Draft

2025 Electric Integrated Resource Plan

and

2025 Washington Clean Energy Action Plan

September 3, 2024
Schedule of Additional Documents

1. 2025 Electric Integrated Resource Plan

Section	Chapter	Availability
	Executive Summary	October 1, 2024
1	Introduction, Stakeholder Involvement, and Process Changes	October 1, 2024
2	Preferred Resource Strategy	Available
3	Economic and Load Forecast	Available
4	Existing Supply Resources	Available
5	Resource Needs Assessment	Available
6	Distributed Energy Resources Options	Available
7	Supply-Side Resource Options	Available
8	Transmission Planning & Distribution	Available
9	Market Analysis	October 1, 2024
10	Portfolio Scenarios	October 1, 2024
11	Action Plan	Available

2. 2025 Washington Clean Energy Action Plan

3. 2025 Electric Integrated Resource Plan Appendix

Section	Appendix	Availability
A	TAC Presentations	IRP website
B	Work Plan	IRP website
C	Draft AEG EE/DR Potential Assessment	Available
D	10-year Transmission/Distribution Plan	Available
E	Transmission Generation Integration Study	Available
F	DER Study	Available
G	Public Input and Results Data	October 1, 2024
H	Confidential Inputs and Models	January 2, 2025
I	Historical Generation Operation Data (Confidential)	January 2, 2025
J	New Resource Transmission Table	January 2, 2025
K	Resource Portfolio Summary	October 1, 2024
L	Washington State Schedule 62	January 2, 2025
M	Public Comments	January 2, 2025

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.

2025 Electric IRP
Executive Summary

This section will be available on October 1, 2024

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Acronym List

ADSS: Avista's Decision Support System

AEG: Applied Energy Group

aMW: Average Megawatt(s)

ARAM: Avista Reliability Assessment Model

BCP: Biennial Conservation Plan

CAIDI: Customer Average Interruption Duration Index

CCA: Climate Commitment Act

CEMI: Customer Experiencing Multiple Interruptions

CBO: Community Based Organizations

CCA: Climate Commitment Act

CC&B: Customer Care and Billing

CDD: Colling Degree Day

CEAP: Clean Energy Action Plan

CEIP: Clean Energy Implementation Plan

CETA: Clean Energy Transformation Act

CBI: Customer Benefit Indicator

CPA: Conservation Potential Assessment

CPI: Consumer Price Index

CT: Combustion Turbine

CCCT: Combined Cycle Combustion Turbine

CTA: Consumer Technology Association

DER: Distributed Energy Resource

DOE: Department of Energy

DOH: Department of Health

DPAG: Distribution Planning Advisory Group

DR: Demand Response

EAG: Equity Advisory Group

EAAG: Energy Assistance Advisory Group

EEAG: Energy Efficiency Advisory Group

EIA: Energy Independence Act

ELCC: Equivalent Load Carrying Capability

ERWH: Electric Resistance Water Heater

EUE: Expected Unserved Energy

EUI: Energy Use Index

EV: Electric Vehicle

FERC: Federal Energy Regulatory Commission

FSP: Forward Showing Program

H2: Hydrogen

HDD: Heating Degree Day

HG: Mercury

IAQ: Indoor Air Quality

IOU: Investor-Owned Utility

IP: Industrial Production Index of the U.S. Federal Reserve

IPCC: Intergovernmental Panel on Climate Change

IRP: Integrated Resource Plan

GHG: Greenhouse Gas

GISS: Goddard Institute for Space Studies

GWh: Gigawatt-hour(s)

HRSG: Heat Recovery Steam Generator

LDC: Local Distribution Center

LGIR: Large Generation Interconnection Request

LOLE: Loss of Load Expectation

LOLEV: Loss of Load Expected Events

LOLH: Loss of Load Hours

LOLP: Loss of Load Probability

MIP: Mixed Integer Program

MISO: Mid-Continent Independent System Operator

MSA: Metropolitan Statistical Area

MW: Megawatt(s)

MWh: Megawatt-hour(s)

NC: Named Community

NCIF: Named Community Investment Fund

NEEA: Northwest Energy Efficiency Alliance

NEI: Non-Energy Impact

NOx: Nitrous Oxide

NREL: National Renewable Energy Laboratory

OASIS: Open Access Same-time Information System

O&M: Operations and Maintenance

P2G: Power to Gas

PPA: Power Purchase Agreement

PRiSM: Preferred Resource Strategy Model

PRM: Planning Reserve Margin

PRS: Preferred Resource Strategy

PT: Production Tax (ratio)

PUD: Public Utility District

PURPA: Public Utility Regulatory Policies Act

QCC: Qualifying Capacity Credit

QF: Qualifying Facility

RA: Resource Adequacy

RAP: Real Average Energy Price

RCP: Representative Concentration Pathway

RCW: Revised Code of Washington

RFP: Request for Proposal

RMJOC: River Management Joint Operating Committee

SBCC: State Building Code Council

SCR: Selective Catalytic Reduction

SMR: Small Modular Reactor

SO2: Sulfur Dioxide

SPP: Southwest Power Pool

T&D: Transmission and Distribution

TAC: Technical Advisory Committee

TE: Transportation Electrification

TEP: Transportation Electrification Plan

TOU: Time of Use (Rates)

TRC: Total Resource Cost

UCT: Utility Cost Test

UEC: Unit Energy Consumption

UPC: Use Per Customer

UTC: Washington Utilities and Transportation Commission

VOC: Volatile Organic Compounds

VER: Variable Energy Resource

WAC: Washington Administrative Code

WECC: Western Electricity Coordinating Council

WPP: Western Power Pool

WRAP: Western Resource Adequacy Program

1. Introduction

This section will be available on October 1, 2024

2. Preferred Resource Strategy

The IRP starts with Avista's current resource position and projected load growth. The Preferred Resource Strategy (PRS) is mix of new generation, storage, demand response, market purchases, and energy efficiency options to meet load growth in a safe, reliable, cost-effective, and equitable manner as reasonably possible. The PRS must also meet state and federal policy goals, such as Washington's clean energy and reduced greenhouse (GHG) emissions goals. The resource strategy is not a specific action plan, but it does guide what types of resources Avista may pursue to meet load growth while honoring regulatory and policy requirements. The actual acquisition of new resources will use a Request for Proposal (RFP) process or other market opportunities to obtain the needed resources.

Section Highlights

- Energy efficiency meets 32% of future load growth; the biennial energy efficiency target for 2026-2027 is 55% higher than the 2024-2025 target.
- Demand Response reduces system peak load 4% by 2045.
- Wind generation may be acquired as early as 2029 if it benefits customers to acquire the resource early.
- Avista's capacity position may drive the need for new resources earlier if loads increase faster than forecasted.
- Transmission interconnect and capacity limits could decrease future generation acquisition and may drive alternative resource choices rather than preferred options.
- Meeting Washington's 2045 clean energy targets will require a diversified clean capacity portfolio using emerging technologies such as small modular reactors, power-to-gas (ammonia/hydrogen) fueling combustion turbines, and long-duration energy storage technologies.

For supply-side acquisitions, the procurement of resources will be through energy market transactions and a RFP from energy suppliers. This IRP shows resource owners and developers the timing, size, and types of resources most applicable for procurement. Avista expects this process may result in a different resource mix compared to the one presented in this chapter once real projects are known. Lastly, the IRP helps determine the avoided costs of serving future loads and shows how external forces and policies impact the utility's resource mix. Avista will use this strategy to inform its Washington Clean Energy Implementation Plan (CEIP) for 2026 through 2029; however, the ultimate action plan approved by the Commission for this period may differ from this plan.

The PRS uses the best available information at the time of the analyses, including Avista's interpretation of Washington's Clean Energy Transformation Act (CETA) requirements. CETA's "use rules" determine how renewable energy will qualify as either "primary" or "alternative" compliance to the 2030 greenhouse neutral standard. The IRP utilizes a least-cost planning methodology with specific social cost impacts specified by Washington's requirements such as the social cost of greenhouse gas (SCGHG) and Non-Energy Impacts (NEI). Due to divergent Idaho and Washington state energy policies, Avista separates the two jurisdictions for this plan by creating an individual resource selection plan as needed for each state while adding shared system resources where possible. Actual resource acquisitions are not separated by jurisdiction at this time.

Avista's PRS describes the lowest reasonable cost resource mix considering risk, 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 Washington State policies. The PRS includes supply-side resources, distributed energy resource (DER) options, energy efficiency, and demand response (DR) to serve customer loads. The plan compares resource options to find the lowest-cost portfolio considering the non-power costs/benefits (such as NEIs) to meet seasonal capacity deficits, annual energy needs, and CETA requirements. The analysis considers a minimum spending threshold using the Named Communities Investment Fund (NCIF)[1] to enhance the equitable transition to clean energy in Washington's Named Communities. The Idaho portion of the plan utilizes a least cost methodology without societal cost estimates.

Distributed Energy Resource Selections

Energy Efficiency Selections

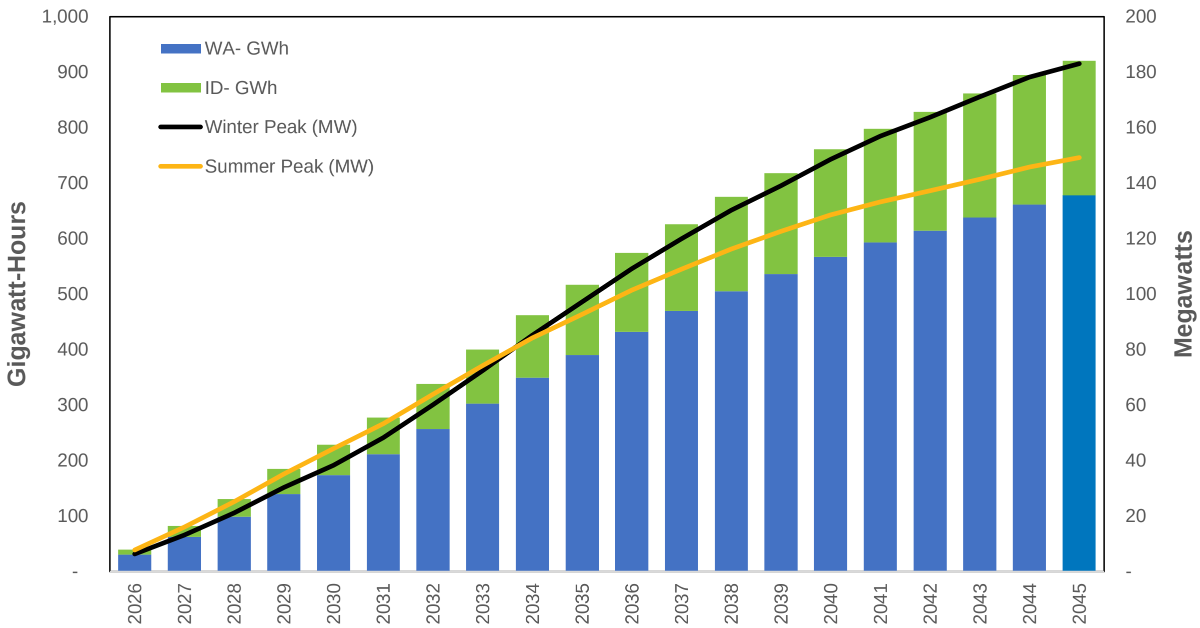
Energy efficiency savings meets 32% of future load growth in this plan. However, new loads, including electric transportation and building electrification, will outpace energy efficiency adoption. Without electrification, energy efficiency would keep future load growth flat. Avista's load forecast (described in Chapter 3) is net of future energy efficiency savings. Avista adds back the selected quantity of efficiency savings to the load forecast through an iterative technique in the Preferred Resource Strategy Model (PRiSM) until the amounts of energy efficiency selected and load added are equal. This evaluation considers over 3,000 energy efficiency measures and individually models each program's capacity and energy contributions to rigorously evaluate each program's benefit to the system. This method ensures an accurate accounting of peak savings.

Over the planning horizon, energy efficiency programs will reduce 870 cumulative gigawatt-hours of energy sales between 2026 and 2045. When considering the reductions of transmission and distribution losses by energy efficiency, loads are 105 aMW less with these programs. Figure 2.1 shows total energy and peak hour savings by state for both winter and summer. Winter peaks are reduced by nearly 183 MW and summer peaks are reduced by approximately 149 MW. Over the IRP planning horizon, 26% of energy efficiency comes from Idaho customers and 74% from Washington customers. Washington has more energy efficiency savings relative to its 65% share of total load due

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

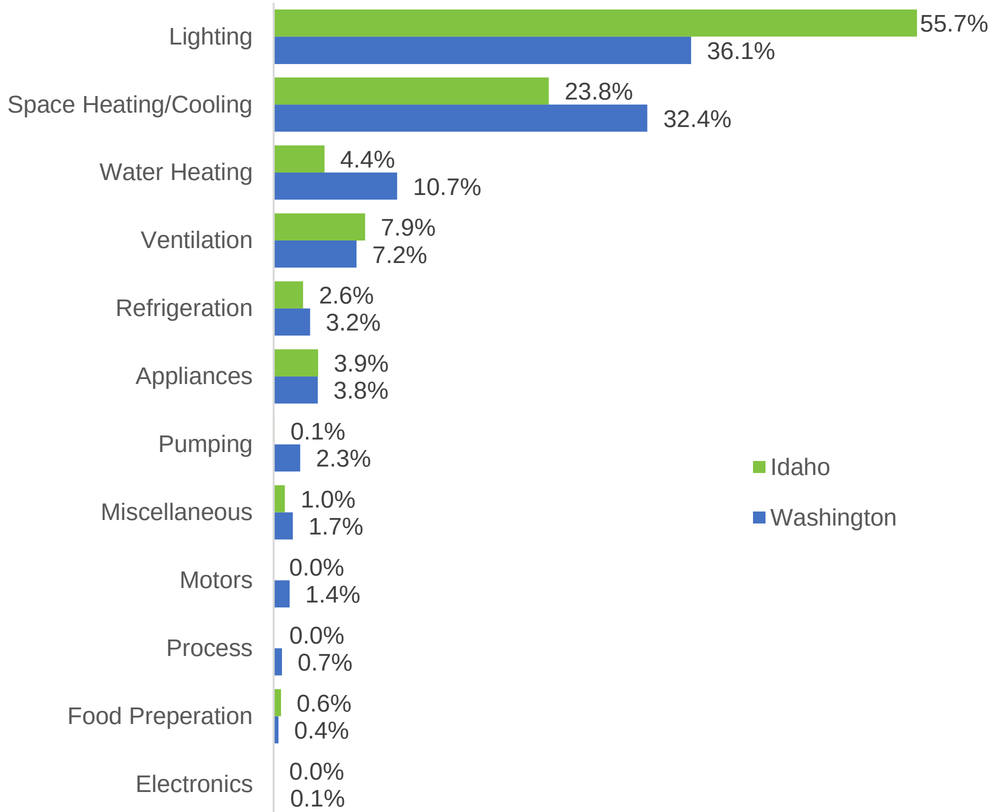
to its higher avoided costs driven by CETA and other policies, such as including societal benefits in the economic evaluation.

Figure 2.1: Energy Efficiency Annual Forecast



Commercial customers deliver 59% of the total energy efficiency savings, followed by residential customers (33%), with the remainder from industrial customers. Of the total savings, low-income households provide 16% of the energy efficiency savings and receive benefits at zero or minimal customer cost. The greatest sources of energy efficiency, at 68%, are from lighting and space heating/cooling measures. Figure 2.2 shows the program type by share of the total percentage of savings through 2045. Idaho has fewer program types due to lower avoided costs triggering fewer programs overall, while Washington’s higher avoided costs identify more programs as cost effective.

Figure 2.2: Energy Efficiency Savings Programs by Share of Total



Washington Biennial Conservation Plan

The amount of energy efficiency the PRS identifies leads to specific programs in Washington and Idaho. To meet Washington's Energy Independence Act (EIA) requirements, the IRP determines cost-effective solutions and potential new programs for business planning, budgeting, and program development. Pursuant to Washington requirements, the biennial conservation target must be no lower than a pro rata share of the utility's ten-year conservation potential. In setting 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 2.3 shows the annual selection of new energy efficiency in Washington compared to the 10-year pro-rata share methodology.

The 2026-2027 achievable potential identified by the Conservation Potential Assessment (CPA) is 58,873 MWh for Washington although the pro-rata share of the ten-year potential is 73,672 MWh. The target exceeds the achievable potential by nearly 14,799 MWh over the two-year period. The pro-rata target is higher than the two-year potential as savings occurring later in the 10-year period as compared to the first two years of the plan increases the target. Avista will have a challenge to identify and acquire this additional energy efficiency. Table 2.1 outlines Avista's biennial target of 73,672 MWh and includes adjustments for NEEA and decoupling. This biennial target is 55% higher than the 2024-25 goal of 47,635 MWh.

Figure 2.3: Washington Annual Achievable Potential Energy Efficiency (GWh)

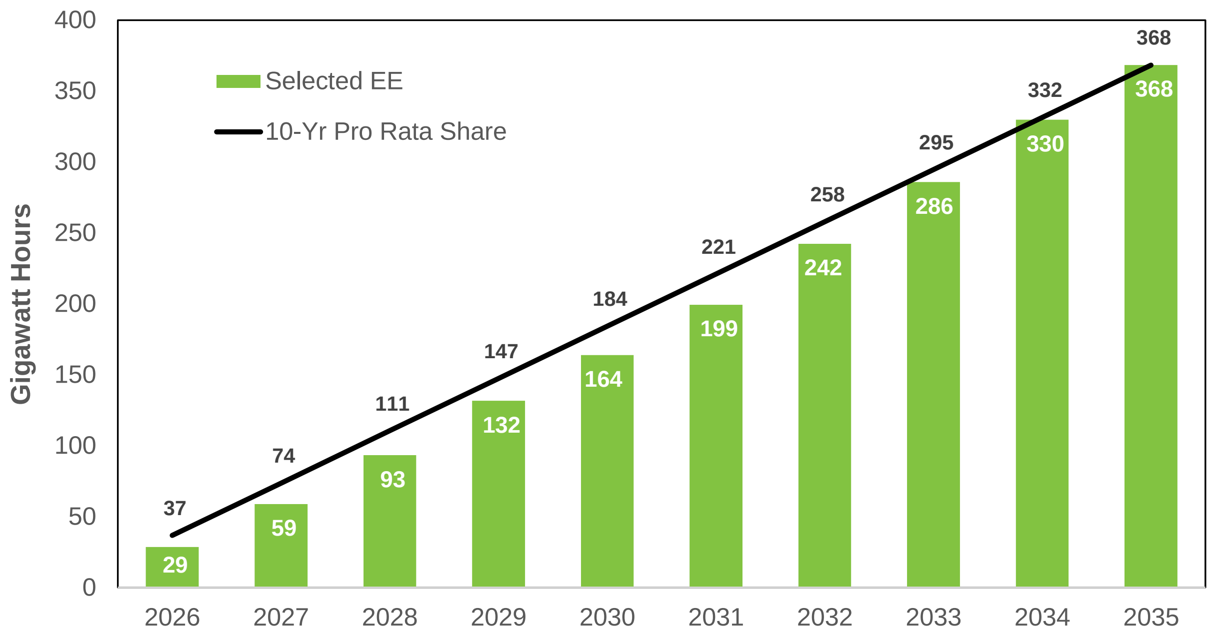


Table 2.1: Biennial Conservation Target for Washington Energy Efficiency

2026-2027 Biennial Target (MWh)	
CPA Pro-Rata Share	73,672
NEEA Programs	12,877
EIA Target	**86,549**
Decoupling Threshold	4,327
Total Utility Conservation Goal	**90,877**
Excluded Programs (NEEA)	-12,877
Utility Specific Conservation Goal	**77,999**
Decoupling Threshold	-4,327
EIA Penalty Threshold	**73,672**

Demand Response Selections

Demand response (DR), Virtual Power Plants (VPPs), and/or modified retail pricing programs will be integral to Avista's strategy to meet peak customer load requirements with non-emitting resources. Avista added 30 MW of industrial DR within the last three years and agreed to pilot three DR programs in the 2021 CEIP process. There is uncertainty in these programs' ability to meet planning reserve margin (PRM) due to the time duration limits and load snap back effects without traditional resources available to meet high demand days. Further, programs using retail rates, such as Time of Use (TOU) rates, are not dispatchable and are dependent on customers' willingness to participate at the time of the DR event. Given these concerns, DR's valuation within the IRP may change in the future based on learning derived from the pilot efforts. Chapter 6 has more details about DR options considered in this plan.

Three major changes from the 2023 IRP when evaluating DR include:

(1) Use of a capacity adjustment by assuming the demand reduction lowers load and therefore lowers the total MWs estimated in the planning reserve margin (PRM).
(2) Programs assume a Transmission & Distribution (T&D) financial credit of $25.38 per kW-year[2] to account for potential savings in T&D investment.
(3) The Qualifying Capacity Credit (QCC) remains higher in the future compared to the 2023 IRP.[3]

These changes significantly increase future DR programs compared to prior IRPs, and, along with updated costs and program assumptions, lead to the savings shown in Figure 2.4. DR selections total 51.6 MW of winter savings in Washington by 2045 (56.3 MW summer) and 10.6 MW winter (4.3 MW summer) in Idaho. The programs by year and state are shown in Table 2.2. Without advanced metering infrastructure in Idaho until 2029, Idaho DR programs are deployed later than Washington due to later automated meter infrastructure deployment. Overall, less DR is expected in Idaho due to lower-cost alternatives such as natural gas turbines, whereas Washington must use higher-cost methods to meet peaks due to CETA requirements. When combining existing DR programs with the PRS's DR selection, system peak load could be reduced 4% by 2045, with Washington programs decreasing peak load between 5% and 6%.

Avista is piloting TOU rates and Peak Time Rebate programs over the next two years (2025-2026) and partnering with Northwest Energy Efficiency Alliance (NEEA) to evaluate CTA-2045 grid-enabled water heaters (see Chapter 6 for further information). Lessons learned from these pilots will provide greater understanding of the program benefits, costs, and acceptance to determine whether DR will be selected earlier in the 2027 IRP as compared to this plan's selection. If the capacity need is greater, DR in Washington would likely be selected earlier. However, due to other resources being selected to meet the capacity need, DR is pushed to periods when greater resource deficits occur. Avista expects third-party aggregators will submit proposals in future RFPs where the DR resource could be more cost effective compared to other options.

[2] The credit was created by the revenue requirement of net value of current T&D plant assets on a historic basis and is compared against the peak load for the system to estimate a $/kW-year value.
[3] The 2023 IRP assumed the QCC value by 2045 is 20% of the 2024 value. This IRP assumes the 2045 value is 80% of the 2026 QCC value, significantly increasing the amount of capacity DR is assumed to deliver to the system.

Figure 2.4: Total Demand Response by State and Year in Winter

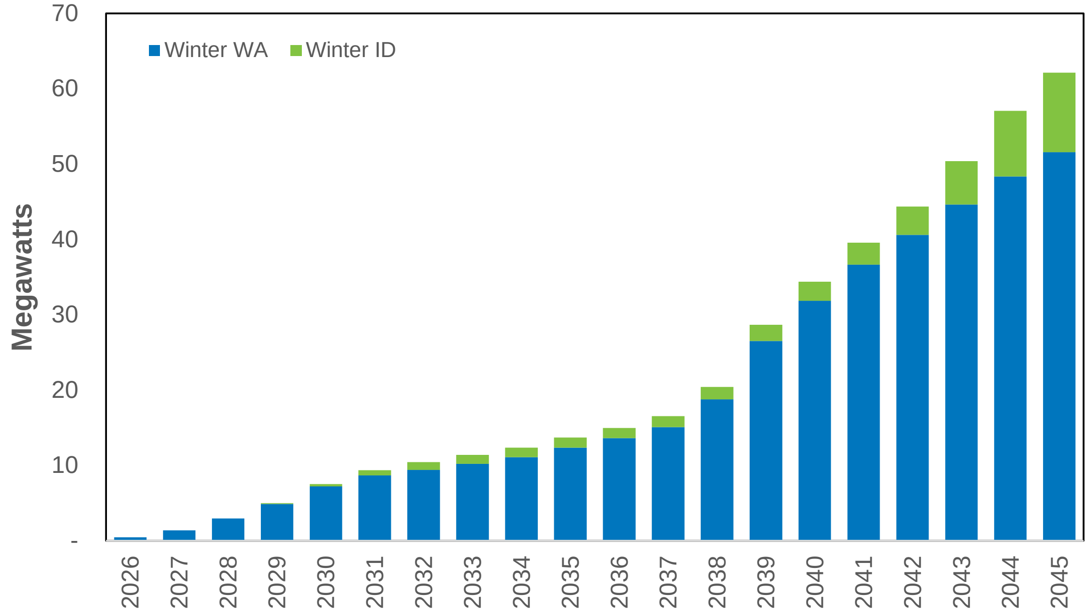


Table 2.2: Demand Response Selection

Program	Customer Segment	Washington Start Year	Idaho Start Year
Electric Vehicle TOU	Commercial	Available	2029
Battery Energy Storage	All	2026	2035
Variable Peak Pricing	Large Com./Ind.	2026	2029
Peak Time Rebate	Res./Com.	2035	2040
Behavioral	Res./Com.	2038	2043
Time of Use Rates	Res./Com.	2038	n/a
Third Party Contracts	Large Com.	2039	2044
CTA ERWH	Res./Com.	2041	n/a
Central A/C	Res./Com.	2043	n/a

Washington Named Community Investment Fund (NCIF)

The IRP focuses on ensuring enough energy or capacity is available to meet customer load for specific periods of time. The NCIF will fund future projects with unknown energy benefits and will be developed based on direction from the communities Avista serves. Even though the specific actions or projects are unknown, the IRP needs to account for these benefits by reducing resource acquisition targets. The actual funding decisions may or may not impact overall resource needs and rely on Avista's Equity Advisory Group's (EAG) recommendations. Given that an IRP cannot forecast specific projects, this analysis is designed to estimate possible project impacts by selecting resources or energy efficiency programs meeting NCIF objectives. This is done by including $0.4 million of incremental supply-side DERs each year (after tax incentives) and providing an additional $2 million of energy efficiency upfront spending estimated by the present value of the Utility Cost Test (UCT) for resource selection.

The result of this effort is the selection of approximately 22.1 MW of community solar through 2045. The quantity of community solar is a direct result of Washington State (Commerce) and NCIF funding covering 100% of the community solar costs including land and administration. The IRP modeling suggests between 2026 and 2033, the period when Commerce funding is available, 9.9 MW could be developed (1.4 MW per year). After the state funding expires, the new solar estimate drops to 1 MW per year. The total final amount of solar added to benefit these communities may differ from this forecast and will be determined based on upon available funding and project limitations. Due to project funding priorities, it is also possible that no community solar is added if the funds are allocated to other projects.

In addition to assumed new community solar, Avista's energy efficiency targets are 3.4%, or 22.4 GWh higher to reflect additional investments in Named Communities through 2045.[4] For the 2026-27 biennial period, the energy efficiency target increases 3% to reflect this anticipated additional spending.

Distribution Scale Energy Storage

Using energy storage on the distribution system may mitigate the need for upgrading certain portions of the delivery system when summer peak temperatures drive the need for enhancing distribution substations. This IRP did not identify any distribution level storage using generic system benefits combined with energy benefits. This does not mean future projects lack economic value or will not be the least cost solution for customers, but rather that a future distribution study will need to be performed using this IRP's avoided cost calculations to evaluate potential feeder upgrades against traditional methods of delivering energy. The 2027 IRP will incorporate those results as the Avista distribution plan determines if energy storage is a solution to solve future needs of the delivery system.

Supply-Side Resource Selections

The PRS is designed to meet resource needs described in Chapter 5 with generic new resources as described in the DER (Chapter 6) and supply-side resources (Chapter 7) chapters. When Avista prepares to acquire new resources for its energy/capacity needs, an All-Source RFP will be issued to find the best resource options to meet the need rather than using specific IRP resource requirements. The resource strategy discussed here is based on the best available information for planning purposes and is a result of future load expectations and resource pricing. Due to uncertainty about these planning assumptions, Avista continuously evaluates the alternative portfolios discussed in Chapter 10 and will continue to revise this plan every two years.

[4] For energy efficiency, energy potential is estimated using low-income versus non-low income and does not include geographic areas.

Avista separates resource selection between its two jurisdictions in this plan due to differing state-level policy objectives and financial evaluation methodologies. Each state is separated according to its load along with its planning risk adjustments (totaling the planning obligation). Existing resources are netted against the obligation for each state using the existing Production Transmission (PT) ratio to allocate resource costs, approximately 65.5% assigned to Washington and 34.5% to Idaho in 2026. The PT ratio is adjusted each year based on the expected state-level load changes within the load forecast. The amount of assigned existing resources shifts to the faster-growing state as it gets a higher percentage of the PT ratio. New resources are then selected based on the objective function described later in this chapter to fill any needs.

Existing Thermal Generation Forecast

The resource strategy includes the retirement or exit of several resources of the existing power supply portfolio. The first resource exit is the 222 MW of Colstrip Units 3 and 4 at the end of 2025 when ownership is transferred to NorthWestern Energy. There are also approximate retirement dates and PPA expirations for several of Avista's natural gas peaking facilities and wind facilities. While these dates are subject to change, this plan uses current expected retirement dates to determine the need for additional resources. These retirements include Northeast by the end of 2029, Kettle Falls combustion turbine (CT) and Boulder Park CT by the end of 2039, and Rathdrum CT by the end of 2044. The Lancaster PPA concludes at the end of 2041, and Coyote Springs 2, the final natural gas facility, does not have a planned retirement year. Given CETA's 2045 100% clean energy requirement, this IRP determines that Avista could best utilize Coyote Springs 2 in 2045 by co-firing 30% of its fuel with hydrogen for Washington customers and allocate the remaining 70% of the production to Idaho customers to offset the capacity losses of Rathdrum units 1 & 2 when they retire. Table 2.3 summarizes resource retirement assumptions. Avista's schedule for long-term power purchase contracts, including wind PPAs, are included in Chapter 4. At this time, Avista has no plans to retire any of its hydroelectric resources.

Table 2.3: Thermal Resource Portfolio Exit Assumptions

Resource	Fuel Type	Final Year	Capacity (MW in January)
Northeast	Natural Gas	2029	64.0
Boulder Park	Natural Gas	2039	24.6
Kettle Falls CT	Natural Gas	2039	10.9
Lancaster	Natural Gas	2041	281.7
Rathdrum CTs	Natural Gas	2044	174.5
Total			**555.7**

Supply-Side Resource Selections (2026 to 2035)

Avista recently completed a large resource acquisition process acquiring long-term contracts for hydroelectric power from Chelan PUD and Columbia Basin Hydro, extending the Lancaster PPA, and adding the Clearwater Wind PPA. Following the 2023 IRP, Avista expected these acquisitions would create a long position and new resources would not be required for a few years. However, the long resource position quickly dissipated with the addition of a large-load customer and overall customer load growth, especially in winter. These changes now show a small energy and capacity deficit in January 2026, while most of the remaining months are long until 2030.

Avista plans to meet small capacity and energy deficits between 2026 and 2029 by using short term market purchases and the demand response programs mentioned earlier in this chapter. To meet the Idaho customer portion of the 2030 capacity deficit, a 90 MW natural gas combustion turbine (CT) is selected. This resource replaces the expected lost capacity of the Northeast CT and addresses future natural gas retirements while accommodating load growth in Idaho. This analysis models this capacity addition as a third unit at the Rathdrum CT site. Table 2.4 summarizes the capacity addition plan through 2035. Avista expects the RFP resource selection will be different from this IRP, as the IRP assumes non-specific project sites, interconnection, and locational budgets in its evaluation whereas the proposals received in the RFP will have specific projects and costs.

The 2023 IRP determined that the early acquisition of 400 MW of wind was cost-effective due to available production tax credits. This plan produces the same result but also shows the need for additional wind capacity due to the higher electric market price forecast and the potential for more wind availability than assumed in the prior plan. This plan selects 200 MW of northwest wind in 2029, followed by an additional 200 MW each year through 2032 and 157 MW in 2033 for a total of 857 MW of wind. This includes wind located in Montana and off Avista's transmission system but still within the northwest. This IRP finds that wind benefits customers of both states and selects 357 MW of wind as a system resource and 500 MW as a Washington-only resource. However, this selection of wind comes with several important caveats:

- These selections are a result of high electric market prices and low-priced wind PPAs. If actual PPA pricing is higher or market prices fall, the resource selection will change as a result of the RFP process.
- Avista's transmission system can accommodate up to 500 MW[5] of wind without substantial transmission expansion. If wind projects are exported off Avista's system, the resource selection will result in less wind for Avista customers at low pricing.
- The model assumes tax credits will expire in 2032[6] and not be extended, thus driving early acquisition. If tax credits expire early, or are extended, the wind acquisition strategy will change.

[5] The 2023 IRP assumed only 200 MW of additional wind would be available without major transmission expansion.
[6] The credit may be extended for projects meeting the safe harbor construction requirements.

To account for this uncertainty, the plan will be revised in the 2027 IRP. However, a future all-source RFP will provide real options to evaluate whether early acquisition of this amount of wind is cost effective given Avista's resource needs.

Table 2.4: Resource Selections (2026-2035)

Resource	Year	Jurisdiction	Capability (MW)	Energy Capability (aMW)
Northwest Wind	2029	Washington	200	69
Northwest Wind	2030	Washington	200	69
Natural Gas CT	2030	Idaho	90	86
Northwest Wind	2031	Washington	100	34
Montana Wind	2031	System	100	44
Montana Wind	2032	System	100	44
Northwest Wind	2033	System	157	54
Total			**947**	**399**

Supply-Side Resource Selections (2036 to 2045)

The IRP did not select utility-scale supply-side resources between 2034 and 2040 due to the early acquisition of renewables, the utilization of new transmission, and the ability of DR and energy efficiency to meet load growth-related requirements. As Washington's 100% clean energy target approaches, the deadline to replace natural gas resources, while meeting higher load growth due to electrification, will require substantial new resources after 2040. Idaho resource needs follow load growth and natural gas resource retirements. Table 2.5 outlines the resource additions and the associated production from added resources between 2036 and 2045. New resources are selected using familiar technologies such as natural gas turbines, wind, solar, lithium-ion batteries, and biomass, but also technologies new to Avista, including power-to-gas combustion turbines (CTs), nuclear, iron-oxide energy storage, and geothermal. While 2045 is a long way off, Avista will need to follow technology development and potentially develop sites for these resources up to 10 years ahead of need. Therefore, the 2045 targets will be continually evaluated in future RFPs to ensure resources can be developed in time to meet state goals.

To meet Washington's 2045 clean energy requirements, a diversified mix of new resources will be required including wind, solar, 4-hour lithium-ion energy storage, biomass, geothermal, nuclear, and 100-hour iron-oxide energy storage. Power-to-gas technologies, where renewable energy is converted to hydrogen and either consumed directly as hydrogen or converted into ammonia, are also required. As mentioned earlier, the 2036-2045 strategy also includes co-firing a 30% hydrogen blend in the Coyote Springs 2 facility to enable the plant to continue to provide some capacity to Washington customers.

Table 2.5: PRS Resource Selections (2036-2045)

Resource	Year	Jurisdiction	Capacity (MW)	Energy Capability (aMW)
Natural Gas CT	2040	Idaho	90	86
Power to Gas CT	2040	Washington	90	5
PPA Wind Renewal/Repower	2041	Washington	140	48
Natural Gas CT	2042	Idaho	95	90
Power to Gas CT	2042	Washington	210	11
PPA Wind Renewal/Repower	2043	Washington	120	41
Solar + 90 MW 4-hour Storage	2043	Washington	180/90	53
Solar + 60 MW 4-hour Storage	2044	Washington	120/60	36
Iron-Oxide 100-hour Storage	2044	Washington	26	n/a
Northwest Wind	2044	Washington	108	37
Iron-Oxide 100-hour Storage	2045	Washington	85	n/a
Nuclear	2045	Washington	100	98
Northwest Wind	2045	Washington	200	69
Geothermal	2045	Washington	20	18
Kettle Falls Upgrade	2045	System	10	9
Kettle Falls Unit 2	2045	Washington	58	29
Coyote Springs 2 Hydrogen co-fire	2045	Washington	n/a	n/a
Total			**1,652**	**629**

Transmission Requirements

Avista will require new transmission to integrate new generating resources and access new markets. Historically, the IRP only modeled interconnection costs for new resources and did not conduct detailed transmission studies. Avista does, however, develop a 10-year transmission plan with specific transmission projects (see Appendix D). The IRP considers limits on resources with low-cost interconnections and determines whether resource need triggers a major transmission build. As a result of this analysis, the IRP modeling identified upgrades to integrate new generation in the Rathdrum, Idaho area. This location will likely be the site of future generation, whether it be natural gas, hydrogen-based fuels, or energy storage. Increasing the intertie between north Idaho and Spokane is required to site any generation.

The second major project is a new DC transmission line between Colstrip, Montana, and North Dakota. This proposed line by Grid United would create a diversified market for Avista to participate in for energy purchases and sales. This market could provide reliable capacity to offset the need for building new generation resources due to diversity in time, weather, and other market conditions. Furthermore, this line could allow Avista and other utilities to arbitrage the price differences between the Northwest and the Midcontinent Independent System Operator (MISO) and/or Southwest Power Pool (SPP) markets to benefit customers.

In this IRP, Avista modeled this transmission resource as providing a capacity benefit in a limited manner when Montana wind generation is not available. The initial analysis did not consider any arbitrage value as this analysis will be evaluated outside of the IRP prior to making any investment decision. With these assumptions, the new line was selected by the model in 50 MW increments for the Washington service area. Avista then evaluated whether the arbitrage value would select the new transmission line earlier, all at once, or for both jurisdictions. Avista found that a minimal arbitrage value resulted in the model selecting the line all at once when available for both jurisdictions. Therefore, this IRP assumes Avista will participate in the line at 300 MW with an expected on-line date of 2033. At the time of this IRP, Avista has not committed to this project, but this IRP analysis shows the new transmission line appears to be a favorable project in lieu of alternative generation resources.[7]

Avista has limited firm transmission rights to the Mid-Columbia market and other regions. This IRP identifies that Avista should invest in new transmission projects to increase connectivity to both markets and/or other balancing authorities to import resources and diversify market access. The challenge with this conclusion is identifying the specific locations and markets for these transmission enhancements when the location of new resources is uncertain.

The last new transmission asset Avista should consider developing is the Big Bend area in the western part of its system. This area has solar and wind potential but needs new transmission to deliver these resources to Avista’s load or to other utilities. This IRP did not specifically select resources in this area due to the approximate $260 million cost and 10 or more years of development time to expand the system. Given the risk of wind resources in low-cost connection areas of the transmission system being exported to another buyer, Avista may need to access wind resources for the 2045 100% clean energy compliance. Developing this transmission may give Avista optionality to meet future load needs if lower cost wind is not available when needed or loads grow faster than anticipated.

Power-to-Gas Fuels

Toward the end of this plan, Avista identifies two types of power-to-gas (P2G) projects. The first is to co-fire hydrogen at Coyote Springs 28 for up to 30% of its fuel supply by 2045. To achieve this, additional hardware will be required at the facility along with new fuel-handling equipment. This includes a dual gas control module, manifold skid, hazardous gas and fire detection system upgrades, detection systems, adding welded fuel nozzles, metering and sensors, and an additional selective catalytic reduction (SCR) catalyst or ammonia injection component to reduce NOX emissions. However, the biggest challenge will be sourcing the hydrogen fuel supply. The IRP analysis assumes a fuel delivery system will be in place, although the method of fuel delivery and/or storage is

[7] The IRP analysis was conducted prior to the announcement by the DOE awarding a $700 million Grid Resilience and Innovation Partnership (GRIP) grant to the project.

[8] GE has expressed this technology’s maximum hydrogen co-fire ability is 32%, so 30% is used as a conservative planning estimate.

unknown. The Pacific Northwest Hydrogen Hub, funded in part by the U.S. Department of Energy or separate hydrogen supply chain with on-site fuel storage are potential options.

The second P2G project identified in this plan is new combustion turbines using clean energy-based ammonia. Ammonia can be commercially derived from hydrogen produced by excess clean energy and efficiently stored and transported. Turbine manufacturers are developing turbines capable of using this fuel source. This IRP assumes ammonia is a cost-effective way to store energy in a relatively small footprint for long durations. This technology does not use natural gas as fuel but operates with similar characteristics. The advantage with ammonia, compared to hydrogen, is the ability to store large quantities without underground storage, and the ability to transport the energy via rail or truck. Significant infrastructure for ammonia production, handling and storage for industrial and agricultural use already exists. Due to hydrogen and ammonia being new generation fuels with no major supply chain in place in the Northwest for this use, Avista limited this technology to 300 MW. Absent a robust supply chain similar to the natural gas system, Avista would need four 30,000 metric ton tanks to store the fuel to meet the high fuel usage scenario studied in this plan. Due to storage requirements and safety concerns, Avista limited the locations for this technology due to larger land requirements than a similar natural gas facility with access to pipelines.

The storage needs of these ammonia facilities will be determined by how much the facility is expected to operate and what energy is used to create the fuel. For example, if solar and water were to be used in the development of the ammonia through hydrolysis and the Haber-Bosch process in the 95th percentile use case (i.e., ammonia is called on to run at a 19% capacity factor), it would require an equivalent 1,600 MW of solar capacity using a 13.4% round trip efficiency rate from solar power to long-duration dispatchable ammonia power. However, if the ammonia creation were not dependent on solar energy and refilled faster during winter months, the storage requirements to operate at higher capacity factors would be less due to a just-in-time delivery system. Given ammonia is a world-wide commodity, it is possible Avista will be able to access supply without having to internally develop its own supply chain, reducing the need for large amounts of storage and self-development of additional renewable resources dedicated to fuel production. Given this identified technology need is more than 10 years away, Avista can monitor the development of both the generation technology and supply chain for this option.

Nuclear Energy

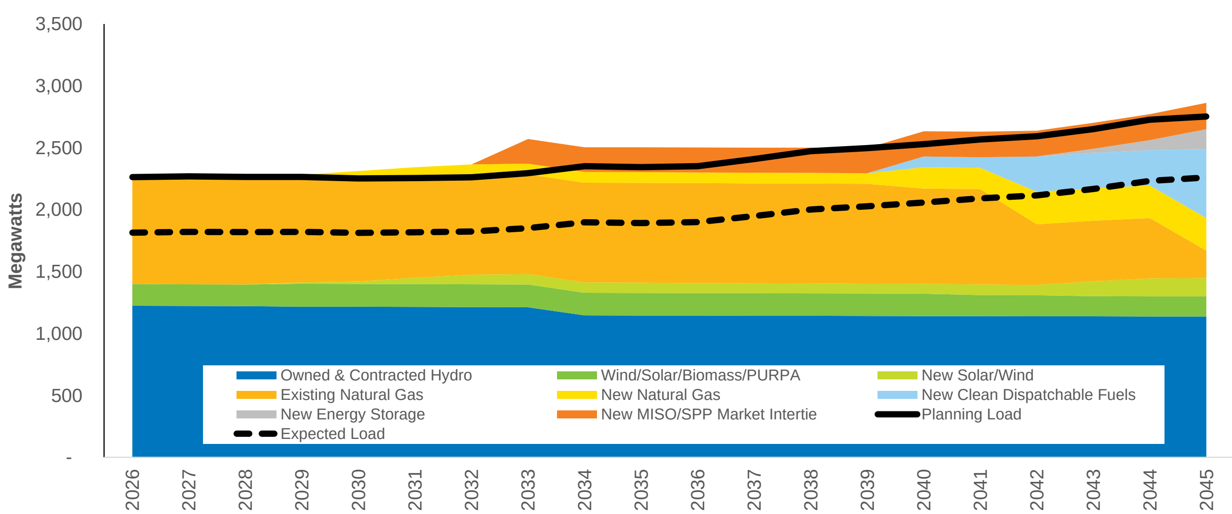
For the first time since the 1980s, nuclear power appears in the resource plan. While not appearing until 2045, small modular reactors (SMR) could play a key role in developing a reliable and clean resource portfolio replacing Avista’s natural gas resources. Given the time horizon for the selection, Avista will continue to monitor this resource development as other utilities and developers are pursuing it. Avista will need to consider all resource options to meet the clean capacity acquisitions needed beginning in 2040. With potential long lead time and permitting, the development and procurement phase of this resource may need to begin as early as 2030 to ensure it can be completed in time.

