increase. The increase is mitigated due to the Expected Case Pricing including a portion of these costs due to an increased probability of a future carbon pricing policy at the national level.

Table 10.5: PVRR and Emission Changes

	Change in PVRR vs Expected Case Market Pricing				Change in Levelized GHG MT vs Expected Case Market Pricing		
Portfolio	High NG Prices	Low NG Prices	National GHG Price		High NG Prices	Low NG Prices	National GHG Price
1- Preferred Resource Strategy	1.8%	-3.1%	-0.1%		-11%	6%	-9%
3- Baseline Portfolio	2.1%	-3.3%	0.0%		-12%	7%	-11%
15- Clean Portfolio by 2045	1.6%	-2.9%	-0.1%		-9%	6%	-8%
	Change in PVRR vs PRS				Change in Levelized GHG MT vs PRS		
Portfolio	High NG Prices	Low NG Prices	National GHG Price		High NG Prices	Low NG Prices	National GHG Price
3- Baseline Portfolio	-0.6%	-1.1%	-0.8%		4%	7%	4%
15- Clean Portfolio by 2045	0.6%	1.0%	0.8%		-4%	-6%	-4%

Table 10.6: Jurisdiction PVRR Sensitivity Analysis

Portfolio	Change in PVRR vs Expected Case Market Pricing					
	Washington			Idaho		
	High NG Prices	Low NG Prices	National GHG Price	High NG Prices	Low NG Prices	National GHG Price
1- Preferred Resource Strategy	1.2%	-2.7%	-0.2%	3.3%	-4.0%	0.1%
3- Baseline Portfolio	1.8%	-3.1%	-0.1%	2.8%	-3.8%	0.0%
15- Clean Portfolio by 2045	1.3%	-2.7%	-0.2%	2.3%	-3.4%	0.0%

National GHG Pricing Portfolio

If a national GHG gas pricing plan were passed by the US Congress, Avista would deviate from the PRS described in this IRP. Avista created a new optimized portfolio for this future. This portfolio includes several changes from the PRS. The resulting changes reduce the system PVRR by only $13 million (0.1%) but include several portfolio changes shown in Table 10.6 below. The most significant changes are increases in wind, storage, and baseload renewable resources for Washington. This is likely due to higher market prices justifying a change in resources to meet capacity and clean energy requirements. Idaho's changes are far less dramatic, where natural gas is still preferred, but at a lower amount in exchange for increases in energy storage, plant upgrades, and energy efficiency.

Table 10.6: Jurisdiction PVRR Sensitivity Analysis

Resource Selection	Washington				Idaho		
	1- Preferred Resource Strategy	18- National GHG Pricing	Change		1- Preferred Resource Strategy	18- National GHG Pricing	Change
NG CT	0	0	0		304	277	-27
Solar	10	10	0		0	0	0
Storage Added to Solar	0	0	0		0	0	0
Wind	945	1,145	200		0	0	0
Storage	130	469	339		67	119	52
Hydrogen/Ammonia	696	318	-378		0	0	0
Other "Clean" Baseload	0	78	78		0	0	0
Existing Plant Upgrades	0	3	3		0	2	2
DR Capability	7	7	0		0	0	0
EE- Winter Capacity	57	57	0		24	25	1
EE- Summer Capacity	59	59	0		24	25	1

11. Washington Customer Impacts

Section Highlights

- Avista's 2021 Clean Energy Implementation Plan (CEIP) was approved with 38 conditions by the Washington Utility and Transportation Commission.
- Seven Customer Benefit Indicators (CBI) are applicable to resource planning.
- The non-energy impacts are used to enhance resource selection by accounting for benefits to customers.
- Avista's planning methodology for CBIs was reviewed by the newly formed Equity Advisory Group (EAG).
- Avista created a Named Community Investment Fund (NCIF) to increase energy related investments in disadvantaged communities.

Consistent with the Clean Energy Transformation Act (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 IRP includes an assessment of energy and non-energy benefits and the reductions of burdens to Vulnerable Populations and Highly Impacted Communities (i.e., Named Communities); long- and short-term public health and environmental benefits, costs, and risks; and energy security risks. These impact areas are considered in various portfolio analyses and incorporated into the Preferred Resource Strategy (PRS) through the inclusion of non-energy impacts (NEIs) and Customer Benefit Indicators (CBIs) metrics where applicable. Using these metrics, Avista estimates the degree to which 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 clean energy transition and maintains accountability for Avista's resource and program choices. While Avista is committed to ensuring the equitable implementation of the specific actions identified in the Clean Energy Implementation Plan (CEIP), there are several circumstances where NEIs or CBIs are not applicable to the long-term planning process. In these circumstances, NEIs and CBIs are utilized for the evaluation and selection of programs offered by Avista 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 Technical Advisory Committee (TAC) and Energy Efficiency Advisory Group (EEAG) in the review of each resource, program selection and/or implementation. In addition, the methodology was reviewed with the Equity Advisory Group (EAG) to ensure the evaluation is 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 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 for resource strategy evaluation within the traditional IRP planning process through increased stakeholder input regarding equity issues and continuous progress evaluation. Throughout the CEIP process, the EAG was instrumental in identifying communities or individuals who have historically, or who are currently, experiencing inequities. Avista has taken a first step to incorporate “recognition justice” into its planning efforts. These groups are described in the “Named Communities” section below. The equity areas identified under CETA are categorized and briefly discussed in Table 11.1.

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

[1] WUTC Docket UG-210755 Final Order 09, paragraph 56.

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 CEIP development. 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 IRP Progress Report and this IRP to provide TAC meeting topics and a discussion forum for IRP inputs ahead of the meetings. The development of this IRP and Washington's 2023 Electric IRP Progress Report includes feedback from the TAC, thus ensuring representation from stakeholders and individuals where additional policies and procedures may be identified and considered going forward.

Table 11.1: Named Communities

Topic	Observations
Affordability	• Factors impacting ability to pay for energy • Balance of electric bill with other expenses
Energy Resilience and Security	• Factors such as location, condition, etc. limiting the ability to have power quickly restored • 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 harm • Housing conditions • Location to pollution
Community Development	• Factors going beyond individual socio-economic or sensitivities • Factors pertaining to larger groups of individuals
Public Health	• Factors disproportionally impacting health associated with social or environmental indicators

Named Community Identification

Avista must identify communities who are disproportionally impacted by adverse socioeconomic conditions, pollution, and climate change to ensure planning and implementation processes are fair and have an equitable distribution of clean energy transition benefits. To do this Avista identifies two types of community groups,

[2] See Docket UE-210295.

Highly Impacted Communities and Vulnerable Populations (WAC 480-100-605), jointly referred to as Named Communities and are defined as follows:

- **Highly Impacted Community** means a community designated by the Washington Department of Health (DOH) 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:
  - Adverse socioeconomic factors, including unemployment, high housing, and transportation costs relative to income, access to food and health care, and linguistic isolation; and
  - 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 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 11.1. 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 11.1: Named Communities