System Overview

Figures 2.5 through 2.7 summarize the future resource additions by combining the existing portfolio of resources, with already-contracted additions and future resource selections from this plan. The black solid line represents the planning load resources expected to meet (including expected load and a planning margin or reserves to account for unexpected conditions) and the dotted line represents expected load given normal conditions.

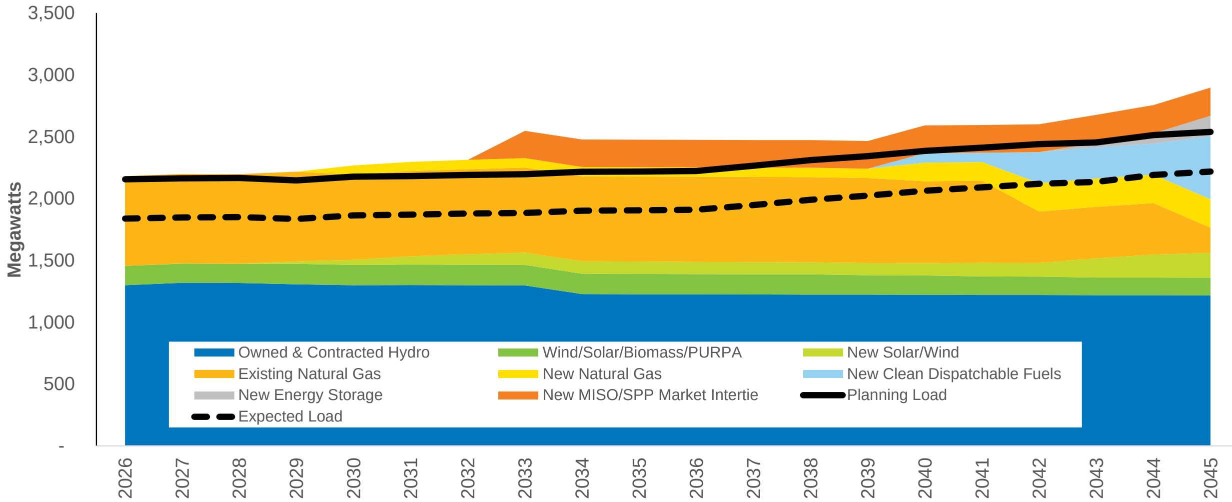
Historically, Avista operated in a long-capacity resource position – meaning resource capability exceeds expected load. But as shown in Figure 2.5, the resource portfolio is nearly balanced until 2033 with the forecasted completion of the North Plains intertie with MISO/SPP. While the planning margin target is met, the risk of meeting customer load is still a concern in the event of unplanned extreme weather conditions or the inability to buy power from the energy market. For example, during the January 2024 cold snap, Avista was near a resource-even position, but extreme cold temperatures and low hydroelectric conditions combined with a temporary loss of generation assets due to natural gas delivery system constraints required Avista to depend on the energy market.

Figure 2.5: System Winter Capacity Load & Resources



The summer capacity position in Figure 2.6 is similar to the winter position, except the portfolio has slightly more excess capacity because the winter capacity targets are the more difficult constraint to meet. Avista plans for a smaller planning margin in the summer compared to winter due to several factors. The system is less reliant on hydroelectric energy as the peak summer hour duration is shorter than winter. Another factor is that summer peak loads do not vary as much as winter peaks.

Figure 2.6: System Summer Capacity Load & Resources

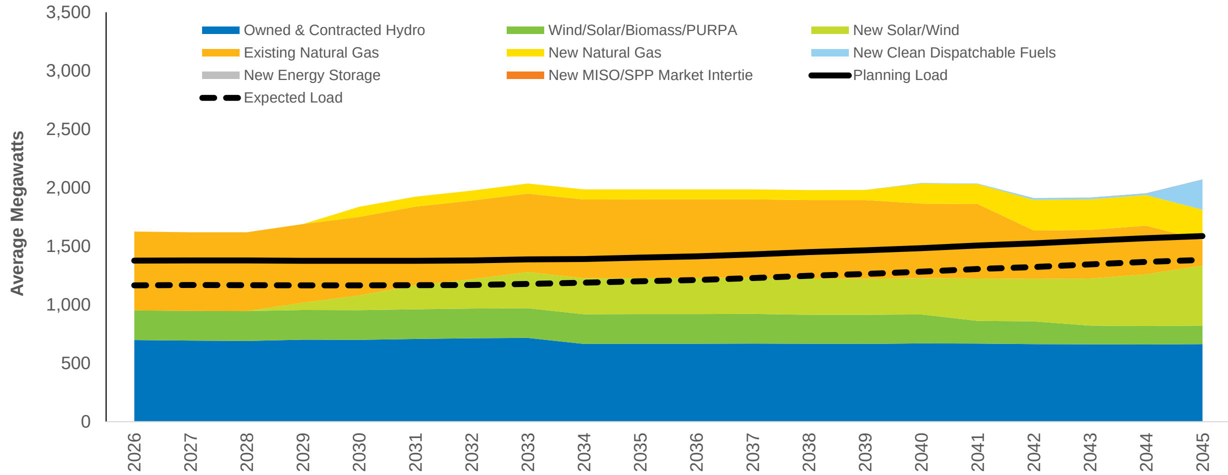


Avista's annual energy position (Figure 2.7) is long compared to the annual average needs because:

(1) Avista solves to meet monthly energy requirements, Avista is generally more constrained in winter and summer months and acquiring energy to meet these shortages creates length in other months since you typically cannot develop or obtain contracts for resources with operations limited to one period of time.
(2) Excess energy in the spring from hydroelectric and wind generation creates an extremely long position compared to load as compared to other seasons.
(3) Avista plans its system to meet peak load requirements. The generation can create excess energy in other time periods when not needed for Avista customers and can be sold to benefit customers assuming the resource is economic to operate.

The solid black line in Figure 2.7 represents the planning load level including the risk of load exceeding expected average weather conditions and/or renewable energy volatility, such as hydroelectric or wind, producing less generation than anticipated in a normal year. The dotted line is the expected average load under normal weather conditions.

Figure 2.7: System Annual Energy Load & Resources



Resource Adequacy Analysis

One of the greatest modeling challenges for the IRP is developing a capacity expansion model to optimize resource selections to meet resource adequacy requirements in a lowest cost manner. The current industry standard for testing resource adequacy is to conduct Monte-Carlo or stochastic analysis of hourly operations to evaluate the probability of not meeting loads with any given resource portfolio. With today's technology, and the large number of simulations over multiple forecast years, it is not possible to add an optimization routine to this effort. To overcome this challenge, capacity expansion models such as PRiSM use a target for adding resources, such as expected load plus a planning margin and develop a system to quantify how resources can meet these load targets, known as Qualifying Capacity Credits (QCC). Avista assigns QCCs to each resource for each forward month to ensure the model selects enough capacity to meet the load target. To validate whether this resource selection passes a Monte Carlo style resource adequacy evaluation, a resource adequacy analysis is required after the PRS is determined.

Avista developed an hourly tool called Avista Resource Adequacy Model (ARAM) to assess resource portfolios for resource adequacy – see Chapter 5 for more information on this model and reliability metrics. This IRP tests two future years (2030 and 2045) using this tool to ensure the PRS complies with Avista resource adequacy tests. Avista's primary focus for reliability planning is to meet a 5% loss of load probability (LOLP). This target means Avista would meet all load requirements in 95% of all future conditions while not exceeding the 330 MW of market purchases during capacity-constrained hours. For the 2030 and 2045 periods when not adding future resources, the PRS meets this requirement with a 3.2% probability in 2030 and 2.3% probability in 2045 as shown in Table 2.6. Also shown are other industry standard reliability metrics used to evaluate resource adequacy. Although the PRS results in a LOLP less than 5%, this does not guarantee Avista will be able to meet 100% of its load in all conditions. For example, in a high load and low water event, the utility still may have to rely on the market above the assumed 330 MW market limits or risk failing to serve all load.

Table 2.6: Reliability Metrics

Metric	2030 w/o new resources	2030 w/ PRS	2045 w/ PRS
LOLP	6.9%	3.2%	2.3%
LOLE	0.227	0.07	0.06
LOLH	2.59	0.73	0.72
LOLEV	0.495	0.176	0.186
EUE	488	115	116

Washington Hourly Clean Energy Analysis

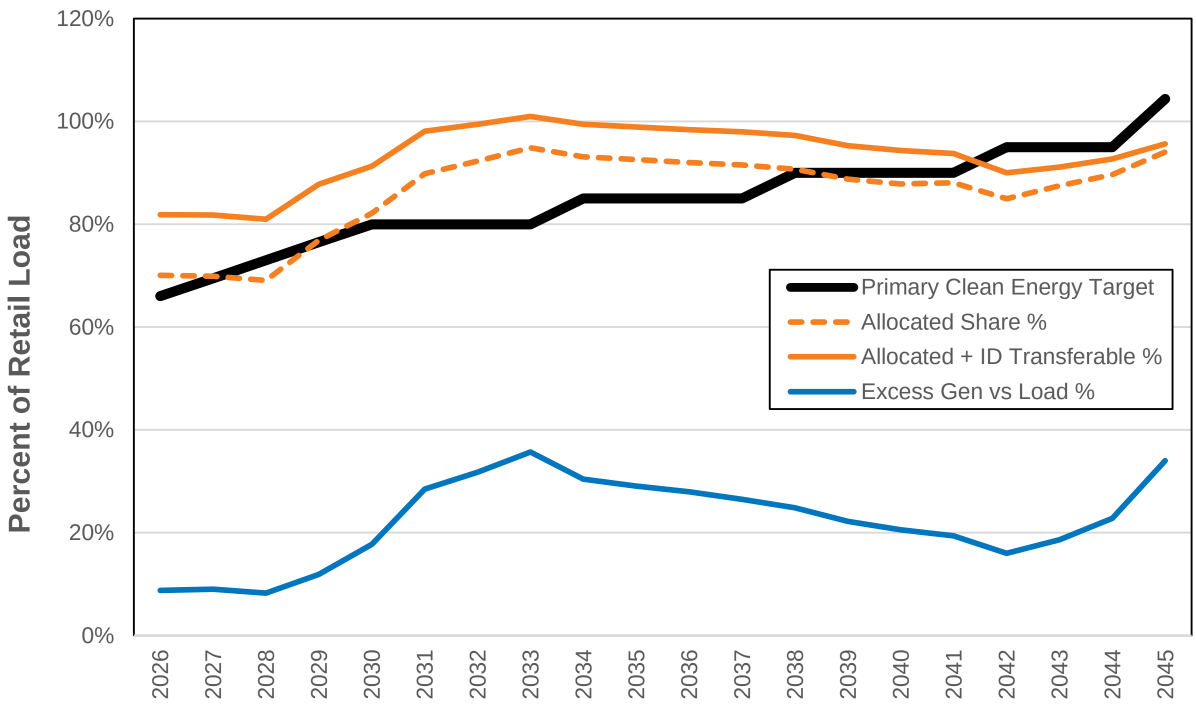
The “use” rules for compliance with CETA’s clean energy standard are still being drafted by the Washington UTC at the time this IRP is being written. The Washington Department of Commerce (governing consumer owned utilities) rules include an hourly analysis requirement in planning. Avista assumes the UTC rules will include a similar requirement for the development of this plan. Today’s capacity expansion models (such as PRiSM) are not able to model at an hourly level of granularity when selecting new resources over 20 years. This limitation also exists in commercially available software, and while theoretically possible, the solution time is likely too long to be useful. In Avista’s situation, PRiSM solves the system on a monthly basis using hourly data from the Aurora model.

For this first hourly analysis, the hourly data from the Aurora modeling is analyzed to determine how well the energy matches up to load (retail load) on an hourly basis. However, this methodology does not show how the utility could use its resources to meet only its load, but rather it dispatches resources to serve regional load as to reflect actual future operations. This is because utilities do not dispatch resources to serve only their own load but also regional demand based on market prices, allowing the utility to optimize its resource portfolio for the benefit of its customers by selling excess energy to others when prices are high and purchasing from the market when prices are lower. Avista is conducting a second analysis to determine whether it could meet the hourly 100% clean energy goal in 2045 if the utility were to dispatch its resources only to load without the market. This analysis should be provided in the final version of the IRP in January 2025. Avista anticipates the PRS will be able to meet this objective.

For this first view of hourly compliance using market-based dispatch, Figure 2.12 provides an annual summary of the results, where the black line represents the annual goal of “primary” compliance or the total amount of energy as a percentage of retail load where clean energy must be generated in the same hour. In 2045, the clean energy goal is above retail load due to the fact Avista must serve all Washington retail load and line losses with clean energy. The orange lines represent how well the Avista portfolio performs against this requirement. The solid orange line includes both the allocated clean energy to Washington based on the current PT ratio plus the transferrable portion from Idaho. As a reference, the dashed orange line shows only the Washington allocated portion. Avista meets the hourly requirement in all years until 2042. In 2042, 90% of the load in all hours is met with clean energy compared to the goal of 95% (assuming market-based dispatch).

The solid blue line represents how much additional clean energy is produced, but the energy produced is excess to the hourly load when the model dispatches to regional loads. The next step is to determine if the Company "could" serve the load targets between 2042 and 2045 by either moving clean energy generation to different hours using either future energy storage or existing hydroelectric storage, or increased amounts of dispatchable clean energy such as ammonia turbines to achieve these targets. This analysis will be performed for only the 2045 period in the final IRP.

Figure 2.8: CETA Hourly Analysis



Air Emissions Forecast

Avista's recent resource portfolio changes will significantly improve its air emission profile. These portfolio changes include transferring ownership of Colstrip Units 3 and 4 to NorthWestern Energy at the end of 2025 and replacing this generation by signing hydroelectric power purchase agreements (PPAs) with Chelan PUD and Columbia Basin Hydro, as well as a 100 MW PPA from Clearwater Wind. Figure 2.8 illustrates the expected clean energy generation as a percentage of customer load by year and by jurisdiction. The chart compares total annual clean energy production for each state's allocated share of energy[9] compared to its estimated state load. In Washington, Avista will need to produce more clean energy than its load to meet the hourly 100% clean energy requirements. On a system basis, the resource portfolio by 2045 could generate 10% excess clean energy as compared to annual average load.

This over generation phenomenon is due to CETA requiring Washington's load to meet 100% of its generation needs using renewable or non-emitting generation in all hours and under all-weather scenarios. This includes meeting higher needs in summer or winter months with clean energy and accounting for renewable and load variability when there are low hydroelectric or wind years. This requirement will create substantial amounts of surplus generation in months with lower loads. This high level of surplus power will be compounded by all other Washington utilities also having surplus production beyond their needs, driving market prices to very low or negative levels. This oversupply could spur development of hydrogen to assist fueling future hydrogen/ammonia CTs. When Avista evaluates meeting CETA's 100% clean energy requirements, three resource strategies could take place in the future:

(1) building long duration energy storage to move renewable energy from lower to higher load periods,
(2) having enough variable energy resources (VER) in place to statistically be able to generate at least the amount of energy needed in higher load periods, or
(3) controlling or owning dispatchable clean generation such as nuclear or biomass.

The 2023 IRP results solve the 2045 challenge, this IRP includes more renewable/non-emitting generation and less energy storage by 2045. The 2025 PRS assumes a more diversified mix of resources including components of all three options to achieve the 100% goal. However, the maturity of some of these technologies, such as long-term storage or nuclear, may not be at a level of commercial availability for a decade or more. Clean resource choices will ultimately be based on the economics of each of the options compared to the cost increase caps set by CETA.

While Avista's resource plan includes significant renewable energy additions, greenhouse gas emissions will still not be zero. Figure 2.9 compares greenhouse gas emissions from 2023 (red line) and the 2019-2023 average (black line) from Avista controlled generation to the forecasted emissions from this plan. When looking at Avista controlled generation's 2026 forecast of emissions (blue bar), emissions are expected to be 59% less than 2023's or 49% less than the 5-year average.

This reduction is mainly due to the removal of Colstrip from the resource portfolio. Also, emissions were higher in 2023 due to a lower-than-normal water year in the Northwest, thus driving market prices higher and making both coal and natural gas cost effective to

[9] This excludes potential transfers of clean energy between states to satisfy CETA requirements.

run at higher capacity factors. Avista expects 2024 may also show higher greenhouse gas emissions due to even lower water availability for hydroelectric generation in the region.

Figure 2.9: System and State Clean Energy Ratios Compared to Load

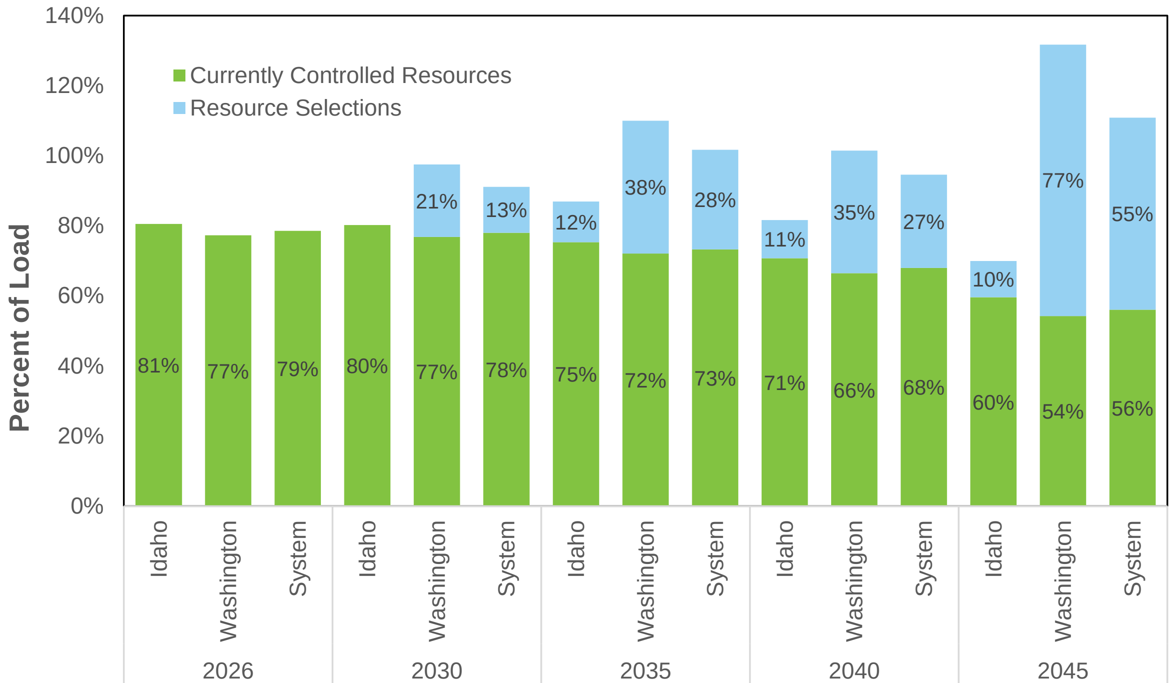
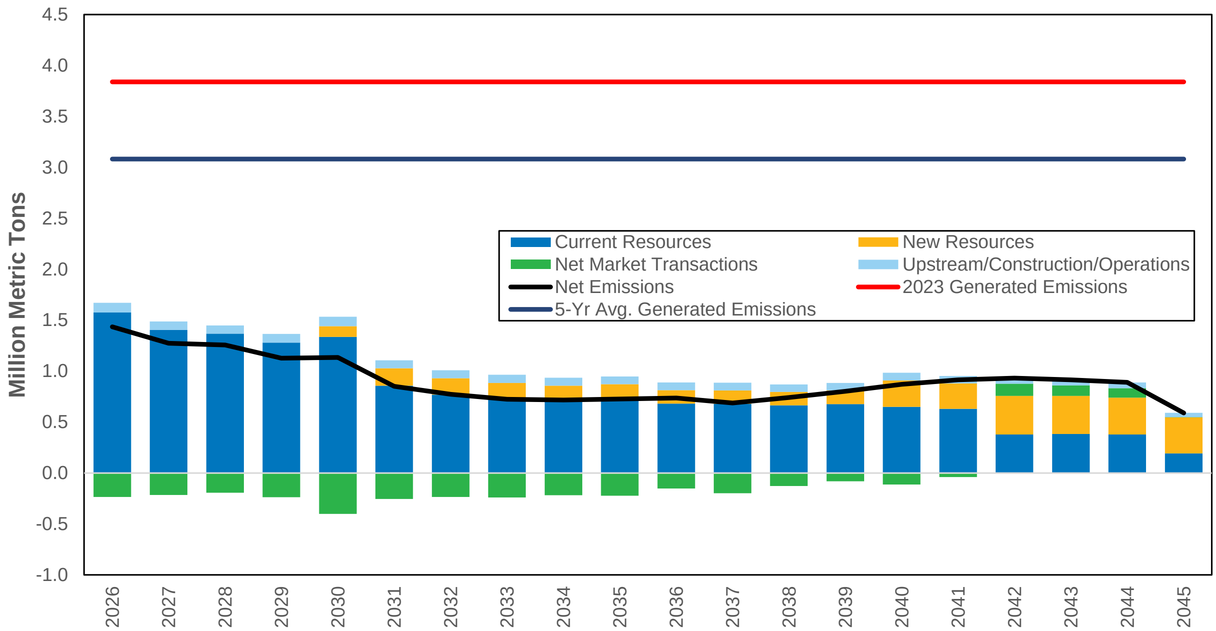


Figure 2.9 also includes estimates for upstream emissions related to natural gas deliveries, construction of new facilities, and plant operations. The chart also estimates the effect of market transaction emissions on the portfolio by either subtracting or adding emissions based on Avista's position – whether Avista is a net buyer or seller of energy (green bar). Emissions notably decline in 2031 due to assuming regional generators will not be given free allowances in the same manner as today under Washington's Climate Commitment Act (CCA), effectively requiring a greater number of facilities to account for the price of carbon when dispatching generating plants. The major drop in current resource emissions in 2042 is due to the expiration of the Lancaster PPA. This plan assumes it is replaced by additional natural gas CTs as shown in the orange bars operating at lower capacity factors. Even with the addition of new natural gas CTs replacing existing facilities, 2045 emissions are estimated to be 82% lower than the 5-year average from 2019 through 2023.

Figure 2.10: Avista System Greenhouse Gas Emissions



An alternative method to calculate total greenhouse gas emissions is to calculate the emission intensity of load. In this example, the total plant emissions (where Avista controls dispatch) are divided by the system load on a pounds per MWh basis. In this case, the 2023 emissions intensity was 867 lbs./MWh compared to the 2019-2023 average of 702 lbs./MWh. The future forecast shows a substantial decline at 340 lbs./MWh in 2026 to 100 lbs./MWh by 2045. The 2045 intensity of emissions is 86% lower than the 5-year average. With this method the annual emissions rate percentage is reduced more than the total emissions due to the reductions from serving more load with a cleaner mix of energy resources.

The last emissions profile for the resource portfolio includes other major air emissions from Avista's generation plants. These emissions are well below air quality standards set by the air regulatory agencies and are controlled and monitored at the plant level with the best available technologies at the time of construction or modification. Avista tracks the four major air emissions in the IRP shown in Figure 2.11: Nitrous Oxide (NO_X), Sulfur Dioxide (SO_2), Mercury (Hg),[10] and Volatile Organic Compounds (VOCs) at owned or controlled plants. After Colstrip leaves the portfolio in 2025, air emissions levels are minimal by using natural gas generation with run time limitations on generators or by emissions control systems. Kettle Falls is the only remaining facility with material air emission levels from wood waste burning. The reason for the 2045 emission increase is

[10] 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 historic emissions intensity rates, although the most recent study conducted after the IRP modeling was complete, indicated them as non-detectable. For Colstrip, a default emission factor is used for mercury emissions.

due to additional biomass generation at Kettle Falls for increased capacity from a second unit being added to the plant.

Beyond wood waste emissions, the plan includes burning both ammonia and hydrogen in combustion turbines. Both fuels have NO_X emission controls and adhere to air quality limits but will still have non GHG air emissions. For existing and potential plants selected to serve Washington customers, a non-energy impact of these emissions was considered in the economic evaluation.

Figure 2.11: System Greenhouse Gas Emissions Intensity

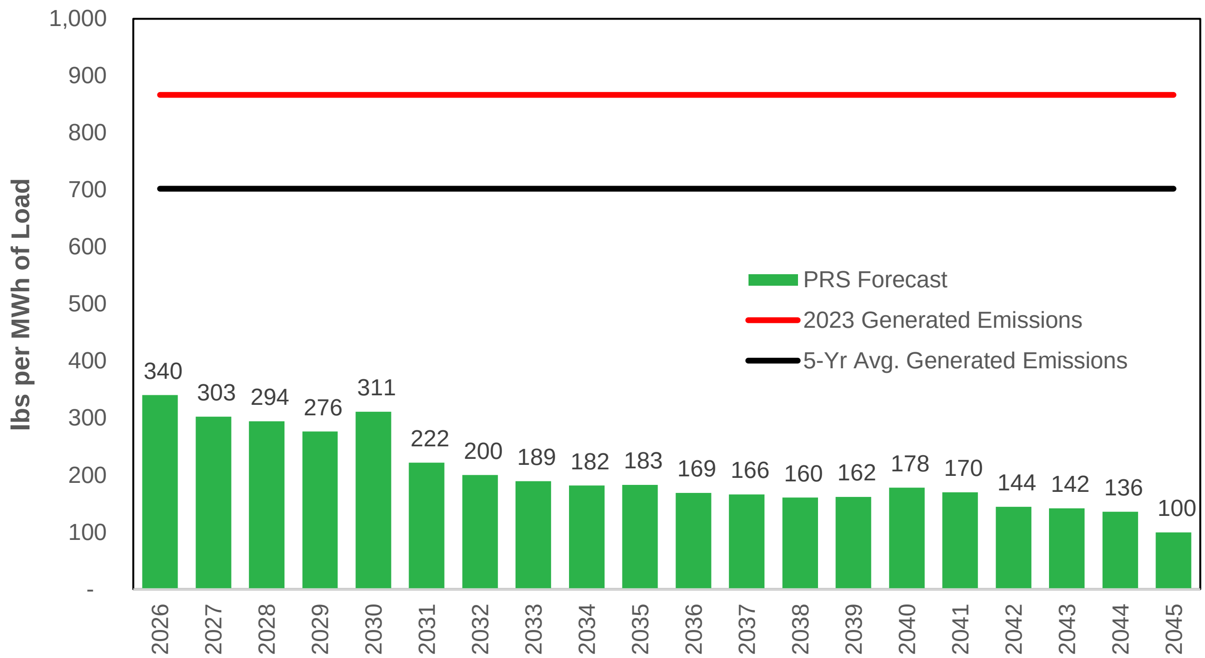
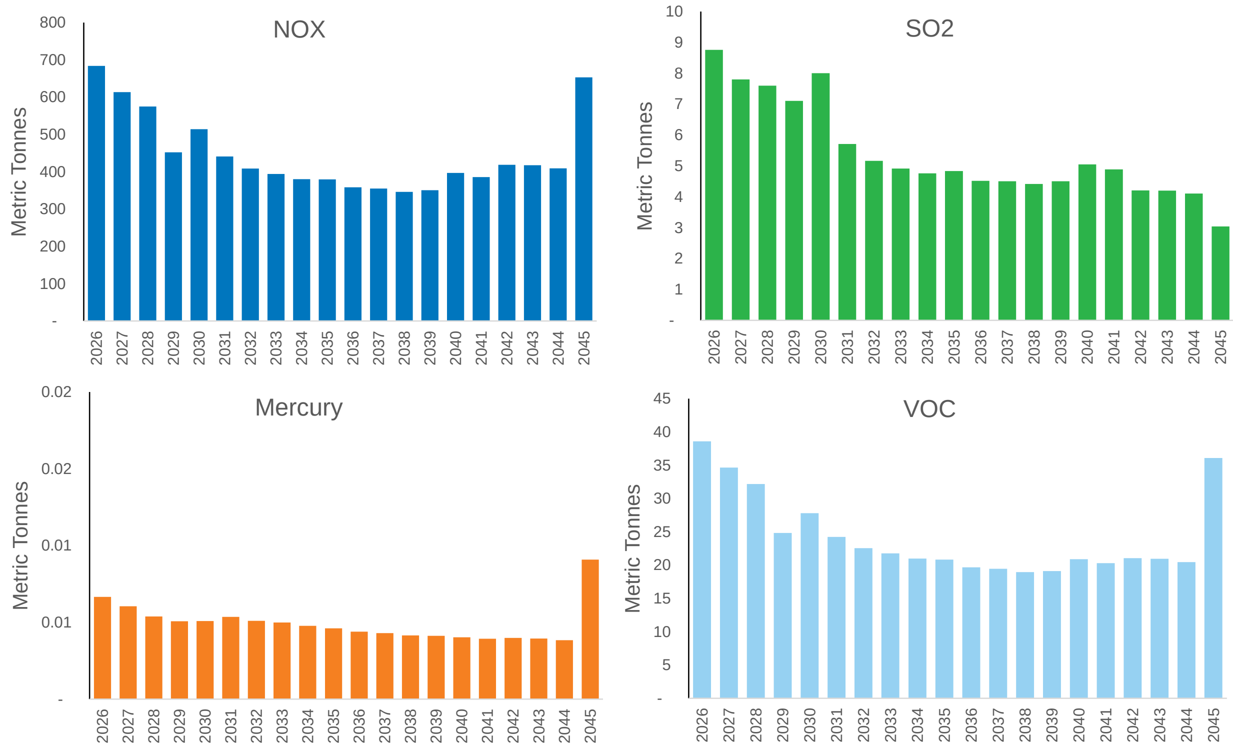


Figure 2.12: Avista Owned and Controlled Generating Plant Air Emissions



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"[11] as a framework to present how Avista manages these risks. While a current long-term resource deficit is projected for 2030, the risks outlined below will inform Avista's ultimate identification of resource needs.

Peak Demand Forecast

Avista's peak demand forecast is based on historical and forecasted future weather conditions. While weather is unknown for future loads, there are other load risks to be considered. Avista considers load changes from other risks in the scenario analysis Chapter 10 – specifically related to the impacts of electrification and customer growth, including the potential for energy intensive data centers to be located within Avista's service territory. Avista developed several load scenarios described Chapter 3 to understand the portfolio implications of load changes. If future loads are lower, there is a

[11] 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.

financial risk, as the outcome is a more reliable system at likely higher costs. However, if future loads are higher, having an underbuilt system that cannot meet a higher load scenario creates a risk of resource adequacy and reliability challenges.

The underlying solution in the scenario analysis to protect against short-term, higher-than-expected loads, is to develop DR programs and a four-hour energy storage system as they have the shortest construction requirement. If data center loads are extremely high in the next 5 years, additional resources will be required, including solar with batteries and potentially natural gas turbines. However, if Avista acquires resources to manage this risk and loads do not materialize, then utility rates will be higher.

Demand-Side Resource Contribution

Avista includes demand-side resources as options when determining the amount and type of resources needed to meet future demand. Demand-side resources may also impact the net demand of the system prior to this inclusion; customer adoption is an example of this. Chapter 6 discusses each of the Distributed Energy Resource (DER) options included in this IRP, including energy efficiency, DR, include other DER generation and storage options.

The focus of DER modeling within the IRP is to ensure supply-side resources are not overbuilt. For example, rooftop solar may reduce Avista’s summer energy needs, but have a limited impact on winter loads. To address this risk, Avista includes an estimate of incremental customer owned generation in its load forecast. The greatest uncertainty or risk regarding demand-side resources is whether they will impact winter peak load requirements. Given most DER additions today are solar, this risk is low. Avista did find that customer storage DR solutions may assist with meeting peak loads. Regardless, a small portfolio risk remains in customer(s) willingness to develop storage solutions or willingness to allow their energy storage to be used to meet system needs.

Power Plant Retirement

Avista’s Colstrip ownership will end December 31, 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 (CCCTs) to serve Washington customers. In this IRP, the ability of these resources to operate until their proposed end date is a significant resource adequacy risk. Avista sees this potential risk for the projected 2029 retirement of the Northeast CTs in the short term. If Northeast is forced to retire earlier due to mechanical failure, given Avista’s short-term projected capacity position is near even, scenario analysis indicates an immediate need to acquire nearly 80 MW of energy storage to replace the lost capacity. However, if the Northeast facility can continue operating beyond 2030, it would delay the need for replacement resources. While it is unlikely, the forced unavailability of another resource will require an immediate replacement. To mitigate this risk, Avista could begin to invest in the development of multiple technologies to be ready and available for construction if resources are retired early and to mitigate the high load risk discussed earlier.

Renewable Contribution

In 2035, 125 MW of wind is expected to be available to meet winter peak load. Of the 1,200 MW of wind capacity, this translates into a 10% QCC, with a majority of this benefit (76 MW) from the Montana portion of the wind portfolio. While wind in Montana has high-capacity factors in winter months, these facilities are known to be unavailable when temperatures are too cold. The region witnessed this phenomenon in January 2024. Given this risk, Avista could see a capacity deficit if the wind turbines cannot operate during cold weather events and if more reliable capacity is not built.

To help mitigate this risk, participating in the transmission line to North Dakota could provide another market to purchase power – gaining access to this region of the country with different load and weather conditions. One risk mitigation effort would be to reduce the QCC of wind resources in winter periods resulting in additional capacity resource selection. Avista expects the Western Resource Adequacy Program (WRAP) process, administered by the Western Power Pool, will continue to monitor the performance of wind in cold weather events and anticipates a future revision to winter QCCs. Additionally, another risk for the wind QCCs revolves around the summer contribution if temperatures are too high and there is a potential need for wind facilities to curtail generation. Given the climate of Avista’s service territory, the last mitigation effort is to ensure any future wind technology Avista acquires must have suitable weather protection packages for year-round operations, but these weather packages may still not be enough to meet the most extreme temperatures seen in Montana winters.

Storage Efficiency

Given the PRS, storage efficiency is not a short-term risk to the utility. In the long-term and under different future scenarios, however, this risk could materialize. 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 improve reliability in small increments. But the need to recharge the storage device after every use reduces its reliability benefit. In this IRP, if the region does not develop enough sustainable and dispatchable resources, the method to mitigate this risk is to reduce QCC values for short duration storage over time.

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, these considerations should be considered when 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 ammonia. These technologies protect against declining efficiencies found in today’s battery technology and offer longer duration periods. These resources have other risks including technological 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 less than 25%.

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 previously developed resource adequacy analysis assumed the utility was limited to 330 MW of market reliance during a peak event. With the development of the WRAP, and the pending binding requirements, Avista may be able to increase its market reliance threshold by adopting lower PRM values compared with those used today. However, in today's environment and reflected by the experience gained in the January 2024 winter peak event, it is clear the regional market is limited in cold weather and drought conditions for our hydroelectric resources. As witnessed in this recent event, the region was short of capacity and imported 4,745 MW[12] from outside the region during a time when transmission capability was also limited. Given Avista's controlled load is 5-7% of the Northwest system, Avista in theory could be allocated 240 MW to 300 MW of this import capability. Considering this range to an actual event gives Avista confidence in the 330 MW assumption for market access during a peak event.

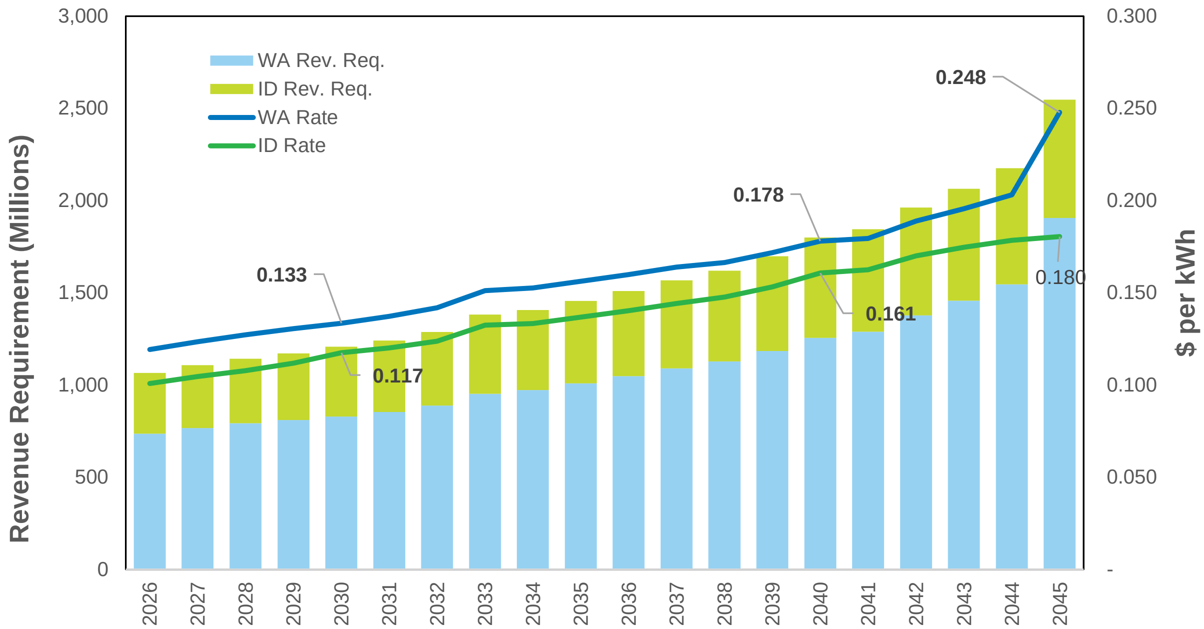
Cost and Rate Projections

The IRP cost and rate projection does not include detailed forecasts 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 projected rates and revenue requirements are shown in Figure 2.13. Rates are calculated by the total revenue requirement divided by retail sales and do not represent rate class forecasts. Also, as future rates will be determined by actual investments and evaluated by the Idaho and Washington commissions, this analysis should only be used for comparative and informational purposes.

The projected Washington revenue requirement grows at 5.1% a year and rates increase 3.9% a year. Between 2040 and 2045, the revenue requirement and rates are estimated to grow faster at 8.7% and 6.8% respectively. Future projected costs and rates for Idaho are generally lower where the average revenue requirement grows at 3.6% each year and rate increases are less at 3.1% annually.

[12] Analysis of the January 2024 Winter Weather Event.pdf (powerex.com).

Figure 2.13: Projected Revenue Requirement and Rate Forecast by State



CETA's Cost Cap Considerations

Avista's resource strategy does not consider CETA's cost cap due to uncertainty of how it will be applied. Given the PRS's cost forecast, the only period when the cost cap could be applicable is 2045. The cost cap is designed to limit compliance costs where compliance is higher than a 2% cumulative investment each year as compared to a resource portfolio not complying with the clean energy standard known as the Alternative Lowest Reasonable Cost Portfolio. This portfolio is determined by placing a SCGHG on the resource choices and includes previous CETA resource additions but excludes CETA's clean energy targets. Lastly, the utility can only request to use the cost cap after the compliance period has ended.

The 2% cost cap is based upon rates in the year prior to the compliance period and does not account for the higher cost of compliance since the law began in 2019. Therefore, the 2% cost is a compounding higher rate and compares only the incremental cost of social costs of the system but not the actual costs of the system. Given these challenges, it is nearly impossible to estimate what the cost cap will be for the 2045 compliance period. It is also unknown if the cost cap in this period will be spread over multiple compliance years or a single year, or if it still applies. Lastly, CETA is mostly focused on meeting the requirements through 2044. The 2045 target is a goal without statutory penalty for non-compliance. Avista expects the legislature will address 2045 planning to meet this goal over the next 10 years. Given the concern of hitting the cost cap in 2045, a portfolio in Chapter 10 attempts to identify a future portfolio meeting a theoretical cost cap. The main difference in this scenario is that the cost constrained portfolio would retain Coyote Springs 2 as a natural gas facility with its full associated pro-rata generation capacity allocated to Washington customers (rather than limiting its share to the hydrogen co-fire), avoiding a second Kettle Falls unit.

Resiliency Metrics

As part of this plan, Avista measures other metrics rather than the emissions and costs, these include job creation, energy burden, generation location, and many others. For example, in Washington Customer Benefit Indicators (CBIs) are created to measure the equitable transition to clean energy. These CBI metrics are available in the 2025 Clean Energy Action Plan (CEAP). Avista added additional metrics for this plan to understand the resiliency of our generation fleet.

Resource Portfolio Diversity and Resiliency

In the TAC process resource diversity was discussed as a measure of resiliency. The goal with this metric is to ensure Avista is not over reliant on one resource type or location. Typically, resiliency is mentioned within the energy delivery system, but when it comes to utility scale power generation, resilience is typically focused on the plants' ability to either operate through or return to operation during an event. Another method to address this potential risk is to have a more diversified resource portfolio. Figures 2.14 and 2.15 show three metrics to measure diversity. Two of the measurements relate to locational diversity for increasing resiliency, and the third is associated with fuel diversity of resources. These metrics are split between winter and summer capacity, as both periods of time are key to Avista's resource adequacy.

The diversity measurement uses the Herfindahl-Hirschman Index. The index is traditionally used to determine market concentration or competitiveness, but in resource planning it has also been used as a measure of resource diversity. Higher scores indicate more concentration of resources, meaning less diversity as a share of the portfolio. Conversely, the lower the score the more diverse the resource mix. From a market concentration perspective, a score greater than 2,500 is considered to be highly concentrated and a score below 1,500 is considered to be competitive, with scores between these amounts indicating moderate levels of market concentration.

Fuel Sources

Fuel diversity is Avista's greatest resource risk. This measurement looks at the source of the fuel for each generator. For example, the fuel source of Avista's Noxon Rapids Hydroelectric project is the Clark Fork River, and the source of Palouse Wind is eastern Washington Wind. For each of Avista's resources, a fuel source is identified. The calculation is high due to the amount of Clark Fork Hydro reliance and Gas Transmission Northwest (GTN) fuel delivery reliance for the Company's natural gas CTs. The index falls (blue line, Figures 2.14 and 2.15) in 2041 due to the expiration of the Lancaster PPA as replacement resources do not use GTN fuel.

Facility (Interconnection Point)

Avista has many small and large generators, but due to the large number of resources, this index (orange line, Figures 2.14 and 2.15) is relatively diverse in total, and results in the lowest score of the three diversity and resiliency metrics evaluated. This measurement could also be related to shaft risk – or the risk of losing one unit causing a resource adequacy event due to its size in relation to total load. Even though this measurement is low, compared to the Company's peer utilities, Avista has one of the highest shaft risks as a percentage of load. Due to this risk, Avista uses its single largest shaft (Coyote Springs 2) as its minimum planning margin quantity for summer capacity planning (18% in the summer).

Transmission (Geographic)

The last metric (green line, Figures 2.14 and 2.15) considered in this analysis is facility location and this metric relates to the location of the resource. The result of this metric is near the limit of concentration. This is due to the concentration of resources limited to a few locations across Avista's small service area. Avista's largest location risk resource is the Noxon Rapids and Cabinet Gorge area. To mitigate risks of transmission outages, Avista developed multiple transmission pathways from this area to move energy to load. The measurement was first discussed to mitigate risk from wildfire, whereas a more diversified locational portfolio would be less impacted by wildfires. It's uncertain if this metric can help assess wildfire risk.

Figure 2.14: Resource Diversity (Winter Capacity)

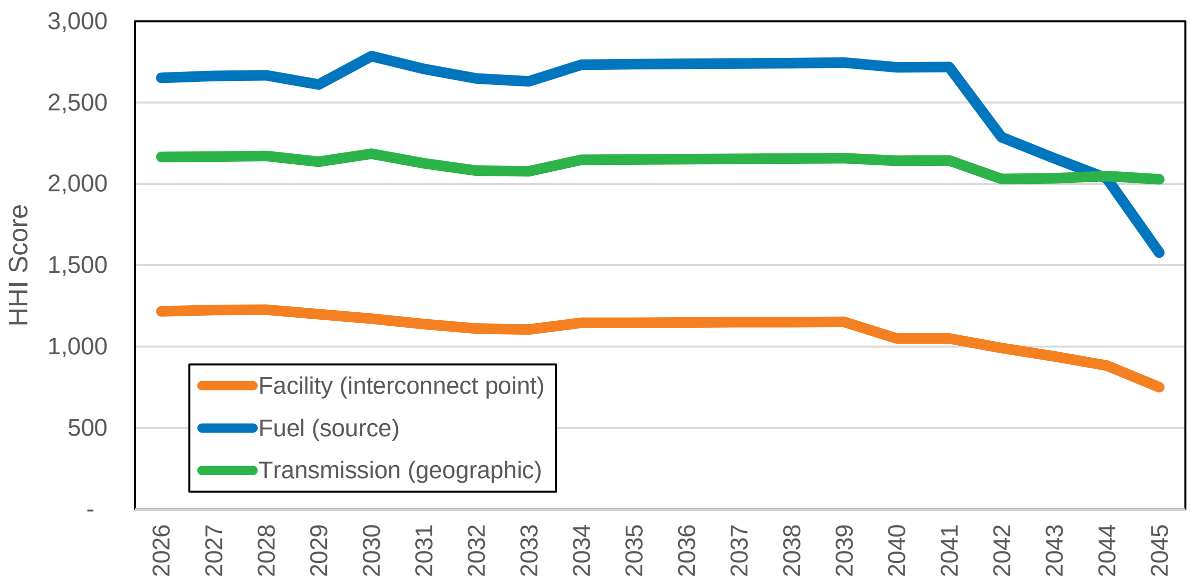
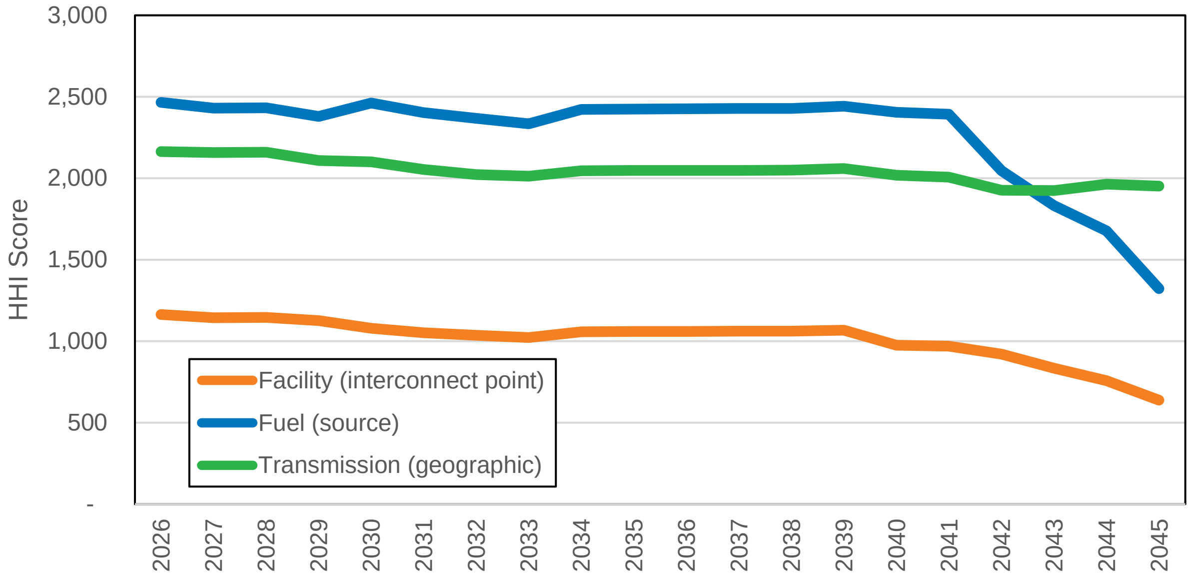


Figure 2.15: Resource Diversity (Summer Capacity)



Modeling Process

Avista utilizes a mixed integer optimization model to select supply-and demand-side resources to meet customer energy and capacity needs. Avista developed PRiSM to aid in resource selection by using information from its hourly 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 using monthly granularity. 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. The PRS version of the PRiSM Excel workbook is publicly available in Appendix G.

PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in its 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. The 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 application. 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 Avista's entire system to ensure each state will be assigned the appropriate amount of incremental costs (if any) of new resource choices. PRiSM must satisfy deficits for each state and the system load and resource balances for each month. For this IRP, the PRiSM model was enhanced to include a simplified monthly natural gas Local Distribution Customer (LDC) model. This model assists in determining the impacts of electrification of buildings. The model co-optimizes solving for natural gas and electric demand allowing for the model to choose to electrify load if the cost of natural gas service is too high. This enhancement was designed for studying building electrification scenarios. This enhancement can also determine what the total system cost impacts are if natural gas load is electrified.

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 (16%, May through September)
    - Winter Planning Margin (24%, October through April)
    - Monthly energy targets by state including additional contingency energy
    - Monthly clean energy requirements
1. 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/Gas 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/transport 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" $NPV_{2026\text{-}45}$) + (ID $NPV_{2026\text{-}45}$) + (LDC Natural Gas $NPV_{2026\text{-}45}$)

Where:

- WA $NPV_{2026\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Social Cost of Greenhouse Gas + Non-Energy Impacts + Energy Efficiency Total Resource Cost
- ID $NPV_{2026\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Energy Efficiency Utility Resource Cost

Subject to:

- Resource 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).

Avoided Cost

Avista calculates the avoided or incremental cost to serve customers by comparing the PRS cost to alternative portfolios. Avista splits avoided costs between energy and capacity to ensure the financial benefits are correctly attributed to the need of the system. Avoided costs are useful to inform prices in new Public Utility Regulatory Policies Act (PURPA) agreements, small resource acquisitions, and energy efficiency. As Washington and Idaho have different energy policies, calculating costs requires an analysis of incremental costs based on each state's specific policies. This portion of the chapter estimates Avista's avoided cost of energy and capacity based on this IRP's portfolio analysis. The calculations here are not used for setting Washington PURPA rates provided in Schedule 62 but may inform its calculation. Specific Schedule 62 calculations are in Appendix L.

Energy Efficiency

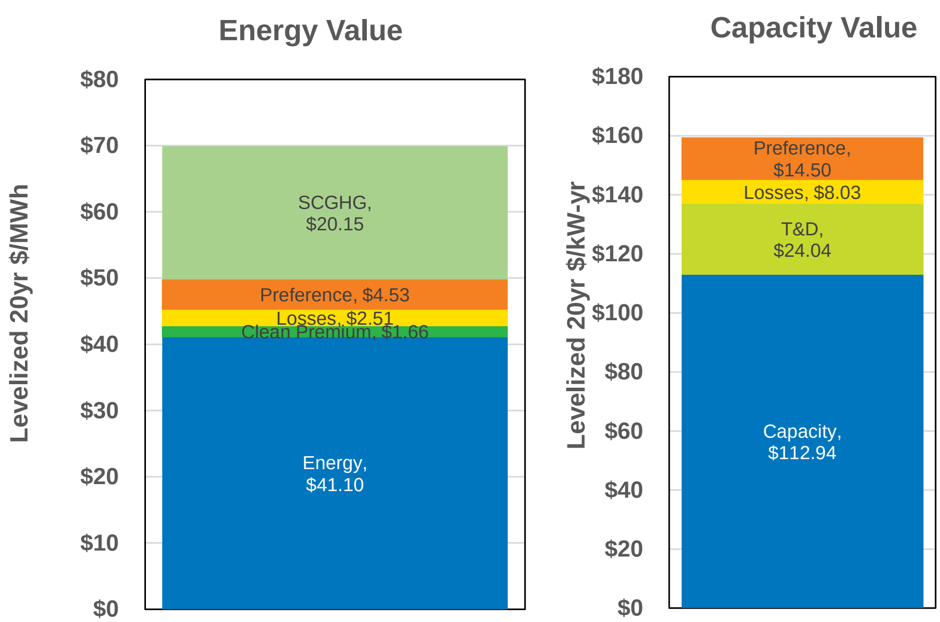
Washington's EIA requires utilities with more than 25,000 customers to acquire all cost-effective and achievable energy conservation.[13] These targets are also used for setting

[13] The EIA defines cost effective as 10% higher cost than a utility would otherwise spend on energy acquisition.

efficiency requirements in Washington's CEIP. For Washington, Avista uses the Total Resource Cost (TRC)[14] test plus non-energy impacts with a social cost of greenhouse gas (SCGHG) savings to estimate its cost-effective energy savings, while Idaho uses the Utility Cost Test (UCT). The estimated avoided cost of energy efficiency in Washington is shown in Figure 2.16 and Idaho's is shown in Figure 2.17. The total 20-year Washington energy avoided cost for energy efficiency is $69.94 per MWh and capacity is $159.51 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.

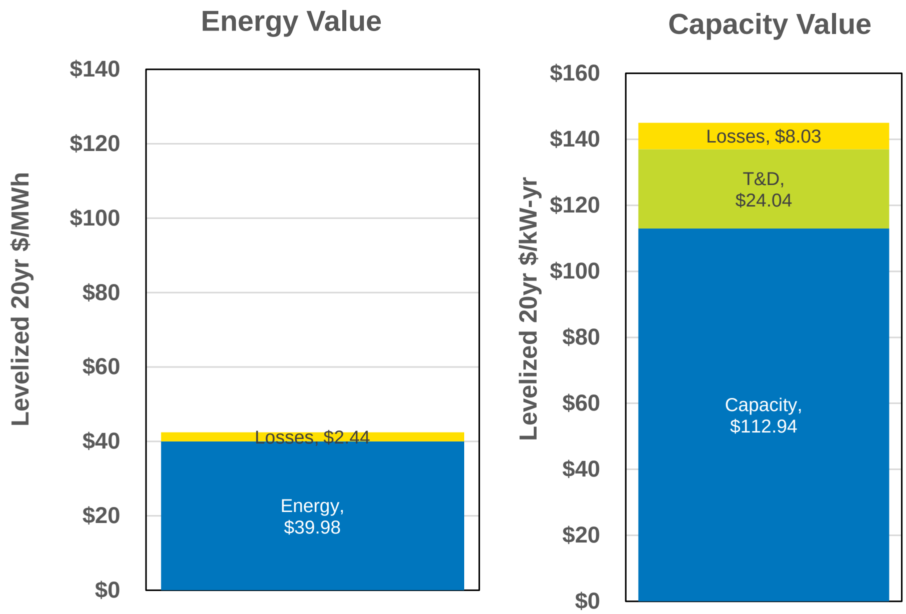
Idaho uses the UCT where the avoided cost is less due to the exclusion of clean energy premiums, the Power Act[15] preference, and avoidance of the social cost of GHG. Idaho 20-year energy avoided cost is $42.33 per MWh and capacity is $159.51 per kW-yr. Avista includes the savings of future transmission and distribution expenses and line loss savings in both states' avoided cost.

Figure 2.16: Washington Energy Efficiency Avoided Cost



[14] See Chapter 5 for further information on the TRC and UCT methodologies.
[15] Washington's EIA requires a 10% cost advantage adder for energy efficiency to give this resource preference as required in the Northwest Power Act.

Figure 2.17: Idaho Energy Efficiency Avoided Cost



Supply Avoided Costs

Avoided costs change as Avista's load and resource positions 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 using the 2025 IRP assumptions. The prices in Tables 2.7 and 2.8 represent energy and capacity values for different periods and product types by state. For example, a new generation project with equal annual deliveries in all hours has an energy value equal to the flat energy price.[16] In addition to the energy prices, these theoretical resources would also receive capacity payments for production at the time of system peak. For this IRP, winter peak months are driving the 2030 resource deficit period.

Capacity value is the resulting average cost of capacity each year. Specifically, the calculation compares a portfolio where the objective is to build only capacity resources to meet only capacity requirements (excluding SCGHG) against a lower-cost portfolio with no resource additions. Avista uses the jurisdiction's annual revenue requirement[17] differences to create annualized costs of capacity beginning in the first year of a major resource deficit. Recognizing the fluctuation of cash flows, the variability in annual values is levelized and tilted using a 2% escalator. 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

[16] Projects with undetermined energy production are estimated based on the resource's hourly production forecast.
[17] 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.

resource at the time of the winter peak hour. For Washington, the capacity requirements calculation uses only clean resources to meet the capacity need.

Capacity pricing at the full capacity payment, shown in Tables 2.7 and 2.8, assumes a 100% QCC or Equivalent Load Carrying Capability (ELCC) in the winter. For example, if solar receives a 2% QCC credit based on ELCC analysis, then it would receive 2% of the capacity payment compared with its deliverable capacity. Avista will need to either conduct an ELCC analysis or utilize the QCC value from the WRAP for any specific projects it evaluates to determine its peak credit. The current forecast assumes Avista's capacity deficit is higher in the winter than summer for all future years of the planning horizon. While a mild winter and hotter than expected summer could result in an actual summer peak greater than winter, Avista must continue to plan for extreme winter events as experienced in January 2024.

VERs such as wind or solar, consume ancillary services because their output cannot be forecasted with great precision. Consequently, VERs seeking avoided cost pricing may receive reduced payments to compensate for ancillary service costs from Avista's VER integration study.

In addition to the capacity premium, Avista includes an energy premium calculation similar to the capacity credit but estimates the cost to comply with monthly energy targets of the system. This adder is included for the first year of new resource additions. For Washington, it corresponds to the first resource addition in 2029 and for Idaho in 2030. This value is calculated by taking the difference between the PRS and a portfolio meeting only state capacity deficits.

Table 2.7: Idaho New Resource Avoided Costs

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2026	$41.61	$42.50	$40.42	$0.00	$0.00
2027	$37.88	$37.26	$38.70	$0.00	$0.00
2028	$35.13	$33.57	$37.19	$0.00	$0.00
2029	$34.57	$33.01	$36.64	$0.00	$0.00
2030	$38.56	$36.84	$40.85	$4.46	$100.30
2031	$43.00	$40.96	$45.74	$4.55	$102.30
2032	$42.74	$40.36	$45.92	$4.64	$104.30
2033	$43.82	$41.29	$47.20	$4.73	$106.40
2034	$43.92	$41.19	$47.54	$4.82	$108.50
2035	$44.93	$42.18	$48.59	$4.92	$110.70
2036	$44.50	$41.72	$48.21	$5.02	$112.90
2037	$45.69	$42.61	$49.82	$5.12	$115.20
2038	$45.66	$42.64	$49.68	$5.22	$117.50
2039	$46.29	$43.19	$50.42	$5.33	$119.80
2040	$47.28	$43.96	$51.69	$5.43	$122.20
2041	$47.66	$44.19	$52.29	$5.54	$124.70
2042	$49.92	$46.35	$54.68	$5.65	$127.20
2043	$50.52	$46.88	$55.38	$5.77	$129.70
2044	$51.24	$47.58	$56.12	$5.88	$132.30
2045	$52.39	$48.71	$57.26	$6.00	$134.90
Levelized	**$42.77**	**$40.64**	**$45.60**	**$3.48**	**$78.20**

Table 2.8: Washington New Resource Avoided Costs

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2026	$41.98	$43.12	$40.46	$0.00	$0.00
2027	$38.14	$37.82	$38.58	$0.00	$0.00
2028	$35.40	$34.18	$37.03	$0.00	$0.00
2029	$35.04	$33.84	$36.64	$3.31	$0.00
2030	$39.18	$37.89	$40.90	$3.37	$132.30
2031	$44.10	$42.38	$46.40	$3.44	$135.00
2032	$44.33	$42.27	$47.09	$3.51	$137.70
2033	$45.40	$43.23	$48.29	$3.58	$140.40
2034	$45.55	$43.17	$48.72	$3.65	$143.20
2035	$46.71	$44.27	$49.96	$3.73	$146.10
2036	$46.40	$43.90	$49.74	$3.80	$149.00
2037	$47.66	$44.82	$51.45	$3.88	$152.00
2038	$47.77	$44.98	$51.51	$3.95	$155.00
2039	$48.48	$45.58	$52.35	$4.03	$158.10
2040	$49.59	$46.43	$53.79	$4.11	$161.30
2041	$50.01	$46.68	$54.44	$4.20	$164.50
2042	$52.31	$48.88	$56.90	$4.28	$167.80
2043	$52.97	$49.45	$57.66	$4.37	$171.20
2044	$53.84	$50.27	$58.61	$4.45	$174.60
2045	$55.07	$51.48	$59.83	$4.54	$178.10
Levelized	**$44.13**	**$42.27**	**$46.60**	**$2.87**	**$103.50**

3. Economic and Load Forecast

Avista's loads are an integral component of the Integrated Resource Plan (IRP). This chapter summarizes the analysis methods and results of customer and load projections between 2026 to 2045. The 2025 IRP utilizes a new load forecasting approach which includes 3 phases: 1) the initial phase covers the first five years of the forecast and uses econometric forecasting similar to prior plans, 2) the second phase calibrates with the first five years and uses an end-use forecast model for the remaining years to forecast specific customer uses of electricity, and, 3) the final phase adjusts the long-term forecast for monthly weatherization, line loss adjustments, and large industrial loads. In addition to the expected case load forecast, multiple scenarios were also conducted to understand effects to load due to population, electric vehicles, and building electrification.

Section Highlights

- The energy forecast grows at 0.93% per year as compared to 0.85% in the 2023 IRP.
- Peak load growth is estimated at 1.32% in the winter and 1.09% in the summer.
- In contrast to previous years, Avista used end-use modeling techniques to develop the long-term load forecast.
- Avista expects a 214 aMW increase in load over the forecast period, a 400 MW increase in winter peak, and a 380 MW increase in summer peak over the next 20 years.
- Increased building and transportation electrification adoption rates in both Washington and Idaho could increase winter peak by 930 MW by 2045.

Medium-term Economic & Load Forecast

This section summarizes customer and load projections for the medium-term forecast. This forecast covers the first five years of the IRP forecast (2024-2028).

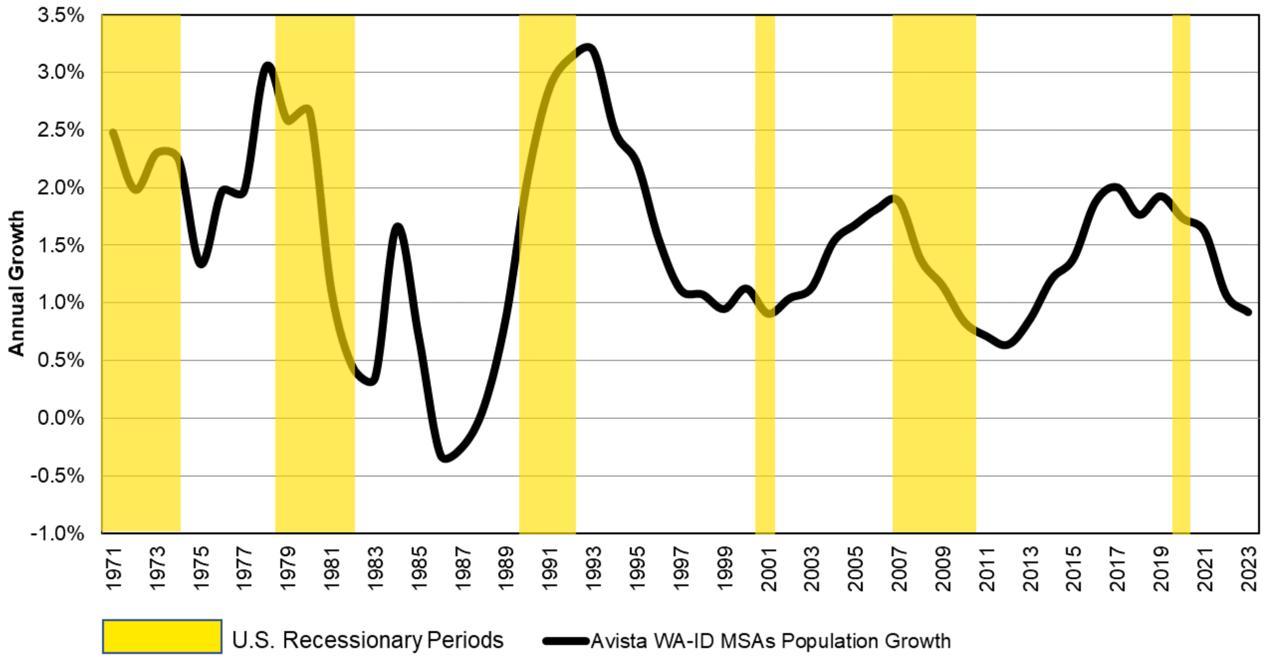
Economic Characteristics

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 and 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 MSAs account for more than 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 electric customers and Idaho the remaining one-third.

Population

Population growth is increasingly a result of net migration to 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 economic trends.[18] 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 3.1 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.[19] The Great Recession reduced population growth from nearly 2% in 2007 to less than 1% from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth above 1% after 2014.

Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2023

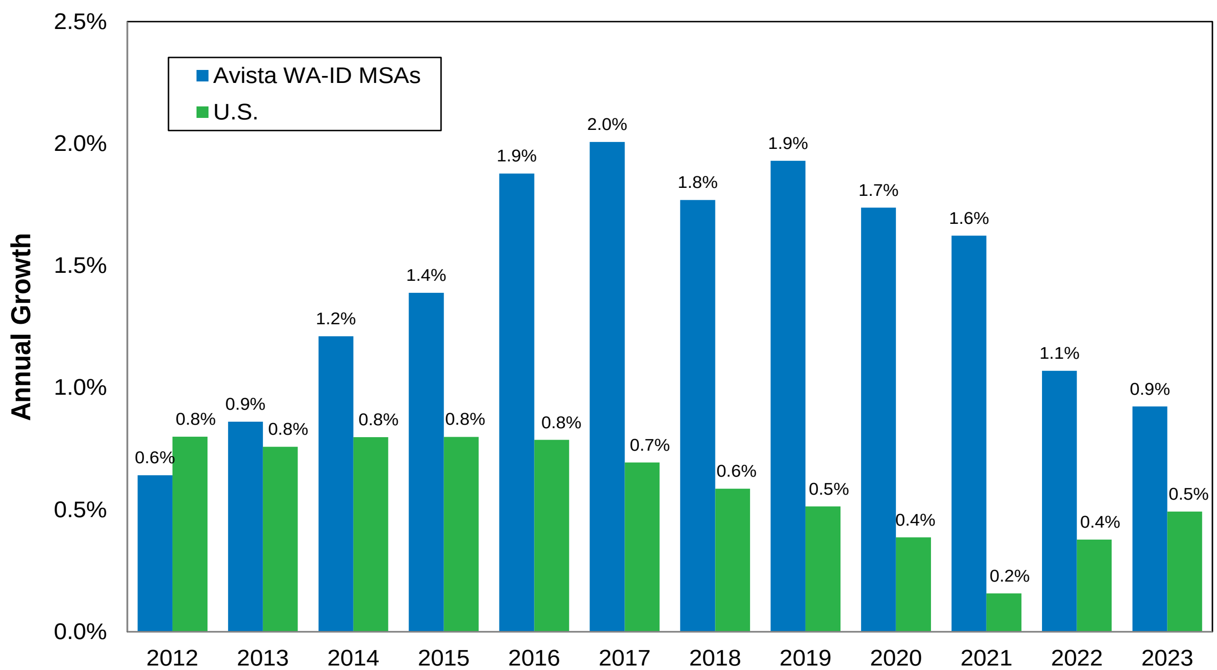


[18] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.

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

Figure 3.2 shows population growth since 2012.[20] Service area population growth between 2010 and 2012 was lower 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.

Figure 3.2: Avista and U.S. MSA Population Growth, 2012-2023

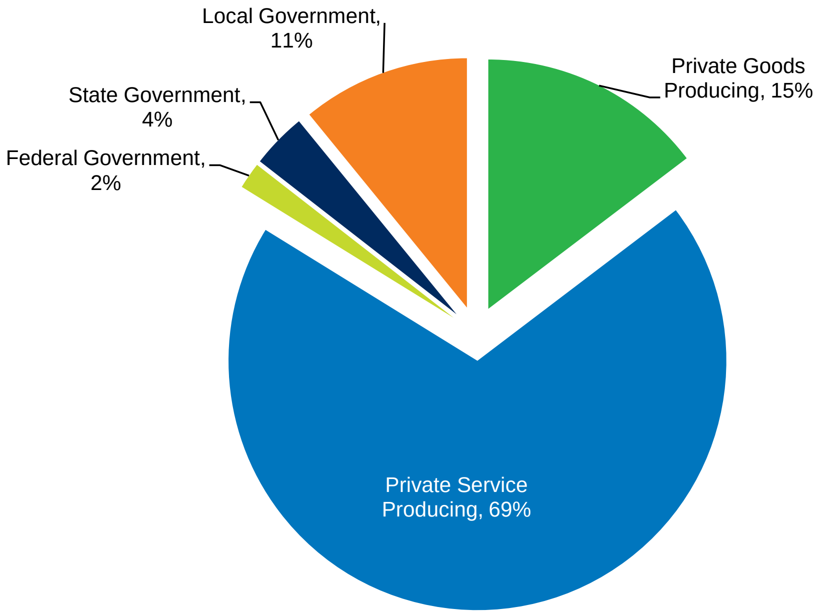


Employment

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 3.3 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 (69%), followed by government (17%) and private goods-producing sectors (15%). 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.

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

Figure 3.3: Avista's MSA Non-Farm Employment Breakdown by Major Sector, 2023



Following the Great Recession, regional employment recovery did not materialize until 2013, when services employment started to grow.[21] 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 3.4 compares Avista's Washington and Idaho MSAs and the U.S. non-farm employment growth for 2012 to 2023.

[21] Data Source: Bureau of Labor and Statistics.

Figure 3.4: Avista and U.S. Non-Farm Employment Growth, 2012-2023

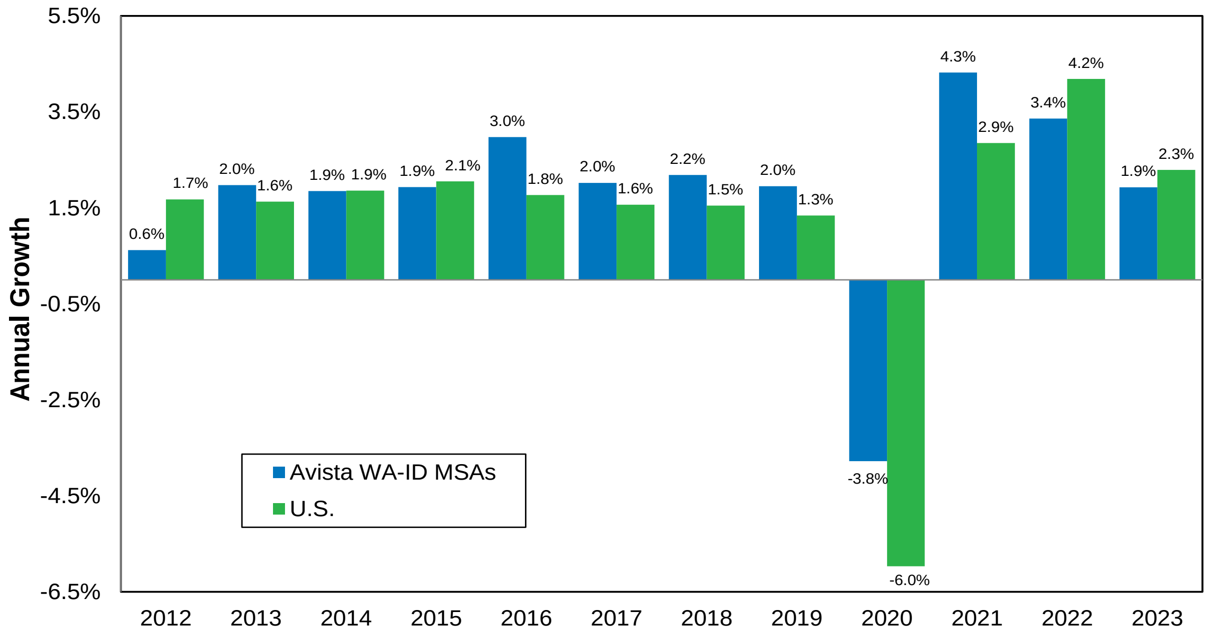


Figure 3.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[22] Regular income includes net earnings from employment, and investment income in the form of dividends, interest, and rent. Personal current transfer 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 locally to 23%. 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-19 transfer payments to households, including enhanced unemployment benefits.

Figure 3.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Although between 1980 and 1990, 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

[22] Data Source: Bureau of Economic Analysis.

capita income fell from 93% in the 1970s to around 85% by the mid-1990s. The income ratio has not recovered.

Figure 3.5: MSA Personal Income Breakdown by Major Source, 2022

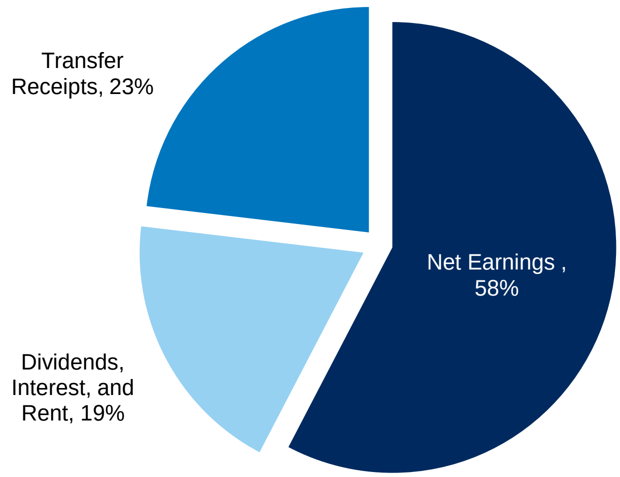
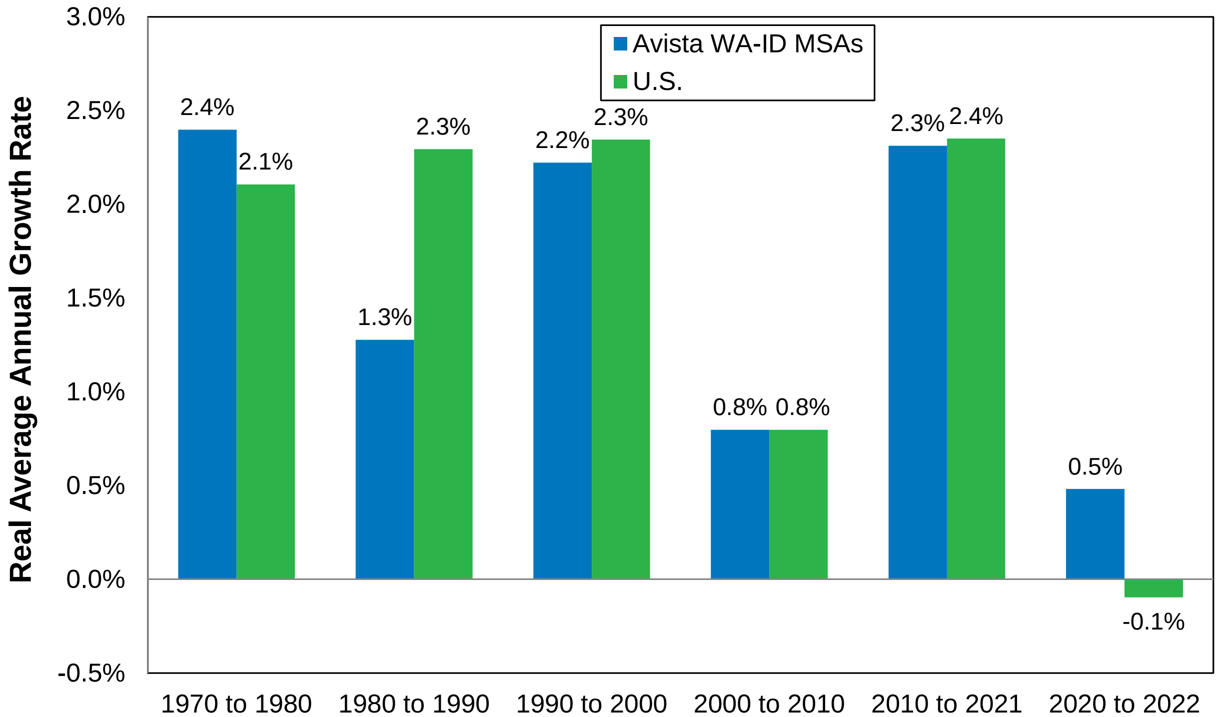


Figure 3.6: Avista and U.S. MSA Real Personal Income Growth



Overview of the Medium-Term Retail Load Forecast

As described above, the load forecast for the 2025 IRP was done in three phases. The following section describes the first phase – the development of a medium-term forecast for the period 2026-2029. The forecast serves as the basis for the second phase, an end-use forecast for the remaining period 2029 to 2045.

The medium-term forecast is based on a monthly use per customer (UPC) forecast and a monthly customer forecast for each customer class in most rate schedules.[23] The load forecast multiplies the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 3.1.

Equation 3.1: 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:

- $\mathrm{F}(\mathrm{kWh}_{\mathrm{t},\mathrm{y}_\mathrm{c}+\mathrm{j},\mathrm{s}})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $\mathrm{F}(\mathrm{kWh}/\mathrm{C}_{\mathrm{t},\mathrm{y}_\mathrm{c}+\mathrm{j},\mathrm{s}})$ = the UPC forecast.
- $\mathrm{F}(\mathrm{C}_{\mathrm{t},\mathrm{y}_\mathrm{c}+\mathrm{j},\mathrm{s}})$ = 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:[24]

Equation 3.2: 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 3.2. 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 are 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

[23] 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.

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

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 Index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC, and OL. See Table 3.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 3.2 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 2024-2028 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 medium-term forecast uses the 20-year average from the 2004 to 2023 period to develop the 2024 to 2028 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.[25] An in-house analysis of temperature in Avista's Spokane/Kootenai service area, using the same 1951-1980 reference period, also reflects an upward shift in temperature starting about 30-years ago. As provided in Chapter 5, the longer-term temperature assumption in the IRP uses the Representative Concentration Pathways (RCP) 8.5 for June, July, August, and September, and the RCP 4.5 for the remainder of the year.

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 show 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

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

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 noted earlier, if non-weather drivers appear in Equation 3.2, 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 2028.

Table 3.1: 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. Figure 3.7 shows the methodology for forecasting IP growth. Figure 3.8 shows the historical relationship between the IP and industrial load for electricity.[26,27] The load values used in Figure 3.8 have been seasonally adjusted using the Census X11 procedure. Over the long run, the historical relationship is positive between industrial load growth and IP growth. However, the sensitivity of industrial loads to IP expansions weakened after. It's unclear if this is a longer-term trend or something more temporary, like the 2002-2007 period of flat load growth with surging IP. In contrast, Avista's industrial load growth has consistently fallen in response to recessions.

[26] Data Source: U.S. Federal Reserve and Avista records.
[27] Figure 3.8 excludes one large industrial customer with significant load volatility.

Figure 3.7: Forecasting IP Growth

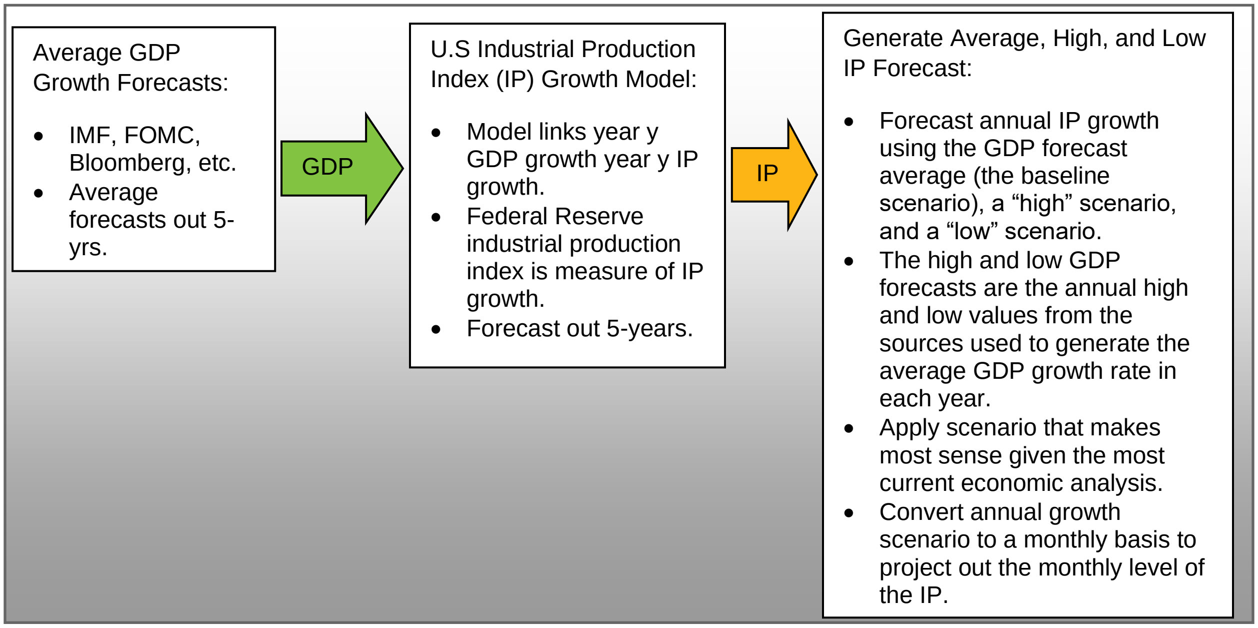
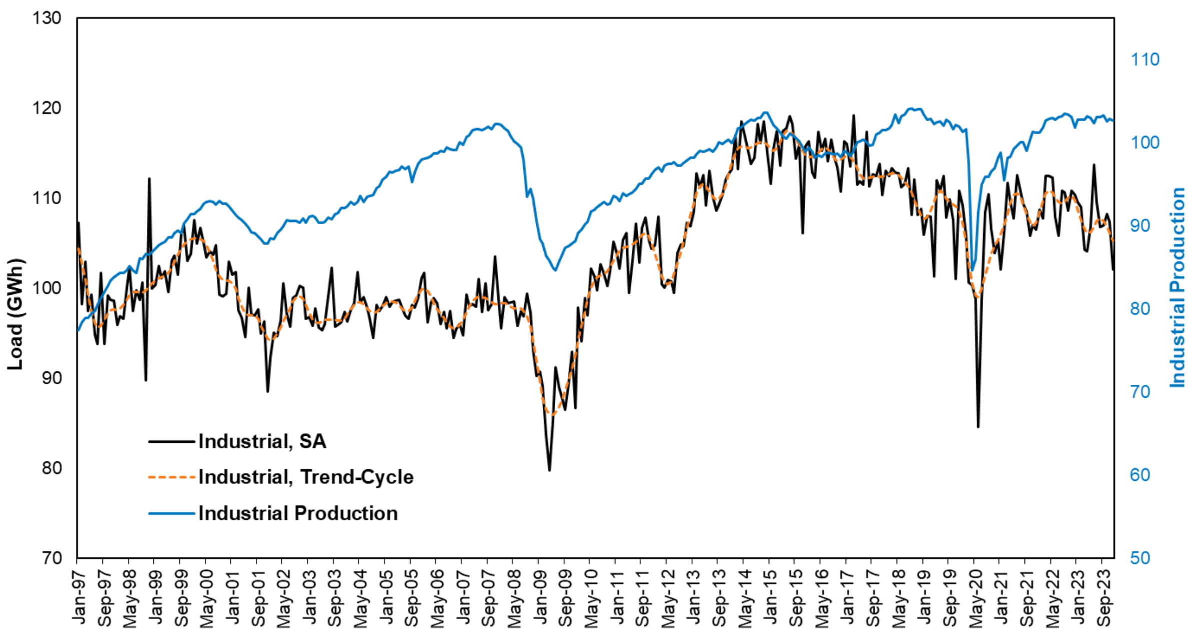


Figure 3.8: Industrial Load and Industrial (IP) Index



Customer Forecast Methodology

The econometric modeling for the customer models ranges from simple smoothing models to more complex autoregressive integrated moving average (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 but are 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 between residential and commercial customer growth over the same 12-month period. Table 3.2 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 models use Schedules 11, while Washington and Idaho Residential models use Schedule 1 as a forecast driver. Historical and forecasted Residential Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

Table 3.2: Customer Growth Correlations, 1998-2023

Customer Class (Annual growth)	Residential	Commercial	Industrial	Streetlights
Residential	1.00			
Commercial	0.72	1.00		
Industrial	-0.29	-0.02	1.00	
Streetlights	-0.19	-0.06	-0.03	1.00

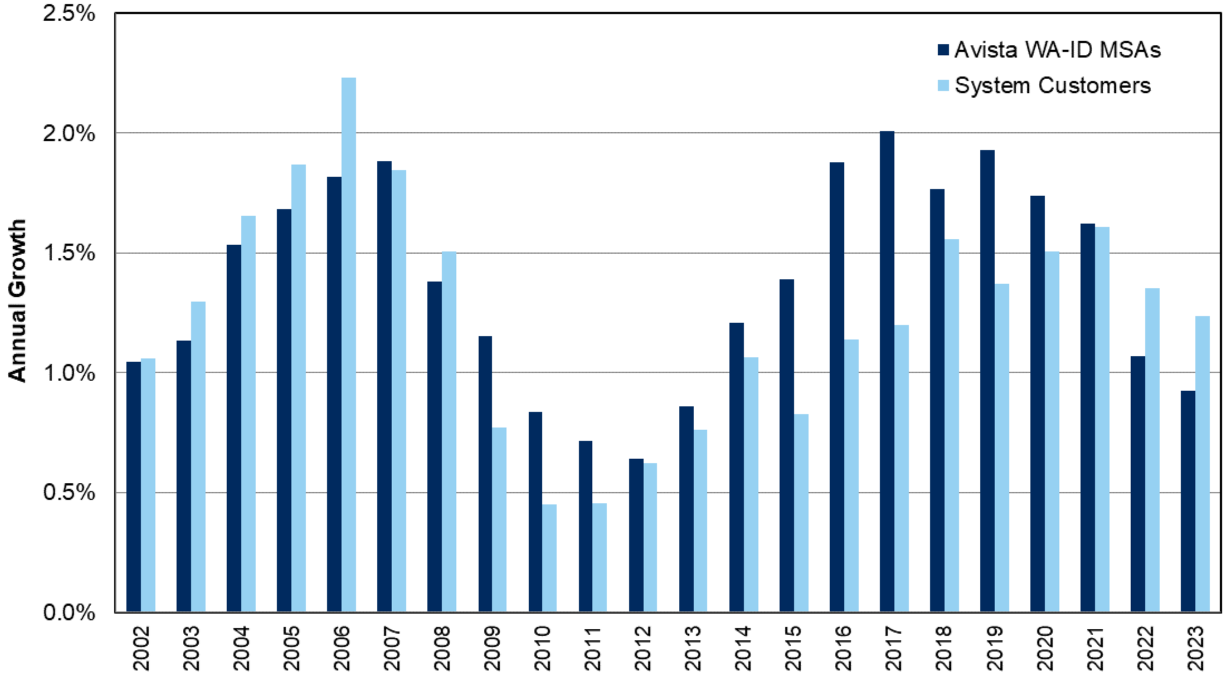
Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[28] Customer growth has closely followed population growth in the combined Spokane/Kootenai MSAs over the last 20 years. Population growth averaged 1.3% over the 2000-2023 period and customer growth averaged 1.2% annually.