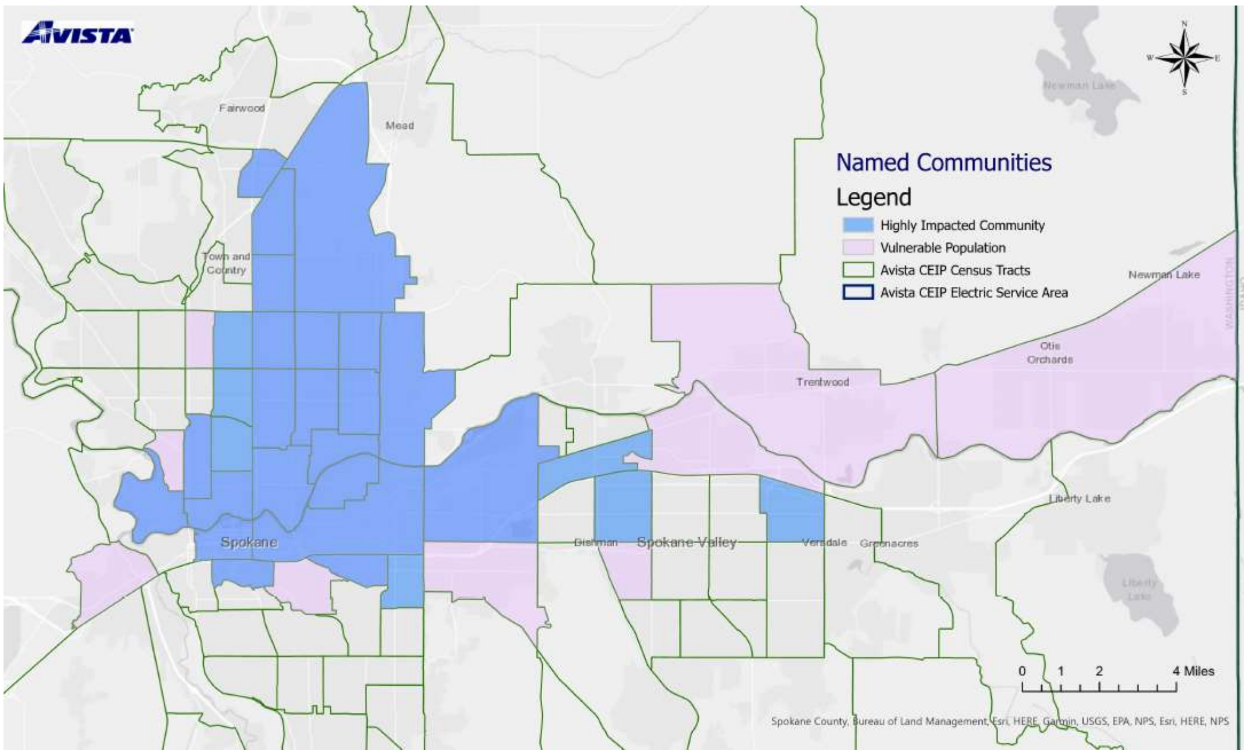
Environmental Exposures	Environmental Effects	Socioeconomic Factors	Sensitive Populations
○ NO_X-diesel emissions ○ Ozone concentration ○ PM 2.5 concentration ○ Populations near heavy traffic ○ Toxic releases from facilities	○ Lead risk from housing ○ Proximity to hazardous waste treatment facilities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

In the 2021 CEIP, Avista’s methodology to determine Vulnerable Population characteristics was conditionally approved.[4] With the help of its EAG and other advisory

[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

groups, Avista 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 identifies areas on a scale of 1 to 10, where 10 is an area 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 11.2 through Figure 11.4. Avista will continue to work with the EAG to identify additional criteria to distinguish Vulnerable Populations.

Figure 11.2: Spokane Named Communities



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

Figure 11.3: Washington Service Area Named Communities

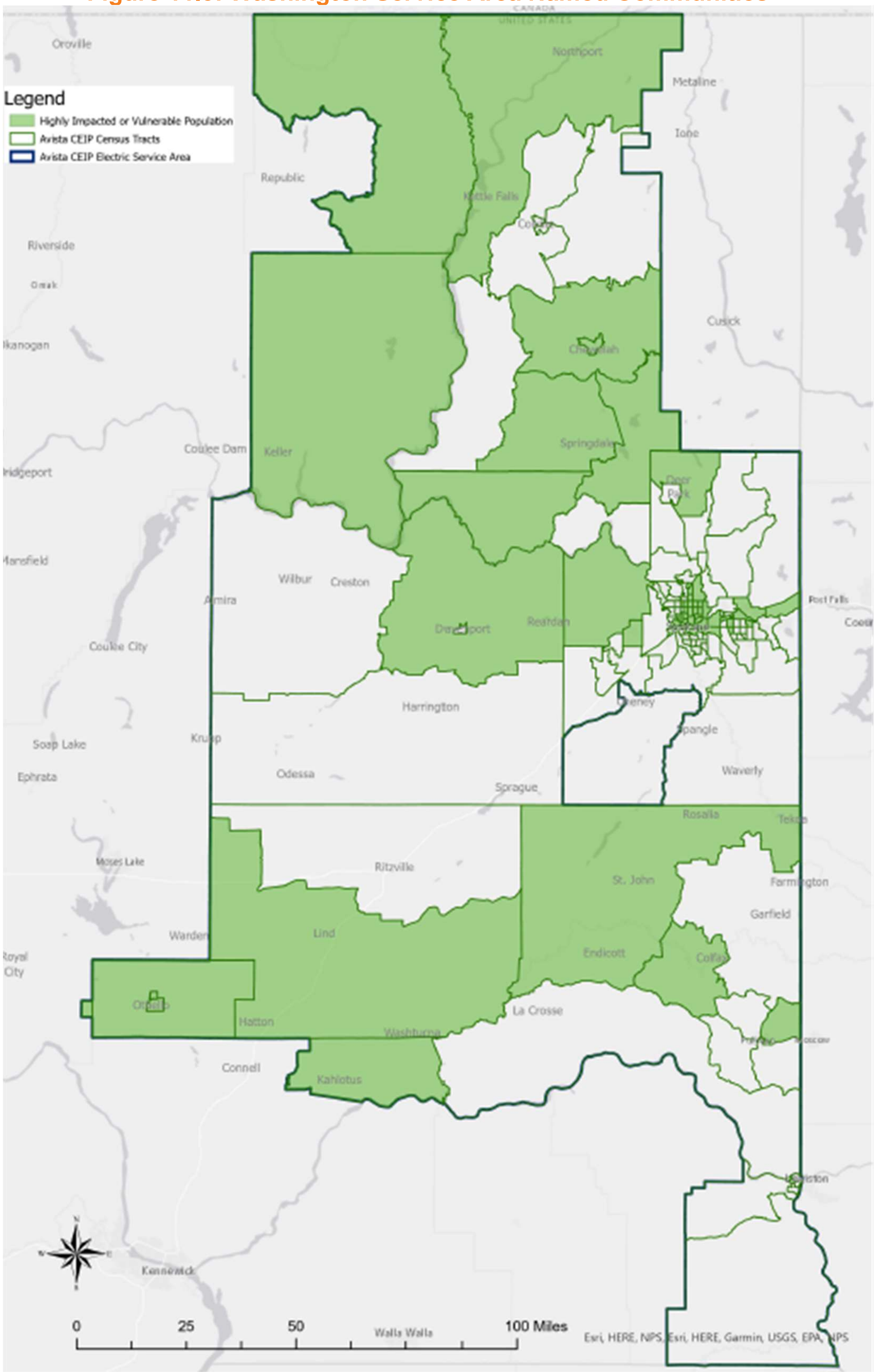
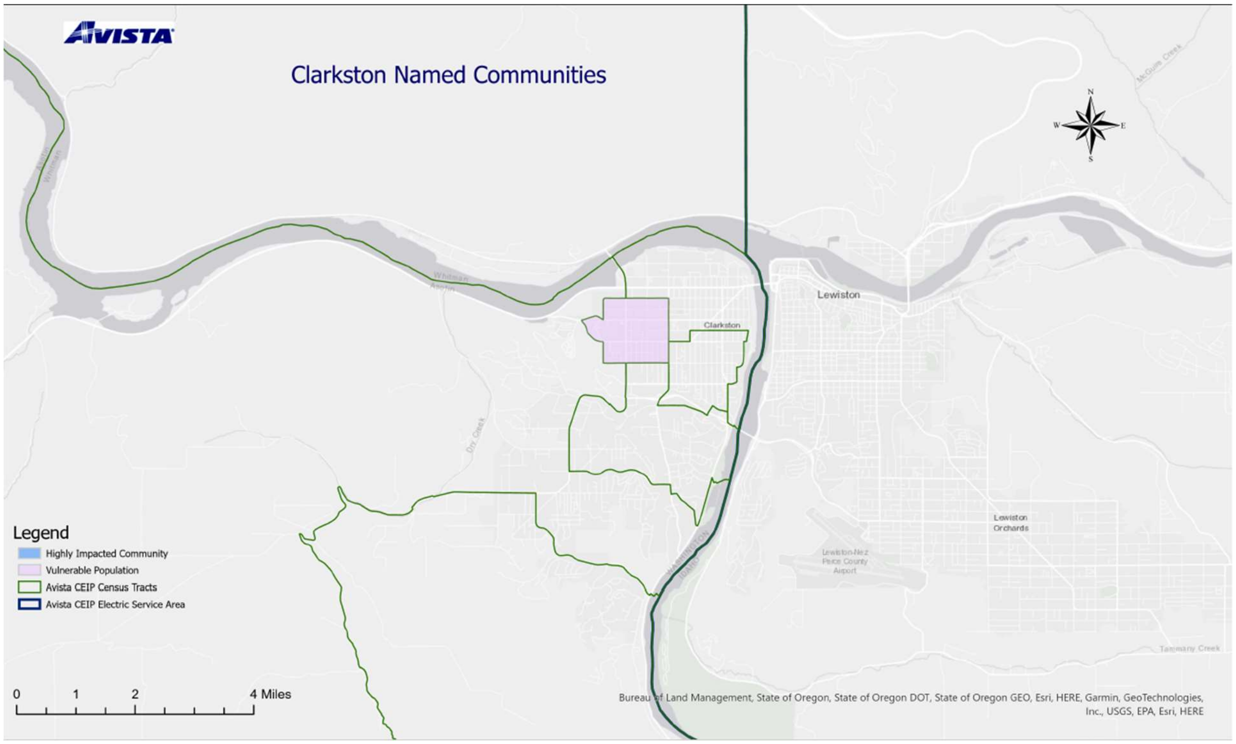


Figure 11.4: Clarkston Area Named Communities



Non-Energy Impacts (NEI)

In certain circumstances, the impacts associated with energy efficiency (i.e., demand-side) or supply-side resources may include additional effects beyond energy or bill savings. These NEIs may be significant compared to energy savings and are typically separated into specific areas as follows:

- Utility Impacts – changes in resource cost, transmission and distribution losses, and demand, leading to reductions in 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 may also be related to public health, safety, reliability and resiliency, energy security, environment (land use, water, wildfire, wildlife), and economic impacts.

NEIs have been incorporated in the selection of energy efficiency[6] programs/measures previously but using NEIs is new in respect to supply-side resource planning. Avista

[6] NEI for energy efficiency resources were incorporated into the 2021 IRP on an overall basis rather than individual measure basis.

engaged with a consultant, DNV[7], to identify and quantify both energy efficiency and supply-side NEIs. After input from recent Washington Utilities and Transportation Commission (WUTC) workshops and Avista's advisory groups, additional 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 additional NEIs may be included in the future as more studies are completed, specifically for solar, storage, demand response and other distributed energy resources (DERs). As part of CEIP Condition No. 2, Avista greed to incorporate NEIs in the 2023 IRP Progress Report as well as this and future IRPs. Outside the resource planning process, NEIs are also helpful in resource selection and utilized in Avista's 2022 All-Source Request for Proposal (RFP).

For energy efficiency, Avista only uses the positive NEI values applied as a 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 are up to $0.75 per kWh. These studies and a summary of how these NEIs 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) 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 was used to select new resources.

NEI values can be useful in resource planning, obtaining additional NEIs quantification 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 best be handled through a joint utility 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,[10] as part of Avista's 2021 CEIP. This fund facilitates investments in programs, projects, initiatives, and other support that traditionally would not be undertaken.

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[7] https://www.dnv.com/

[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

Avista proposed to spend up to approximately $5 million, or 1 percent of its electric retail revenue at the time, each year of the 2021 CEIP implementation period through the NCIF on projects to improve the equitable distribution of energy and non-energy impacts within Named Communities. The NCIF allocation is as follows:

- 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 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 IRP includes forecasts of the relevant CBI impacts for supply or demand side resource selection. As illustrated in Table 11.2, the CEIP includes 14 CBIs, including several metrics for measuring the impact of those CBIs. The metrics boldly highlighted are forecasted in this IRP since they're relevant to resource planning. 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, the CBI to reduce air emissions includes the estimated financial value of the societal harm of those emissions as an NEI. As such, energy efficiency addresses CBIs in its NEI calculations for resource planning purposes. For metrics related to resource planning, this IRP shows both available historical baselines and a forecast for these CBIs.

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

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 11.5 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. Some CBIs have data available to forecast on a long-term basis and can be included in the IRP, while 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 11.5: Planning Process

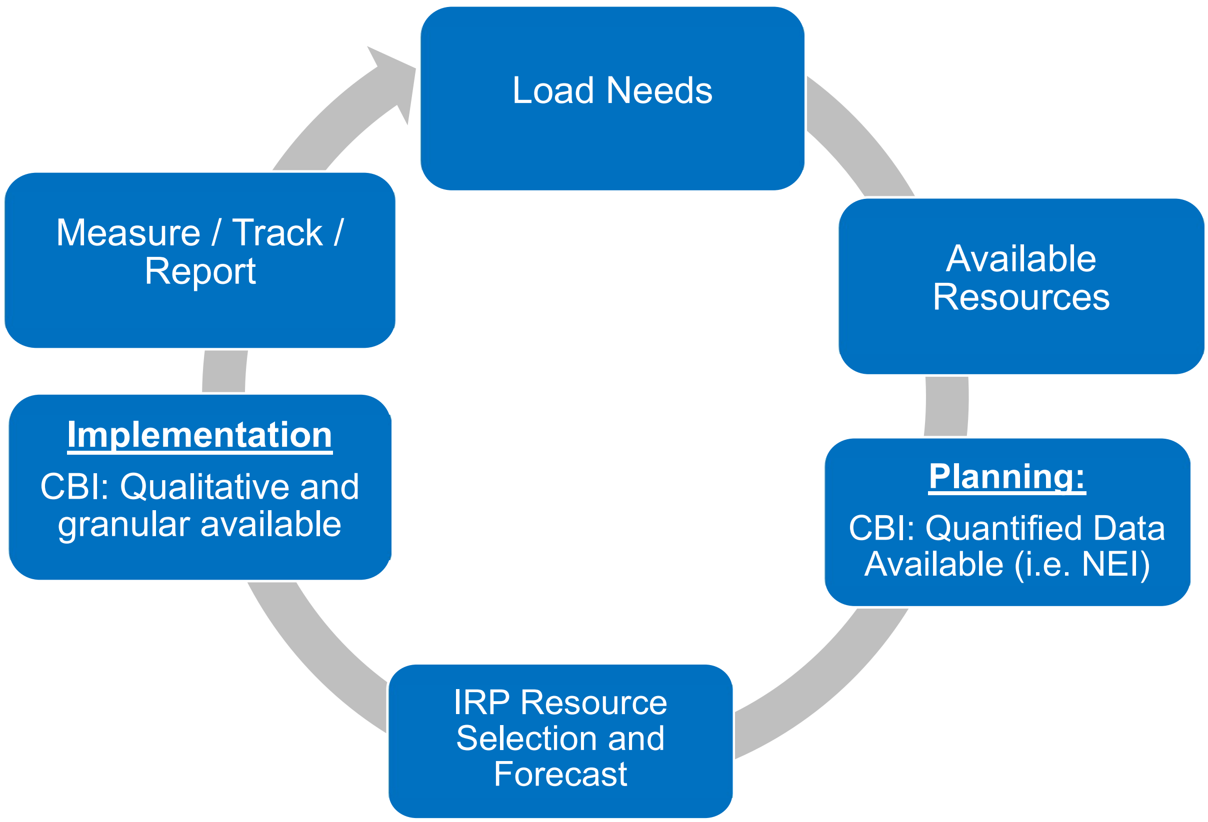

Table 11.2: Customer Benefit Indicators

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 (GHG) 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 resource 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. When combined with CBI No. 3, Avista can monitor the successful steps contributing to this increase in participation. 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); and
- 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 conservation potential assessment (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, while positively 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; and
- Translation services.

These barriers to access 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 relevant to resource planning but rather to program implementation. Avista continually works with its advisory groups to increase participation.