Figure 3.9 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.

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

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

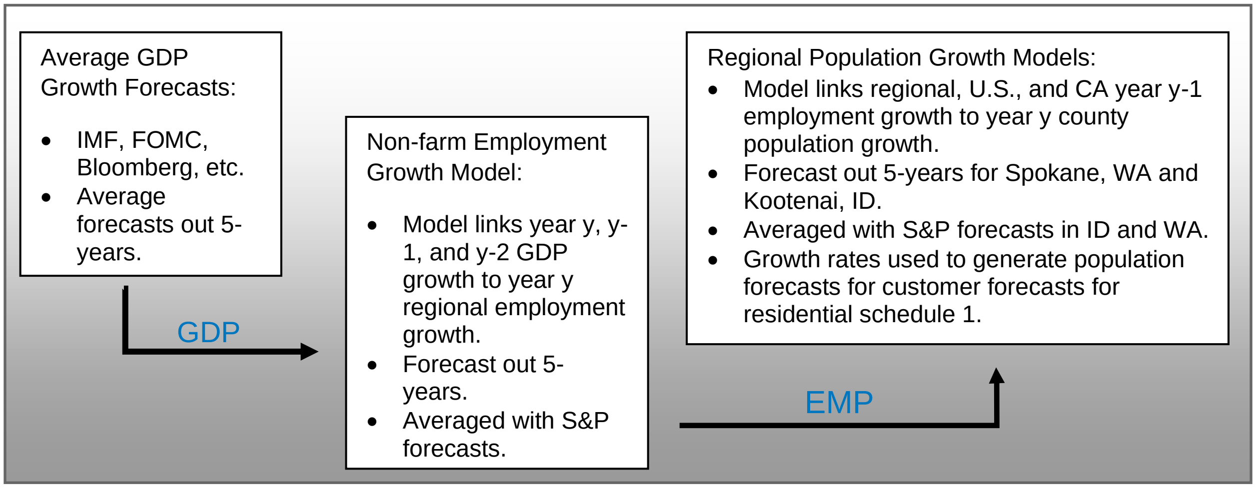
Figure 3.9: Population Growth vs. Customer Growth, 2002-2023



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 S&P Connect (formerly IHS Connect) 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 3.10 summarizes the forecasting process for population growth for use in estimating Residential Schedule 1 customers.

The employment growth forecasts (average of Avista and S&P Connect forecasts) become inputs used to generate the population growth forecasts. The Spokane and Kootenai forecast are averaged with S&P Connect'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.

Figure 3.10: Forecasting Population Growth



Monthly Peak Load Forecast Methodology

The IRP's main requirement is to ensure enough resources are available to meet resource adequacy needs, especially in the coldest and hottest days. Avista develops an estimated peak load for each month and a seasonal peak as part of the load forecast.

The estimated regression Equation 3.3 is used to generate the starting seasonal peak values for 2024. These starting peak values are extrapolated out over time by applying an average annual growth rate over the forecast horizon. The annual growth rates are provided by Applied Energy Group (AEG) as part of the end use forecast to be discussed below. The process of generating the starting peak values follows:

- Historical data going back to 2004 is used to estimate the regression coefficients shown in Equation 3.3. Diagnostic checks are done to ensure the estimated error term from the regression on historical data meets the assumptions that it should be uncorrelated over time and be approximately N(0, σ).
- Using actual weather data by month, the hottest average summer day in a given year and coldest average winter day in a given year is extracted from the average temperature time-series. These summer and winter series reflect two subset series reflecting extreme temperatures.
- Using the subset series of temperature extremes, the average extreme temperature for summer months is calculated using the 20-year period, 2004-2023 (i.e., an average based on n = 20). For winter months, the average extreme temperature is calculated using the 76-year period, 1949-2024. The differing sample size between summer and winter reflects warming summers, if included older summer temperatures the forecast would be biased down. In the winter, temperature anomalies are still heavily skewed to very low temperatures. Therefore, allowing a longer winter average reduces the risk of under allocating peak resources for winter peak.
- The 20-year summer average and 76-year winter average are converted into degree days (CDD for summer and HDD for winter) using a 65-degree

Fahrenheit base. For the starting summer net peak, the CDD value is entered into Equation 3.3 with appropriate values for the remaining values. The same is done for HDD to arrive at the starting winter peak for net peak for 2024/2025.

- Using the full starting peak native load values, peak growth rates provided by AEG's end use forecast are used to escalate the starting values over the IRP's forecast horizon.

Equation 3.3: Peak Load Regression Model

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2 + \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1} + \phi_2 (D_{SUM} \cdot GDP_{t.y-1}) + \phi_3 (D_{WIN} \cdot GDP_{t.y-1}) + \boldsymbol{\omega_{WD} D_{d,t,y}} + \boldsymbol{\omega_{HD} D_{d,t,y}} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{COVID} D_{Jan\ 2022\uparrow=1} + \omega_{OL} D_{Mar\ 2005=1} + \epsilon_{d,t,y}\ for\ t,y = June\ 2004 \uparrow$$

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 natural 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.[29]
- $\mathrm{GDP}_{\mathrm{t.y-1}}$ = extrapolated level of real GDP in month t in year y-1.
- $(D_{SUM} * GDP_{t.y-1})$ = a slope shift variable for GDP in the summer months, June, July, and August.
- $(D_{WIN} * GDP_{t.y-1})$ = a slope shift variable for GDP in the winter months, December, January, and February.
- $\boldsymbol{\omega_{WD} D_{d,t,y}}$ = dummy vector indicating the peak's day of week.
- $\boldsymbol{\omega_{HD} D_{d,t,y}}$ = dummy vector indicating the high peak hours 8 am, 9 am, 4 pm, 5 pm, 6 pm, and 7 pm.
- $\boldsymbol{\omega_{SD} D_{t,y}}$= seasonal dummy vector indicating the month.
- $\omega_{COVID} D_{Jan\ 2022\uparrow=1}$= dummy variable that controls for a step-up in peak following the COVID pandemic starting in January 2022.
- $\omega_{OL} D_{Mar\ 2005=1}$ = a dummy variable to control for an extreme outlier in March 2005.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) error term.

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

Long-Term Load Forecast

Previous IRPs used regression modeling techniques to forecast future load for the entire forecast period. These modeling techniques use load related data, such as temperature, population, and GDP to forecast the future using past data relationships. Avista is currently entering a period where past energy use patterns may not be a good prediction of the future. EV use, building electrification, changes in climate, new energy efficiency efforts, and distributed energy resources are not present in the historical data used for regression models, but will likely be part of the future. End-use modeling addresses this issue by starting at the customer equipment level (EVs, heat pumps, etc.) rather than using historical data. The system load forecast is the aggregation of customers and their adoption rates of customer equipment. This approach allows modification of specific equipment adoption rates based on customer preference, economic considerations, and regulatory frameworks.

Avista contracted with AEG to assist with the end-use portion of the forecast utilizing the load forecast model developed for the energy efficiency potential studies. Development of the model began with a segmentation of Avista's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. AEG utilized information from Avista, the Northwest Energy Efficiency Alliance (NEEA), and other secondary sources, as necessary. AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop the end use model and the resulting forecast. AEG developed LoadMAP™ in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and energy efficiency potential studies. Built in Excel, the LoadMAP™ framework is both accessible and transparent and has the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS[30] and COMMEND[31]) but in a more simplified, accessible form.
- Includes stock-accounting algorithms to treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness. This is done by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data is available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision-choice algorithms or

[30] Residential end-use energy planning system

[31] Commercial-sector end-use planning system

diffusion assumptions. The model parameters tend to be difficult to estimate or observe, and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP™ approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.

- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).
- Can incorporate conservation measures, demand-response options, combined heat and power, distributed generation options, and fuel switching.

The model was calibrated to actual data for 2021 through 2023 and the medium-term forecast for years 2024 through 2028.

Segmentation for Modeling Purposes

The market assessment first defines the market segments (building types, end uses, and other dimensions) with relevance to the Avista service territory. The segmentation scheme for this project is presented in Table 3.3.

Table 3.3: Overview of Avista Analysis Segmentation Scheme

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial, and industrial sectors	Avista short term actuals and forecast from the U.S. Energy Information Administration Annual Energy Outlook (AEO) economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipment data from AEO and ENERGY STAR AEO regional forecast assumptions Appliance/efficiency standards analysis
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	Electric Power Research Institute’s REEPS and COMMEND models and AEO 2021

With the segmentation scheme defined, AEG then performed a high-level market characterization of electricity sales in the base year to allocate sales to each customer segment. AEG used Avista data and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the Avista system totals from billing data. This information provided control totals at a sector level for calibrating LoadMAP™ to known data for the base year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. The market profiles provided the foundation for the development of the baseline projection. A market profile includes the following elements:

- Market size is a representation of the number of customers in the segment. For the residential sector, it is the number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is overall electricity use.
- Saturations define the fraction of homes or square feet with the various technologies (e.g., homes with electric space heating).
- The unit energy consumption (UEC) or the energy use index (EUI) describes the amount of energy consumed in 2022 by a specific technology in buildings that have the technology. UECs are expressed in kWh/household for the residential sector, and EUIs are expressed in kWh/square foot for the commercial sector.
- Annual Energy Intensity for the residential sector represents the average energy use for the technology across all homes in 2022 and is the product of saturation and UEC. The commercial sector represents the average use for the technology across all floor space in 2022 and is the product of the saturation and EUI.
- Annual Usage is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in GWh.
- Peak demand for each technology, summer peak and winter peak, is calculated using peak fractions of annual energy use from AEG's Energy Shape library and Avista system peak data.

The market characterization and market profiles are presented in the report in Appendix C.

Baseline Projection

The following describes the development of the baseline projection of annual electricity use and peak demand for 2026 through 2045 by customer segment and end use without new utility programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes past programs cease to exist in the future. Possible savings from future programs are captured by the potential estimates. The projection includes the known impacts of future codes and standards over the study timeframe. All such mandates defined as of May 2024 are included in the baseline. The baseline projection is the foundation for the load forecast. The load forecast is then developed utilizing the following:

- Current economic growth forecasts (i.e., customer growth, income growth).
- Electricity and natural gas retail price forecasts.
- Trends in fuel shares and equipment saturations.
- Existing and approved changes to building codes and equipment standards.

- Avista’s internally developed short-term sector-level projections for electricity sales.
- AEG’s estimates of electrification from Avista’s natural gas system.

Data Application for Baseline Projection

Table 3.4 summarizes the LoadMAP™ model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 3.4: Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Sector	Residential, commercial, industrial
2	Segment	Residential: single family, multifamily, manufactured home, differentiated by income level Commercial: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous Industrial: total
3	Vintage	Existing and new construction
4	End uses	Cooling, lighting, water heat, motors, etc. (as appropriate by sector)
5	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

The baseline also includes projected naturally occurring energy efficiency during the potential forecast period. AEG’s LoadMAP™ efficiency choice model uses energy and cost data as well as current purchase trends to evaluate technologies and predict future customer equipment purchase shares. AEG also models the adoption of electrification measures for natural gas customers and includes the future effects of this additional electric equipment stock in Avista’s territory. The customer equipment purchase data all feed into the stock accounting algorithm to predict and track equipment stock and energy usage for each market segment.

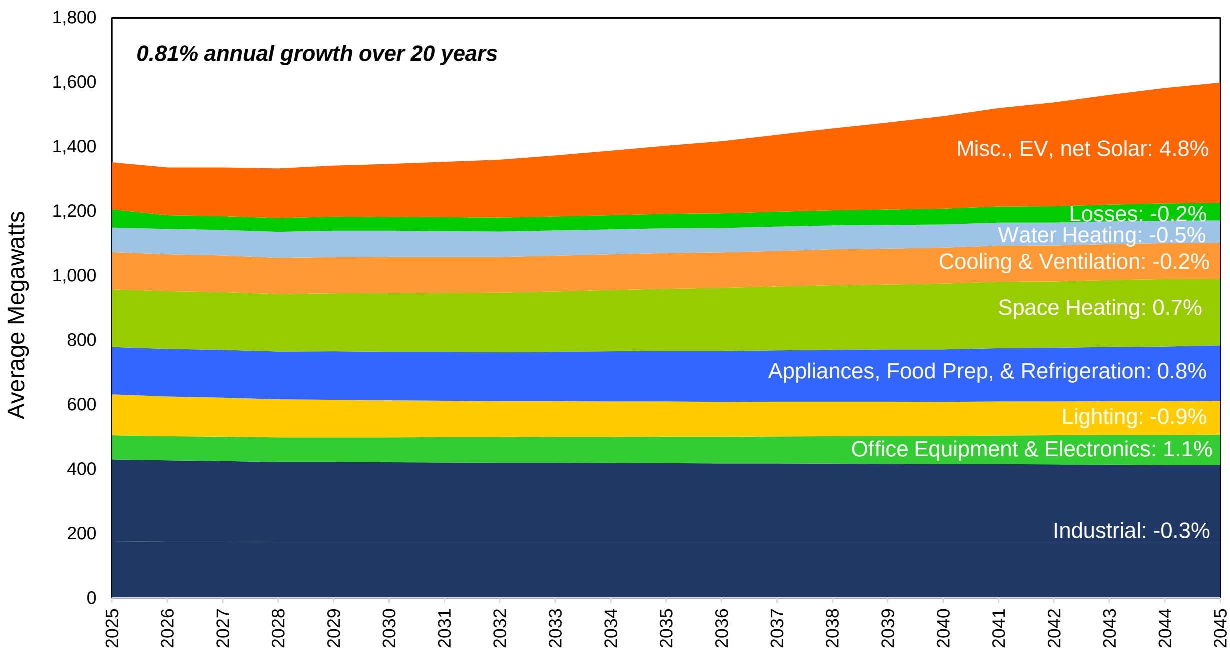
Use of the Baseline Forecast in IRP

AEG has been providing energy efficiency potential assessments for Avista since 2010. A new component of the partnership between AEG and Avista is that the end-use load forecast is now used to inform Avista’s official load forecast for this IRP. The ability to capture specific end-use load movement and changes over time has become critical to Avista’s understanding of the long-term changes to their load.

To facilitate IRP planning, AEG provided the hourly disaggregation of the annual end-use load forecast from the LoadMAP™ model. AEG carefully calibrated the projection to actual Avista system loads by month and hour from 2021-2023, then carried the average of those monthly calibration factors forward throughout the forecast period to create a long-term forecast with the greatest consistency with recorded history and Avista's short-term forecast.

While the main LoadMAP™ engines run on an annual basis, AEG used a combination of region-specific load shapes from the National Renewable Energy Laboratory's (NREL) end use load profiles, Avista's load research data and engineering simulations to further analyze the end-use loads at an hourly level. These load shapes were then calibrated to Avista's seasonal loads and normalized so the value for each hour represents 1/8760th of the year. The energy from the baseline projection for each end use and technology was applied to each shape to compute hourly profiles throughout the forecast period. Figure 3.11 presents the energy forecast for each end use category, and the percentage growth over the forecast period.

Figure 3.11: Change in Energy Use by End Use, 2025-2045



An important component of the load forecast is building electrification. New customers were modeled with new codes and standards favoring electric over natural gas heat. In addition, existing customers were modeled with the option to replace existing gas space or water heating equipment with electric alternatives, using purchase decision logic taken from the US DOE's National Energy Modeling System. Gas-to-electric conversion costs include the possibility of a panel upgrade and associated labor along with the tax benefits form the Inflation Reduction Act (IRA), but do not include any state incentives (as these are not known). The model compares the lifetime cost of ownership including upfront costs and associated lifetime fuel costs. Figure 3.12 and Figure 3.13 show the gas residential heating market transformation for the forecast period.

Figure 3.12: Washington Residential Gas Heating Market Transformation

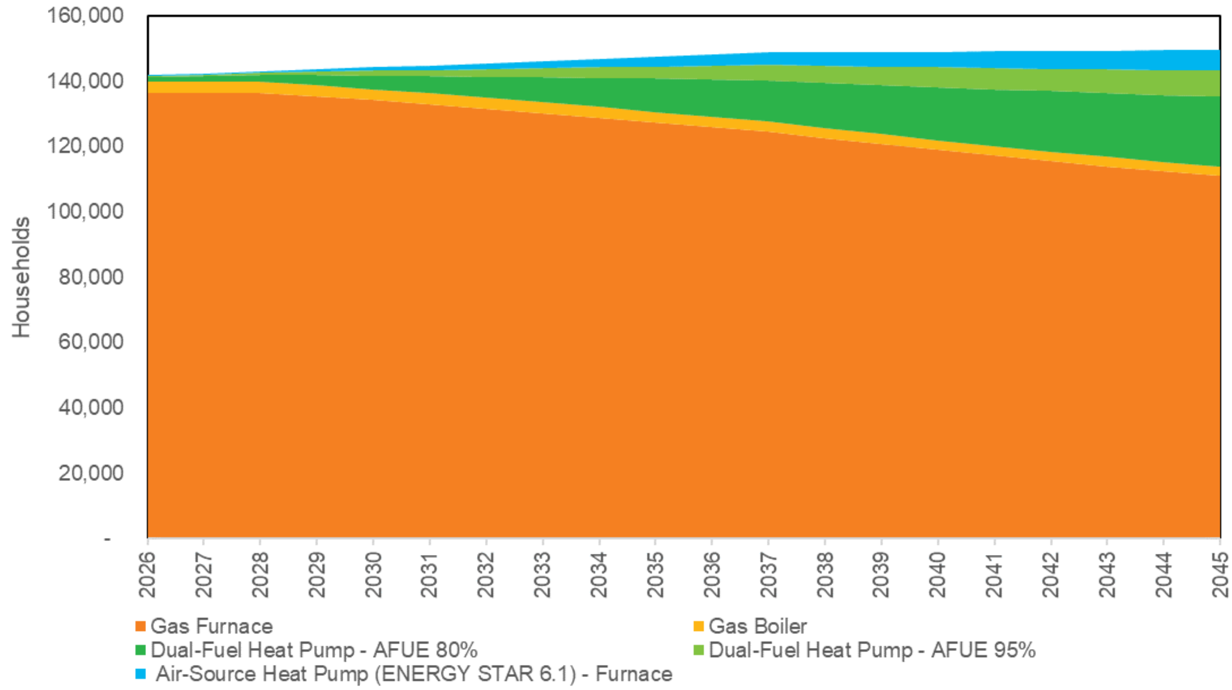
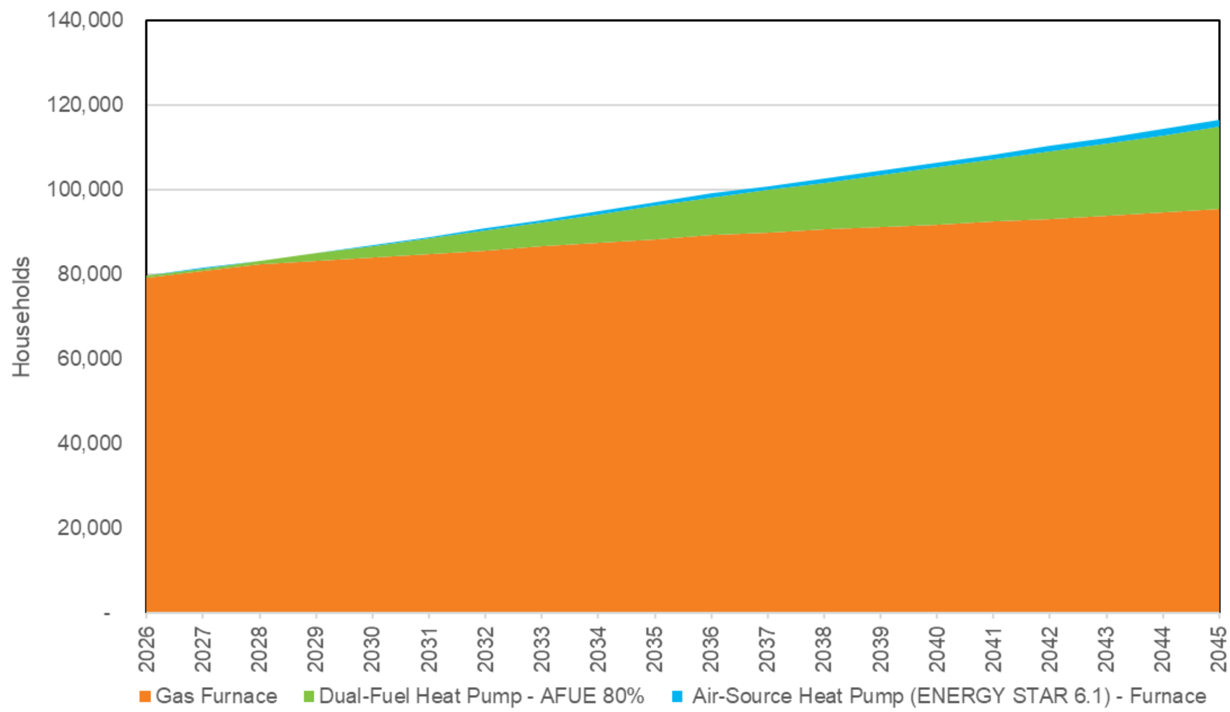


Figure 3.13: Idaho Residential Gas Heating Market Transformation



Load Forecast

The load forecast produced with the end use model does not address some aspects of the final load forecast, both for energy and peak. The following additional analyses were conducted to finalize the load forecast for the IRP analysis:

- Add large industrial loads,
- Add line losses occurring in the delivery of energy from a generator, through the transmission and distribution system to the end customer,
- Peak and energy were adjusted for weather normalization.

Weather Normalization

Weather has a significant impact on load. The AEG model only uses data from 2021 to 2023 to establish weather for their model, therefore a secondary weatherization step was conducted to accurately represent historical data and future weather forecasts. Avista applies weather data on a monthly basis. Each forecast month uses the average of the data from the same month for the previous 20 years, except in the case of winter peak (uses a 76-year rolling average). This is done to capture the full range of possible temperatures.

The energy forecast utilizes monthly HDDs and CDDs while the peak load model utilizes daily average temperature. The first year of the forecast uses historical data, but each subsequent year adds in forecasted weather and removes historical weather such that the last several years of the forecast is based entirely on forecasted weather, except in the case of the winter peak since the 76-year period still includes historical values. The energy forecast is adjusted by total number of monthly HDDs or CDDs, while peak is adjusted according to the coldest or hottest daily average temperature for each month as appropriate for the season. For planning purposes, winter peak is the lowest average daily temperature in January and the summer peak is the warmest average day in August. A seasonal peak for each year was developed in addition to the monthly peak values to reflect extreme events occurring anytime in the season rather than a specific month. This data takes the hottest or coldest day over the course of multiple months for each year, as it cooler and/or in other months rather than using January and August exclusively. The seasonal peak is used to validate the load forecast in reliability modeling and to compare with historical peak values.

As described in Chapter 5, Avista uses the climate forecast data generated by the River Management Joint Operating Committee (RMJOC). Avista uses the RCP 8.5 for the summer months (June, July, August, September) and RCP 4.5 for the remaining months of the year.

Load Forecast

After combining the medium-term, end-use forecast, and weather normalization, the resulting load forecast is shown in Table 3.5 for the expected case's average annual energy in average megawatts (aMW) as well as summer and winter peaks in megawatts (MW). The forecast is for Avista's native load, referring to Avista's retail customers, and does not include other loads within the transmission balancing authority published in FERC or EIA data.

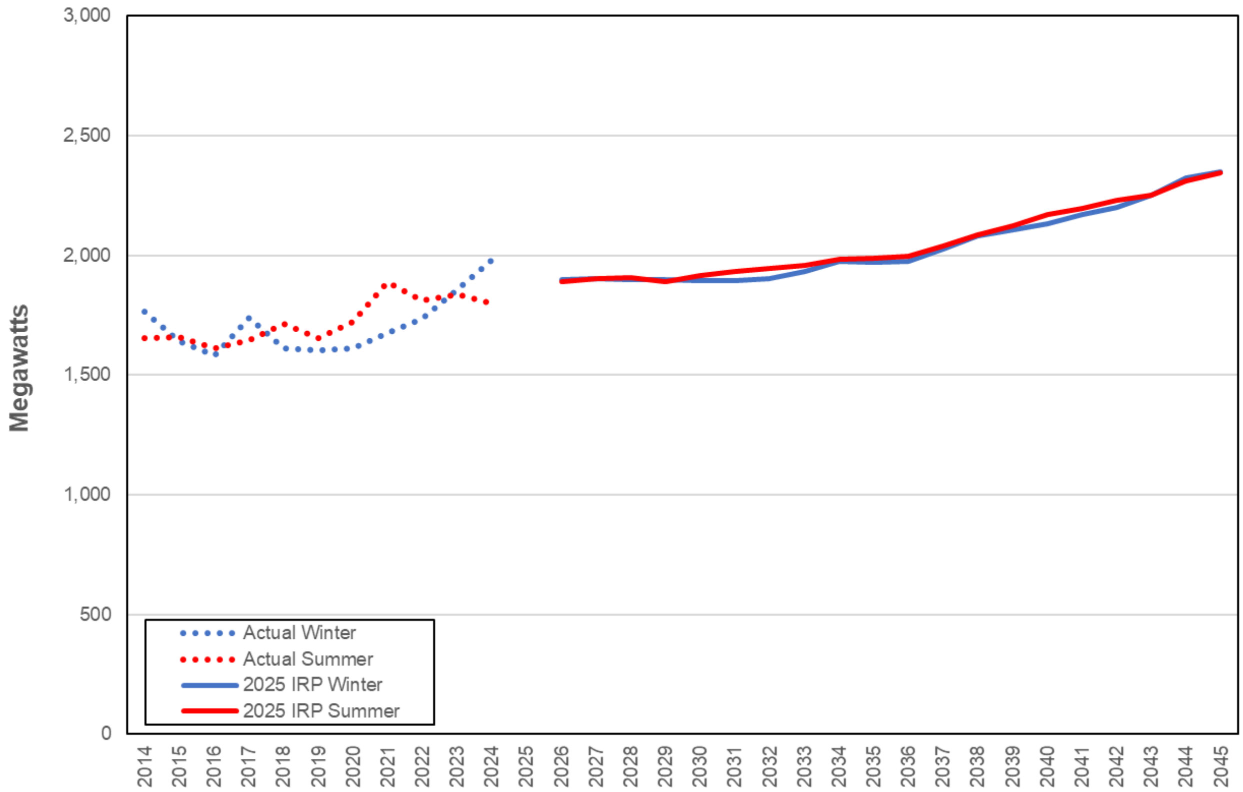
Table 3.5: Expected Case Energy and Peak Forecasts

Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
2026	1,165	1,816	1,837
2027	1,167	1,821	1,846
2028	1,166	1,819	1,850
2029	1,165	1,821	1,835
2030	1,165	1,814	1,863
2031	1,166	1,818	1,870
2032	1,168	1,825	1,878
2033	1,177	1,852	1,884
2034	1,188	1,898	1,902
2035	1,200	1,893	1,905
2036	1,211	1,901	1,909
2037	1,227	1,949	1,948
2038	1,246	2,003	1,990
2039	1,263	2,028	2,023
2040	1,282	2,058	2,063
2041	1,305	2,093	2,090
2042	1,321	2,117	2,119
2043	1,344	2,168	2,135
2044	1,366	2,233	2,191
2045	1,379	2,261	2,217

Figure 3.14 presents the seasonal peak load forecast in comparison to historical peak loads[32] prior to 2022, where winter peaks were often less then summer peaks due to moderate winter temperatures until December 2022 and January 2024. The Spokane area's average coldest day used for planning is 4°, whereas in December 2022 (-3° with a low of -10°) and January 2024 (-4° with a low of -10°) were much colder than the 50th percentile coldest day used for planning.[33] The January 2024 event during Martin Luther King Jr. holiday weekend would have been Avista's all-time peak as shown in Figure 3.14, at a load of 1,981 MW, but industrial loads were curtailed resulting in an official peak load of 1,869 MW. Avista's all-time peak was set during the heat dome event in June 2021, with a peak load of 1,889 MW when temperatures were an average of 93° (high of 109°) compared to the planning temperature of 84°.

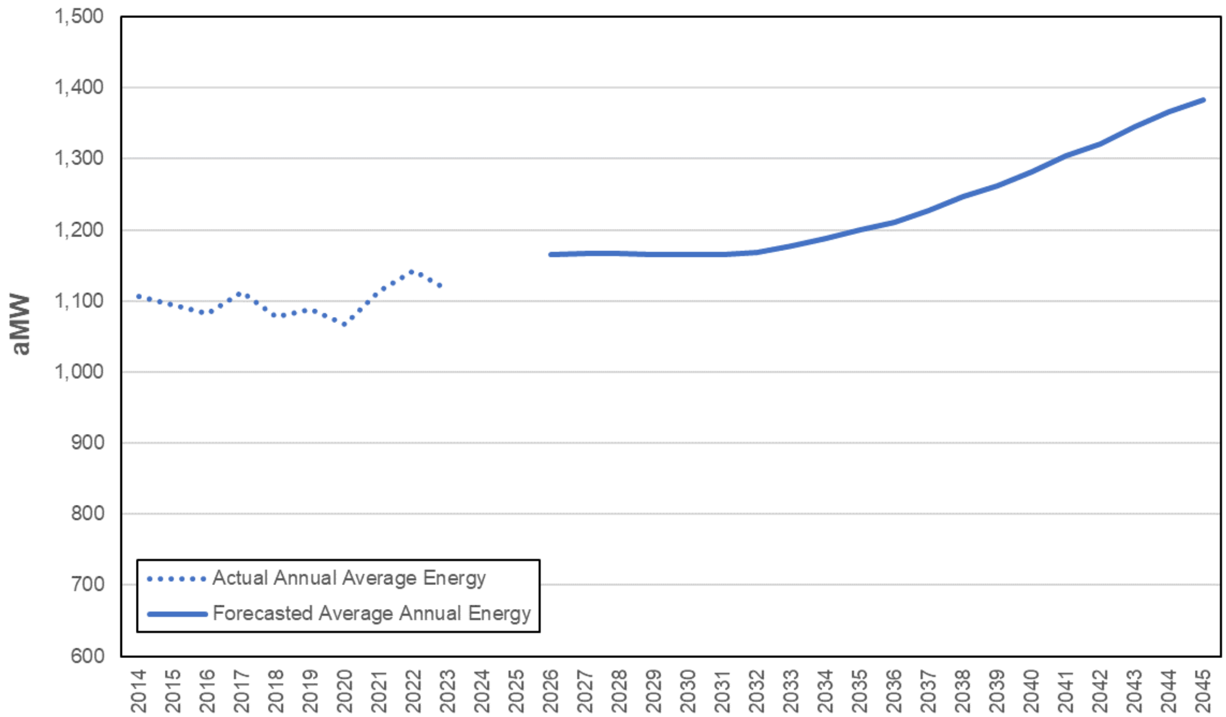
[32] Historical peak load data is corrected for known curtailed load or demand response.
[33] Avista planning margin cover loads when temperature vary from the 50th percentile.

Figure 3.14: History and Forecast Peak Loads



The annual average growth rate for the energy forecast is 0.93% between 2026 and 2045, going from 1,165 aMW to 1,383 aMW. The forecast steps up at the beginning of the forecast period as the result of a new large industrial load as compared to 2023. The forecast is then relatively flat until 2032 when the forecasted annual load increases at a greater rate due to building and transportation electrification beginning to show an impact. Also, as described above, Avista uses a 20-year rolling average temperature in its load forecast, therefore forecasted temperatures, rather than actual historical temperatures, have an increased impact on temperature dependent loads in the later years of the forecast.

Figure 3.15: History and Forecast Annual Energy Demand



Load Scenario Analysis

In addition to the expected case, additional load forecast scenarios were developed, including:

- *High growth*: assumes higher customer/population growth than the expected case.
- *Low growth*: assumes lower customer/population growth than the expected case.
- *RCP 8.5*: uses RCP 8.5 for the winter months as part of the future periods included in the forecast. RCP 8.5 temperature forecast between 2026-2045 is included in the historical average temperature calculation for peak load temperatures.
- *Washington Building Electrification*: This scenario reduces natural gas demand each year to achieve an 80% reduction by 2045. Where 75% of the gas energy is added to Avista's electric load, the remaining load would be applied to other utilities.
- *Washington Building Electrification and High EV forecast*: This scenario adds higher transportation electrification as compared to the previous scenario's building electrification adjustment. It also includes electrifying an equivalent of 806,000 EVs in the Washington service area by 2045 as compared to 560,000 EVs equivalent in the expected case.
- *System Building Electrification and High EV*. This scenario is similar to Washington only electrification scenario but includes Idaho building and

transportation electrification. In this scenario natural gas demand lowers each year to achieve an 80% reduction by 2045. (90% of this load is Avista electric load) and adding an equivalent of 300,000 EVs by 2045 as compared to 65,000 in the expected case forecast.

Figures 3.16, 3.17, and 3.18 present the annual energy, summer peak, and winter peak respectively for each of the load scenarios. Table 3.6 shows the incremental change between the expected case and each scenario in 2045. Energy in the high growth scenario is 19% higher than the expected case, while the low growth scenario is 10% lower. Use of the RCP 8.5 temperatures for the entire year lowers annual energy by 1%. This is due to higher temperatures during the winter months. Washington building electrification increases annual energy use by 8% and EV use that is greater than what is included in the expected case in Washington increases annual energy by 6%. The largest increase is 29% of annual energy resulting from building electrification and high EV use across the entire system, both Idaho and Washington. This scenario also increases winter peak by 41%.

Figure 3.16: Scenario Comparison of Annual Energy (aMW)

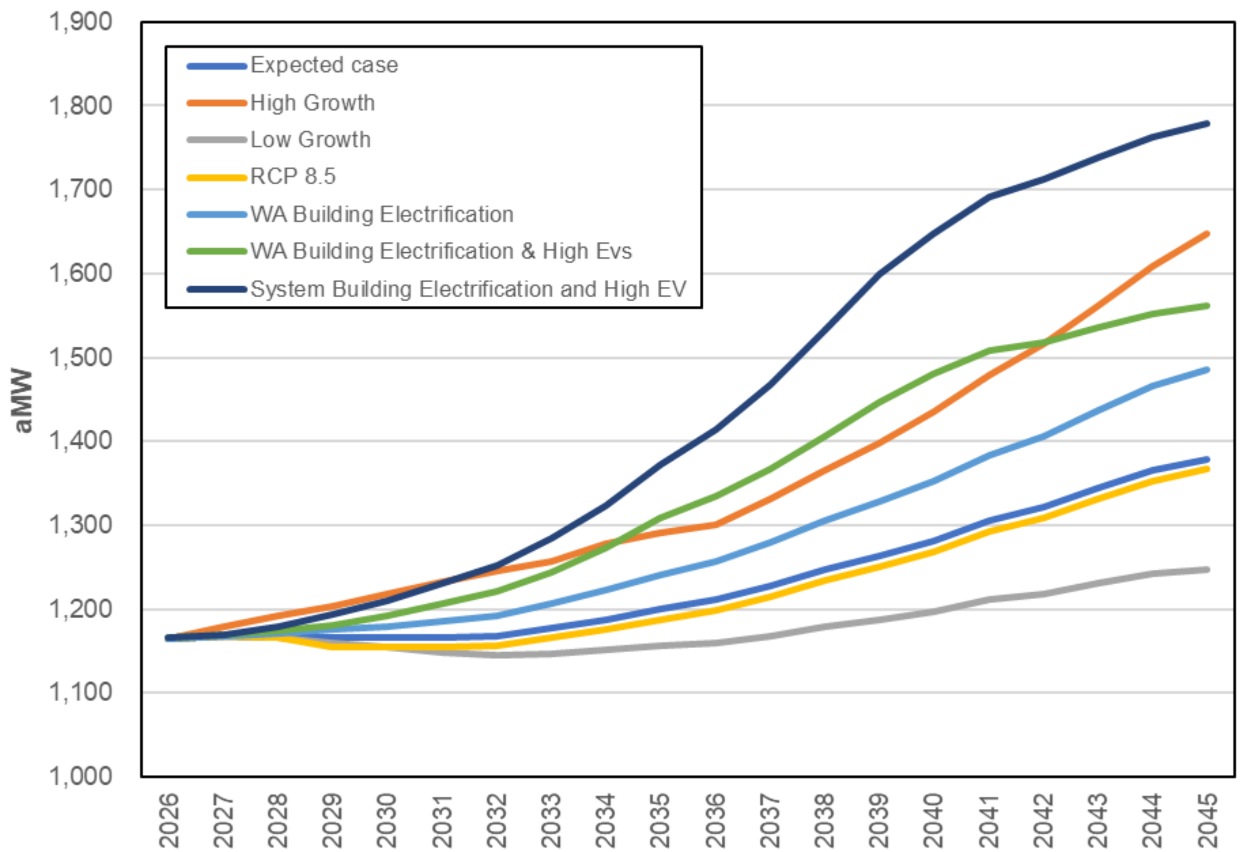


Figure 3.17: Scenario Comparison of Winter Peak (MW)

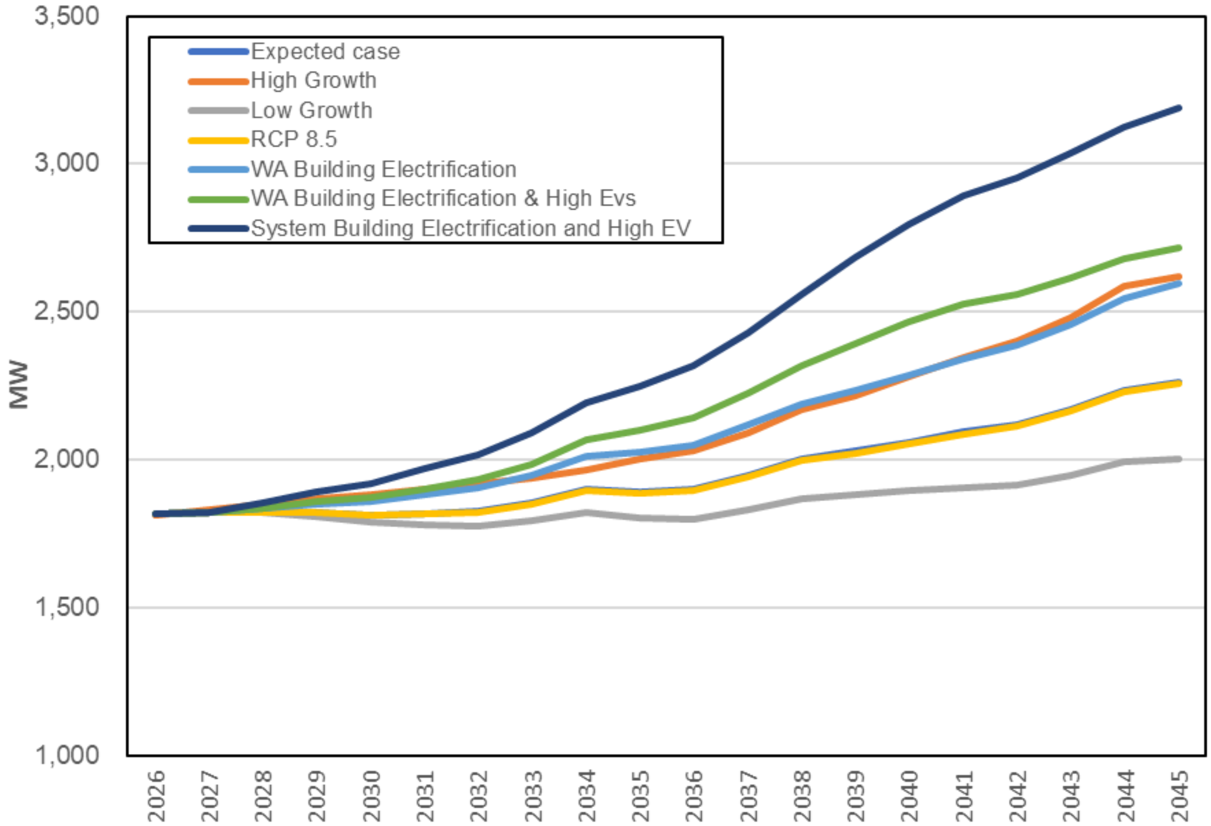


Figure 3.18: Scenario Comparison of Summer Peak (MW)

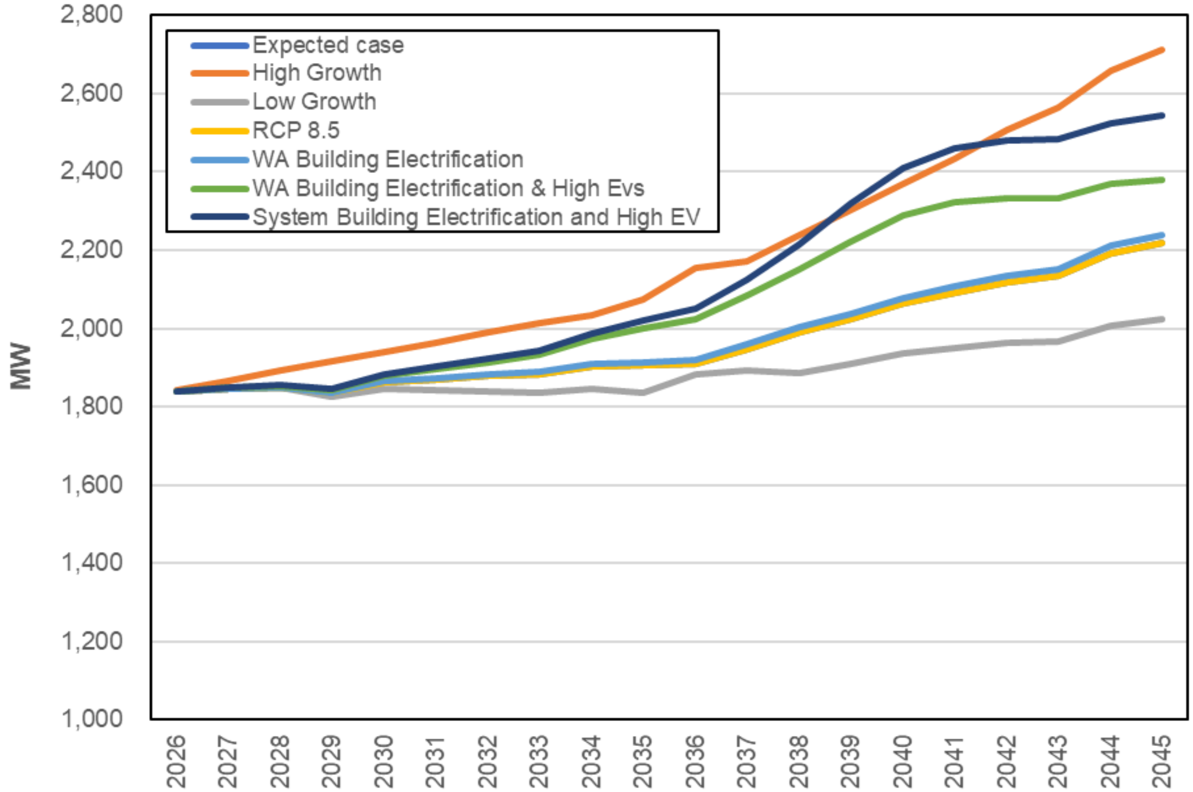


Table 3.6: Incremental Difference between Expected Case and Scenario in 2045

Scenario	Annual Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
High Growth	+268	+357	+494
Low Growth	-132	-258	-193
RCP 8.5	-13	-23	0
WA Building Electrification	+107	+336	+21
WA Building Electrification & High EVs	+183	+456	+161
System Building Electrification & High EV	+401	+930	+325

4. 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. Avista also purchases energy from several independent power producers (IPPs) and regional utilities.