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 investing 30 percent of Avista's total transportation electrification 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 where the impacts of 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 may lead to positive impacts on Avista customers living in these 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 impacts to all customers and specifically those in Named Communities.

Avista will measure the following metrics for this CBI:

- Incremental annual spending of NCIF and other investments in a Named Community;
- Number of customers and/or CBOs served each year; and,
- Applicable quantification of annual energy and non-energy impacts from investments.

Avista includes a related forecast of potential NCIF 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 demand response (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 delivery system or resource adequacy power outages due to their socio-economic or sensitivity factors. 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; and
- 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 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.

In other instances, customer outages may be due to a lack of resource adequacy. The Planning Reserve Margin metric attempts to isolate Avista's ability to generate enough energy to meet customer demand while ensuring reliability through resource generation additions. This metric is included in resource planning as each demand- and supply-side resource may result in different degrees of reliable energy and is 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 with the reduction of 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; and
- Avista's Washington resource air emissions.

The impact to the total weighted days exceeding healthy levels will be from Avista's efforts to reduce emissions and actions taken by others in the 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 Regional Clean Air Agency to track wood use as a primary heating source. Avista will work with its 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 facilities' impacts to overall outdoor air quality. This is explained in the section below discussing the metrics Avista 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 Avista 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 its Biennial CEIP Update Report to be filed by November 1, 2023.

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, while energy efficiency evaluations include this savings in the calculation of avoided costs. Reporting this CBI keeps the issue at the forefront of affordability and/or energy burden conversations during implementation of future investments. Avista includes a utility NEI for a decrease in contact center calls for certain low-income energy efficiency measures to account for reductions in future disconnects.

CBIs Applicable to Resource Selection

While most of Avista’s CBIs are not related to resource planning, this section addresses CBIs with ties or linkages to resource planning. The intent of Avista’s resource selection methodology is to use resource costs and benefits, the NCIF, CETA requirements, and NEI values to inform resource outcomes, while avoiding any preconceived CBI targets or expectations. Constraints or requirements can be created in the PRiSM model to ensure certain metrics are met such as the Planning Reserve Margin requirements or including financial incentives such as NEIs to incent certain decisions. These constraints may drive different outcomes as compared with traditional planning. The following section outlines CBI forecasts, while the specific data used to estimate the metrics and CBI values are included with the PRiSM model in Appendix F. These results can also be measured against a future scenario “Maximum Customer Benefits” scenario and are achieved through increasing CBIs values 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% of income; and
- 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 have electric only vs combined 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. Beyond the assistance provided by the development of a low-income community solar facility, the analysis does not consider additional energy assistance.

The first metric illustrates the forecast of the number of customers with excess energy burden (see Figure 11.6) over the planning horizon. These customers have a combined energy bill between electric and natural gas exceeding 6% 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%. Avista expects to increase the amount of energy assistance participation for those customers through increased outreach and targeted programs.

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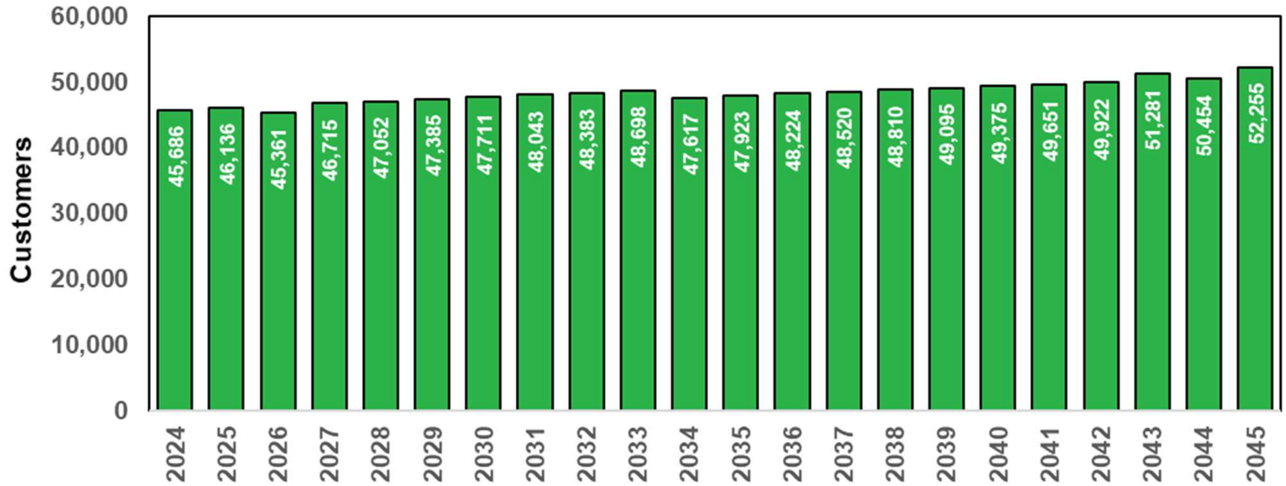
[13] At this time separate tracking on a forecasted basis for known low-income and Named Communities cannot be completed until additional data is gathered. Avista intends to have this information available for the CEIP Progress Report.

[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 11.6: WA 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% threshold as shown in Figure 11.7 in 2024. Avista continues to refine this metric for historical baseline purposes.

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% level. Excess energy burden growth is shown in Figure 11.7 and Figure 11.8 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 11.7: Percent of Washington Customers with Excess Energy Burden

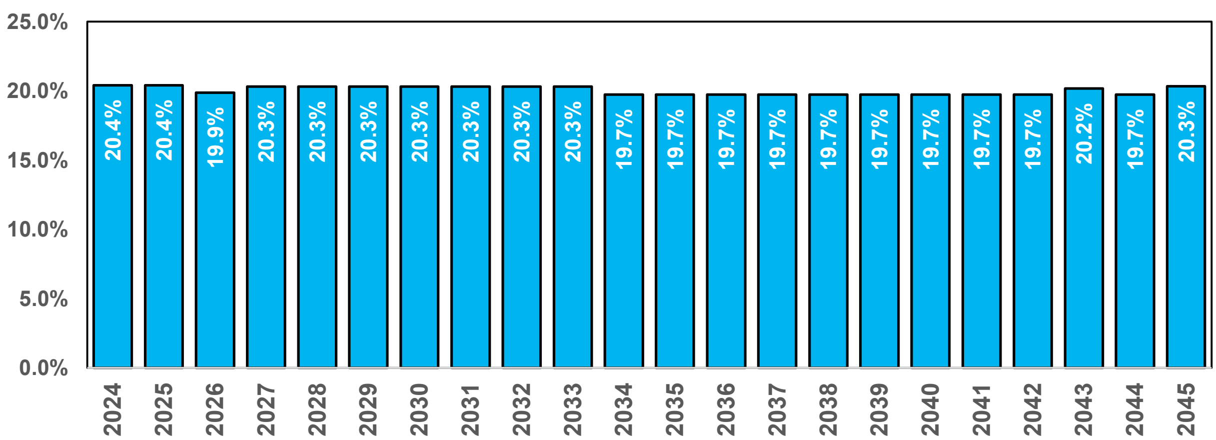
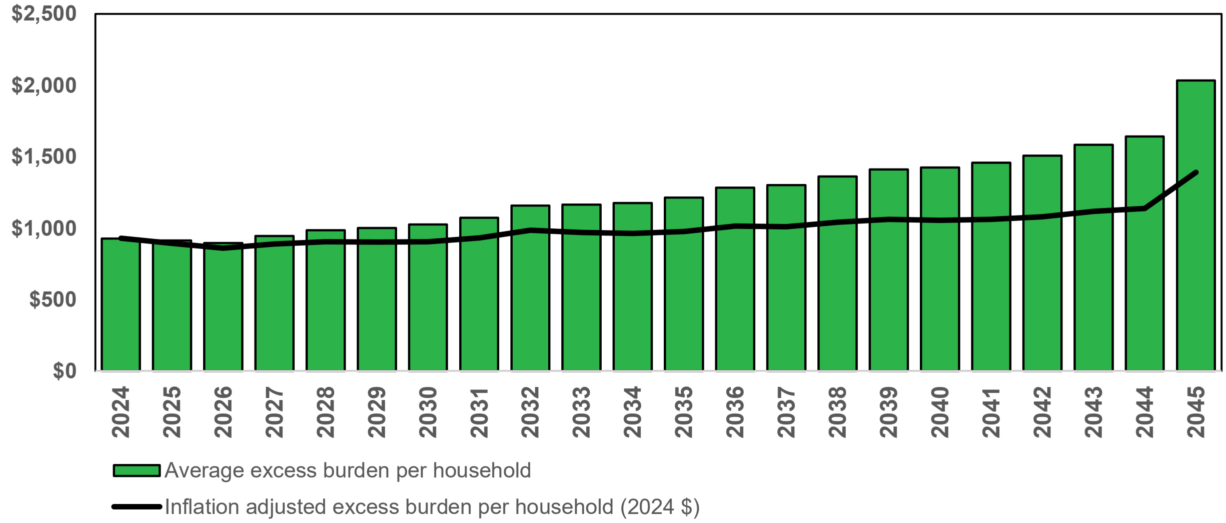