Section Highlights

- Hydroelectric resources provide approximately half of Avista's winter generating capability.
- Natural gas-fired plants continue to represent a fundamental element, both currently and into the clean energy future to maintain system reliability for Avista's generation portfolio.
- Avista will transfer its ownership of Colstrip Units 3 & 4 to NorthWestern Energy on January 1, 2026.
- The 97.5 MW Clearwater Wind project in Montana is commercially operational in September 2024.

Figure 4.1 shows how much annual energy may be generated on Avista's system. This annual energy chart represents the generation potential as a percentage of total supply; this calculation includes fuel limitations (for water, wind, and wood), maintenance, and forced outages. On an annual basis, natural gas-fired generation can produce more energy (48%) than hydroelectric (38%) because it is not constrained by river conditions. Avista's resource mix changes each year depending on streamflow conditions and market prices. Figure 4.2 shows how much generation capacity Avista can rely on during winter and summer peak. This winter and summer capability is the share of total capability of each resource type the utility can rely upon to meet winter (January) and summer (August) peak load. Avista's largest energy supply in the peak winter months is from hydroelectric at 55%, followed by natural gas-fired resources at 39%.

Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure.[34] The Washington State Department of Commerce calculates the resource mix used to serve load, rather than its generation potential. The report includes estimates for regional[35] market purchases without an identified energy source and Avista-owned generation minus renewable energy credit (REC) sales. Figure 4.3 shows Avista's 2023 Fuel Mix Disclosure for 2022 data. The Idaho fuel mix is nearly identical to Washington's except for its allocation of Public Utility Regulatory Policies Act (PURPA) generation. Each state

[34] 11A-Utility-Fuel-Mix-Market-Summary-20240108.pdf from Washington Department of Commerce.

[35] For 2022, the region is approximately 54% hydroelectric, 13% unspecified, 10% natural gas, 9% coal, 8% wind, 4% nuclear and 2% other. When Avista sells RECs from its resources the remaining generation is assigned a fuel mix and an emissions level in the report equal to regional average emissions.

is allocated 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 4.1: 2026 Annual Energy Capability (System)

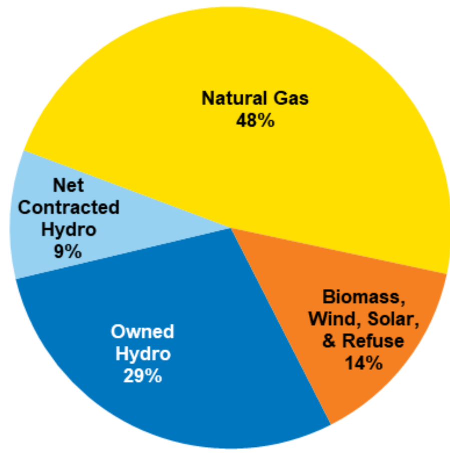


Figure 4.2: 2026 Avista System Seasonal Capability

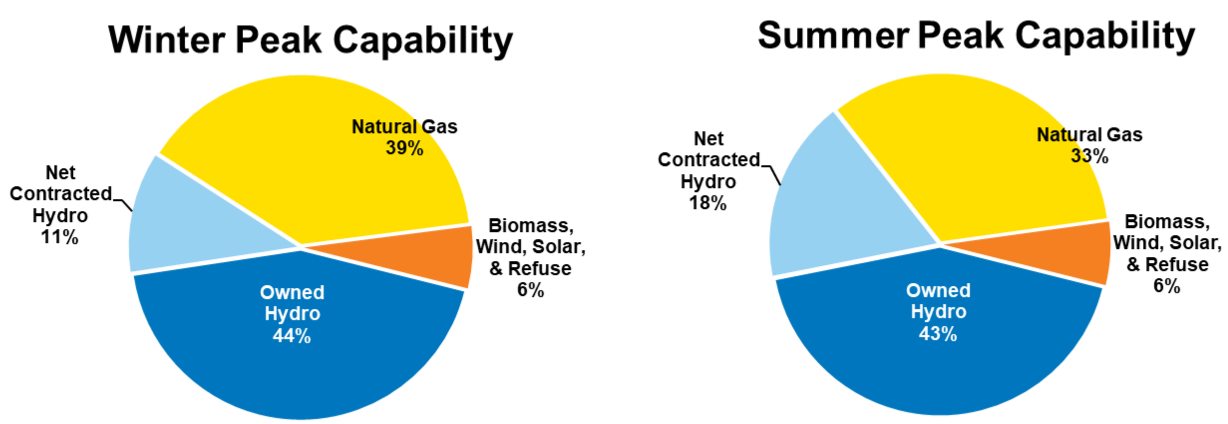
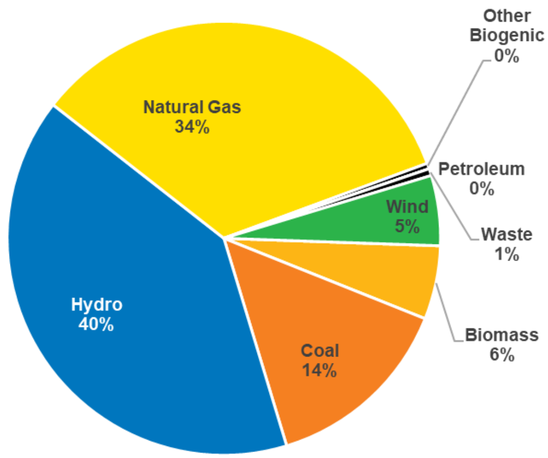


Figure 4.3: Avista's Washington State Fuel Mix Disclosure



Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under a 50-year Federal Energy Regulatory Commission (FERC) operating license through June 18, 2059. The sixth, Little Falls, operates under separate authorization from the U.S. Congress because of its location on tribal land. 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, hydroelectric 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 could produce up to 18.0 MW with its six generating units.

In February 2024, Avista's Post Falls Hydroelectric Dam was selected for U.S. Department of Energy grant funding, receiving a $5 million Hydroelectric Efficiency Improvement Incentive for improvements to increase the facility's efficiency. The goal of the Post Falls Modernization project is to replace existing aging equipment with modern, energy-efficient designs and equipment, and increase the useful life of the facility. The planned updates will not change operations nor capacity of the Post Falls dam and are estimated to be complete in 2029.

Upper Falls

The Upper Falls development is in downtown Spokane's Riverfront Park and began generating in 1922. The project is comprised of a single 10 MW unit on the north channel of the river.

Monroe Street

Monroe Street, Avista's first hydroelectric plant, began serving customers in 1890 in downtown Spokane at Huntington Park. Following a complete rehabilitation in 1992, the single generating unit has a 15 MW maximum capacity rating.

Nine Mile

A private developer built the Nine Mile hydroelectric plant 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.

Long Lake

The Long Lake development is located northwest of the City of Spokane and maintains the Lake Spokane reservoir or Long Lake. The project's four units have a maximum capacity of 88 MW of combined capacity.

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. As Little Falls is partially located on the Spokane Indian Reservation, it was congressionally authorized and is not under FERC jurisdiction. Avista operates Little Falls Dam in accordance with an agreement reached with the Spokane 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 two 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 Avista's 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 4.1 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 4.1: Avista-Owned Hydroelectric Resources

Project Name	River System	Location	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	15.0	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	88.0	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			**972.6**	**1,078.9**	**442.3**

Thermal Resources

Avista owns six thermal generation assets located across the Northwest. These assets provide dependable energy and capacity serving base and peak-load obligations. Table 4.2 summarizes these resources by fuel type, online year, remaining design life, book value at the end of 2025 and the last year of expected service for IRP modeling purposes. Table 4.3 includes capacity information for each of the facilities along with the five-year historical forced outage rates used for modeling purposes.

Table 4.2: Avista-Owned Thermal Resources

Project Name	Location	Fuel Type	Start Date	Last Year of Service[36]	Book Value (mill. $)	Book Life (years)
Rathdrum	Rathdrum, ID	Gas	1995	2044	18.7	7.2
Northeast[37]	Spokane, WA	Gas	1978	2029	0.0	0.0
Boulder Park	Spokane, WA	Gas	2002	2040	12.8	15.7
Coyote Springs 2	Boardman, OR	Gas	2003	n/a	98.7	15.2
Kettle Falls	Kettle Falls, WA	Wood	1983	n/a	59.2	17.4
Kettle Falls CT	Kettle Falls, WA	Gas	2002	2040	1.9	9.9

Table 4.3: Avista-Owned Thermal Resource Capability

Project Name	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)	Forced Outage Rate (%)
Rathdrum (2 units)	176.0	130.0	166.2	5.8
Northeast (2 units)	66.0	42.0	61.8	n/a
Boulder Park (6 units)	24.6	24.6	24.6	10.5
Coyote Springs 2	317.5	286.0	306.5	3.8
Kettle Falls	47.0	47.0	50.7	2.3
Kettle Falls CT	11.0	8.0	7.2	2.7
Total	**864.1**	**759.6**	**864.0**	

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. This facility 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 166.2 MW. Chapter 7, Supply-Side Resource Options, provides details about upgrade 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 current air permits preclude the use of fuel oil. The combined maximum capacity of the units is 66 MW in the winter and 42 MW in the summer, with a nameplate rating of 61.8 MW. The plant air permit limits run time to 50 hours per year, limiting its use to primarily serve reliability events. For the purposes of this IRP, Avista assumes this plant will retire in 2030, but no official retirement date has been set.

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[36] 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 still eligible to serve Idaho customers.
[37] There is no remaining book life but there are five years of remaining tax depreciation impacts to customers.

Boulder Park

The Boulder Park project entered service in 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. For modeling purposes of this IRP, Avista assumes this plant will retire in 2040.

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 Bonneville Power Administration (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.

Colstrip

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

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. Second, Avista installed a 15-kilowatt solar system in Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. Lastly, Avista has a 423-kW Community Solar project, located at the Boulder Park property, began service in 2015.

Table 4.4: Avista-Owned Solar Resource Capability

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

Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet some of its load requirements. These contracts provide many benefits by adding clean generation from low-cost hydroelectric and wind power to the Company's resource mix. This section describes the contracts in effect during the IRP. Tables 4.5 and 4.6 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 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 4.5 provide clean energy, capacity, and reserve capabilities.

Under the 1961 Columbia River Treaty and the 1964 Pacific Northwest Coordination Agreement (PNCA), the Mid-Columbia projects optimize hydroelectric project operations in the Northwest U.S. and Canada. In return for these benefits, Canada receives a share of the energy under the Canadian Entitlement. The Columbia River Treaty and the PNCA manage water storage in upstream reservoirs for coordinated flood control and power generation optimization. The Columbia River Treaty recently concluded negotiations in July 2024. At this time, no specific information is available pertaining to the generation impact, however it is expected less energy will be transferred to Canada under the Canadian Entitlement.

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 their seven hydroelectric projects totaling 146.3 MW of capacity. Avista will begin taking delivery of projects as existing contracts with other utilities expire. Table 4.6 outlines the project delivery timeline, capacity, and energy deliveries for Columbia Basin Hydro. These projects are unique as they are based on the amount of irrigation used by central Washington farmers from March through October, with most of the generation occurring in May through August in a consistent firm energy delivery.

Table 4.5: Mid-Columbia Capacity and Energy Contracts[38]

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

[38] 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 4.5 are presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.
[39] Percent share varies each year depending on Douglas PUD's load growth.

Table 4.6: Columbia Basin Hydro Projects

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

Public Utility Regulatory Policies Act (PURPA)

The passage of PURPA by Congress in 1978 required utilities to purchase power under standardized contracts from resources meeting certain size and fuel criteria. As shown in Table 4.7, Avista has many PURPA, or Qualifying Facility (QF) energy purchase contracts, totaling 139.9 MW, with a five-year average output of 73 aMW. Avista also has PURPA fully net metered generation from customer load shown in Table 4.8 for a total of 7.5 MW. Power from net metered facilities is only purchased if generation exceeds load. Based on Avista's experience with these contracts and ongoing communications with the project owners, the IRP assumes the renewal of these contracts after the term expires. Avista takes the energy as produced, does not control the output of any PURPA resources.

Table 4.7: PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)	5 year avg. Gen. History (aMW)
Meyers Falls	Hydro	Kettle Falls, WA	12/2025	1.30	1.06
Spokane Waste to Energy	Waste	Spokane, WA	12/2037	22.70	13.63
Plummer Sawmill[40]	Wood Waste	Plummer, ID	12/2025	5.80	3.00
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[41]	Hydro	Spokane, WA	12/2037	14.50	4.96
Big Sheep Creek Hydro	Hydro	Northport, WA	6/2025	1.40	0.82
Ford Hydro LP	Hydro	Weippe, ID	6/2026	1.41	0.36
John Day Hydro	Hydro	Lucile, ID	9/2041	0.90	0.24
Phillips Ranch	Hydro	Northport, WA	n/a	0.02	0.00
City of Cove	Hydro	Cove, OR	10/2038	0.80	0.36
Clearwater Paper	Biomass	Lewiston, ID	12/2026	93.80	48.67
Total				**143.26**	**73.23**

[40] The owner publicly announced it is shutting down the mill and generator.
[41] Energy estimate is net of the City of Spokane's pumping load. The City of Spokane owns this facility.

Table 4.8: Net PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)
Spokane County Digester	Biomass	Spokane, WA	8/2030	0.26
Spokane Eco District[42]	Solar/BESS	Spokane, WA	4/2039	1.00
Great Northern	Solar	Spokane, WA	5/2035	0.25
U of Idaho Steam Plant	CHP Steam	Moscow, ID	2/2042	0.83
U of Idaho Solar	Solar	Moscow, ID	2/2026	0.13
Vaagen Brothers Lumber[43]	Biomass	Colville, WA	7/2039	5.00
Total				**7.47**

Lancaster

Avista originally 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 contract, Avista pays a monthly capacity payment for the sole right to dispatch the plant through December 31, 2041. In addition, Avista pays an operational charge and arranges for all fuel needs of the plant.

Palouse Wind

Avista signed a 30-year power purchase agreement (PPA) in 2011 with Palouse Wind for the entire output of the 105 MW project starting in December 2012. The project directly connects to Avista's transmission system between Rosalia and Oaksdale, Washington in Whitman County. Avista has an annual right to purchase the Palouse project per the contract.

Rattlesnake Flat Wind

Rattlesnake Flat Wind located east of Lind, Washington in Adams County was selected in Avista's 2018 RFP as a 20-year PPA. It is 160.5 MW (but output is limited to 144 MW due to its interconnection agreement). The expected net annual output of 469,000 MWh (53.5 aMW). The project began operations in December 2020.

Clearwater Wind III

Clearwater Wind III located in Rosebud and Garfield Counties in eastern Montana was selected in the 2022 all-source RFP as a 30-year PPA. It is 97.5 MW and will begin operation in September 2024 with an estimated annual generation of 367,000 MWh.

[42] This size is a little over 254 kW solar and the battery is greater than 1 MW but is limited to 1 MW output by the inverter/interconnection.
[43] This PPA was signed after the IRP analysis and therefore was not included in the IRP analysis.

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 allowing commercial customers to voluntarily purchase solar energy through 2028. Through Washington state tax incentives participating customers do not pay additional costs for the clean energy attributes from the project.

Power Purchase and Contracts

Avista has intermediate power purchase and sale contracts to optimize Avista's energy position on behalf of customers, such as the Morgan Stanley contract. For resource planning purposes, Avista does not assume contract sale extensions. Table 4.9 describes Avista's other contractual rights and obligations.

Table 4.9: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity Contri-bution (MW)	Summer Capacity Contri-bution (MW)	Annual Energy (aMW)
Lancaster	Purchase	Natural Gas	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
Clearwater Wind	Purchase	Wind	2056	29.7	19.2	42.0
Adams-Nielson	Purchase	Solar	2038	0.4	10.2	5.6
Morgan Stanley	Sale	QF Biomass	2026	-46.0	-46.0	-44.9
Total				**279.6**	**226.9**	**310.4**

Resource Environmental Requirements and Issues

Avista is subject to environmental regulation by federal, state, and local authorities. The generation, transmission, distribution, service, and storage facilities we own or may need to acquire or develop are subject to environmental laws, regulations and rules relating to construction permitting, air emissions, water quality, fisheries, wildlife, endangered species, avian interactions, wastewater and stormwater discharges, waste handling, natural resource protection, historic and cultural resource protection, and other similar activities. These laws and regulations require the Company to make substantial investments in compliance activities and to acquire and comply with a wide variety of environmental licenses, permits, approvals, and settlement agreements. These items are enforceable by public officials and private individuals. Some of these regulations are subject to ongoing interpretation, whether administratively or judicially, and are often in the process of being modified. Avista conducts periodic reviews and audits of pertinent facilities and operations to enhance compliance and to respond to or anticipate emerging environmental issues. The Company's Board of Directors has established a committee to oversee environmental issues and to assess and manage environmental risk.

Avista monitors legislative and regulatory developments at different levels of government for environmental issues, particularly those with the potential to impact the operation of generating plants and other assets. The Company continues to be subject to increasingly stringent or expanded application of environmental and related regulations from all levels of government.

Environmental laws and regulations may restrict or impact Avista’s business activities in many ways, including, but not limited to, by:

- increasing the operating costs of generating plants and other assets,
- increasing the lead time and capital costs for the construction of new generating plants and other assets,
- requiring modification of existing generating plants,
- requiring existing generating plant operations to be curtailed or shut down,
- reducing the amount of energy available from generating plants,
- restricting the types of generating plants that can be built or contracted with,
- requiring construction of specific types of generation plants at higher cost, and
- increasing the costs of distributing, or limiting our ability to distribute, electricity and/or natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. The following sections describe applicable environmental regulations in more detail.

Policies and Other Impacts Related to Climate Change

Legal and policy changes responding to concerns about climate change, and the potential impacts of such changes, could have a significant effect on our business. Direct impacts of climate changes include, without limitation, variations in the amount and timing of energy demand throughout the year, variations in the level and timing of precipitation throughout the year, as well as variations in temperature, and the resulting impact on the availability of hydroelectric resources at times of peak demand as well as an increased risk of wildfire. Indirect impacts include, without limitation, changes in laws and regulations intended to mitigate the risk of, or alter, climate changes, including restrictions on the operation of power generation resources and obligations

Clean Energy Transformation Act

In 2019, the Washington State Legislature passed the CETA, requiring Washington utilities to eliminate the costs and benefits associated with coal-fired resources from their retail electric sales by December 31, 2025. This requirement effectively prohibits sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025. In addition, retail sales of electricity to Washington customers must be carbon-neutral by January 1, 2030 and requires that each electric utility demonstrate compliance with this standard by using electricity from renewable and other non-emitting resources for 100% of the utility's Washington retail electric load over consecutive multi-year compliance periods; provided, however, that through December 31, 2044 the utility may satisfy up to 20% of this requirement with specified payments, credits and/or investments in qualifying energy transformation projects.

As required under the CETA, in October 2021 Avista filed our first CEIP. Our CEIP is a road map of specific actions we proposed to take over the first four years (2022-2025) to show the progress being made toward clean energy goals and the equitable distribution of benefits and burdens to all customers as established by the CETA.

In June 2022, our CEIP was approved by the Washington Utility and Transportation Commission (UTC).

Some highlights of our approved plan include:

- Beginning in 2022, serving 40% of Washington retail customer demand with renewable (or zero carbon) energy, then increase this target to 62.5% by the end of 2025.
- Energy efficiency targets to reduce Washington retail customer load by approximately 2% over the next four years through incentives and programs to lower energy use without impacting the customer.
- A set of 14 CBIs to ensure the equitable distribution of energy and non-energy benefits and reduction of burden to all customers and Named Communities.
- A NCIF that will invest up to $5 million annually in projects, programs and initiatives that directly benefit customers residing in historically disadvantaged and vulnerable communities.

While the CEIP represented our objectives when filed, it is subject to change in the future as circumstances warrant including direct input from the UTC. We are required to file a CEIP every four years.

Emissions Performance Standard

Washington applies a GHG emissions performance standard to electric generation facilities used to serve retail loads, whether the facilities are located within Washington or elsewhere. The emissions performance standard 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 have emission levels higher than 925 pounds of GHG per MWh. The Washington State Department of

Commerce reviews the standard every five years. The most recent review was completed in 2024 and a new rate of 875 pounds CO_2e per MWh will be adopted in October 2024.

Clean Air Act (CAA)

The CAA creates numerous requirements for our thermal generating plants. Colstrip, Kettle Falls, Coyote Springs 2, and Rathdrum CT all require CAA Title V operating permits. Boulder Park, Northeast CT and other operations require minor source permits or simple source registration permits. We have secured these permits and certify our compliance with Title V permits on an annual basis. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. Avista actively monitors legislative, regulatory and other program developments of the CAA that may impact our facilities.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash. Colstrip produces CCRs. The CCR rule has been the subject of ongoing litigation. In August 2018, U.S. Court of Appeals for the D.C. Circuit struck down provisions of the rule. In December 2019, a proposed revision to the rule was published in the Federal Register to address the D.C. Circuit's decision. 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 along with existing state obligations expressed through the 2012 Administrative Order on Consent (AOC) with the Montana Department of Environmental Quality (MDEQ). These requirements continue despite the 2018 federal court ruling.

The AOC requires MDEQ to review Remedy and Closure plans for all parts of the Colstrip plant through an ongoing public process. The AOC also requires the Colstrip owners to 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. Avista is responsible for our share of two major areas: the Plant Site Area and the Effluent Holding Pond Area. Generally, the plans include the removal of boron, chloride, and sulfate from the groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system to convert the facility to a dry ash storage. Our share of the posted surety bonds is $16.8 million. This amount is updated annually, with expected obligations decreasing over time as remediation activities are completed.

Washington Climate Commitment Act

The CCA, and its implementing regulations, established a cap-and-invest program to reduce GHG emissions and achieve the GHG limits previously established under Washington State law. The final rules implement a cap on emissions, provide mechanisms for the sale and tracking of tradable emissions allowances and establish additional compliance and accountability measures. The state issues allowances necessary to serve our Washington retail electric load; off-system wholesale sales may result in additional obligation costs. The CCA also directly impacts on our Idaho electric operations as it applies to wholesale power sales delivered to Washington or power generated in Washington for Idaho customers. In May 2023, a "lesser-than" model was approved for use in calculating the allowances needed for compliance that assumes hydroelectric or other renewable generation is first used for wholesale sales, therefore reducing the number of allowances required. Annually, the model and its resulting calculations must be certified by an independent third party and submitted to the Washington Department of Ecology (Ecology) for approval. If the independent third party or Ecology disagrees with the approach or any of the calculations, it could result in a change to the number of allowances needed for compliance and could result in changes to anticipated costs for our electric operations. For Washington electric, we are allowed to defer any incremental costs associated with the CCA in accordance with our regulatory accounting order; however, in Idaho we are not allowed to pass any costs associated CCA compliance to Idaho customers.

EPA Regulations for Power Plants

On April 25, 2024, the EPA released a package of final regulations addressed to electric generation facilities. These include:

- Greenhouse gas regulations for new natural gas-based turbines and existing coal-based units, pursuant to section 111 of the CAA. This rule finalizes (a) the repeal of the Affordable Clean Energy rule; (b) guidelines for GHG emissions from existing fossil fuel-fired steam generating electric generating units; and (c) revisions to existing performance standards for new, reconstructed or heavily modified fossil fuel-fired stationary combustion turbine electric generating units.

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule). The ELG Rule applies to wastewater discharges from coal-based generating units and establishes pollution control requirements. The Rule builds upon the 2015 and 2020 ELG Rules. It includes a subcategory of requirements for coal plants retiring or repowering by the end of 2028 and provides additional compliance pathways for coal plants retiring by the end of 2034.

- Updated Mercury and Air Tox Standards, pursuant to section 112 of the Clean Air Act (MATS Rule). The MATS Rule sets emissions limits for filterable particulate matter for coal-based generating units. The Rule reduces those limits from the standards that were originally set in 2012.

- Disposal of Coal Combustion Residuals from Electric Utilities – Legacy CCR Surface Impoundments (CCR Rule). The CCR Rule builds on 2015 regulations, the rule applies to active power plants disposing coal combustion residuals in surface impoundments or landfills, by regulating inactive surface impoundments at inactive power plants and CCR management units at active and inactive power plants.

We are in the process of analyzing each of these rules to assess the impact, if any, it may have on our existing generating units, including Colstrip and/or our natural gas-fired generating units. At this time, there are no indications that the implementation of these rules would impact our agreement to transfer our Colstrip ownership to NorthWestern on December 31, 2025. Along with the other owners (including the operator), we have assessed the CCR Rule and believe there will not be a material change to our asset retirement obligation for Colstrip.

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code requiring most new commercial buildings and large multifamily buildings to install all-electric space heating. An amendment to the code allows natural gas to supplement electric heat pumps. In addition, in November 2022, the SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heat source.

Both the commercial and residential building and energy codes were the subject of legal challenges in both Washington State Superior Court (the State Action) and in the Federal District Court for the Eastern District of Washington (the Federal Action). In the Federal Action, (Avista was a party), the plaintiffs challenged the amendments on the grounds that they were preempted by the federal Energy Policy and Conservation Act (EPCA), citing the Ninth Circuit's decision in California Restaurant Association v. Berkeley (the Berkeley Decision), which involved similar restrictions on the use of natural gas in new construction in Berkeley, California.

In May 2023, the SBCC voted to delay the effective date of the code amendments and commenced an emergency rulemaking process to evaluate additional amendments to the code considering the Berkeley Decision. As a result of this action, in July 2023, the Federal District Court declined to issue a preliminary injunction to prevent the amendments from taking effect. The plaintiffs in the Federal Action subsequently dismissed the action, without prejudice to their ability to refile after the SBCC rulemaking process is complete.

The SBCC has since voted to approve revised residential and commercial energy regulations to continue to require new residential and commercial buildings in Washington to use electricity as the primary heat source. Considering this action, the plaintiffs in the State Action amended their complaint to challenge the new regulations. The State Action remains pending.

In May 2024, Avista, along with Cascade Natural Gas Corporation, Northwest Natural Gas Company, and a coalition of homebuilders, heating unit dealers and other parties, filed a lawsuit challenging the approved building codes on the grounds that they are preempted by EPCA. The lawsuit was filed in the United States District Court for the Western District of Washington. This lawsuit remains pending.

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 CT, Lancaster, Northeast and Rathdrum. Table 4.10 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.

Table 4.10: 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

5. Resource Need Assessment

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 Washington's clean energy goals, as well as other applicable policies. This chapter presents the long-term load and resource position through 2045to determine Avista's projected resource requirements. Notwithstanding future resource changes, there are several fundamental changes to Avista's Loads & Resources (L&R) since the 2023 IRP, including the following developments:

- A 30-year Power Purchase Agreement (PPA) (97.5 MW) with Clearwater Wind will be online in 2024.
- Stimson Lumber (5.8MW), a Qualifying Facility (QF) located in Plummer, Idaho closed in 2024.
- A new Washington industrial customer increased load by 34.3 aMW beginning in August 2024.
- Three Columbia Basin Hydro contracts begin in 2025 totaling 105.8 MW of capacity.
- A 5% slice (87.5 MW) of the Chelan PUD PPA comes online in 2026.

Section Highlights

- Avista's Planning Reserve Margin (PRM) requirement is 24% in the winter and 16% in the summer.
- Avista's first long-term capacity and energy resource deficiency begins in January 2030.
- The Western Resource Adequacy Program's (WRAP) qualifying capacity credits (QCC) are used for Avista's resource capacity position.
- Under normal weather conditions, Avista has sufficient clean energy resources to meet its projected Washington's Clean Energy Transformation Act (CETA) targets through 2034.

Capacity Requirements

Avista must plan for 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. Under the PRM requirements, utilities are obligated to carry more generating capacity to address uncertainty and meet forecasted peak demand.

On average, reserve margins increase customer rates as compared to resource portfolios without reserve margins due to the extra cost of carrying rarely used generating capacity.

Traditionally, reserve resources have the physical capability to generate electricity, but most have higher operating costs, thus limiting revenue and dispatch. A balance must be achieved between carrying enough capacity to address potential events and the cost of carrying the unused capacity.

Prior to the development of the WRAP, Northwest electricity providers were operating without an industry-standard reserve margin level, as it is difficult to enforce standardization across systems with varying resource mixes, system sizes, and transmission interconnections. Although the North American Electric Reliability Council (NERC) defines reserve margins at 15% for predominately thermal systems and 10% for predominately hydroelectric systems, it does not provide an estimate for energy-limited hydroelectric systems such as Avista's. The WRAP is still in a non-binding trial phase, so Avista cannot count reliably on other utilities meeting their reserve margin requirements.

In prior IRPs prior to 2023, a PRM of 16% in the winter months and 7% in the summer months plus operating reserves and regulation requirements resulted in a total reserve margin of 24.6% in the winter months and 15.6% in the summer months. Those margins were derived from a study of resources and loads using 1,000 simulations of varying weather for loads, thermal generation capability, forced outage or derates on generation, water conditions for hydroelectric plants, and wind generation. The reserve margins ensure Avista's system can meet all expected load in 95% of the simulations, or a 5% Loss of Load Probability (LOLP).

To align its PRM methodology with the WRAP, the 2023 IRP used a 22% PRM in the winter and a 13% PRM in the summer along with reducing resource capabilities to account for outages and other derates by using the WRAP's QCC methodology. Avista did not conduct any additional reliability analysis to validate the resulting PRM would result in a 5% LOLP due to the fact the region would be resource sufficient if all utilities met their WRAP targets.

Avista conducted a reliability analysis for the 2025 IRP to ensure the planning margin creates an adequate system. Avista developed a LOLP study using its Avista Resource Adequacy Model (ARAM)[44] to determine the ability of its system to meet load and reserves each hour when subjected to 1,000 iterations with different combinations of water years, load, temperature, maintenance, forced outages, and VER production. The model optimizes storage hydro projects within parameters of each project's FERC license. This allows a realistic representation of the hydro system's capability to meet load. This study utilized the current expected portfolio of load and resources in 2030 along with the ability to purchase up to 330 MW from the market. Avista conducted multiple studies adding capacity resources (i.e., natural gas turbine) to achieve a 5% LOLP (see Table 5.1). The result of this analysis indicates a need of 50 MW by 2030 and infers a

[44] ARAM is an Excel-based model using VBA code and Excel's linear optimization add-in What's Best!

24% planning margin in the winter months to be resource adequate. The summer months reflect minimal resource adequacy shortfalls due to existing resource flexibility and the addition of the Columbia Basin Hydro projects. To ensure enough resource adequacy, Avista is using a summer planning margin based on its single largest contingency resource as a percentage of load. The largest single contingency is Coyote Springs 2 at 16% of summer peak load. The new study identifies a slightly larger PRM than the 2023 IRP value for winter months. Much of this change is due to accounting for reserves Avista must hold to participate in the Western Energy Imbalance Market (EIM) due to its renewable energy fleet. In addition to LOLP there are 5 other metrics used to evaluate reliability. The following defines how each is calculated[45]:

- **LOLP** – *Loss of Load Probability*: Calculated by counting the number of iterations where there is unserved load or unmet reserves and dividing by the total number of iterations. This metric can be used to determine the probability or likelihood of events due to insufficient capacity.
- **LOLE** – *Loss of Load Expectation:* Calculated by counting the days where there is unserved load or unmet reserves and dividing by the total number of iterations. The majority of entities conducting LOLE studies primarily use it to establish resource adequacy criteria. Industry standard is 0.1 days per year LOLE.
- **LOLEV** – *Loss of Load Expected Events*: Calculated by counting the number of consecutive blocks of unserved load or unmet reserves and dividing by the number of iterations. The LOLEV metric is useful in systems that are concerned with the frequency of events, regardless of duration or magnitude.
- **LOLH** – *Loss of Load Hours:* Calculated by summing the number of hours with unserved load or unmet reserves and dividing by the total number of iterations. The LOLH metric is computed by a large number of entities in North America. However, only one entity uses this metric as a reliability criterion, with their criterion set a 2.4 hours per year.
- **EUE** – *Expected Unserved Energy:* Calculated by summing all the unserved MWhs over the study period and dividing by the number of iterations. Two versions are presented, one with unmet reserves and one without. EUE is useful in estimating the size of the loss of load events so planners can estimate the cost and impact of the loss of load events.

[45] Reliability metric information from the NERC, Probabilistic Adequacy and Measures Report, July 2018

Table 5.1: 2030 Resource Adequacy Study

Metric	2030 without New Resources	2030 with 30 MW New Resources	2030 with 50 MW New Resources
LOLP	6.9%	5.5%	5.1%
LOLE	0.23	0.16	0.10
LOLH	2.59	1.92	1.56
LOLEV	0.50	0.40	0.33
EUE (with reserves)	488	338	268
EUE (without reserves)	468	325	256

Western Resource Adequacy Program

In response to the growing penetration of renewable variable energy resources and retirements of thermal generation in the West, the Western Power Pool (WPP) initiated an effort in 2019 to understand capacity issues in the region and identify potential solutions. The product of these efforts resulted in the WRAP. The WRAP's purpose is to leverage the 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:

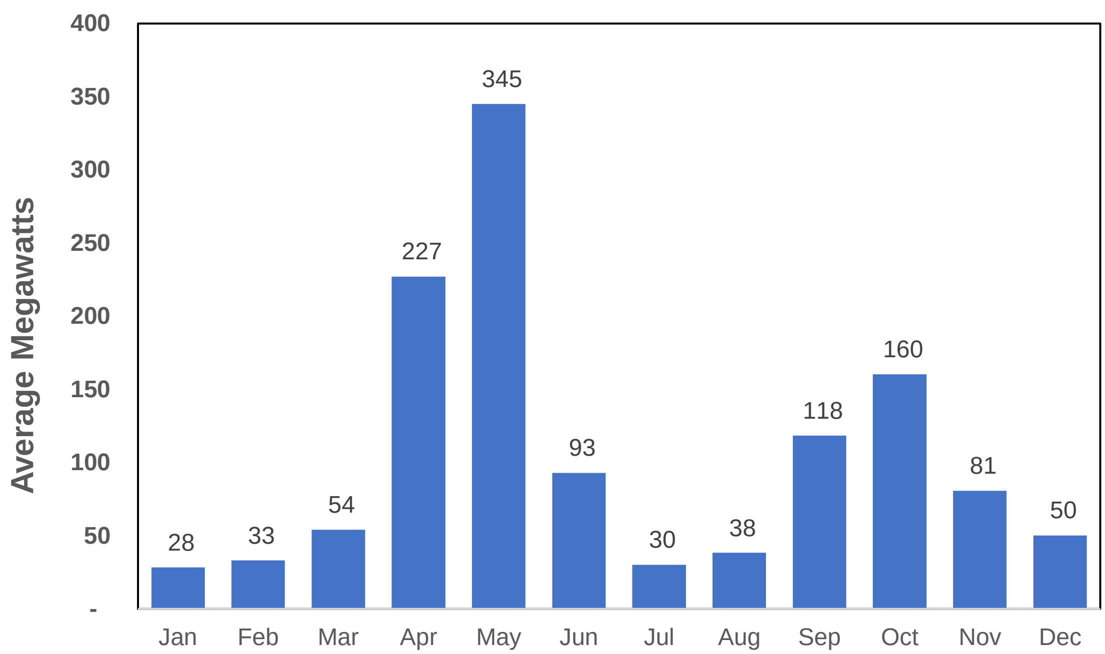
> *The WRAP leverages the existing bilateral market structure in the West to develop a resource adequacy construct with two distinct aspects: (1) a Forward Showing Program through which WPP forecasts Participants' peak load and establishes a Planning Reserve Margin ("PRM") based on a probabilistic analysis 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 resource adequacy planning and compliance framework where program participants voluntarily join. However, once committed, utilities are obligated to comply with requirements or be fined for non-compliance. To demonstrate compliance with the WRAP's Forward Showing Program (FSP), a participant must demonstrate its QCCs for resources and contracts are equal to or greater than peak demand, plus the assigned monthly PRM and less demand response programs. 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 FSP for 2024 have been established and Avista has adequate resources to meet the requirement. The WRAP is continually updating its business practices to reflect best practices and updated data from historical operations.

Maintenance Planning

Avista generating units require periodic maintenance over the planning horizon. The challenge is forecasting when and what units will be unavailable due to future maintenance needs. Avista includes an adjustment to its peak planning forecast to account for unit maintenance using a combination of historical outages and a forecast of routine maintenance schedules. Avista's forecast shown in Figure 5.1 is a total of the maintenance from all plants on average. This amount is in additional adjustment above the PRM Avista includes when calculating its capacity position. Most maintenance occurs in the spring and fall months when loads are lower, while hydro maintenance is at higher levels in the spring allowing thermal units to go on maintenance due to extra generation supply.

Figure 5.1: Maintenance Adjustment for Capacity Planning



Avista's Capacity Need Assessment

Based on Avista's analysis of resource adequacy, Avista is temporarily short capacity in 2026 until a sale contract expires. After this contact expires, Avista is in a near balanced position until 2030. In 2030, Avista expects between load growth, retirement of the Northeast CT, and expiration of a long-term PPA the utility will be deficient on a permanent basis until new resources are acquired. Figure 5.2 illustrates the winter capacity need by comparing the controlled resources in the blue bars compared to the peak load and PRM in the black line. Avista's summer position is similar to winter as the first permanent resource deficit also begins in 2030 and is shown in Figure 5.2.

Figure 5.2: Winter One-Hour Peak Capacity Load and Resources Balance

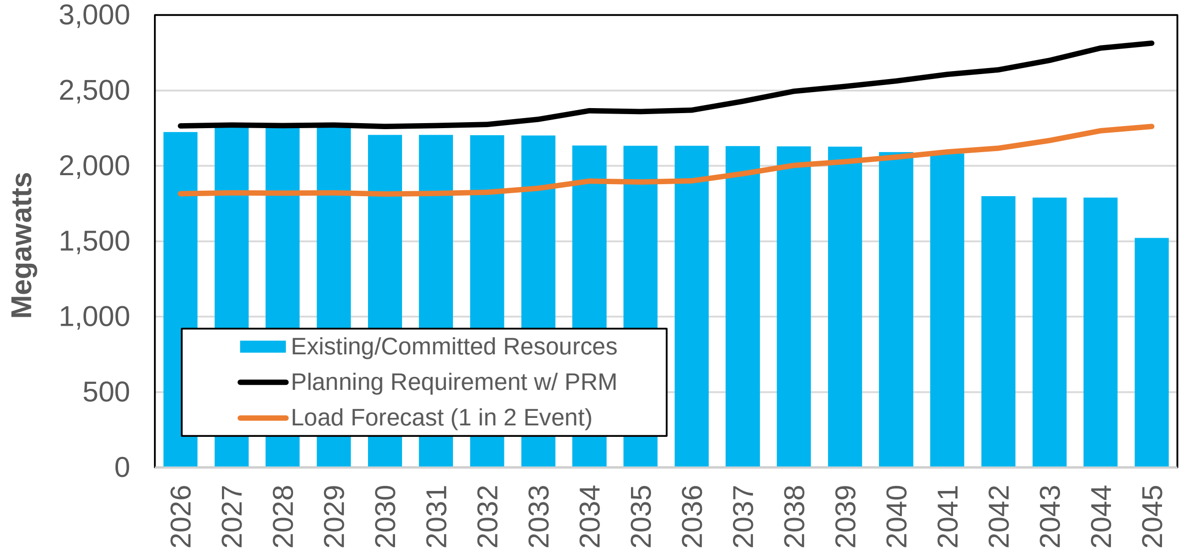
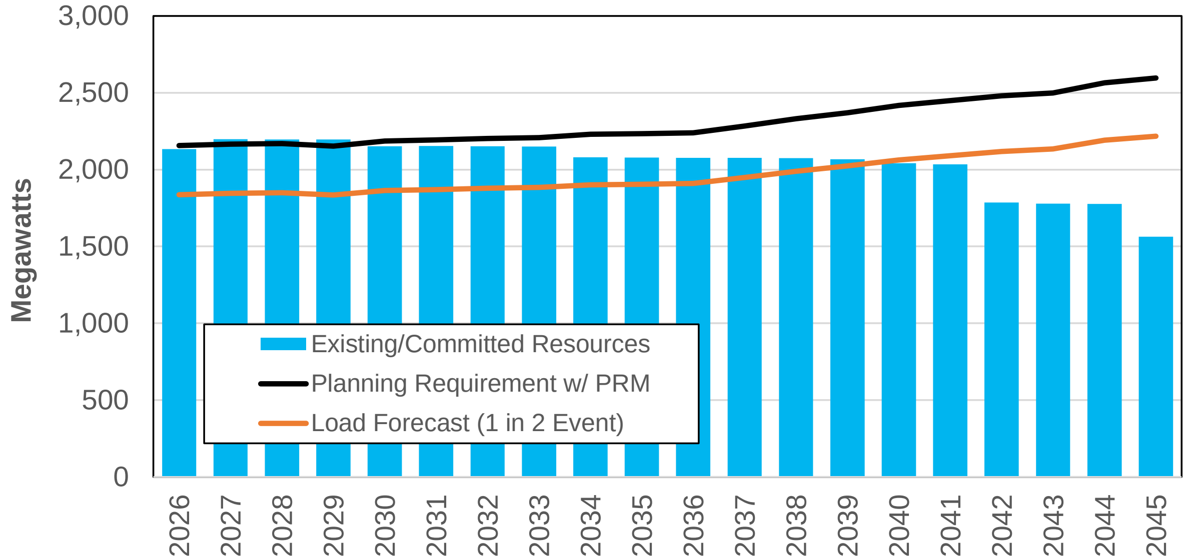


Figure 5.3: Summer One-Hour Peak Capacity Load and Resources Balance



Energy Requirements

In contrast to peak planning, energy planning determines the need based on customer demand with a time duration element. Avista evaluates energy planning on a monthly target basis for meeting customer demand, renewable targets, and evaluating generation risks. In the transition to renewable energy resources with differing energy delivery time periods, Avista is now using monthly energy requirements. This ensures Avista does not acquire too much energy in certain periods such as spring and not enough in higher expected load months such as August or January. This monthly planning creates significant generation length in spring and fall months as renewable resources typically do not only supply energy in the months needed.

The monthly energy analysis requires additional steps beyond capacity planning to account for 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 2026 to 2045 period. A discussion of monthly demand is provided in Chapter 3. Table 5.2 details how monthly generation for each resource type is evaluated.

Table 5.2: Monthly Energy Evaluation Methodologies

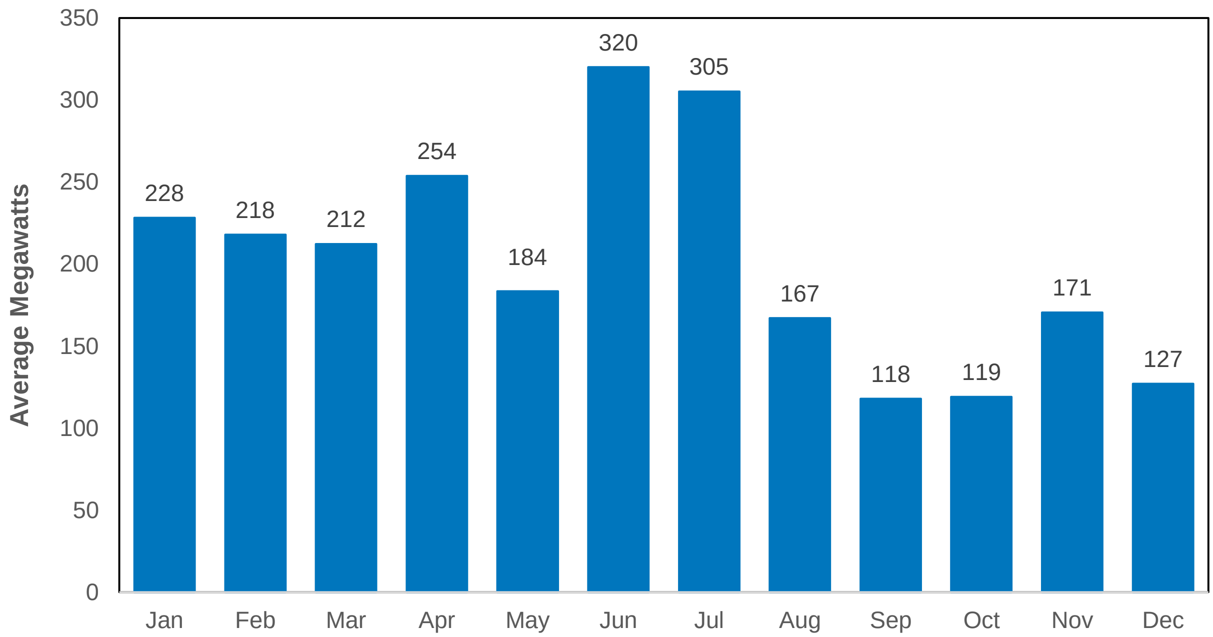
Resource Type	Evaluation Methodology
Biomass	Unit capacity reduced by a percentage according to planned and forced outage rates.
Natural Gas Combined Cycle	Unit capacity adjusted for monthly ambient average temperature and reduced by a percentage according to planned and forced outage rates and any runtime 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.

Energy Risk/Contingency Evaluation

In addition, hydro generation and load both include the predicted impact of forecasted temperature changes and risk evaluation includes variability in all renewables rather than just hydro. Energy planning is based on average conditions. The load forecast utilizes 20-year average weather conditions, 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. Avista adds a contingency adjustment to the load and resource balance evaluation to address this risk

Avista develops a monthly estimate of load and generation for each hydro, wind, and solar facility for weather conditions for each month between 1948 and 2019 for the contingency adjustment. Total generation is then subtracted from load for each month creating a monthly energy position of at-risk components of the portfolio. A distribution of the variability is created with this historically based data set, and Avista uses the 95th percentile of the monthly values as compared to the expected position. The result represents the energy necessary to meet the risk of above average loads occurring during periods of low hydro, wind, and solar production. The result of this analysis is shown in Figure 5.4. These energy quantities are added to the load forecast to account for the variability.

Figure 5.4: Energy Contingency Assumption



Net Energy Position

Avista's net energy position is determined by summing all generation rights from Avista's facilities and PPAs and subtracting obligations including forecasted monthly load, contracted sales, and accounting for the energy contingency. Table 5.3 presents net monthly energy positions for selected years.

Table 5.3: Net Energy Position

Month	2030	2035	2040	2045
January	-26	-69	-168	-866
February	22	46	-13	-733
March	170	184	81	-578
April	345	328	216	-310
May	706	692	581	101
June	518	501	355	-143
July	173	142	-11	-672
August	74	41	-96	-725
September	198	191	83	-533
October	170	164	55	-565
November	59	27	-85	-744
December	16	-2	-147	-836

Forecasted Temperature & Precipitation Analysis

The 2023 IRP first included future climate forecasts for estimating load and hydro generation and the 2025 IRP uses the same forecasts. The forecast is based on the climate analysis 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 (2018 and 2020) for the 2020-2100 study period utilizing downscaled global climate models (GCMs), hydrology and reservoir operation models to predict monthly river flows for locations throughout the Columbia River Basin, including all of Avista's hydroelectric facility locations. The RMJOC has not conducted any new analysis, nor has any other organization conducted similar analysis to replace the RMJOC dataset. Therefore the 2023 IRP dataset is being used in the 2025 IRP.

There is significant uncertainty in projecting future temperatures and precipitation and the subsequent 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 expected 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 following scenarios:

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

Table 5.4 provides a comparison of the temperature increases projected under the various scenarios.

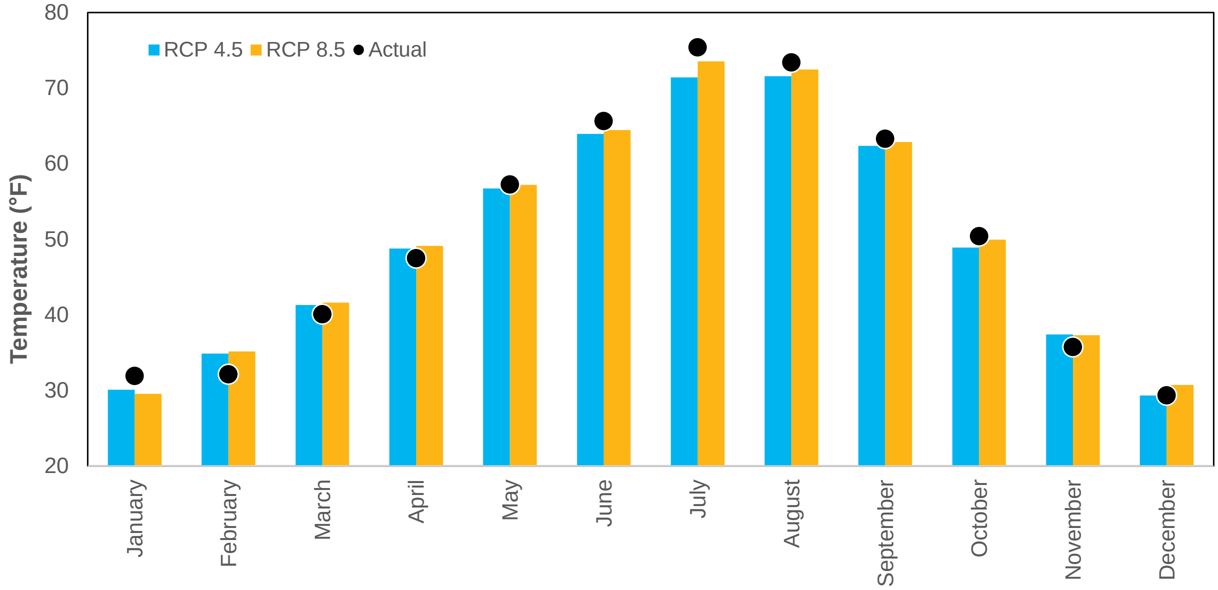
Table 5.4: Comparison of Temperature Increases by RCP

	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. Avista selected modeling results based on the RCP 4.5 for winter months and RCP 8.5 for summer months for load forecasting and RCP 4.5 for hydro forecasting. Avista chose this approach given:

- RCP 8.5 is at the high end of potential future GHG emissions,
- there are significant worldwide efforts to mitigate GHG emissions,
- the intermediate scenarios are similar during the IRP planning horizon,
- using RCP 8.5 for planning protects against higher summer temperatures,
- during time periods where both modeled and actual values are available, the RCP 4.5 and 8.5 have overestimated winter temperatures on average (except for January) but have underestimated summer temperatures for the Spokane region as shown in Figure 5.5.

Figure 5.5: Monthly Average Temperature RCP 8.5, RCP 4.5, and Actual 2020-2024



Hydro Forecasting

Utilizing a regression modeling relating flow to generation, Avista converted each of the 19 BPA-selected monthly river flow modeling combinations for Avista facilities. The median of the 19 modeling combinations was selected to represent generation at each facility for each specific month and year.

Avista 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 these 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 month and year over the planning horizon.

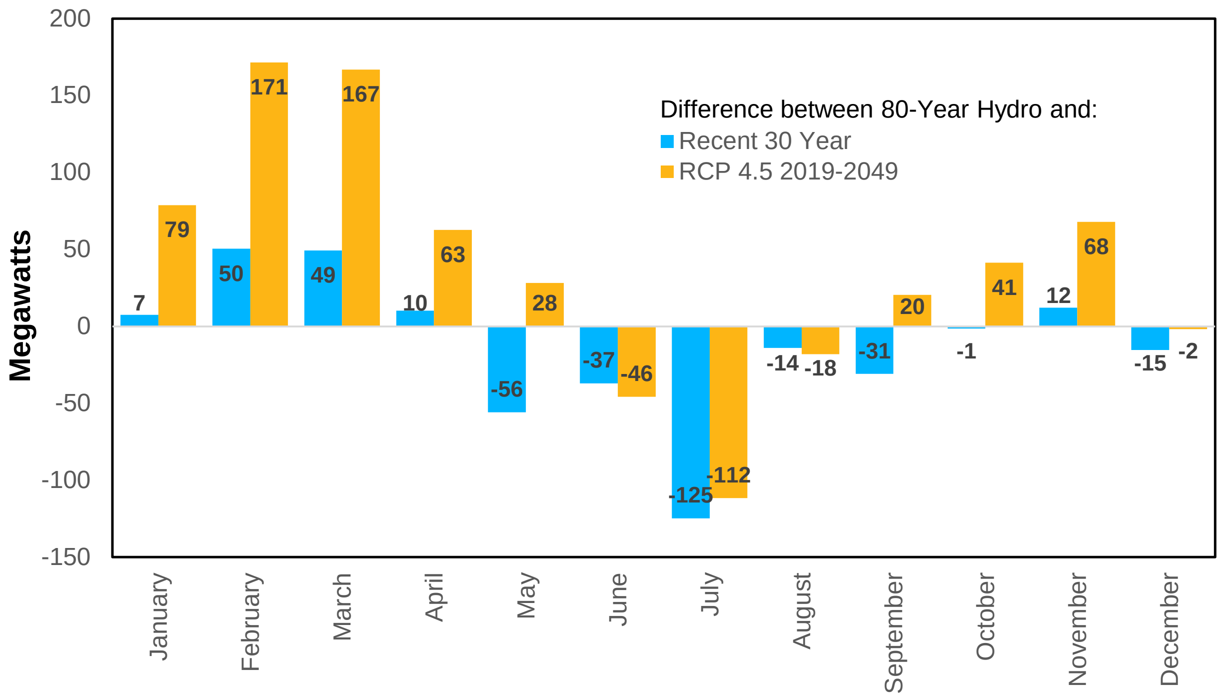
Prior IRPs used monthly hydro generation by estimating generation occurring under current operating parameters for each water year from 1929 to 2008 (80-year hydro record) and taking the median value for each month for each facility. In this analysis, Avista changed the methodology to use the median 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 5.5 and Figure 5.6 present the differences between the 80-year hydro record and 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 snowpack melt.

Table 5.5: Hydro Generation Forecast Comparison (aMW)

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



In addition to impacting hydro generation, warming temperatures will also impact demand. Specifically, where the forecast assumes 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 3.

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% of their energy from qualified renewables by 2020. Utilities must seek to acquire all cost-effective energy efficiency. In 2011, Avista signed a 30-year PPA for Palouse Wind to help meet the EIA goal. In 2012, an EIA amendment allowed Avista's Kettle Falls biomass generation to qualify for the goals beginning in 2016. More recently, Avista acquired the Rattlesnake Flat Wind, Adams Nielson Solar,[46] and Clearwater Wind III adding to qualified generation.

Table 5.6 shows the forecasted Renewable Energy Credits (RECs)[47] Avista needs to meet the EIA's renewable requirements and the qualifying resources within Avista's current generation portfolio. This table does not reflect the EIA REC banking provision allowing a single year of retainment of RECs. Avista uses this banking flexibility as needed to manage variation in renewable generation.

Table 5.6: Washington State EIA Compliance Position Prior to REC Banking (aMW)

	2026	2028	2030
Two-Year Rolling Average WA Retail Sales Estimate	726.8	739.7	739.7
Renewable Goal	109.0	111.0	110.9
Incremental Hydro	18.0	18.0	18.0
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
Clearwater Wind	41.9	41.9	41.9
Excess Renewable Excess before rollover RECs	**93.7**	**91.7**	**108.0**

Washington State's Clean Energy Transformation Act

CETA requires Washington State electric utilities to serve 100% of Washington retail load with renewable and non-emitting electric generation by 2045. Beginning in 2030, at least 80% of generation must be from renewable and non-emitting electric generation and up to 20% can be met with alternative compliance options including alternative compliance

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

[47] These RECs are qualifying RECs within Avista's system. For state compliance purposes, Avista may transfer RECs from one state's allocation shares to another at market prices. Avista may also sell excess RECs to reduce customer rates.

payments, unbundled RECs, or investing in energy transformation projects. CETA requires the Washington Utilities & Transportation Commission (UTC) to adopt rules for implementation. In this IRP, the 20% alternative compliance component is assumed to decrease to zero in 5% increments by 2045.

A remaining unknown consideration for compliance with CETA relates to the UTC's determination of compliance with RCW 19.405.030(1)(a) defining "use" of clean energy. The UTC has an ongoing rulemaking proceeding[48] where it is still determining the interpretation of "use" in CETA. While CETA rulemaking is still in development, Avista's 2021 Clean Energy Implementation Plan (CEIP) includes compliance targets approved by the UTC for 2022-2025. Avista's 2021 CEIP was conditionally approved in Order 01 of Docket UE-210628. The 2021 CEIP does not include a commitment or approved targets for the 2026-2029 or 2030-2044 periods. Between 2030 and 2044, all generation used to serve Washington electric retail load must be greenhouse gas neutral, while up to 20% 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 5.7 presents the approved interim targets for 2022-2025 and preliminary targets through 2045.

Table 5.7: CETA Compliance Target Assumptions

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.		

Multijurisdictional utilities face unique challenges with CETA compliance as resource costs and benefits are allocated to each state using a ratio derived from load. The IRP proposes resource selections based on each state's policies, however, when resources are added to the system, the other state still receives its share of the costs and benefits.

[48] Docket UE-210183.

Until a new allocation methodology is approved by each Commission, Avista makes the following assumptions:

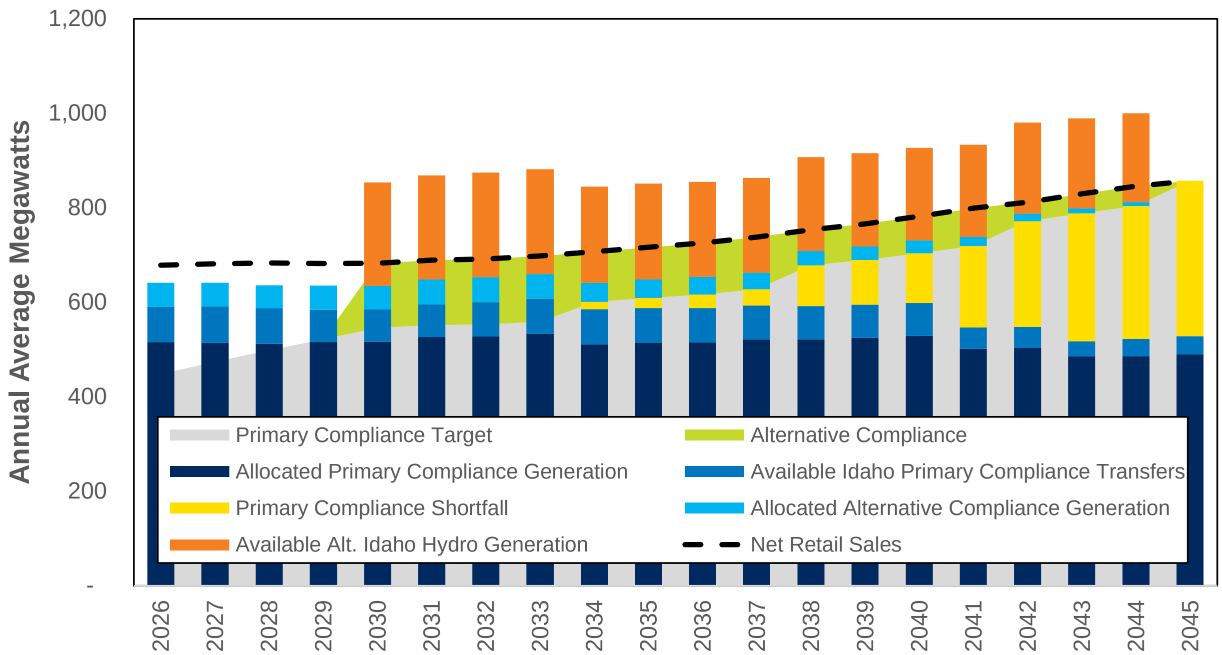
- Qualifying clean energy is determined by procurement and delivery of energy to Avista's system.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary customer programs such as Solar Select.
- Voluntary customer REC programs, such as Avista's My Clean Energy™ program, do not qualify toward the CETA standard.
- Compliance generation includes:
    - Washington's share of hydro generation operating or contracted before 2020 (legacy hydro),
    - All wind, solar, and biomass generation in Avista's portfolio. Nonpower attributes or RECs 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 in Washington.
    - Newly 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[49] when purchasing the nonpower attributes from Idaho to Washington.
- Avista is not planning to use Idaho's share of legacy hydroelectric to meet Washington's clean energy goals prior to 2030, however actual compliance may include them due to variability in clean resource availability (e.g., for a low water year). Avista may include these hydro resources toward alternative compliance if it is economic to acquire the renewable energy attributes.
- Avista uses total monthly generation to estimate if clean energy counts toward the compliance target or alternative compliance. If Washington's clean energy generation total is greater than its "net retail load," excess generation is applied toward alternative compliance. However, all generation below "net retail load" counts as compliant clean energy to meet the 4-year CEIP targets such as 80% 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 5.7. The analysis demonstrates Avista has enough qualifying resources to meet primary compliance targets through 2033 using this methodology but will need additional energy for the 2034-2038 CEIP period. Depending on the outcome of the clean energy "use" rules, the shortfall could change as well as actual production due to weather outside of average conditions. For alternative compliance, between generation exceeding retail load and legacy hydro energy from Idaho, Avista has enough qualifying energy to meet this requirement through

[49] Such as Palouse Wind and Kettle Falls with historical precedence of transferring between states for EIA compliance.

2044. (Alternative compliance is not required after 2045 by statute, but rather a goal of serving 100% of demand with clean energy). The light blue bar in Figure 5.7 represents the amount of energy transferable from Idaho for primary compliance. Avista's modeling selects this energy only if new generation is more expensive.

Figure 5.7: Washington State CETA Compliance Position



Reserves and Flexibility Assessment

Avista released a Request for Information (RFI) for a Variable Energy Resource (VER) integration study in February 2022. Energy Strategies was selected to develop a framework to quantify the incremental integration cost of a range of potential VER penetration levels as informed by Avista's 2023 IRP Preferred Resource Strategy (PRS) to serve Avista's projected load.

This VER integration study supports Avista's efforts toward carbon-neutrality goals and providing reliable, lowest cost energy. A VER integration study was performed in 2007 and updated in 2014, but changes regarding resource capital costs, Avista's current and projected resource mix, Avista's participation in the Western EIM, and state policies requiring greater VER penetration, all warranted an updated study.

Phase I

Integration cost is primarily driven by the need to hold higher levels of operating reserves caused by the variability and uncertainty of VER production. Energy Strategies developed data inputs for 12 VER scenarios for modeling in Avista's Decision Support System (ADSS) production cost model. These 12 production profiles were based on likely development locations informed from past generation proposals and utilized National Renewable Energy Laboratory's (NREL) Wind Integration National Dataset (WIND) and Solar Integration National Dataset (SIND) as well as National Solar Radiation Database (NSRDB) datasets to compile site-specific proxy production and forecast profiles for each VER site. Energy Strategies calculated reserve levels utilizing 2021 actual operations with confidence intervals via statistical analysis based on seven historical weather years. Energy Strategies also evaluated the impact of Western EIM on reserves and determined the diversity savings benefit to be approximately 50%. The results of their study are shown in Figure 5.8.

VER Integration Cost Estimates

Avista utilized its Avista Decision Support Software (ADSS) product cost model to run the 12 VER scenarios (13 including the existing scenario) to calculate integration costs as well as high and low sensitivities. Energy Strategies' Phase 1 reserve amounts were adjusted for diversity benefit and used as constraints in the ADSS model. The resulting integration costs per $kW-month and $/MWh for the scenarios and sensitivities are shown in Table 5.8.

Figure 5.8: Flexible Reserves Required by VER Future

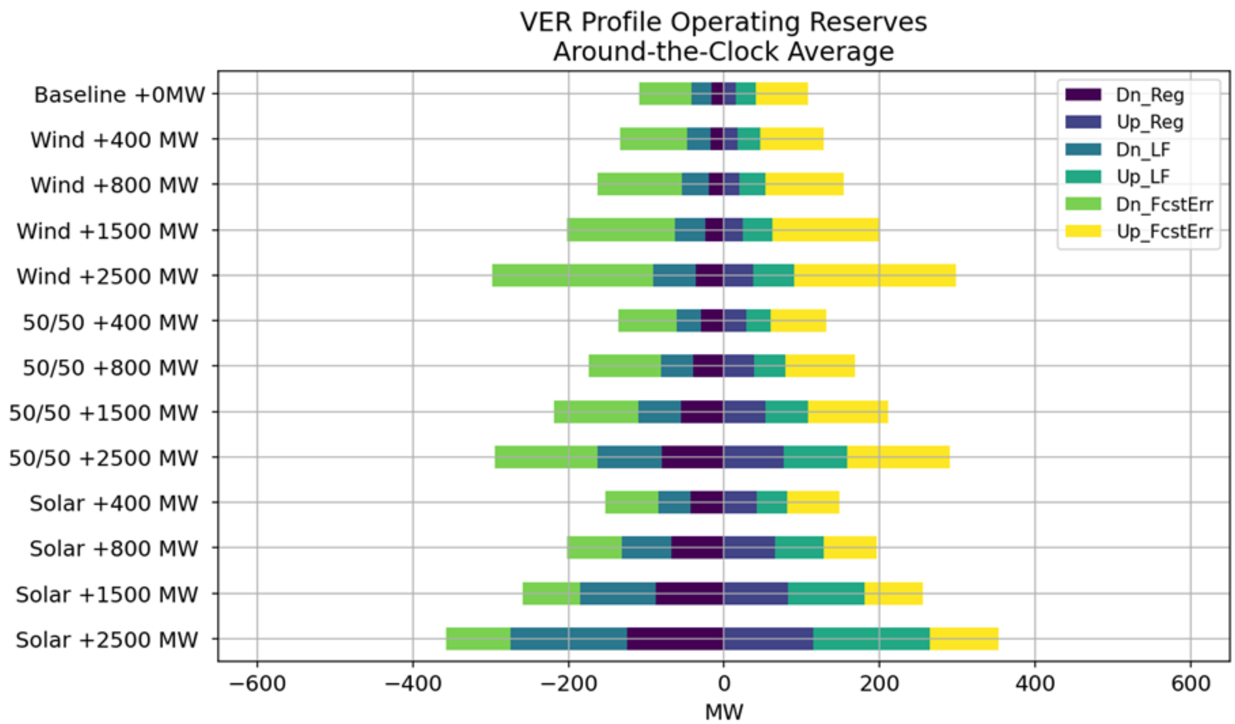


Table 5.8: VER Study Results

Scenario	Integration Cost ($/kW-month)			Integration Cost ($/MWh)		
	Base	High	Low	Base	High	Low
Existing Portfolio	0.19	0.40	0.15	0.54	1.12	0.44
50/50 + 400 MW	0.16	0.34	0.09	0.56	1.19	0.32
50/50 + 800 MW	0.19	0.39	0.11	0.69	1.43	0.40
50/50 + 1,500 MW	0.17	0.33	0.10	0.70	1.41	0.43
50/50 + 2,500 MW	0.22	0.39	0.20	0.98	1.74	0.90
Solar + 400 MW	0.12	0.26	0.07	0.40	0.85	0.23
Solar + 800 MW	0.12	0.25	0.07	0.43	0.90	0.25
Solar + 1,500 MW	0.11	0.23	0.07	0.43	0.87	0.27
Solar + 2,500 MW	0.21	0.33	0.22	0.84	1.33	0.90
Wind + 400 MW	0.22	0.48	0.13	0.89	1.90	0.50
Wind + 800 MW	0.27	0.56	0.16	1.21	2.50	0.70
Wind + 1,500 MW	0.25	0.48	0.19	1.25	2.44	0.94
Wind + 2,500 MW	0.85	1.21	0.79	4.92	7.05	4.56

Phase II

Energy Strategies validated the integration costs resulting from the ADSS modeling. In addition, a calculator for varying levels and combinations of VERs was created to aid in estimating integration costs for resource planning and selection. This work will be completed in the third quarter of 2024.

Capacity Planning for Reserves and Flexibility

When Avista joined the Western EIM, it required the company to maintain flex ramp reserves prior to the operating hour. Flex ramp reserve amounts are based upon historical load, solar, and wind variations. As VERs are added to the system, if all other assumptions remain constant, Avista will need to increase the amount of flexible ramp resources it must carry. In addition to the flex ramp requirement, Avista must also carry operating reserves in the event of a generator outage. Other reserves the utility must maintain handle generation ramping hour-to-hour. Fortunately, for Avista, the hydro system provides much of its reserve capability along with its natural gas peaking fleet. When selecting the resource strategy, the model includes a requirement to carry enough reserves to meet the flexibility requirements using either existing resources or new resources. A summary of the flex ramp requirements assumed depending upon the new resources acquired are shown in Figure 5.8 as used in the integration cost estimate. For inclusion in the resource plan, Avista translated the finding from this study into an equation to calculate flexibility based on the amount of load and resources as follows:

Equation 5.1: Modeled Flex Ramp

Modeled Flex Ramp (MW) = 83.8 + Total Solar x 0.10 + Total Wind 0.12 + Load x 0.21

Natural Gas Pipeline Analysis

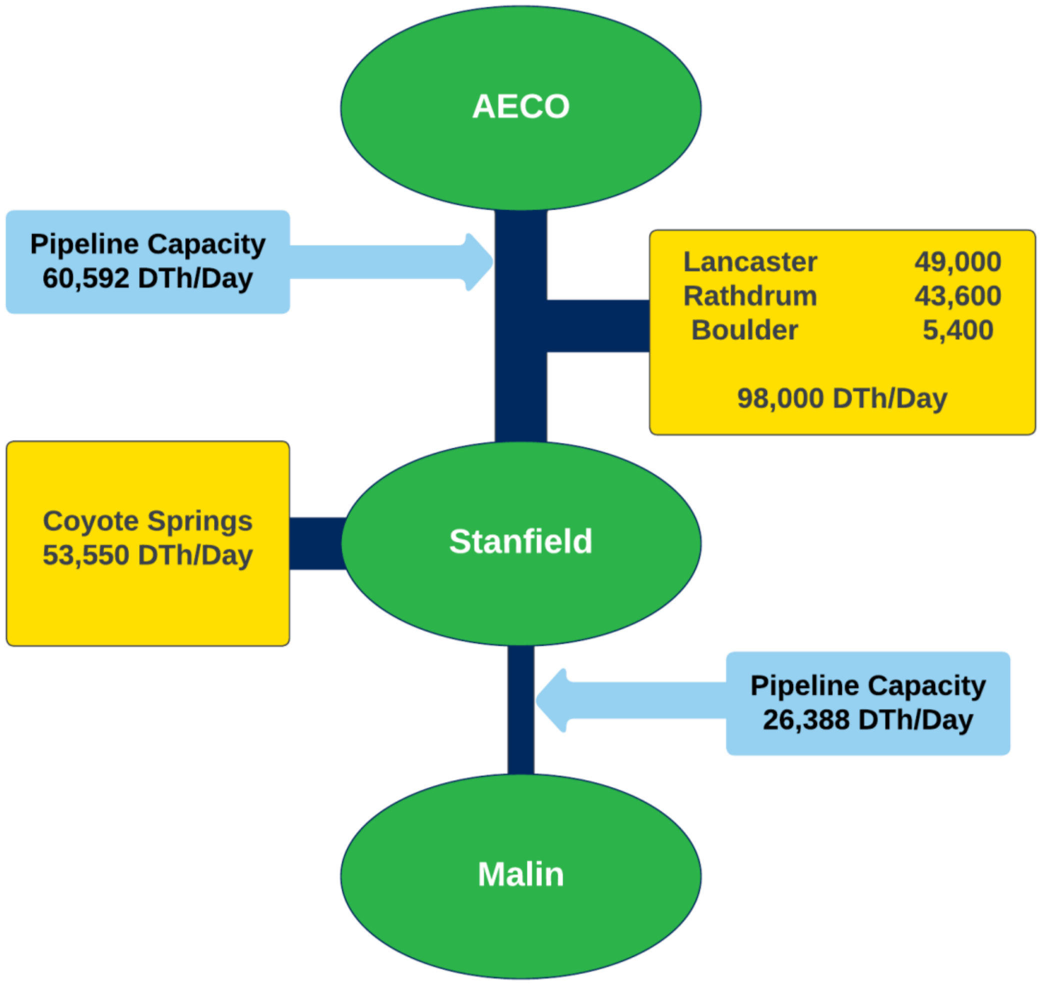
Avista transports fuel to its natural gas-fired generators using the Gas Transmission Northwest (GTN) pipeline owned by TC Energy (formally TransCanada). The pipeline runs between Alberta, Canada and the California/Oregon border at Malin, Oregon. Avista holds 60,592 dekatherms per day of capacity from Alberta to Stanfield, Oregon and controls another 26,388 dekatherms per day from Stanfield to Malin. Figure 5.9 below illustrates Avista's firm 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 148,342 dekatherms per day based on the average of the top five historical natural gas burn days of 2023 and 2024, as shown in Table 5.9.

Avista does not have firm transportation rights for the entirety of its natural gas generation capacity but rather relies on short-term transportation contracts to meet needs above its 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 to 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. Historically, when suppliers control the pipeline capacity, it has resulted in a pricing issue rather than a supply issue. In extreme winter conditions or if pipeline capacity is lost (as occurred in January 2024), the inability to control gas capacity could result in shutting off gas generation. Avista has identified three solutions to address this issue; 1) install on-site alternative fuel storage, i.e., fuel oil, 2) acquire or build new natural gas pipelines, or 3) develop regional Liquefied Natural Gas (LNG) storage. On-site fuel oil storage is possible for smaller natural gas turbines with modifications and air permit modifications. Either acquiring or building new natural gas pipelines is not a viable option. If Avista is going to solve this fuel supply risk, an LNG facility should be constructed. This solution could also alleviate pipeline delivery risk to the local gas delivery system.

Table 5.9: Top Five Historical Peak Day Natural Gas Usage (Dekatherms)

Date	Boulder Park	Coyote Springs 2	Lancaster	Rathdrum	GTN Total	Firm Rights
1/18/2024	4,573	51,540	46,806	45,931	148,849	60,592
1/30/2023	4,571	51,567	48,206	44,441	148,785	60,592
1/17/2024	5,349	51,455	45,273	46,651	148,728	60,592
2/16/2024	5,451	50,530	46,611	45,404	147,996	60,592
1/16/2024	5,372	51,939	43,781	46,260	147,351	60,592

Figure 5.9: Avista Firm Natural Gas Pipeline Rights



6. Distributed Energy Resource Options

Distributed Energy Resources (DERs) include energy efficiency, demand response, existing resources, and new resource options such as customer sited solar and energy storage. In WAC 480-100-605 DERs are defined 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.*

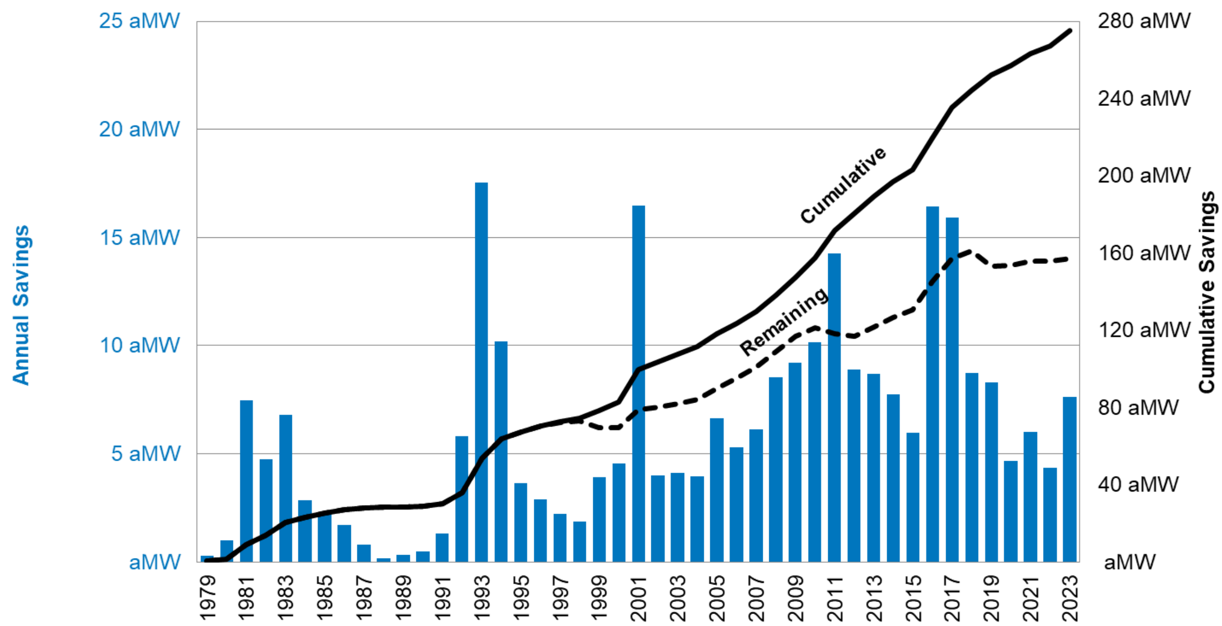
Section Highlights

- Energy efficiency programs currently serve 156 aMW of load, representing nearly 12.2% of customer demand.
- More than 3,000 energy efficiency measures and 16 demand response options are considered for resource selection.
- Avista's solar net metering program includes 4,433 customers generating with 29.9 megawatts of capacity.
- Community solar, roof-top solar, energy efficiency, demand response and distributed energy storage are options for utility resource selection.

Energy Efficiency

Avista's energy efficiency programs provide cost-effective opportunities for customers to save energy by replacing old equipment with better performing, energy efficient equipment. The energy efficiency programs offer a wide array of low-cost measures to our customers. Since 1978, Avista has acquired 275 aMW of energy efficiency. Currently 156 aMW of this savings remains as a load reduction due to our efforts becoming code or standard practice. Figure 6.1 illustrates Avista's historical electricity conservation acquisitions using an average 18-year measure life. The 18-year measure life accounts for the difference between the cumulative (solid black line) and online trajectories (dotted black line) where program savings is no longer counted as energy efficiency. Currently 156 aMW of energy efficiency programs serve customers, representing nearly 12.2% of 2023 customer load.

Figure 6.1: Historical Conservation Acquisition (System)



Avista provides energy efficiency and educational offerings to the (inclusive of low-income and named communities) commercial and industrial customer segments. Program delivery mechanisms include prescriptive, site-specific, regional, upstream, midstream, behavioral, home energy audits, market transformation, and third-party direct install options. Prescriptive programs provide fixed cash rebate 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 upgrades to lower energy efficiency or U-value windows.

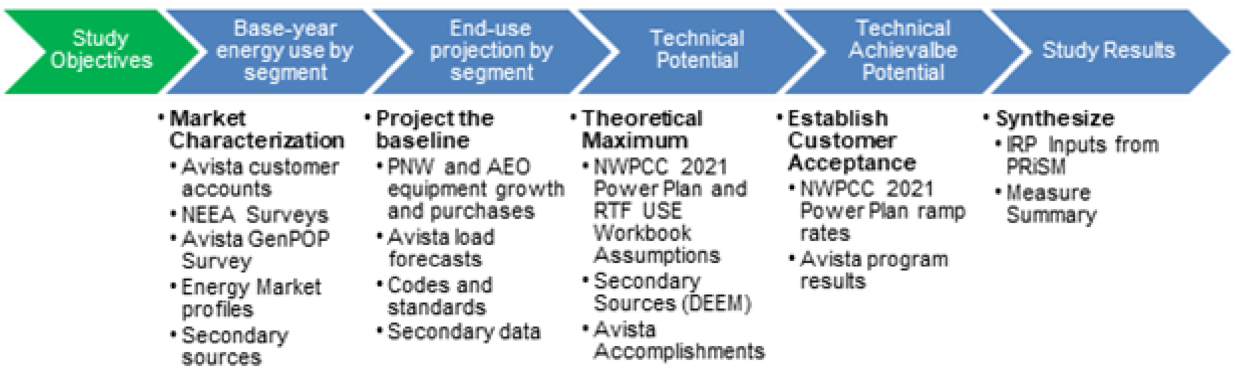
Site-specific programs, or customized offerings, provide cash incentives for cost-effective energy saving measures or equipment not meeting prescriptive rebate requirements. Site-specific programs require customized approaches for commercial and industrial customers because of the unique characteristics 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 multiple languages where possible) in the forms of education, outreach, and other resources to customers to encourage participation in efficiency programs and measures.

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 20-year potential for energy efficiency in accordance with the Energy Independence Act's (EIA) energy efficiency goals and provides data on resources specific to Avista's service territory for use in the resource selection process. 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 and list of energy efficiency measures is included in Appendix C.

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 estimated *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 steps shown in Figure 6.2 to assess and analyze energy efficiency and potential within Avista's service territory.

Figure 6.2: Analysis Approach Overview



AEG's CPA 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 2023 base year.
2. Develop a baseline projection of energy consumption and peak demand by sector, by segment and by end use for 2026 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 2026-2045.

Market Segmentation

The CPA considers Avista customers by Washington and Idaho service territories and by sector. The residential sector includes single-family, multi-family, manufactured homes, and low-income customers[50] 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.

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 2024 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 Northwest Power and Conservation Council's (NPCC or 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.

[50] The low-income threshold for this study is 200% 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.

Avista, through its PRiSM model, considers other performance factors for the list of more than 3,000 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.[51] The guide represents comprehensive national industry standard practice for specifying energy efficiency potential. As shown in Table 6.1, two types of potential results were specifically included in this study – technical potential and achievable technical potential by state.

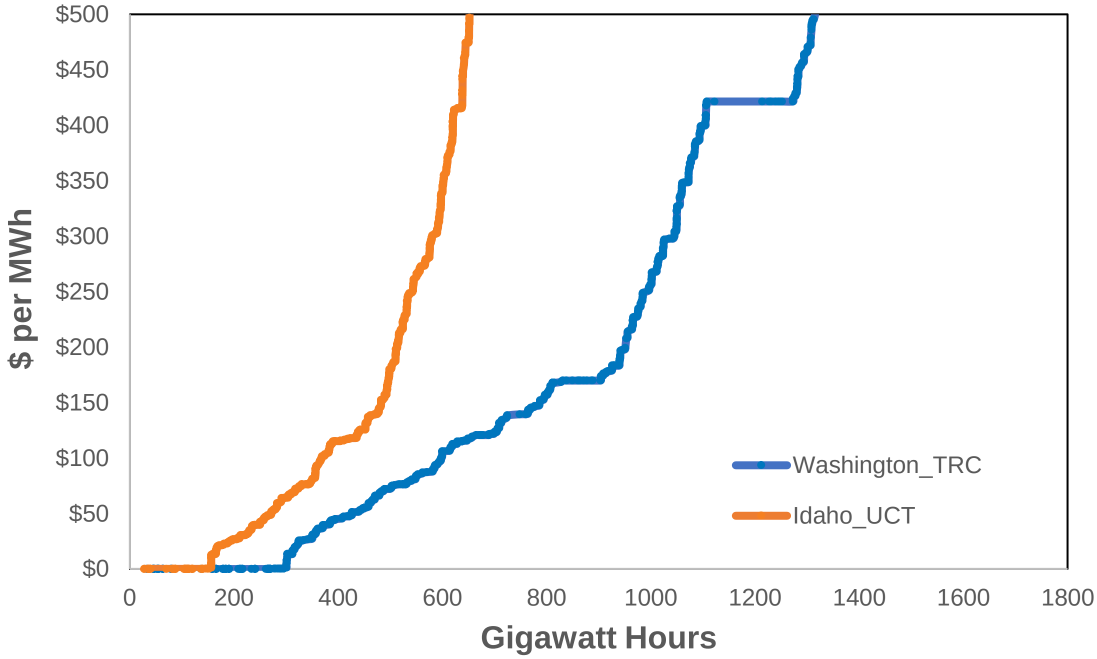
Table 6.1: Cumulative Potential Savings (Across All Sectors for Selected Years)

	2026	2027	2030	2040	2045
Technical Potential (GWh)	191.4	387.2	593.7	1,915.5	2,832.2
Washington	128.2	258.8	396.5	1,290.5	1,928.2
Idaho	63.1	128.4	197.2	625.0	904.0
Total Technical Potential (aMW)	**21.8**	**44.2**	**67.8**	**218.7**	**323.3**
Technical Achievable Potential	86.0	183.2	295.1	1,274.6	2,082.5
Washington	56.6	120.4	194.2	853.4	1,431.0
Idaho	29.4	62.8	100.9	421.2	651.6
Technical Achievable Potential (aMW)	**9.8**	**20.9**	**33.7**	**145.5**	**237.7**

Future programs must be cost effective to be selected for future implementation. Figure 6.3 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 150 GWh, then quickly rises. As for Washington, using the Total Resource Cost (TRC) method, there is "no cost" energy efficiency until reaching approximately 300 GWh, then linearly increases until around 1,100 GWh, then goes up exponentially. The amount of energy efficiency the model selects will be where the supply curve meets the avoided cost. For example, if Washington's avoided cost were $100 per MWh, then 600 GWh of energy efficiency would be selected. Avista uses a more sophisticated resource selection approach, considering 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.

[51] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. https://www.energy.gov/sites/default/files/2023-10/napee-vision_1.pdf

Figure 6.3: Jurisdiction Supply Curves



Technical Potential

Technical potential finds the most energy-efficient option commercially available for each purchase decision regardless of its cost. This theoretical case provides the broadest and highest definition of savings potential because it quantifies savings if all current equipment, processes, and practices in all market sectors were replaced by the most efficient and feasible technology. The technical potential case is provided for planning and informational purposes. Technical potential in the CPA is a "phased-in technical potential," meaning only the current equipment stock at the end of its useful life is considered and changed out with the most efficient measures available. Non-equipment measures, such as controls and other devices (e.g., programmable thermostats) phase-in over time, just like the equipment measures. All measures are implemented according to ramp rates developed by the Council for its 2021 Power Plan and apply to 100% of the applicable market.