Figure 11.8: Average Washington Customer Excess Energy Burden



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; and
- Number of projects in Named Communities.

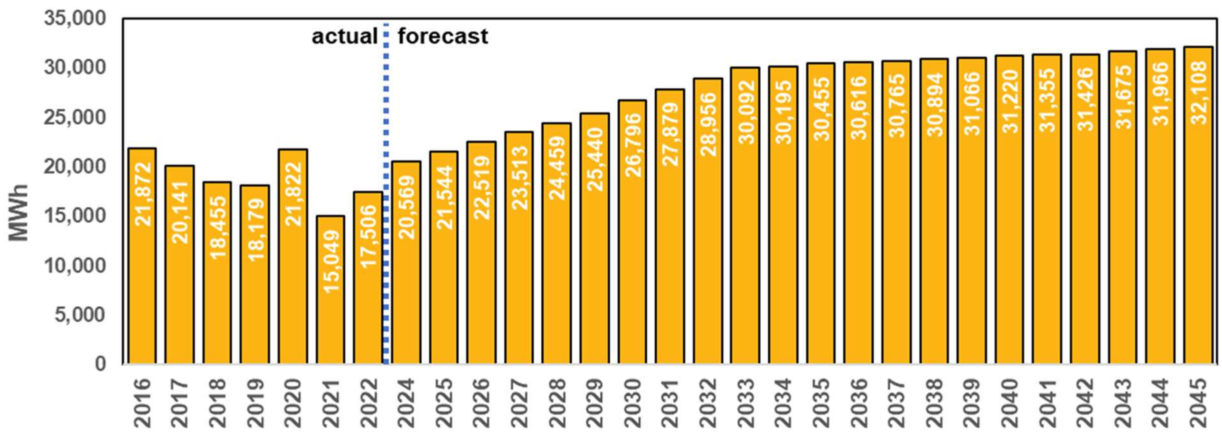
The IRP forecast includes DER production and capacity, but the number of projects is outside the planning scope and cannot be accurately forecasted. There are three methods for bringing these resources to the system. The first is PURPA development. Historically, this method has brought the most energy 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 the published avoided cost rates. 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 11.9. 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.

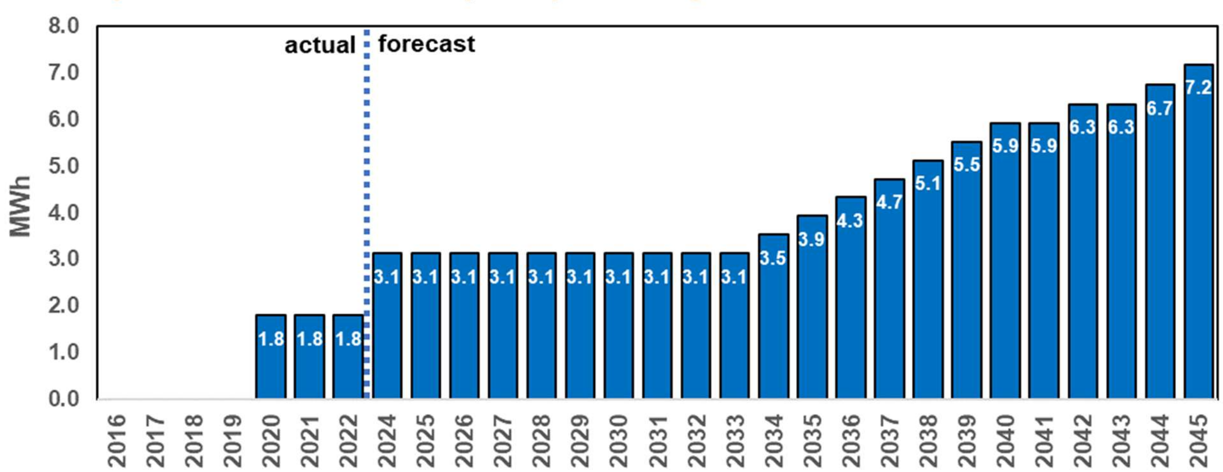
and Avista's NCIF. This plan includes expected storage related DERs to be added in Named Communities to enhance distribution systems and provide system peak capacity. The DER additions described above are shown in Figure 11.10.

Figure 11.9: Total MWh of DER in Named Communities



Avista partnered with the Department of Commerce in Washington on two Clean Energy Fund Projects, to install 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 Spokane 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's 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 11.10: Total MWh Capability of Storage DER in Named Communities



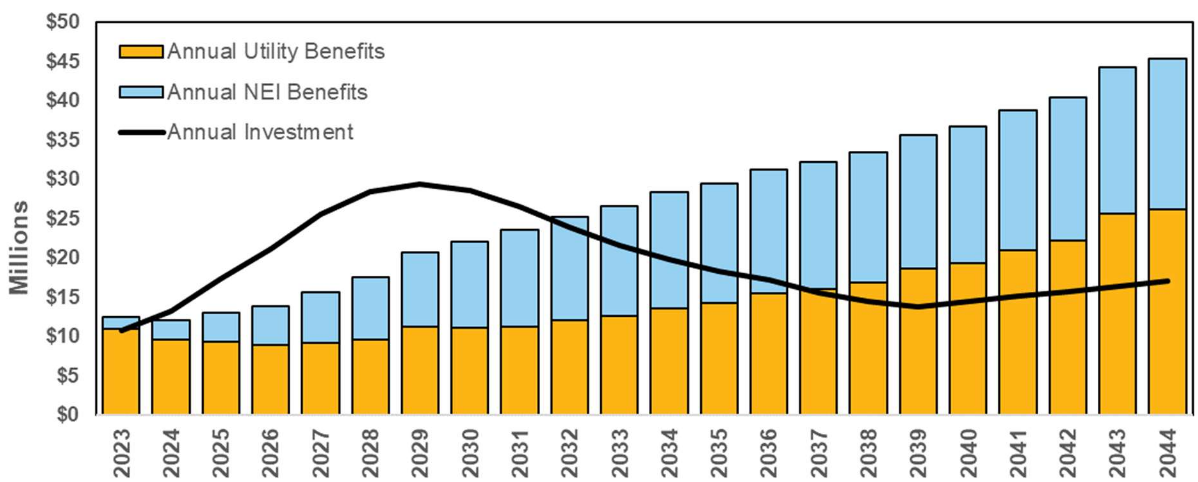
CBI No. 6 – Investments in Named Communities

This plan includes high level estimates for investments and benefits in Named Communities. This CBI includes three metrics:

- Reduction of Energy Burden;
- Energy Resiliency; and
- Risk Reduction.