Technical Achievable Potential

The technical achievable potential refines the technical potential by applying customer participation rates accounting 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% 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. These 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's economic potential 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's economic potential 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 offerings, including midstream 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 more than $2.3 million in Avista rebates in 2023 to offset the cost of implementing energy efficiency measures. All programs within the residential portfolio contributed 7,122 MWh to the 2023 annual first-year energy savings.

Low-Income Sector Overview

Currently Avista leverages the infrastructure of several network Community Action Agencies (CAAs) and one tribal weatherization organization to deliver energy efficiency programs for 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 energy efficiency measures beyond Avista's contributions. The agencies have 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, but not limited to seniors, low-income, and those in Named Communities. Each outreach encounter includes information about bill payment options and energy management tips, along with the distribution of low-cost weatherization materials. Avista partners with community organizations to reach these customers through community resource events, at area food banks/pantry distribution sites, senior activity centers, or affordable housing developments. Low-income energy efficiency programs contributed 622 MWh of annual first-year electricity savings in 2023.

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 lack uniformity.

More than 5,100 prescriptive and site-specific nonresidential projects received funding in 2023. Avista contributed approximately $21.1 million for energy efficiency upgrades to offset costs in non-residential applications and realized over 49,139 MWh in annual first-year energy savings in 2023.

Demand Response

Current Demand Response Programs and Pilots

Avista's current Demand Response (DR) resources include residential and general service Time-of-Use (TOU) rates and Peak Time Rebate (PTR) pilots, commercial Electric Vehicle (EV) TOU rates and one bilateral agreement with an industrial customer for 30 MW. The industrial customer agreement was executed in 2022 for a four-year term with provisions to extend it another six-years. Avista is also working with NEEA and other utilities in the region on an End Use Load Flexibility (EULF) pilot with a focus on direct load control for grid-enabled water heaters and line voltage thermostats. These pilots will influence future IRPs, just as past pilot experience influenced this IRP.

Historical Demand Response Programs and Pilots

Avista piloted DR technologies between 2007 and 2009, to examine cost-effectiveness and customer acceptance. The pilot tested scalable Direct Load Control (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 offered Avista and its customers hands-on experience with equipment that provides "near-real time" feedback on energy usage. The insights from the pilot study are detailed in a report submitted to the Idaho Public Utilities Commission.[52]

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. A 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.[53] More importantly, the technology used in the DR portion of the SGDP predicted if equipment was available for participation in the control event, providing 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 events 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.[54]

[52] 20100303FINAL REPORT.pdf (idaho.gov)

[53] For example, no more than a two-degree Fahrenheit offset for residential customers and an energy management system at WSU with a console operator.

[54] Front_Matter.pdf (energy.gov)

Experiences from both pilots showed high customer engagement; however, recruiting participants was challenging. Avista's service territory has a high level of natural gas adoption meaning many customers cannot participate in typical DLC electric space and water heat programs because they have natural gas appliances. Additionally, customers did not seem overly interested in the DLC programs offered. Bonneville Power Administration (BPA) found similar customer interest challenges in their regional DLC programs.[55]

Avista paid customers direct incentives for program participation in both DLC pilots. A premium incentive to recruit and retain customers was provided and was not intended to be scalable. Avista will need additional analysis to determine cost effective payment strategies beyond pilots to mass-market DLC programs. If 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 plan.

Demand Response Potential Assessment Study

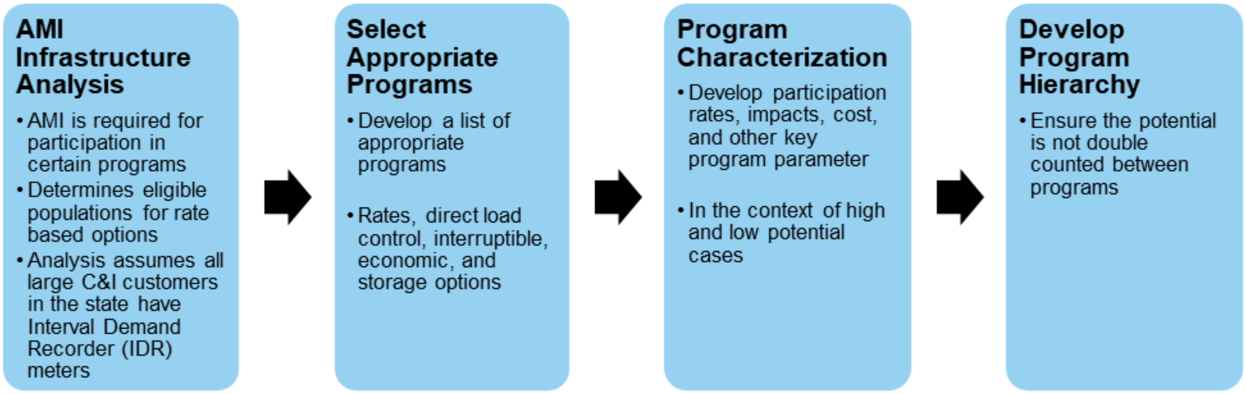
Avista retained AEG to study the DR potential for Avista's Washington and Idaho service territories for this IRP. The study estimates the magnitude, timing, and costs of DR resources likely available to Avista for meeting both winter and summer peak loads. Figure 6.4 outlines AEG's approach to determine the potential size of DR programs available in Avista's service territory. Many DR programs require Advanced Metering Infrastructure (AMI) for billing purposes. All DR pricing programs, behavioral and third-party contract programs included in this study require AMI as an enabling technology. The AMI deployment is complete in Washington, and AEG broadly assumes Avista would follow with AMI metering in Idaho beginning in 2026 (potentially) with a three-year ramp rate for full deployment, finishing in 2029.

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.

Lastly, for the pilot programs included in the potential, AEG based on program roll-out beginning in 2024 and includes TOU rate options, PTR, and DLC of grid-enabled water heaters. AEG forecasted the potential program savings as if the programs matured and operated through 2045. Each pricing pilot will run for two years. The DLC grid-enabled water heater pilot is a project Avista is participating in with several other regional utilities and led by NEEA.

[55] BPA's partnership with Kootenai Electric Coop, Report (bpa.gov).

Figure 6.4: Program Characterization Process



Demand Response Programs

This potential process identifies several DR program options shown in Table 6.2. 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 (virtual power plant). 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 TOU, PTR, and variable peak pricing. Each option requires a new rate tariff for each state in Avista's service territory.

Table 6.2: 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 Smart Appliances	X	X			X	X
	EV VG1 Telematics (Behavioral)	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
	Time-of-Use Opt-out	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	X

Direct Load Control

DLC programs require an enabling technology to drive load change for Avista's residential and general service customers in Idaho and Washington and allow Avista to directly control a variety of customer end-use appliances during capacity constrained hours. For example, DLC smart thermostat programs would leverage a customer's smart thermostat installation and rely on the customer's Wi-Fi for communications with the grid and utility. Likewise, DLC smart appliances (refrigerators, clothes washers, and dryers), DLC central air conditioning, DLC water heating, and DLC CTA-2045 water heating programs assume controlling the device enables a version of a load control for the utility. Typically, DLC programs take five years to mature to maximum participation levels and AMI technology is preferred to evaluate and measure event response and system impacts.

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 a capacity constrained 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. This 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. These assumptions determine the eligible population for participation in this program and the study assumes a third party would administer all aspects of the program.

Thermal Energy Storage

Thermal energy storage stores thermal energy (hot or cold) for later use and can be used to balance energy demand between different times of the day. It has primarily been used in non-residential buildings but, as technology advances, may have the potential for future use in residential applications. Thermal energy storage technologies can include sensible heat storage (storing energy by heating or cooling a material), latent heat storage (using phase-change materials to store energy from solid to liquid) and thermo-chemical storage (using chemical reactions to store and release energy). As an example of latent heat storage, 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 (Virtual Power Plant)

Battery energy storage technologies draw electricity during low demand periods and store it for use later during capacity constrained periods. The program assumes customers own the batteries as part of their on-site renewable generation system. An incentive can be offered to help cover part of the installation costs of the battery system. Once enrolled in the program (i.e. virtual power plant), customers allow the utility to automatically manage (charge/discharge) the battery during capacity constrained periods in exchange for an annual participation payment.

Behavioral

A behavioral DR program is a voluntary reduction in response to digital behavioral messaging. The program sends notifications requesting customers to reduce usage via text or email messages. To minimize costs, the plan assumes the program would work in tandem with an energy efficiency behavioral reporting program. Also required for the program is AMI technology to evaluate and measure the impact of the program events.

Behavioral EV V1G Telematics

This concept pays a monthly incentive to change charging behavior using the EV on-board charging system. If customers charge during on-peak hours no more than three times per month a customer would receive an incentive. After one-year the incentives end, but it is assumed off-peak charging behavior is set and will continue.

Time of Use Rates (Opt-In)

A TOU rate is a time-varying energy rate. Relative to a revenue-equivalent flat rate, the TOU rate is higher during either higher load or price periods, while the rate during other periods is lower. This provides customers with an incentive to shift energy consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a DR option, per se, but rather a pricing program to encourage a change in behavior. Large price differentials are generally more effective than smaller differentials for TOU programs and AMI is required.

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.

Two Opt-in TOU rate designs are being piloted in Washington State for residential and general service customers. The pilots began in June 2024 and will run for two years. Evaluations will be conducted to determine how Avista can deploy cost effective TOU programs more broadly post-pilot. Avista did not model TOU-opt out due to lower long-term capacity savings than the opt-in program design.

Variable Peak Pricing

The Variable Peak Pricing (VPP) is an option under a TOU program where the rate 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. Through the VPP program, customers are billed 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 VPP 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 period 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 dependent on enrollment in other DR programs to avoid double counting of savings, but like the other pricing programs, it does require AMI for billing purposes.

A PTR program is being piloted in Washington State for residential and general service customers. The pilots began in June 2024 and will run for two years. Evaluations will be conducted to determine how Avista can deploy cost effective PTR programs more broadly post-pilot.

Electric Vehicle Time of Use

Rather than a typical TOU rate applying on/off peak prices to the whole customer's usage, the EV TOU rate program applies on/off peak prices exclusively to the EV load. This program requires EVs to be metered separately. Avista currently offers this rate option in Wahington and when AMI is available in Idaho, a similar pricing program could be available.

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 are uncertainties in factors such as market conditions, regulatory climate, the economic environment, and customer sentiments influencing participation in DR programs.

DR options require time to mature 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 6.3 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 for 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.[56]

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

Table 6.3: DR Program Steady-State Participation Rates (% 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%	10%	-	-
Smart Appliances DLC	5%	5%	-	-
Third Party Contracts	-		15%	15%
EV V1G Telematics	20%	-	-	-
DLC Electric Vehicle Charging	13%	7%		
Time-of-Use Pricing Opt-in	20%	20%		
Time-of-Use Pricing Opt-out	-	-	25%	25%
Variable Peak Pricing	15%	15%	-	-
Peak-Time Rebate	-	20%	10%	-
Electric Vehicle Time-of-Use	-	0.5%	1.5%	1.5%
Thermal Energy Storage	50%	50%		
Battery Energy Storage	20%	-	-	-
Behavioral	10%	10%	-	-

Cost and Potential Assumptions

Each DR program 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 DR program, the potential for double counting savings from DR programs exists. To address this possibility, a participation hierarchy assumes an integrated approach where program savings are based upon many programs being available. 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 each program and its levelized costs are shown in Table 6.4. The cost of the programs within this table represents the on-going operations and capital cost required to start and maintain these programs for programs beginning in 2026. The capital costs are amortized and recovered over a 10-year period. These tables include the estimated potential megawatt savings for 2030 and 2045 to illustrate program potential. These estimates are the expected amount of demand reduction from all program participants using an "integrated" methodology, whereas potential may be higher for a program where only one program is in place. It is also worth noting these savings are net demand savings rather than the higher amount of load needed under contract to realize these savings.

Table 6.4: System Program Cost and Potential

Program	$/kW-Month	Winter (MW)		Summer (MW)	
		2030	2045	2030	2045
Battery Energy Storage	$35.6	3.1	13.0	3.0	12.7
Behavioral	$148.0	3.0	3.2	2.1	2.2
DLC Central AC	$166.7	-	-	11.6	15.4
EV V1G Telematics	$430.2	9.1	47.1	9.1	47.1
DLC Smart Appliances	$341.7	3.2	4.0	3.2	4.0
DLC Smart Thermostats - Cooling	$482.6	-	-	24.7	33.4
DLC Smart Thermostats - Heating	$30.6	9.2	14.6	-	-
DLC Water Heating	$634.7	2.8	3.5	2.8	3.5
CTA-2045 ERWH	$154.1	3.4	5.6	1.5	2.4
CTA-2045 HPWH	$538.1	0.5	13.2	0.3	8.5
Thermal Energy Storage	$783.7	-	-	0.6	0.6
Third Party Contracts	$101.4	17.7	21.0	22.4	26.6
Time-of-Use Opt-in	$217.1	3.4	4.2	2.4	3.0
EV TOU Opt-in	$40.4	1.2	9.6	1.2	9.6
VPP Rates	$21.6	4.8	5.7	6.1	7.2
Peak Time Rebate	$78.5	7.9	10.1	6.1	7.9
Total Potential		**69.2**	**154.8**	**97.1**	**184.2**

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

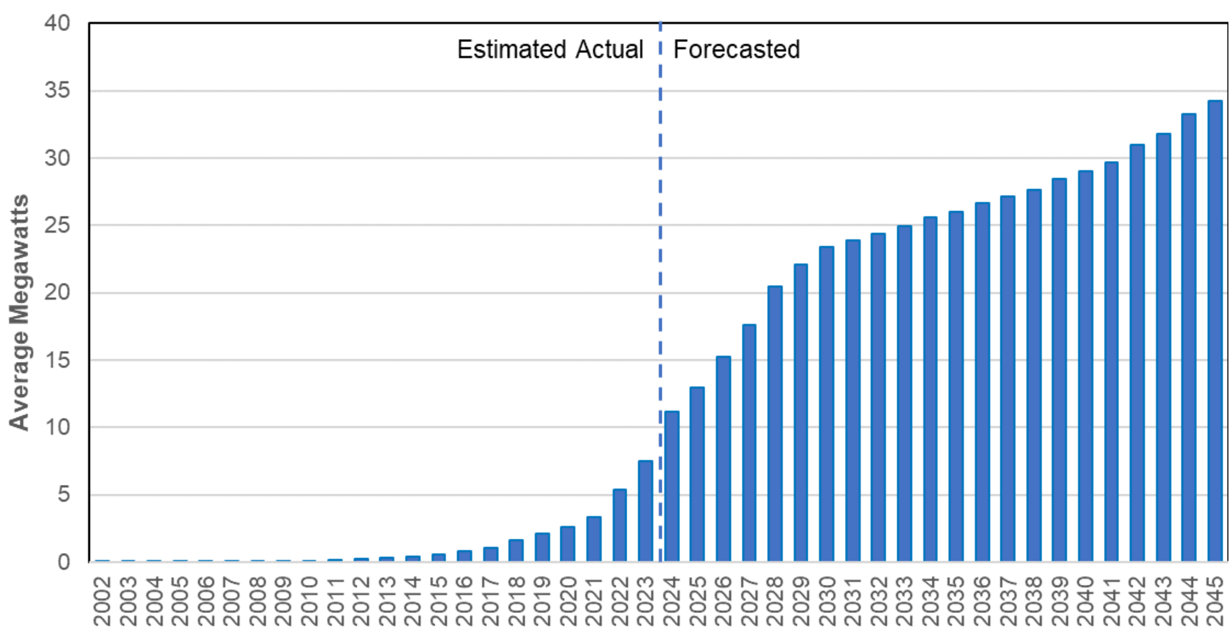
The second major factor related to whether a program is cost effective considers the program's ability, compared to alternatives, qualify as load reduction or the program's Qualifying Capacity Credit (QCC). The QCC is uncertain for these types of programs in the future Western Resource Adequacy Market (WRAP). This analysis assumes a 6-hour reduction is required to receive 100% QCC, whereas the QCC is a percentage of the hour reduction. For example, a 4-hour program is 67% and a 3-hour program is 50%. The QCC values are increased by the PRM to account for peak load reduction. Effectively this new change gives DR programs a higher capacity benefit compared to the 2023 IRP analysis. Avista is uncertain if DR programs will be as valuable today as in the future when the region has more capacity limited resources. To account for this potential lost QCC value, DR is reduced 20% linearly between 2030 and 2045 from the 2026 value.

Distributed Generation Resources

Customer-Owned Generation

Avista has 4,433 customer-installed net-metered generation projects on its system as of December 2023, representing a total installed capacity of 29.9 MW. 89% percent of installations are in Washington; most are in Spokane County. Figure 6.5 shows annual energy production. The estimated actual is based on on-line capacity, while the forecasted generation is provided by the DER potential assessment study. Solar is the primary net metered technology followed by wind, combined solar and wind systems, and biogas. The average size of customer installations is 6.7 kilowatts. In Idaho, solar installation rates continue to increase without a major state subsidy, but as of December 2023, only 596 Idaho customers participate as compared to Washington's 3,837 customer installations.

Figure 6.5: Avista's Net Metering Generation (aMW)



Net-metered installations are exponentially increasing due to federal incentives, increasing solar vendor sales, environmental concerns, rising energy costs, and expiring state incentives. If the growth of net-metering customers continues 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.

Avista-Owned Solar

Avista operates three small solar DER projects. The first solar project is three kilowatts located at its corporate headquarters. Avista installed a 15-kilowatt solar system in

Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. The 423-kW Avista Community Solar project, located at the Boulder Park property, began service in 2015.

Table 6.5: 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**

Solar Generation & Storage Opportunities

This IRP includes both utility owned distribution-sized solar generation and storage for residential, commercial, and community sized projects as resource options. Customer and distribution sized resources have gained traction to promote equitable outcomes for specific communities or to solve local supply issues. For this analysis these DERs are included as resource options for the Named Community Investment Fund (NCIF) but they can also be selected if cost effective without the additional funding. The resource configurations and costs are shown in Table 6.6. The costs are shown in nominal levelized cost dollars and include the benefits of the Inflation Reduction Act (IRA) through 2033, cost assumptions are based on information provided by TAC members and the 2023 National Renewable Energy Laboratory (NREL) resource cost study.[57] A low-income community solar option is based on the expected net cost to Avista customers after accounting for grants provided by the State of Washington. The costs are levelized cost of energy for solar resources over the life of the asset and costs for energy storage is the levelized cost of capacity for the life of the asset assuming battery reconditioning.

[57] NREL (National Renewable Energy Laboratory). 2023. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Technologies | Electricity | 2023 | ATB | NREL

Table 6.6: DER Generation & Storage Options Size and Cost

Project Name	2026$ /MWh	2035$ /MWh	2026$ / kW-Month	2035$ / kW-month
Existing res. building solar	166	287	-	-
Existing res. building solar with storage	166	287	24.99	42.51
New res. building solar	154	266	-	-
New res. building solar with storage	154	266	23.62	39.92
Com. building solar	120	140	-	-
Com. building solar with storage	120	140	26.88	38.19
Utility owned solar array	59	68	-	-
Utility owned solar array with storage	59	68	17.83	21.34
Stand-alone energy storage (4hr)	-	-	17.34	25.38
Stand-alone energy storage (8hr)	-	-	30.89	44.17
Low-income Community Solar Program	27	68	-	-

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 includes all known utility costs and, where required (i.e., Washington), known non-energy or social impacts. The Washington Utilities and Transportation Commission (UTC) is developing a proposal[58] for evaluating DERs as part of a workshop process with the assistance of Synapse Energy Economics. Currently, the UTC has put out draft proposals of the types of considerations utilities should use when conducting resource planning activities through a workshop series and has sought comments from utilities. While this concept continues to be in draft form, it provides 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 6.7 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. "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. Many of the values discussed are qualitative and difficult to quantify for use in modeling.

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

Table 6.7: DER Cost and 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	Indirect	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	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,[59] 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 analysis was completed in 2024 and will be used in future distribution planning activities. Avista hired AEG, who subcontracted with Cadeo, to conduct this analysis. The planned work covered both electric transportation and customer owned generation as shown in the list below. The study also included a scenario regarding upper limits of Named Community DER potential by removing income limitations. This scenario considers Named Communities areas have the same DER penetration as non-Named Community areas to provide a high case scenario in the event of incentives for areas with lower incomes.

- EVs
    - Local charging: light, medium, heavy duty
    - Charging related to interstate travel
- New Generation and Storage
    - Residential and commercial solar
    - Residential and commercial storage
    - Other renewables (wind, small hydro, or other technologies)

The DER potential study contemplated a downscaled distribution level energy efficiency and DR forecast using the CPA/DR potential. Unfortunately, there is not a useful way to complete this task in a reasonable time and budget for the entire system. Avista proposes this future DER analysis should only include feeders with potential capacity constraints with needs reflecting either DR or energy efficiency as a solution.

DER Study Results

The reference scenario in Table 6.8 summarizes the 2045 DER potential results. The residential and fleet electric vehicle supply equipment (EVSE) will have the most significant load impacts in Avista's Washington service territory adding nearly 1,700 GWh of energy consumption in 2045. Customer solar will decrease energy consumption by almost 130 GWh in 2045. The term "peak" in the chart refers to a planning peak beginning at 17:00 and ending at 18:00 local time.

[59] 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 6.8: Summary Results for 2045, Reference Scenario

Resource	Capacity (MW)	Annual Load Impact (GWh)	Share of Nameplate Capacity in Named Community	July Peak Load impact (MW)	December Peak Load Impact (MW)
Customer Solar	105	-127	46%	-33	0
Customer Battery Storage	96	2	58%	-3	-9
Customer Wind	1	-0.3	45%	-0.1	0
Residential EVSE	1,544	853	38%	62	62
Fleet EVSE	692	841	67%	101	105
Public and Workplace EVSE	171	206	60%	33	33

Study Recommendations

As the team notes in the Utility Survey Memo (Appendix B of the DER study found in Appendix D), the current state of DER potential forecasting highlights many of Avista's data gaps. The AEG team recommends six actions Avista can take before the next iteration of the DER potential study to increase the fidelity and depth of insights from a future location-specific study.

1) **Address Fleet Data Gaps.** For this study, the team estimated the size and location of commercial fleets using two methods. First, Avista surveyed commercial vehicle fleets in its service territory, identifying dozens of smaller fleets. Additionally, the team used secondary data and satellite imagery to identify many larger fleets in the service territory, including school district buses and parcel delivery vehicles. While these efforts successfully obtained data from dozens of fleets, they are not comprehensive and likely undercount smaller light duty vehicle fleets. Three activities the team recommends Avista pursue to collect additional fleet data include:

    - **Continued outreach to fleet operators**. Avista has begun outreach to fleet operators in its service territory to understand their electrification plans and possible charging locations. Collecting and refining data from these outreach activities will advance Avista's ability to inform forecasting studies.

    - **Analysis of satellite imagery**. Though an imperfect indicator of the presence of vehicle fleets, satellite imagery is a low-effort method of identifying fleets at Avista's commercial and industrial service points. Collecting and enhancing data from an analysis of satellite imagery will advance Avista's ability to inform forecasting studies.

    - **Acquire fleet inventory data**. Washington's Department of Ecology is currently conducting a fleet inventory that requires fleets with five or more vehicles to register vehicle types, counts, and depot locations. The team recommends that Avista pursue this data source for its service territory when it becomes available.

2) **Develop Commercial EV Charging Profiles**. Limited data are available to characterize EVSE charging profiles, especially for commercial fleets. The AEG Team recommends that Avista conduct load research on commercial fleet charging.

3) **Develop Seasonal EV Charging Profiles**. The team did not have sufficient data to characterize seasonal differences in EV charging profiles (kW per hour) and driving patterns (vehicle miles traveled per day), so AEG assumed the summer and winter charging profiles are the same in Avista's service territory. However, the winter charging profile could be more significant due to vehicle cabin space heating or smaller because of less EV driving in the winter. Therefore, AEG recommended that Avista conduct load research on seasonal EV charging.

4) **Conduct Additional Scenario Analyses**. The DER adoption forecast analyzed two scenarios: a reference scenario and a high-incentive scenario. Consider adding additional scenarios to study the impacts of climate change (e.g., weather, customer grid resiliency) and ancillary services incentives on DER forecasting. Integrate the DER and DR Potential Studies. Some types of DERs, like EV charging and customer battery storage, can be leveraged in DR events. Therefore, it would benefit Avista to integrate its DER and DR potential studies to avoid overestimating or underestimating the combined potential.

5) **Consider Adding Building Electrification**. Building electrification and load flexibility can affect customer's decisions regarding DER installations. Therefore, including building electrification and associated load control measures (e.g., connected thermostats, heat pump water heater switches) in future DER potential studies would provide Avista with a more comprehensive understanding of customer load growth and opportunities to shape it with programs and rates.

6) **Consider Adding Emerging Technologies**. Emerging technologies, such as autonomous vehicles and vehicle-to-grid technologies, can change customer energy consumption patterns. Therefore, in future DER potential studies, Avista may want to consider emerging technologies as they become commercially available.

Named Communities Investment Fund

Chapter 4 of the Company's 2021 CEIP identified the specific actions Avista will undertake to meet the four-year interim targets to ensure community benefits are recognized and progress on Customer Benefit Indicators (CBIs) are addressed. This chapter outlines programs and initiatives demonstrating the Company's commitment of efforts and resources to ensure the benefits of the Company's transition to cleaner energy are extended to all, especially those who are members of Named Communities. As part of this commitment, Avista is investing 1% of total electric retail revenues or approximately $5 million through the NCIF annually as shown in Table 6.9.

Table 6.9: NCIF Spending by Category

NCIF Amount	NCIF Category
40% or up to $2 million	Energy Efficiency Supplement
20% or up to $1 million	Distribution Resiliency
20% or up to $1 million	Customer & Third-Party Grants & Incentives
10% or up to $0.5 million	Outreach & Engagement
10% or up to $0.5 million	Other Projects, Programs, or Initiatives

The utilization of the NCIF will include guidance from its equity and community-based partners, specifically the Equity Advisory Group (EAG). In its founding year, the EAG played a critical role in identifying CBIs and defining Vulnerable Populations. It continues to be a vital partner for providing equity guidance considerations for a variety of Avista's programs and projects to help assure an equitable clean energy transformation for all customers. Avista is enthusiastic about assisting and supporting all customers, especially those in Named Communities in the equitable transition to clean energy by leveraging the NCIF.

Early in 2023, the EAG participated in a Results Based Accountability (RBA) activity to identify and prioritize energy efficiency initiatives for Named Communities and identified the following priorities:

- Improve awareness and energy efficiency for Spokane Tribe, multi-family, and manufactured homes.
- Increase tree canopy.
- Increase access to energy efficiency products and appliances.
- Increase awareness and engagement in energy efficiency programs.
- Match funds for energy efficiency grant applications to community-based organizations and tribal partners.
- Improve energy efficiency for those without stable housing.

The group's prioritized initiatives for the energy efficiency NCIF grants focus to closely align with the Specific Actions identified in Chapter 4 of the 2021 CEIP (i.e., energy efficiency programs for multi-family split incentive, manufactured/mobile homes, single family weatherization and community and small business, with the Community Identified Projects being addressed with the EAG RBA). A few distinctions of the EAG's initiatives are callouts for those who are unhoused, tree canopy, and emphasis for tribal partners – the latter are a component of Highly Impacted Communities.

Avista continues to engage with and update the EAG on the progress of their identified NCIF initiatives above. The Company also provides updates to other interested parties through public participation meetings on spending, projects implemented, and the impact to Named Communities through the NCIF. The NCIF administration and governance includes an internal advisory group with representation from Avista's Energy Efficiency department and other interested parties such as regulatory, external communications, and the clean energy department to evaluate all NCIF awards for projects and programs.

In 2023, 21 projects were awarded or utilized NCIF funding totaling $1,382,129. This included 10 energy efficiency projects, two distribution resiliency projects, five customer or community grants, a pilot for medical battery back-up and outreach and engagement. The energy efficiency projects funded in the report year included health and safety for manufactured homes, efficiency upgrades at an affordable housing complex and homes in an area devasted by the wildfire, a lighting project at a rural fairground, and energy audits for the buildings located on tribal land. The information from the audits was used to submit a resiliency grant to a state organization. This project, funded by the grant award coupled with the NCIF, is expected to save approximately 340,000 kWh per year, while saving over $30,000 in annual energy costs for the one building alone. The upgrades are also expected to offset 3,091 pounds of CO_2e by replacing aging equipment and decommissioning outdated, high-emitting refrigerant.

In most cases, resiliency projects span multiple years. In 2023, NCIF committed to a community center project that is expected to be completed in 2025. This project received state funding along with an NCIF grant and is designed to help develop a neighborhood resilience center to provide shelter and resources during climate and other emergencies. As of June 2024, four awards were committed for workforce development, HVAC replacements, tree plotter software for planned tree canopy and air conditioner distribution to Avista electric customers were made, totaling $315,906. Avista will expand outreach activities to raise awareness of NCIF to engage underrepresented groups in the upcoming year.

Other Company Initiatives

Spokane Tribe Partnership

Avista continues to partner with the Spokane Tribe of Indians to design a grid resiliency solution in Wellpinit, WA. This project is funded through a design grant from the Department of Commerce Clean Energy Fund, with matching funds provided by Avista. The goal is to develop an energy delivery platform to enhance grid resiliency for Wellpinit and surrounding areas. The solution, termed a "resiliency station," is envisioned as a modernized, centralized facility providing energy resiliency in Wellpinit through a microgrid solution with an integrated battery energy storage system. The microgrid will be a small-scale power system operating independently from the traditional grid to serve critical loads when source power is interrupted, allowing vital support services to remain functioning during outages, wildfire scenarios, and other natural disasters.

The resiliency station would create a "critical loads" circuit to prioritize power to three buildings identified by the Tribe as critical to operations during emergencies. They include the Spokane Tribal administrative building, the David C. Wynecoop Memorial Health Clinic, and the Tribal Public Safety building. This station would replace some of the existing stepdown infrastructure in Wellpinit, freeing up the area for future redevelopment while improving the aesthetics and functionality of the distribution system. Based on preliminary modeling, Avista estimates the resiliency station could leverage existing generation resources, including solar and diesel generators, to sustain typical summer building loads for all three buildings for up to seven days.

A site located in Wellpinit, along Agency Loop Road, has been identified as the preferred project site. The approximately 0.72-acre site is large enough to house a battery energy storage system, pad mount equipment, and a control enclosure for microgrid controls. Station components will be securely enclosed to isolate critical electrical components from the public, while simultaneously providing an innovative means to showcase the facility, educate the public, and support the Spokane Tribe's long-term vision of energy sovereignty.

Over the last few months, Avista has provided technical assistance to the Tribe as they completed an application for $2.75 million from the Washington State Department of Commerce Tribal Clean Energy grant fund towards construction of the resiliency station. Total project costs are expected to be approximately $6.65 million. Avista and the Spokane Tribe are committing to funding the balance of the project from a variety of sources including Avista's NCIF and a U.S. Department of Energy Grid Resiliency Formula Grant that has been awarded to the Spokane Tribe.

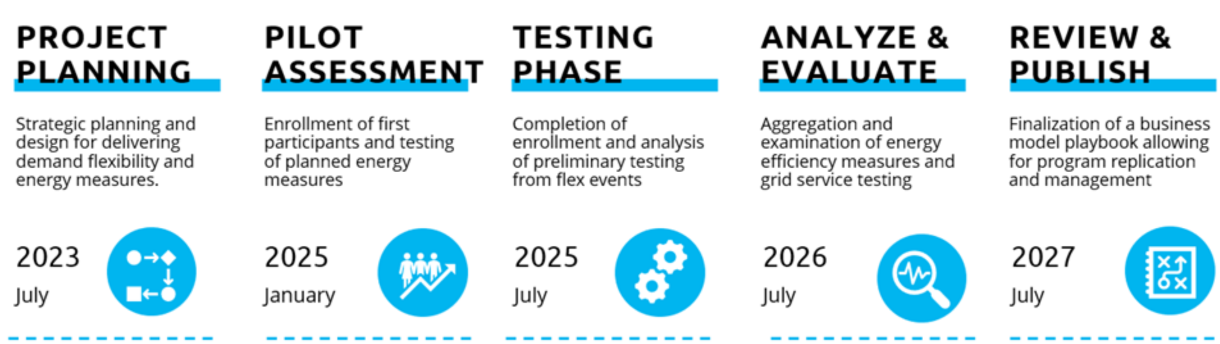
Connected Communities

Avista partnered with Edo, Pacific Northwest National Labs (PNNL), and Urbanova to create a business model to scale grid-enabled and efficient buildings to actively participate in offsetting electric production and the delivery of demand resources as an effort to elevate overloading a distribution feeder near its capacity. Edo, a business partnership between McKinstry and Avista Development, is the prime recipient of the Department of Energy's Connected Communities grant award. Edo represents the scalable business model for creating "Active Demand and Energy Management" services. Avista, a subrecipient in the grant award, is responsible for designing customer product solutions to combine energy efficiency, residential smart thermostats, commercial building energy optimization systems, managed EV charging, and residential battery technology to be aggregated into a locational targeted virtual power plant. Avista will operate "as an aggregator" to schedule, dispatch, and control the customer demand products to address system balancing requirements at the supply and delivery systems.

The project will recruit 20-25 commercial participants and 50-100 residential participants, with the goal of creating between 1 to 2.5 MW of flexible load. The utility will administer "flex events" where Avista will adjust dispatchable assets such as smart thermostats and residential batteries. Customers will retain the ability to "opt out" of flex events by manually overriding event set points. Customers will receive varying incentive payments depending on their level of participation.

Commercial and Industrial recruitment launched in the second quarter of 2024. Residential and small and medium business customer recruitment will launch in the third quarter of 2024. All participating customers must reside within the Third and Hatch substation service boundary for the Connected Communities pilot project to help with feeder capacity. The Third and Hatch substation has eight distribution feeders serving four distinct neighborhoods. Most of these neighborhoods are in the City of Spokane Opportunity Zone. Figure 6.6 outlines the timeline for the Connected Communities program.

Figure 6.6: Connected Communities Timeline



7. Supply-Side Resource Options

Avista evaluates several generation options including Distributed Energy Resources (DERs) and utility-scale resource options to meet future resource deficits. This resource plan evaluates upgrading existing resources, constructing utility-owned new generation facilities, and contracting with other energy companies. This chapter describes the costs and characteristics of the utility-scale resource options Avista is considering in the 2025 IRP. Most options are generic, as resources are typically acquired through competitive processes such as a Request for Proposal (RFP). Due to siting, engineering or financial requirements, this process may yield resources differing from this IRP in terms of size, cost, and operating characteristics. It may also result in securing output from existing resource options available in the region.

Section Highlights

- Future competitive acquisition processes may identify new or existing resources using different technologies with differing costs, sizes, or operating characteristics.
- The Inflation Reduction Act (IRA) tax incentives are included in resource costs.
- Solar, wind, and other renewable resource options are modeled as Power Purchase Agreements (PPA) instead of utility ownership.
- Avista models several energy storage options including pumped storage hydro, lithium-ion and flow batteries, hydrogen, iron-oxide, and ammonia.

New Resource Options

Resource options in this analysis include those commercially available and future resource technology options with a strong likelihood of commercial availability. The analysis does not include theoretical options or technologies in pre-commercial phases, nor does it consider variants of a technology, such as natural gas or wind plants made by different manufacturers. A representative plant for each technology type was chosen. 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 has historically modeled these resource types as PPAs as IPPs financially capture tax benefits for these resources 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- and renewable natural fueled gas-fired SCCTs, energy storage, hydrogen fuel cell, biomass, and upgrades to existing facilities. New 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 as they may appear in a future RFP.

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 a competitive RFP process for resource acquisitions where possible to ensure the lowest cost resource is acquired for customers. However, other acquisition processes 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 described in this chapter do not include the cost related to upgrading the transmission or distribution system described in Chapter 8 or third-party wheeling costs. All costs are considered on Avista's side of the interconnection point. Avista excludes costs on the third-party side of the interconnection point to allow for consistent cost comparison as resource costs 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 portfolio analysis. All costs are levelized by discounting nominal cash flows by the 6.5% weighted average cost of capital approved by the Idaho and Washington Commissions.[60] All costs in this section are in 2026 nominal dollars unless otherwise noted. All cost calculations and operating characteristic assumptions for generic resources and PPA pricing calculations are available in Appendix G and Avista's website.[61]

Avista relies on several sources for resource costs including the National Renewable Energy Laboratory (NREL)[62], Northwest Power and Conservation Council (NPCC or Council), publicly available energy consultant reports, 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 was utilized to ensure assumed costs for solar,

[60] Idaho Order No. 35909 in Case No AVA-E-23-01, Washington Dockets UE-220053 Final Order 10/4.
[61] www.myavista.com/about-us/integrated-resource-planning.
[62] NREL (National Renewable Energy Laboratory). 2023. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Technologies | Electricity | 2023 | ATB | NREL

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 reflect the cost of energy if the plants generate electricity during all available hours of the year. Plants do not generally 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.[63] Without this separation of costs, resources operating infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources provide 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% 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 energy and not expected to operate. For generators limited by fuel availability, such as solar or wind, resource costs are divided by its expected production.

Distributed Energy Resources

This IRP includes several DER 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), each are discussed in Chapter 6. Avista includes forecasts for customer-owned solar and electric vehicles as part of its load forecast discussed in Chapter 3.

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 in Chapter 6 along with the energy, capacity, and ancillary service benefits traditional utility scale projects offer. Any additional benefits due to project location, such as improving line loss with DERs over alternative utility scale projects are also included. Other locational benefits may be credited to the project if it alleviates distribution constraints. Projects on the customer side 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 CCCT generation are cost volatility due to reliance on natural gas (unless utilizing hedged fuel prices) and air 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. While larger size plants with

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

higher efficiencies are available such as 2x1 configuration, these are too large for Avista's system without a partner. Avista prefers CCCT plants with nameplate capacity ratings between 180 MW and 312 MW unless it is sharing the facility with other utilities.

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. Without access to water rights, a more capital-intensive and less efficient air-cooled technology is required. 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 cooling technologies.

This analysis includes one CCCT plant option sized at 312 MW in 1x1 configuration with duct fire capability. Avista reviewed several CCCT technologies and sizes and selected this plant type as the best fit for the needs of Avista's customers for IRP planning. 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 units in the Pacific Northwest.

The most likely location for a new CCCT is in the Rathdrum, Idaho area, 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 lack of state taxes or fees on carbon dioxide emissions, such as Washington's Climate Commitment Act (CCA) unless imported into the state of Washington.[64] Likely CCCT sites 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 Gas Transmission Northwest (GTN) pipeline. Avista owns a site with these potential natural gas connection points if it needs to add additional capacity from a CCCT or other technology.

CCCT 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 allowance for funds used during construction (AFUDC) on a greenfield site, are approximately $1,422 per kW in 2026 dollars. These estimates exclude the cost of transmission and interconnection. Table 7.1 details the levelized plant cost assumptions, split between capacity and energy, for the combined cycle option

[64] 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%. Washington also has higher sales taxes and carbon dioxide mitigation fees for new plants.

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 7.2 summarizes key cost and operating components of natural gas-fired resource options. Competition from alternative technologies and the need for additional flexibility for intermittent resources are likely to put downward pressure on future CCCT costs. Avista is not modeling carbon capture for natural gas facilities until proven technology can be demonstrated.

Natural Gas-Fired Peakers

Peaking resources, such as natural gas-fired simple cycle combustion turbines (SCCT) and reciprocating engines, provide low-cost capacity 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 support for variable energy resource integration.

This analysis models frame and reciprocating engine technologies; however, other technologies would be considered in resource acquisition. Natural gas-fired peakers have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. Table 7.1 depicts the levelized cost for these technologies. Table 7.2 reflects the cost and operational characteristics based on internal engineering estimates. This analysis also considers using Renewable Natural Gas (RNG) as an alternative fuel in its CT analysis or offsetting natural gas use with Renewable Thermal Certificates.

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 includes the cost of on-site fuel storage such as liquified natural gas (LNG) for all natural gas turbine options within the capacity expansion model netted for the market arbitrage benefit the assets creates. Avista assumes non-firm gas transportation is available except for short-term peak events requiring the use of on-site LNG storage. In addition to on-site fuel storage, other options could be available for existing and new natural gas resources to ensure plant availability for resource adequacy events, such as 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, or on-site fuel oil.

Table 7.1: 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)	62.0	107.1	49.4	180
7F .04 CT Frame Greenfield (Washington)	64.0	109.7	51.1	
7F .04 CT Frame Greenfield + RNG (Idaho)	229.6	120.7	215.1	90
7F .04 CT Frame Greenfield + RNG (Washington)	229.9	123.3	215.1	
Reciprocating Engine (ICE) Machine (Idaho)	64.3	160.3	45.4	185
Reciprocating Engine (ICE) Machine (Washington)	66.2	164.2	46.8	
NG CCCT (1x1 w/DF) (Idaho)	60.3	193.7	37.5	312
NG CCCT (1x1 w/DF) (Washington)	61.9	197.7	38.7	

Table 7.2: Natural Gas-Fired Plant Cost and Operational Characteristics[65]

Plant Name/Location	Capital Cost with AFUDC ($2026/kW)	Fixed O&M ($2026/ kW- yr)	Heat Rate (Btu/ kWh)	Variable O&M ($/MWh)	Total Project Size (MW)	Total Cost (Mil$-2026)
7F .04 CT Frame Greenfield (Idaho)	929	5.6	10,040	3.3	180	168
7F .04 CT Frame Greenfield (Washington)	953					172
7F .04 CT Frame Greenfield + RNG (Idaho)	929	16.7	10,040	3.8	90	168
7F .04 CT Frame Greenfield + RNG (Washington)	953					172
Reciprocating Engine (ICE) Machine (Idaho)	1,422	5.6	8,190	6.9	185	264
Reciprocating Engine (ICE) Machine (Washington)	1,459					271
NG CCCT (1x1 w/DF) (Idaho)	1,422	33.0	6,820	5.5	312	443
NG CCCT (1x1 w/DF) (Washington)	1,459					455

Wind Generation

Wind resources have no direct air 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 of wind facilities are changing given regional transmission limitations, federal tax credits, low construction prices, and the potential for energy storage. These factors allow sites to be built with

[65] 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.

higher capacity levels than the transmission system can currently integrate. When wind facilities generate additional MWhs above the physical transmission limitations,[66] 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.

Capital expenditures, including construction financing and O&M costs for onshore wind with start dates from 2026 to 2045 can be found in Tables 7.3 and 7.4, respectively. 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 35% and 38% depending on location and 42% to 52% range in Montana and offshore locations. This plan assumes Northwest wind (Washington and Oregon) has a 35% average capacity factor, while Montana and offshore wind have average capacity factors of 44% and 50%, respectively. A statistical method, based on regional wind studies was used to derive a range of annual capacity factors depending on the wind regime in each year (see Chapter 10, stochastic modeling assumptions subsection for details).

Offshore wind has higher expected annual capacity factors (50%), but development and operating costs are also much 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.

Levelized wind costs change substantially due to the capacity factor but can also be impacted even more by tax incentives and ownership structure. Table 7.5 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, including the cost of the PPA, excise taxes, commission fees, and uncollectables[67] to customers. These prices do not include transmission costs for either capital investments or wheeling purchases nor integration costs. If a wind PPA is selected in Avista's resource strategy, the model assumes the PPA will extend through at least 2045.