This illustration includes the annual utility invested cost of resources in this IRP and compares these values to the annual utility and non-energy impacts 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 11.11 shows the projected investments and benefits. Resource selection choices are driven by high non-energy impacts 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 11.11: Total MWh Capability of Storage DER in Named Communities



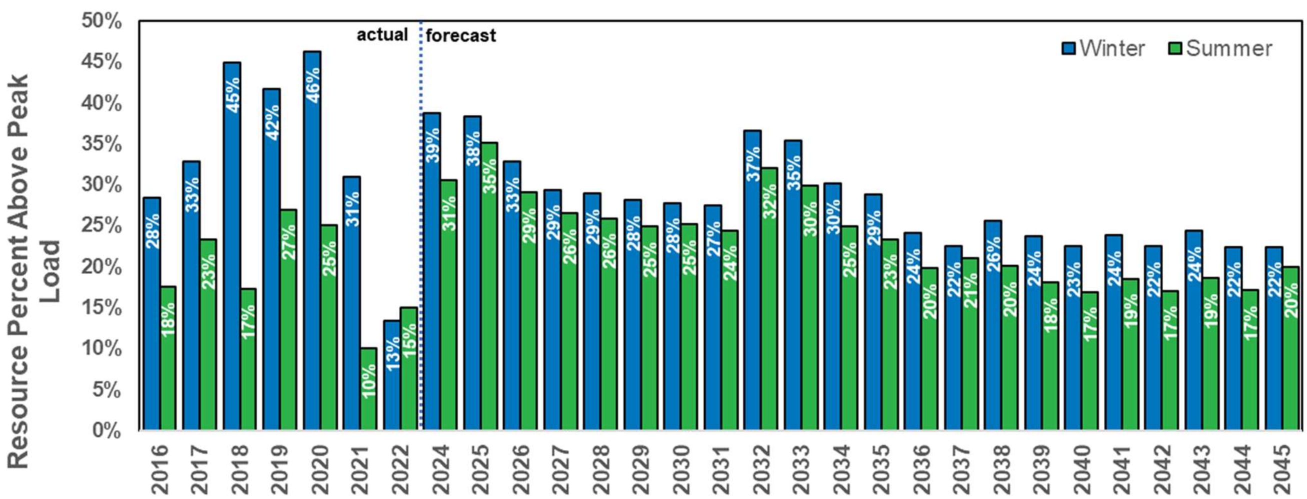
This CBI includes a third metric accounting for the number or sites and projections of future DERs. This forecast does not include this metric as the number of project sites will be determined during implementation.

CBI No. 7 – Energy Availability
This CBI is designed to ensure Avista has a reliable system for all customers including Named Communities and has three metrics:

- Average Outage Duration;
- Planning Reserve Margin (Resource Adequacy); and
- Frequency of Customer Outages.

These 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 11.12 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 Qualifying Capacity Credit (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 11.12: Planning Reserve Margin



[18] QCC values were derived by the Western Resource Adequacy Program with input from participating utilities and compilation by the program administrator – SPP.

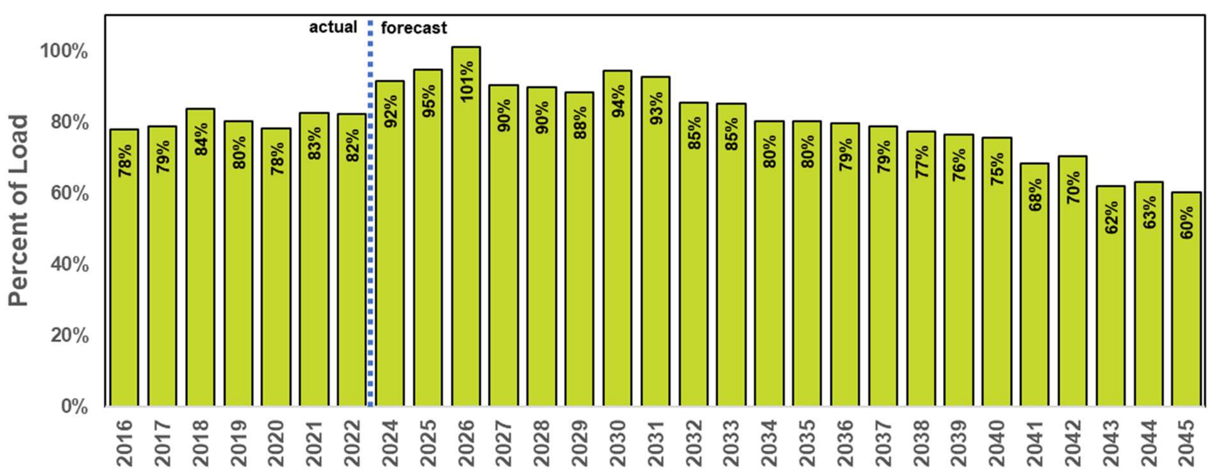
CBI No. 8 – Energy Generation Location

CETA encourages the use of local resources to enhance energy security. As such, this CBI will address the following metric:

- Percent of generation located in Washington or connect to Avista's transmission system.

To address energy security, Avista quantifies the amount of generation located within Washington State or directly connected to Avista's transmissions system used for customer needs. These options should provide an increased reliability rate as potential disruptions may be minimized by the proximality to load. This metric is energy agnostic on the type of energy used. Figure 11.13 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 Chelan PUD and Columbia Basin Hydro. 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 a decrease in connected resources due to selection of external resources, such as Montana wind. These resources are preferred due it its cost than local resources due to necessary system transmission upgrade costs. Economic benefits of local generation were included as a NEI, but these benefits are overshadowed by the high costs of new transmission.

Figure 11.13: Generation in Washington and/or Connected to Avista Transmission



CBI No. 9 – Outdoor Air Quality

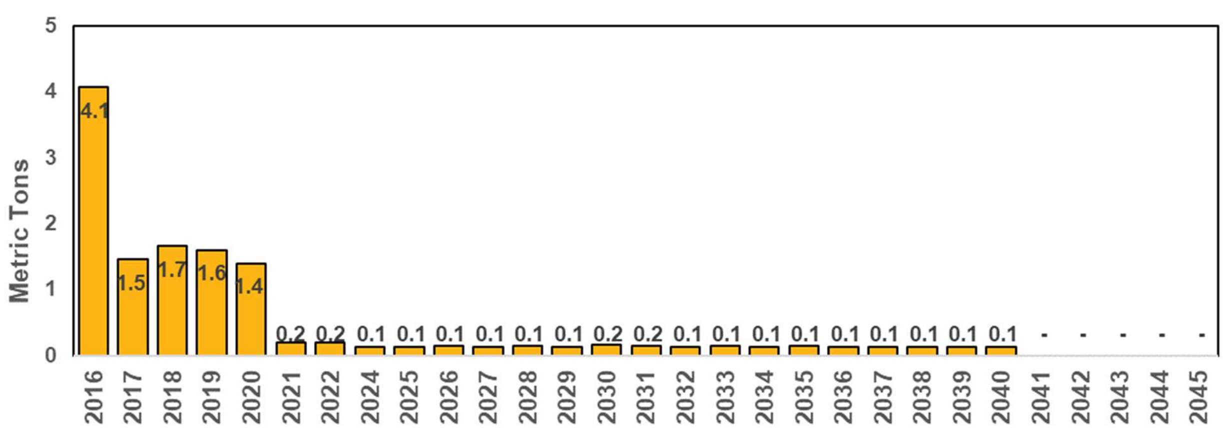
As discussed above, Avista's resource air emissions are forecastable within an IRP. The Outdoor Air Quality CBI measures the following:

- Weighted average days exceeding healthy levels; and
- Avista's Washington plant air emissions.

The impacts to unhealthy days within local communities are typically related to events outside of Avista's control and are after the fact calculations conducted by a third 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. 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 (CT), Boulder Park, and Northeast CT. 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 11.14 through 11.17 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. Avista does not directly monitor mercury emissions for its natural gas facilities as the emissions are de minimis.

Figure 11.14: Avista Located Washington State Facility's SO_2 Emissions



[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 11.15: Avista's Washington State Facility's NO_x Emissions

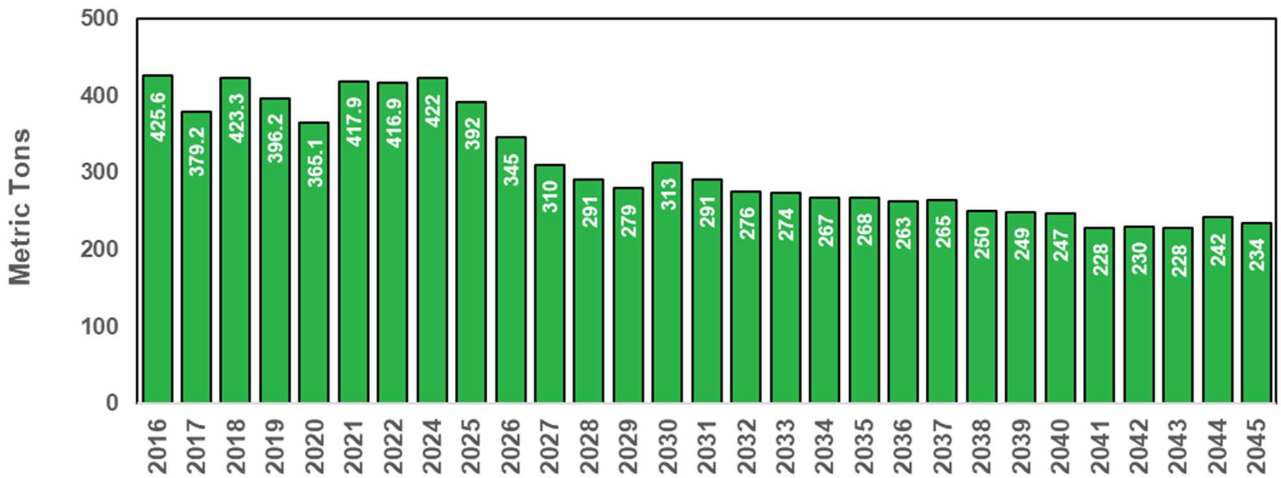
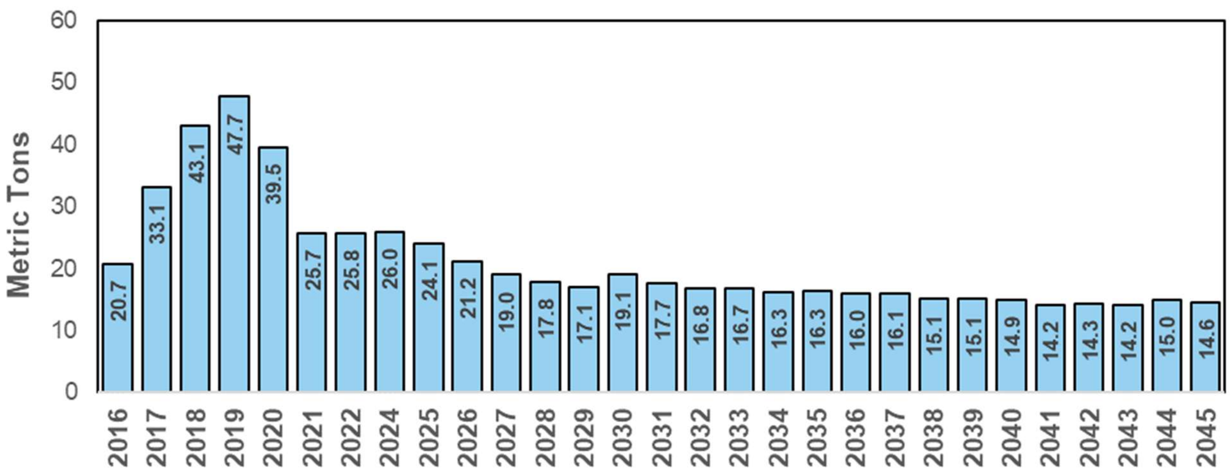


Figure 11.16: Avista's Washington State Facility's VOC Emissions



CBI No. 10 – Greenhouse Gas Emissions
There are two metrics for GHG Emissions covered in this section:

- Avista's GHG emissions; and
- Regional GHG emissions.

The first metric estimates the amount of direct emissions from Washington's share of power plants and how those change considering market transactions (labeled as "net emissions"). Figure 11.18 shows direct GHG emissions rising until the end of 2025 when Colstrip ownership is transferred and removed from Avista'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 decline as additional clean energy resources are brought on the western interconnect system. Net emissions are lower than direct emissions in the near-term as the calculation removes emissions related to power sold off the system. Later in the planning horizon, system sales decrease and Avista may need to purchase power. This forecast includes emissions associated with those purchases. Lastly, due to the Climate Commitment Act (CCA) 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 GHG metric (shown in Figure 11.19) 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 GHG 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 GHG 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 uncertainty of electric vehicle adoption. Natural gas emissions are also nearly flat until 2045, 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 11.17: Washington Direct and Net Emissions

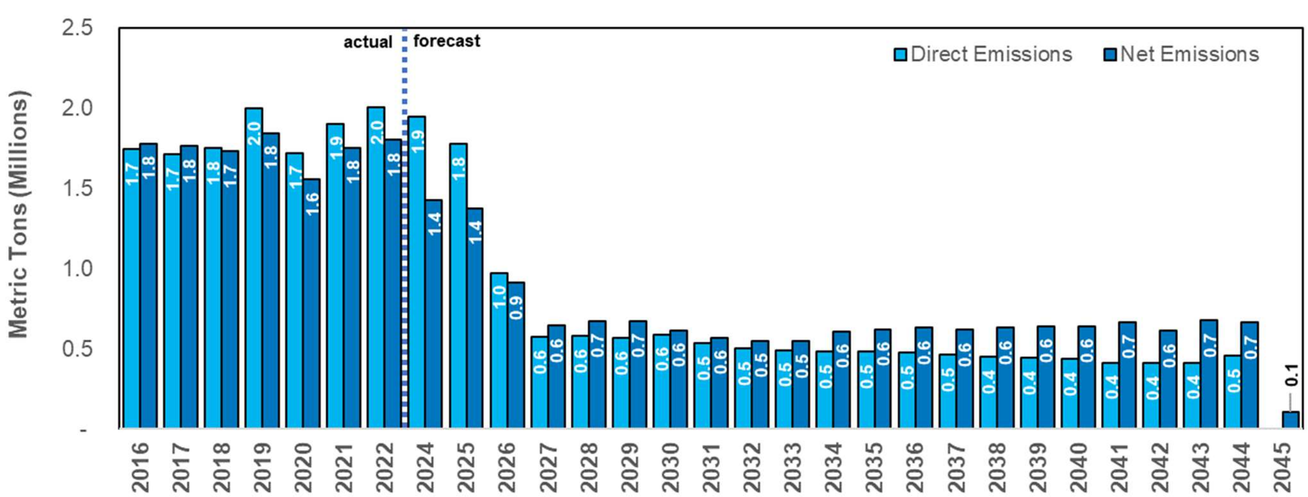
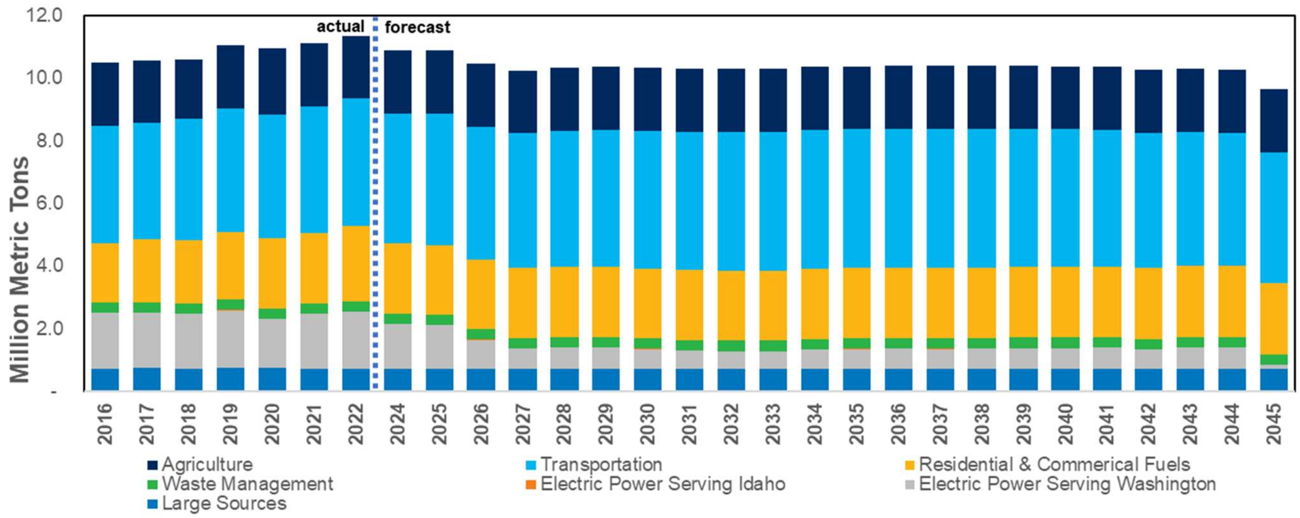


Figure 11.18: Avista Washington Service Area Direct and Net Emissions



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. Avista's CBIs approved in the 2021 CEIP will remain as is until updated or modified in its upcoming biennial CEIP update or 2025 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.

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12. Action Items

The IRP is an ongoing and iterative process balancing regular publication timelines while pursuing the best resource strategy for the future as the market, laws, and customer needs evolve. The biennial publication date provides opportunities to document ongoing improvements to the modeling and forecasting procedures and tools, as well as enhance the process with new research as the planning environment changes. This section provides an overview of the progress made on the 2021 action items and details of the 2023 IRP Action Plans for the 2025 IRP.

Avista's 2021 PRS provided direction and guidance for the type, timing, and size of future resource acquisitions in 2021. The 2021 Action Plan highlighted the activities for development in the 2023 IRP. These activities include resource acquisition processes, regulatory filings, and analytical efforts for the next IRP.

2021 IRP Action Items

- Investigate and potentially hire a consultant to develop both a hydro and load forecast to include a shift in climate in the Inland Northwest. This analysis would include a range in new hydro conditions and temperatures so the Company can utilize the new forecast for resource adequacy planning and baseline planning.

    Avista expanded its planning department since the 2021 IRP, the additional staff brought a hydrologic analytical background and was able to use Bonneville Power Administration's regional work for Avista's needs rather than securing outside services. Please see chapters 2 and 4, as well as the TAC 6 presentation in Appendix A for the results of these studies.

- Investigate streamlining the IRP modeling process to integrate the resource dispatch, resource selection and reliability verification functions.

    Avista acquired PLEXOS for use in natural gas and electric planning. Avista plans to use PLEXOS for resource valuation and its market risk evolution in the 2025 IRP. It is also possible it could replace PRiSM as the capacity expansion tool. More details about the use of PLEXOS in the planning process will be available in the 2025 IRP process.

- Study options for the Kettle Falls CT regarding potential reductions of the natural gas supply in winter months. The Company will investigate alternatives for this resource including fuel storage, retirement, or relocation of the asset.

    After further internal review and discussions, Avista decided to not make any changes to Kettle Falls CT's availability. Avista will continue to evaluate changes to the facility at a later time

- Determine how to best implement the Washington Commission's strong encouragement under WAC 480-100-620 (3) regarding distribution energy resource planning as a separate process or in conjunction with the 2025 IRP.

This IRP includes a new distributed energy resource chapter, it outlines the costs and assumptions used in this plan. Avista is also using a consultant to examine the resource potential for distribution energy resources (more details are available in Chapter 5). Further, Avista's formed a Distribution Planning Advisory Group, its first meeting was on March 29, 2023 to address how to best plan the future distribution system. Finally, this IRP includes non-energy impacts to all resources as part of its economic evaluation for Washington resources.

- Form an Equity Advisory Group to ensure a reduction in burdens to vulnerable populations and highly impacted communities and to ensure benefits are equitably distributed in the transition to clean energy in the state of Washington. This group will provide guidance to the IRP process on ways to achieve these outcomes.

Avista formed its Equity Advisory Group (EAG) to ensure all customers are benefitting from the transition to clean energy through the equitable distribution of energy and nonenergy benefits and to help identify ways to reduce energy burdens to communities and populations identified as being highly impacted by fossil fuel pollution and climate change. Please see Avista's Washington Clean Energy page at www.myavista.com/about-us/washingtons-clean-energy-future for additional details about the EAG and how to participate.

- Avista will conduct an existing resource market potential to estimate the amount and timing of existing resources available through 2045.

The 2023 All-Source RFP provided details about near term resource possibilities. The RFP received 32 proposals with options from 21 developers for 11 technology types including wind, solar, storage, natural gas, biomass, waste heat and demand response. No additional analysis of existing resource market potential was determined to be necessary beyond the RFP results at this time. Updates about the 2023 RFP are available in Appendix A in the TAC 6, 8, and 9 presentations.

- Conduct further peak credit analysis to understand the reliability benefits of all resources including demand response options with different duration and call options of the wide range of DR program options.

Avista chose to use the WRAP numbers for peak credits or Qualifying Capacity Credits (QCC). More refinements to the QCC numbers and their implementation in planning will continue as this regional program develops. Additional details about the WRAP are in the TAC 7 presentation in Appendix A and within Chapter 4.

- Avista will partner with a third-party consultant to identify non-energy impacts that have not historically been quantified for both energy efficiency and supply side resources.

Avista contracted with a consultant, DNV, to develop non-energy impacts for use in this and future IRPs. Please refer to the DNV presentation in TAC 3 in Appendix A, the April 2023 final report on non-energy impacts in Appendix D, and how those impacts were applied in Chapter 6. After completion of this study, numerous additional work on nonenergy impacts can be undertaken. Avista suggest these efforts be dealt with at state level analysis or process.

- Formalize the process for public to submit IRP-related comments and questions and for Avista to share responses to those requests.

  After discussions with the TAC and internally, Avista decided to maintain its open process for soliciting and sharing comments and questions. This was done to accommodate the wide variety of participants in our planning process who range from well-funded and staffed organizations who submit detailed written requests and questions about the process and its assumptions to individual customers who more comfortable visiting one-on-one with the planning team.

  Avista will continue to keep using this less formalized approach to help encourage this collaborative format that includes open questions in the TAC process, availability of the planning team and other Avista subject matter experts by email, phone and in person based on the needs and preferences of TAC participants.

  Avista welcomes suggestion and improvement of ideas to provide more transparency to the public who wishes to engage in the process.

- Develop a transparent methodology to include pricing data and consider available options for new renewable generation and energy storage options.

  Significant amounts of data, assumptions, supplementary reports, TAC presentations, recordings of meetings, meeting notes, and non-proprietary models are posted on the IRP web site for review by TAC members, customers, and other interested parties regarding this topic. This data includes the workbook used to develop resource costs with documentation of source data and the fully functional model used for resource decisions.

2023 IRP Action Items

The 2023 Action Plan was developed with input from Commission Staff, Avista's management team and members of the TAC on the analytical and other projects needed to further development and inclusion in the 2025 IRP.

- Incorporate the results of the DER potential study where appropriate for resource planning and load forecasting.
- Finalize the Variable Energy Resource (VER) study. This study outlines the required reserves and cost of this energy type. Results of this study will be available for use in the 2025 IRP.
- Study alternative load forecasting methods, including end use load forecast considering future customer decisions on electrification. Avista expects this Action Item will require the help of a third-party. Further, studies shall continue the range in potential outcomes.
- Investigate the potential use of PLEXOS for portfolio optimization, transmission, and resource valuation in future IRPs.
- Continue to work with the Western Power Pool's WRAP process to develop both Qualifying Capacity Credits (QCC) and Planning Reserve Margins (PRM) for use in resource planning.
- Evaluate long-duration storage opportunities and technologies, including pumped hydro, iron-oxide, hydrogen, ammonia storage, and any other promising technology.
- Determine if the Company can estimate energy efficiency for Named Communities versus low-income.
- Study transmission access required to access energy markets as surplus clean energy resources are developed.
- Further discuss planning requirements for Washington's 2045 100% clean energy goals.