[66] If transmission is limited due to contractual reasons, an additional option is to buy non-firm transmission to move the excess power.
[67] 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. Utility scale options are discussed here, while distributed systems under 5 MW located primarily on the customer side of the meter, are discussed in Chapter 6. Utility-scale on-system solar facilities assume a minimum capacity of 100 MW to take advantage of economies of scale and single axis systems. There are also two generic locations for resource selection, the first is local on-system resources within Avista's transmission system with a higher capacity factor potential, and the second option is further south either in Oregon or Idaho and requires transmission acquisition. Avista expects other locations to participate in future RFPs. Tables 7.3 and 7.4 show capital and fixed O&M forecasts for these resources, and the levelized prices for a 20-year PPA are detailed in Table 7.5. These costs do not include transmission costs associated with new construction, wheeling purchases, or integration costs.

Table 7.3: Forecasted Solar and Wind Capital Cost ($/kW)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	1,469	1,592	1,680	5,730
2030	1,382	1,573	1,711	5,888
2035	1,231	1,670	1,827	6,230
2040	1,266	1,768	1,947	6,677
2045	1,292	1,867	2,070	7,210

Table 7.4: Forecasted Solar and Wind O&M ($/kW-yr.)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	23.97	31.33	33.75	100.22
2030	23.49	32.14	35.27	102.74
2035	22.63	34.67	38.02	107.85
2040	24.16	37.35	40.93	114.63
2045	25.74	40.19	44.00	122.81

Table 7.5: Levelized Solar and Wind Prices ($/MWh)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	37.62	34.89	28.32	127.83
2030	28.37	28.73	23.86	125.54
2035	45.26	47.50	42.59	147.74
2040	46.37	63.33	58.44	169.46
2045	47.23	66.75	61.94	180.69

Solar with Energy Storage (Lithium-ion Technology)

Solar paired with energy storage reduces costs attributable to sharing local infrastructure, it can also directly shift energy deliveries, manage intermittent generation, use common equipment, increase peak reliability, and can prevent energy oversupply by storing the excess generation.

Lithium-ion technology prices are declining and will likely continue to fall due to increasing manufacturing levels and product enhancements. Levelized costs for the three storage level types modeled as solar PPAs and based on a 100 MW solar facility are shown in Table 7.6. Avista modeled 2-hour duration and 4-hour duration options. Avista's experience with solar generation from its 19.2 MW Adams-Neilson PPA reveals significant energy variation due to cloud cover and that 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 4-hour and 2-hour designs. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power.

Table 7.6: Levelized Cost for Lithium-Ion Storage at a Solar Facility ($/kW-month)

Year	100 MW/ 400 MWh	100 MW/ 200 MWh	50 MW/ 200 MWh
2026	15.18	10.17	6.25
2030	14.72	10.08	6.20
2035	17.88	12.15	7.25
2040	18.17	12.44	7.40
2045	18.34	12.67	7.51

Stand-Alone Energy Storage

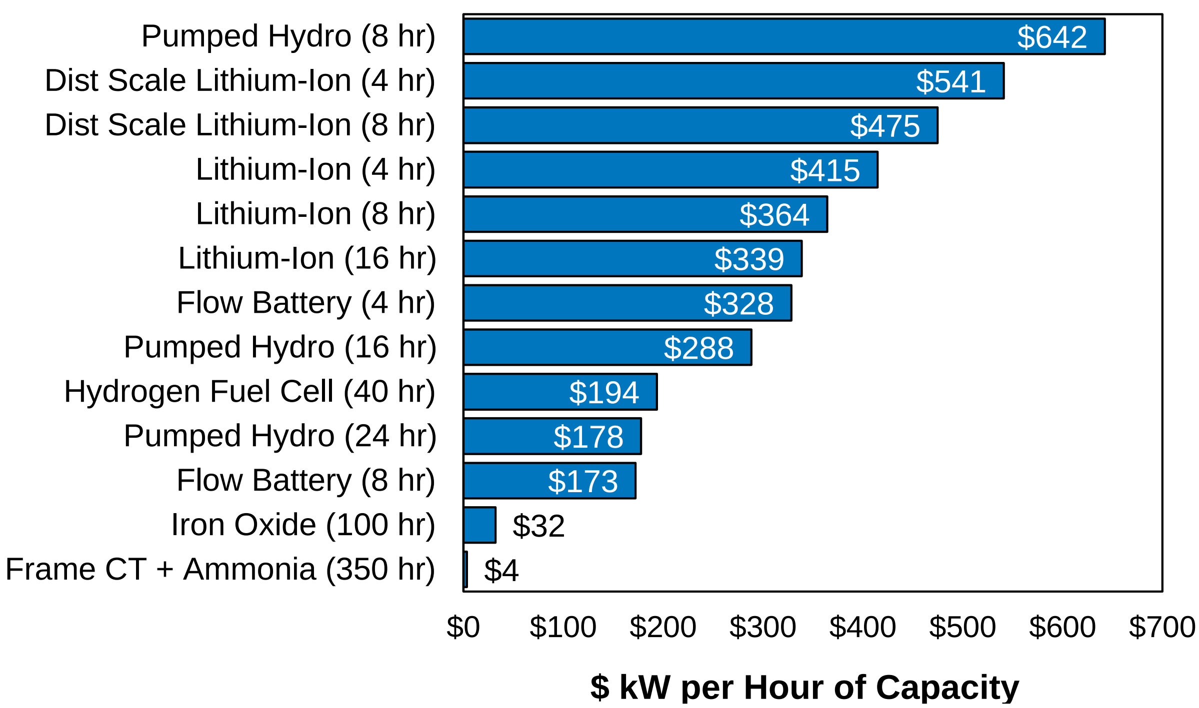
Energy storage resources are gaining significant traction to meet short-term capacity needs in the western U.S. Energy storage does not create energy but shifts it from one period to another in exchange for a portion of the energy stored. Avista modeled several energy storage options including pumped hydro, lithium-ion and flow batteries, and iron oxide. In addition to the technological differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is rapidly changing due to technological advancements and the 2022 Inflation Reduction Act (IRA), providing tax credits for all storage technologies through 2032.[68] In addition to changing prices for existing technologies, new technologies are entering the storage space with similar characteristics and pricing as those modelled in this IRP such as battery systems using sodium solid state technology. The rapid change in pricing and emergence of new technologies justify the need to update prices and technology options for each IRP.

[68] The IRP does consider extension of the tax credits for safe-harbor construction where the tax credit can be available for projects under construction in 2032, but not complete.

Another challenge with energy storage concerns pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Energy 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. Please see Chapter 8 for more details about using storage as a non-wire alternative.

Energy storage cannot be shown in $ per MWh as with other generation resources because storage does not create energy, but rather stores it and incurs losses. The analysis shown in Figure 7.1 illustrates the cost differences between the technologies when capital cost (2030 dollars) 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 within modeling the resource operations within Aurora.

Figure 7.1: Energy Storage Upfront Capital Cost versus Duration



Pumped Hydro Storage

Pumped hydro is the most prolific energy storage technology currently used in both the U.S. and internationally. This technology uses two or more water reservoirs at different elevations. When prices or loads are low, water is pumped to a higher reservoir and then released during higher price or load periods. This technology may also help meet system integration needs from intermittent generation resources. Only one of these projects exists in the northwest and several more are in various stages of the permitting process. Advantages with pumped hydro include the technology's long service life and Avista's familiarity with the technology as a hydro generating utility. The greatest disadvantages are high capital costs and long permitting cycles.

Pumped hydro has good round trip efficiency rates; Avista assumes 80% for most options. Projects 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 this technology with three different durations including 8, 16, and 24 hours. Durations are the number of hours the project can run at full capacity. Pricing and duration of these facilities are based on projects currently being developed in the Northwest. As an energy-limited water 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 7.7. Options also include a $0.54 per MWh variable payment for each MWh generated (2021 base year, escalating with inflation).

Table 7.7: Pumped Hydro Options Cost ($/kW-month)

Year	8 hours	16 hours	24 hours
2026	25.37	23.01	21.47
2030	27.70	25.12	23.45
2035	30.91	28.04	26.17
2040	55.45	50.11	46.62
2045	61.89	55.93	52.04

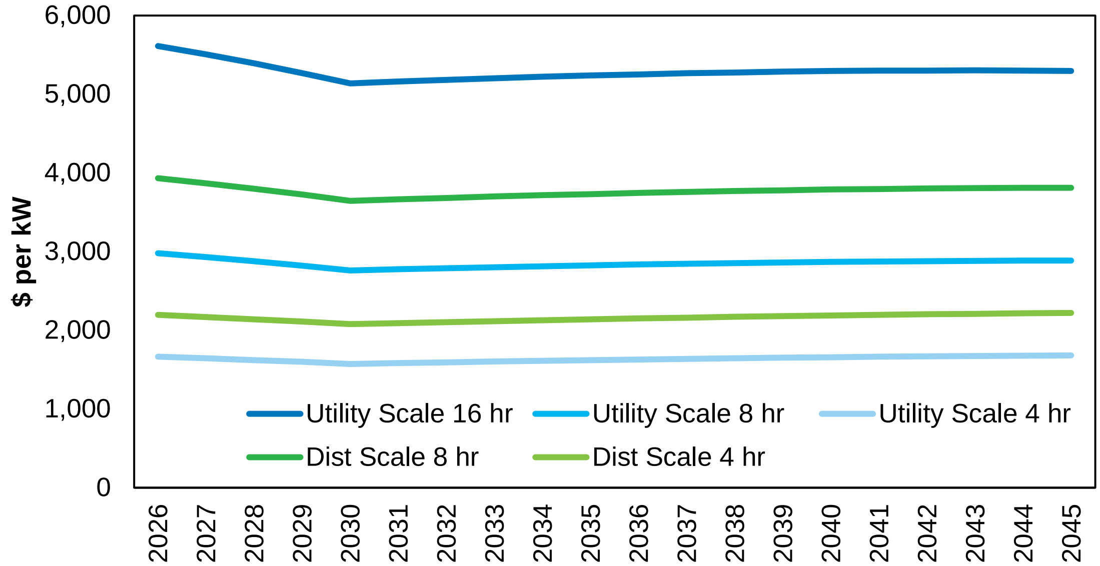
Lithium-Ion Batteries

Lithium-ion technology is one of the fastest growing segments of the energy storage space. This section focuses on energy storage as a stand-alone resource rather than coupled with solar as discussed earlier. For modeling purposes, lithium-ion assumes utility ownership, but it could be acquired through a PPA for a 20-year life with augmentation of the battery cells. Fixed O&M costs include replacement cells to maintain 80% energy conversion efficiency and capacity for this storage option. Estimated costs include 2022 IRA federal tax credits.

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 allowing the construction of utility scale projects.

Avista modeled five stand-alone configurations for lithium-ion batteries. Two DER small-scale sizes (<5 MW) with 4-and 8-hour durations for modeling the potential for use on the distribution system and three larger systems (25 MW+), including 4-and 8-hour durations, as well as a theoretical 16-hour configuration. Modeling assumptions for these scenarios were derived from publicly available energy consultant sources. Figure 7.2 shows the capital cost forecast for each configuration of size and duration considered. Avista classifies the 4-hour battery as the standard technology with capital and fixed O&M costs in 2026 of $1,663 per kW and $41.57 per kW-year, respectively.

Figure 7.2: Lithium-ion Capital Cost Forecast



Storage technology is often displayed differently than other resources to illustrate the cost since it is not a traditional capacity resource. Table 7.8 shows the levelized cost per kW-month for each configuration. This calculation reflects the levelized cost for the capital, O&M, and regulatory fees, including capital reinvestments, over 20 years divided by the capacity. These costs do not consider any variable costs, such as energy purchases.

Table 7.8: Lithium-Ion Levelized Cost ($/kW-month)

Year	Utility Scale 4 hour	Utility Scale 8 hour	Utility Scale 16 hour
2026	13.25	23.61	44.33
2030	12.73	22.29	41.41
2035	19.41	33.79	62.55
2040	19.82	34.23	63.05
2045	20.07	34.35	62.93

Flow Batteries

This plan models flow batteries with 4-and 8-hours duration in 25 MW increments. Flow batteries have the advantage over lithium-ion because they do not degrade over time which leads to a longer operating life. The technology consists of two tanks of liquid solutions flowing adjacent to each other through a membrane to generate electrons moving back and forth for charging and discharging.

Flow battery capital costs in 2026 are $1,317 and $1,383 per kW for the 4-and 8-hour duration batteries, respectively, both falling 10% by 2035. Fixed O&M costs of $71.52 and $80.46 per kW-year increase with inflation. Flow batteries have round-trip efficiencies between 67% and 70%. Given Avista's recent experience with flow batteries at its pilot project in Pulman, Washington, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 7.9 shows the levelized cost per kW-month of capacity.

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 inside the battery to convert iron to rust and later convert it back to iron. Due to the low cost of iron relative to other elements, a long-duration resource can be obtained at similar cost compared to what is currently available, shorter duration technologies.

This analysis assumes a 100 MW iron-oxide battery with a 36.5% round-trip efficiency with 100 hours, or 10,000 MWh, of storage. Capital costs are estimated at $3,037 per kW (2026 dollars) and increase due to inflation. The fixed O&M cost of $27.90 per kW-year and levelized cost of iron oxide storage is $248.04 per kW-year ($20.67 per kW-month) for iron oxide storage, increasing with inflation in future periods. The actual costs are uncertain given this resource is relatively new for commercial energy use.

Table 7.9: Storage Levelized Cost ($kW-month)

Year	Flow Battery 4-hour	Flow Battery 8-hour	Iron Oxide 100-hour
2026	15.01	16.31	20.67
2030	15.26	16.62	21.06
2035	20.46	22.15	33.66
2040	21.45	23.27	34.33
2045	22.54	24.50	35.05

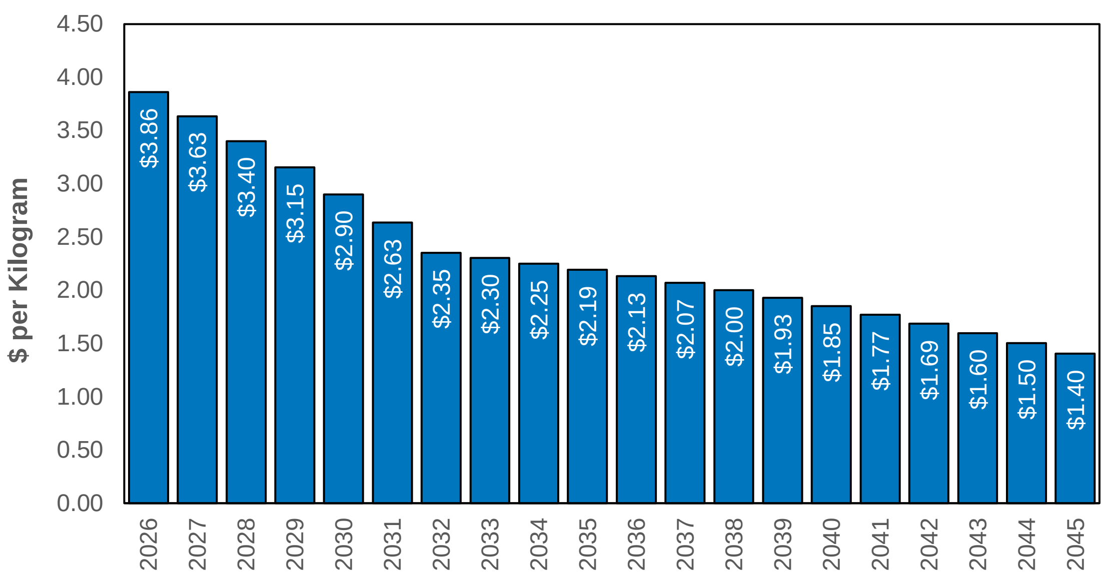
Renewable Green Hydrogen

The use of green hydrogen, in the energy sector has been considered as a perennial option for the distant future. This technology allows long-duration energy storage with the potential to store enough power to continuously run for several days. Hydrogen can be delivered by pipeline, truck, or rail and stored in tanks or underground caverns before being converted back to power using a fuel cell or hydrogen-fueled turbine. The ability to store hydrogen in tanks similar to liquid air means medium term durations can be obtained. Significant research and development (R&D) dedicated to green hydrogen technologies in transportation and other sectors may result in reduced costs or increased operating efficiency. Transportation and other sectors could possibly 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, absent carbon sequestration, results may produce similar levels of greenhouse gas emissions (GHG) from the combustion of the underlying fuels. If hydrogen is obtained from clean energy through either electrolysis of water,[69] pyrolysis,[70] or even mined, the amount of associated GHG emissions can be greatly reduced and therefor considered green hydrogen. If renewable energy prices are low, the operating cost of creating green hydrogen could also fall if hydrogen producers have access to power with low wholesale electricity prices; however, capital costs would remain steady without significant technology enhancements.

Converting hydrogen back into power could be done with a hydrogen fuel cell or directly in a combustion turbine similar to natural gas-fired generation. Figure 7.3 shows the forecasted delivered price (nominal) of green hydrogen to a potential fuel facility in Avista's service territory[71]. The development and delivery of green hydrogen is estimated based on the projected cost of electrolyzer technology with reduction in costs expected due to scaling and access to low-cost renewable electric power and water.

Figure 7.3: Wholesale Green Hydrogen Costs per Kilogram



69 Current estimates require 2-3 gallons of water to create 1 kilogram of hydrogen.
70 Involves cracking natural gas into hydrogen and carbon black using electricity from clean resources.
71 1 kg of hydrogen is equivalent to 0.12 mmbtu natural gas or if hydrogen is $3.86 per kg is equal to $32.17 per mmbtu of natural gas equivalent.

The second step in the hydrogen fuel concept is to convert the hydrogen back to power. For this conversion, a fuel cell would be assembled for utility scale needs (Avista uses 25 MW increments for this resource). The estimated capital cost for a fuel cell is $7,095 per kW with a forty-hour storage vessel plus fixed O&M at $200 per kW-year (2026 dollars). Table 7.10 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 than a CT to provide an emission free resource and due to likely limitations of storing the quantity of fuel required to operate a CT.

There are significant safety concerns relative to hydrogen to be resolved and mitigated as hydrogen fuel ignites more easily than gasoline or natural gas. 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 hydrogen handling would be necessary to ensure safe use. Appropriate engineering along with safety controls and guidelines could mitigate the safety risks 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 CT, currently co-firing is possible at Avista’s Coyote Springs 2 and Rathdrum units if adequate cost-effective hydrogen supplies are available. While this is a viable option, Avista also considers an ammonia turbine to address storage and safety concerns with hydrogen.

Ammonia

An alternative resource option to hydrogen is clean ammonia.[72] Ammonia could be sourced from the same process as green hydrogen, but ammonia requires an additional step by adding nitrogen using the Haber-Bosch process. Current estimates, considering the hydrogen electrolysis process, estimate the round-trip efficiency of this technology with a CT for power production at 13%,[73] although with technology improvements the round-trip efficiency may reach 20%. The advantage of ammonia as a fuel over hydrogen is its ability to be stored in larger volumes in an aqueous form and transported in larger quantities at a lower cost. Hydrogen storage in large quantities requires large geologic storage and this is not known to exist near Avista’s service area.

For this resource option, two 90 MW capacity combustion turbines (180 MW) using a common 30,000 metric ton storage tank could hold 55,812 MWh hours of energy storage, enough to generate power for 310 consecutive hours at full capacity. Ammonia storage

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[72] Using ammonia as a fuel is clean from a GHG perspective but burning it emits NOx as part of the combustion process. Manufacturers are currently working on SCR controls for ammonia fuel related NOx emissions, in the meantime, Avista assumes 0.015 lbs per mmbtu of combustion for this emission.

[73] This assumes one metric ton of ammonia requires 13.9 MWh of power from the upstream processes including 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.

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

Avista estimates ammonia gas turbine capital costs at $1,079 per kW (2026 dollars) and expected to increase with inflation due to the use of mature technology. In 2026, fixed O&M costs are $16.74 per kW-year and carry a $3.75 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 7.3 adjusted for conversion and transportation costs. As ammonia will be created from clean 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 7.10.

Table 7.10: 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)
2026	89.52	131.42	12.84	215.12
2030	97.75	103.95	14.02	234.38
2035	109.10	82.92	15.64	260.92
2040	121.77	63.70	17.46	290.49
2045	135.92	46.02	19.49	323.40

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management and are considered renewable and clean resources. In the biomass generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale levels of generation. Avista’s 50 MW Kettle Falls Generation Station consumes more than 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 this 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 not being able to secure a reliable long-term fuel source.

Based on market analysis of fuel supply and the 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 $5,308 per kW in addition to the $32.09 per kW-year and $4.13 per MWh of fixed and variable O&M costs (2026 dollars).

The levelized cost is $649.18 per kW-year ($54.10 per kW-month) for a 2026 project plus fuel and variable O&M costs. Avista modeled two methods of creating new biomass power for this IRP's analysis: the first is to upgrade the existing Kettle Falls facility by 10 MW and the second is to add a second unit to the facility.

Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal GHG 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 geothermal resources. Ongoing geothermal costs are low, but the capital required for locating and proving viable sites is significant. The cost estimate for a future geothermal PPA is $57.90 per MWh in 2026 at Avista's transmission interconnection point.

Nuclear

Avista includes nuclear power as a non-emitting fuel resource option by modeling small modular reactors (SMRs). 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 will have challenges developing a nuclear project. In addition, a project may require partnerships with other utilities in the Western Interconnect who want to incorporate nuclear power into their resource mix and offer Avista a PPA.

The viability of nuclear power is changing 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 rely on industry studies, recent nuclear plant license proposals, and the small number of recently completed projects. SMR designs could increase the potential for additional nuclear generation by shortening the permitting and construction phase and making these traditionally large projects (over 1,000 MWs) a better fit for smaller utilities. Given this possibility, Avista included an option for small scale nuclear power in the IRP analysis. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $143.76 per MWh assuming capital costs of $8,224 per kW (2026 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 the technologies become economically viable with any changes in state or federal incentives.

Exclusion from the analysis does not automatically exclude non-modeled technologies from Avista's future resource portfolio. The non-modeled resources can still compete with resources identified in the resource strategy through competitive acquisition processes when the Company solicits resources to fill known resource needs. Competitive acquisition processes can identify cost effective technologies to displace resources in the resource strategy. Another possibility includes acquisition through a Public Utility Regulatory Policies Act (PURPA) contract. PURPA allows developers to sell qualifying power to Avista at set prices and terms[74] outside of an RFP process.

Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane 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 fell 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 Northwest Power and Conservation Council (NPCC) estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Many landfills consider cleaning the landfill methane to create pipeline quality gas due to low wholesale electric market prices. This form of RNG has become an option for natural gas utilities to offer a renewable gas alternative to customers. The duration of this form of gas 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)

Plants with anaerobic digesters 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 natural gas pipelines as RNG. These facilities tend to be significantly smaller than most utility-scale generation projects at less than five megawatts. Most digester facilities are at large dairy and cattle feedlots, but like landfill gas, many developers are opting to inject the gas into natural gas pipelines as RNG to achieve higher returns on their investment.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed help 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 of these projects offset energy use at the facility so there may be little, if any, surplus generation

[74] PURPA rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

capability. Avista currently has a 260-kW wastewater digester system under a net metered PURPA contract with a Spokane County wastewater facility.

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 using 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 development 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 such costs are driven by host operations. The best method for the utility to acquire this technology is likely through PURPA or through a future RFP.

Coal

New coal-fired plants are extremely unlikely due to current policies, 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 to distribute to buildings via a pipeline for end use space and water heating. Avista provided steam for downtown Spokane using a coal-fired steam plant, a concept still used in many cities and college campuses in the U.S. and Europe but using natural gas as a fuel source. Creating new heating districts necessitates suitable conditions, collaborative partners, and a forward-thinking approach, much like the developments seen in Spokane's University District.

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 Washington Nuclear Project

Number 3 (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 BPA's New Resource 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 priced, 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 when it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs and likely take place after the current BPA agreements with public power customers ends in 2027. Purchasing power from BPA is advantageous as it's counted as nearly carbon free and can be used for compliance with Washington's Clean Energy Transformation Act (CETA) legislation and the CCA, but this benefit may result in a premium cost.

Existing Resources Owned by Others

Avista has purchased long-term energy and capacity from regional generation, specifically the Public Utility Districts in the Mid-Columbia region, Columbia Basin Hydro's irrigation projects, and a tolling agreement for the Lancaster Generating Station. Avista contracts are discussed in Chapter 4, but extensions or new agreements could be signed. If utilities are long on capacity, it is possible to develop agreements to increase Avista's capacity position. Since these potential agreements are based on existing assets, prices depend on future markets and may not be cost-based. Avista could acquire or contract for energy and capacity of existing facilities without long-term agreements. The Company anticipates these resources will be offered into future RFPs and may replace any selected resources.

Upgrade Opportunities

Avista has investigated opportunities to add capacity at existing facilities for the last several IRPs and implementing these projects if and when cost effective. The potential project upgrade opportunities for this IRP are outlined below.

Rathdrum CT

There are two options to upgrade the existing Rathdrum CT. The first is to uprate the combustion and turbine components at the Rathdrum CT, as the firing temperature can increase to 2,055 degrees from 2,020 degrees providing a 5 MW increase in output. The second project would install a new inlet evaporation system that could increase the Rathdrum CT capacity by 10 MW on a peak summer day, but no additional energy is expected during winter months.

Existing PPA Renewals and/or Repowering

Avista has three renewable energy PPAs expiring within the current IRP time horizon. The analysis includes the opportunity to repower facilities or renew the PPA at prices reflective of similar project pricing. For Palouse wind, the PPA is assumed to be able to be repowered to 120 MW in 2043. Although the Rattlesnake Flat Wind PPA does not assume a repower option due to transmission limitations, it is eligible for renewal in 2041. Adams-Neilson Solar remains at 20 MWs with a renewal option in 2039.

Non-Energy Impacts

Washington's CETA requires investor-owned utilities to consider equity-related non-energy impacts (NEIs) in integrated resource planning. Avista contracted with DNV for the 2023 IRP to perform a NEI study on supply-side resources 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.

DNV completed a supply-side NEI database and final report on April 8, 2022. Avista includes NEIs using this study in 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 NEIs include the societal impacts of Avista's decision making when selecting new resources and represent quantifiable values to prioritize resource choices. By including these impacts, the analysis can prioritize resource decisions more equitably. For example, resources with air emissions versus those without emissions are evaluated to consider the environmental impact on local communities. The NEI values used for this analysis are in Table 7.13.

There were areas with insufficient information for DNV to provide estimated NEI values for any specific NEI types for specific supply-side resources. Where Avista did not have a value from DNV, it estimated values by using approximation techniques. For many of these areas, the research value and effort needed to address these gaps were significant. Examples of some of these areas 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, however quantifying these would require significant time and investment. It appears a more cost-effective consistent approach would be best conducted at a state-wide level.

As part of an effort to continue to enhance the use of NEIs in the IRP Avista acquired the IMPLAN model. IMPLAN is an economic model where the user inputs the direct impacts of investments, and the model calculates the indirect and induced economic and employment impacts of the investments. For example, the investment in a local wind project has a direct investment in the equipment and employment used to develop the project. The indirect effects are the impacts to the local economy of the related spending, such as construction workers and spending money at local restaurants and hotels during the development of the wind site. The induced effects are based on the multiplier process in the local economy where the local recipients of the hypothetical wind project would spend a portion of that money on local goods and services.

Avista used IMPLAN to estimate the economic effects to the local economy and then used the results in the NEI portion of the IRP analysis. IMPLAN was used to model the impacts of both the capital spending and the operation of different types of resources. Avista also considered the economic effects of plant construction by placing an economic benefit for local generation resources compared to out-of-service area resources for selection in this plan. Table 7.11 shows the resource NEI values used in developing the IRP. The negative numbers indicated a benefit of the resource, and a positive value represents a cost. The economic benefits include the value of induced and indirect economic growth from operating the resource. Safety includes the estimated cost of potential injuries or deaths. Public health includes costs related to air emissions other than GHG. Lastly, operating jobs per MW is included as a reference point of the estimated long-term jobs created per MW of the resource.

Table 7.11: IRP Resource NEI Values

<table>
<tr><th>Resource</th><th>Economic Benefits ($/MWh)</th><th>Safety ($/MWh)</th><th>Public Health ($/MWh)</th><th>Operating Jobs (per MW)</th></tr>
<tr><td>Solar (Washington)</td><td>-0.71</td><td rowspan="2">0.23</td><td rowspan="2">N/A</td><td rowspan="2">0.02</td></tr>
<tr><td>Solar (Out of State)</td><td>-0.30</td></tr>
<tr><td>Wind (Washington)</td><td>-0.57</td><td rowspan="2">0.44</td><td rowspan="2">N/A</td><td rowspan="2">0.04</td></tr>
<tr><td>Wind (Out of State)</td><td>-0.29</td></tr>
<tr><td>Natural Gas SCCT</td><td rowspan="3">-4.81</td><td rowspan="3">0.14</td><td>5.28</td><td rowspan="3">0.51</td></tr>
<tr><td>Natural Gas CCCT</td><td>2.04</td></tr>
<tr><td>Power to Gas SCCT</td><td>N/A</td></tr>
<tr><td>Storage</td><td>-0.60</td><td>N/A</td><td>N/A</td><td>0.25</td></tr>
<tr><td>Wood Biomass</td><td>-4.69</td><td>0.19</td><td>14.85</td><td>0.32</td></tr>
<tr><td>Small Modular Nuclear Reactor</td><td>-0.50</td><td>0.13</td><td>N/A</td><td>0.60</td></tr>
<tr><td>Pumped Hydro</td><td>-0.37</td><td>0.30</td><td>N/A</td><td>0.07</td></tr>
<tr><td>Hydrogen Fuel Cell</td><td>-4.81</td><td>0.14</td><td>N/A</td><td>0.51</td></tr>
<tr><td>Geothermal</td><td>-3.20</td><td>0.14</td><td>N/A</td><td>0.53</td></tr>
</table>

8. Transmission & Distribution Planning

This chapter introduces Avista's Transmission and Distribution (T&D) systems, 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 chapter also describes how distribution planning is incorporated into the Integrated Resource Plan (IRP) and Avista's merchant transmissions system rights.

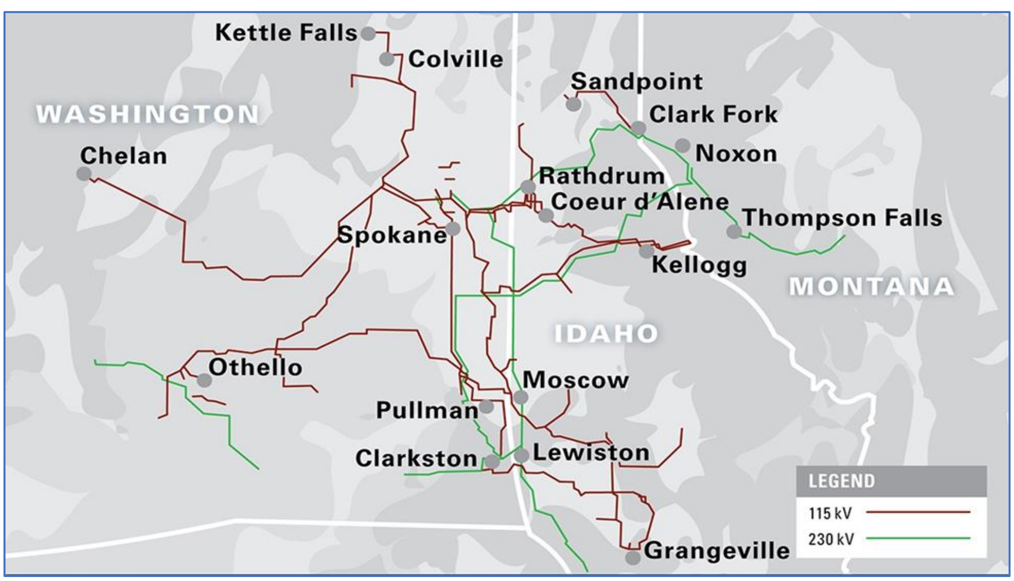
Section Highlights

- Transmission Planning estimates costs of locating new generation on Avista's system for the IRP.
- Avista formed a Distribution Planning Advisory Group (DPAG) for additional involvement of interested parties, education, and transparency.
- Avista's cluster study process for new generation connects includes 26 projects, including wind, solar, energy storage, natural gas, biomass, and hydro.

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 1,600 miles of 115 kV transmission lines (see Figure 8.1).

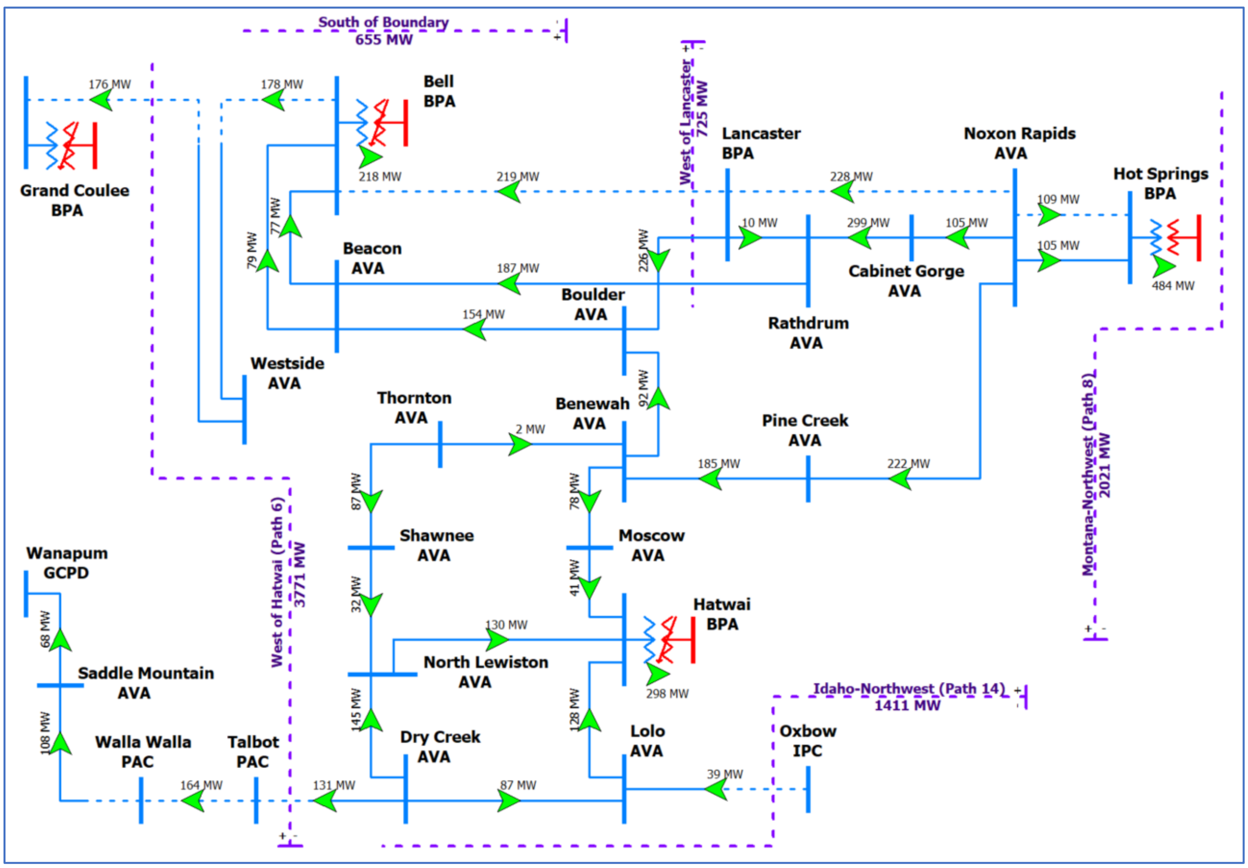
Figure 8.1: Avista Transmission System



230 kV Transmission System

The backbone of Avista's Transmission System operates at 230 kV. Figure 8.2 shows a station-level depiction of Avista's 230 kV Transmission System including network interconnections to neighboring utilities and relevant path boundaries. 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 8.2: 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.[75] See Figure 8.3 for the map of NERC Interconnections including WECC.

RC West

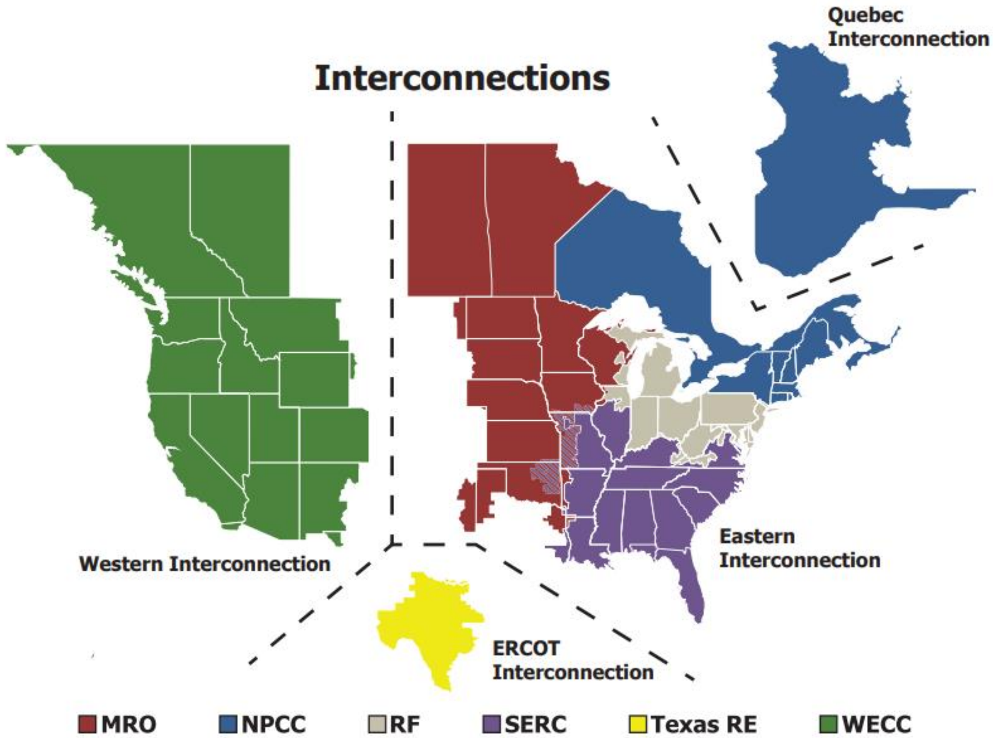
California Independent System Operator's (CAISO) Reliability Coordinator (RC) West performs the federally mandated reliability coordination function for a portion of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system,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

Western Power Pool

Avista is a member of the Western Power Pool (WPP)[76], 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) and Avista participates in each.

[75] NERC Interconnections.pdf
[76] The organization was formally named the Northwest Power Pool.

Figure 8.3: NERC Interconnection Map



NorthernGrid

NorthernGrid formed on January 1, 2020, and includes membership from fourteen utility organizations within the Northwest and many external parties. 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, which can be found on Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat:

- 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 parties, including, but not limited to transmission customers, interconnection customers, and state authorities.

Additional information regarding Avista's system planning work is in the Transmission Planning folder on Avista's OASIS site noted above. Avista's most recent transmission planning document highlights several areas for additional transmission expansion work including:

- **Big Bend** - Transmission system capacity and performance has significantly improved with the completion of the Othello Substation and an interconnecting 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 improved reliability and reduced the impacts of system faults. This project supports 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 projects improved transmission system performance in northern Idaho. The addition and expansion of distribution substations and a reinforced 115 kV transmission system were 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 contributes to heavily loaded distribution facilities. Additional performance issues have been identified that impact 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 determine how to best address a possible double transformer outage in this area.

- **Spokane** - Several performance issues exist in the Spokane area transmission system, and they are expected to get worse with additional load growth. The Westside 230 kV station capacity increase and Sunset Substation rebuild are complete. The staged construction of new facilities to support load growth in the West Plains is under development with the Blue-Bird – Garden Springs 230 kV project. A new 230 kV source into the greater Spokane area will offload the Beacon station, improving system performance 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

A summary of the generation interconnection location, size, and associated costs for new and existing generation sites are listed in Tables 8.1 and 8.2 below. Further information regarding each alternative can be found in the detailed integration study in Appendix E. These studies provide a high-level view of generation integration, performance, and cost estimates, and are similar to the system impact 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 8.1: New Generation Sites - Integration Cost Estimates

Point of Interconnection (POI) Station or Area of Integration	Request (MW)	POI Voltage	Cost Estimate ($ million)[77]
Big Bend area near Lind (Tokio)	100/200	230 kV	127.8
Big Bend area near Odessa	100/200/300	230 kV	170.5
Big Bend area near Othello	100/200	230 kV	216.8
Big Bend area near Othello	300	230 kV	258.7
Big Bend area near Reardan	50	115 kV	9.7
Big Bend area near Reardan	100	115 kV	12.8
Lewiston/Clarkston area	100/200/300	230 kV	1.9
Lower Granite area	100/200/300	230 kV	2.9
Palouse area, near Benewah (Tekoa)	100/200	230 kV	2.4
Rathdrum Prairie, north Greensferry Rd	100	230 kV	34.0
Rathdrum Prairie, north Greensferry Rd	200/300/400	230 kV	53.9
Sandpoint Area	50	115 kV	1.6
Sandpoint Area	100/150	115 kV	48.2
West Plains area north of Airway Heights	100/200/300	230 kV	2.4

Table 8.2: Existing Generation Sites - Integration Cost Estimates

Point of Interconnection (POI) Station or Area of Integration	Request (MW)	POI Voltage	Cost Estimate ($ million)
Kettle Falls Station	50	115 kV	1.6
Kettle Falls Station	100	115 kV	19.0
Northeast Station	50	115 kV	1.6
Northeast Station	100	115 kV	7.7
Northeast Station	200	230 kV	25.9
Palouse Wind, at Thornton Station	100/200	230 kV	1.4
Rathdrum Station	25/50	115 kV	11.1
Rathdrum Station	100	230 kV	15.9
Rathdrum Station	200	230 kV	48.4

Large Generation Interconnection Requests

Third-party generation entities may request transmission studies to understand the cost and timelines required for integrating potential new generation projects. These requests follow a defined FERC process to estimate the system impacts, the facility requirements, and cost estimates for project integration. After this process is completed, a contract to integrate the generation interconnection project may occur and negotiations can begin to enter into a transmission agreement, if necessary. Table 8.3 lists information associated with potential third-party resource additions currently in Avista's interconnection queue.[78]

[77] Cost estimates are in 2024 dollars and use engineering judgment with a 50% margin for error.
[78] OATI OASIS.

Table 8.3: Third-Party Large Generation Interconnection Requests

Serial or Cluster Number	Type	County	State	Size (MW)
Q59	Solar/Storage	Adams	WA	60
Q60	Solar/Storage	Asotin	WA	150
Q97	Solar/Storage	Nez Perce	ID	100
TCS-03	Solar/Storage	Adams	WA	80
TCS-14	Wind/Storage	Garfield	WA	375
CS23-06	Wind	Whitman	WA	256
CS23-12	Storage	Franklin	WA	199
CS23-13	Solar	Lincoln	WA	40
CS23-14	Solar	Spokane	WA	40
CS24-01	Solar	Adams	WA	1.1
CS24-02	Storage	Spokane	WA	0.5
CS24-03	Storage	Adams	WA	150
CS24-04	Storage	Spokane	WA	100
CS24-05	Natural Gas CT	Kootenai	ID	203
CS24-06	Natural Gas CT	Bonner	ID	120
CS24-07	Solar	Adams	WA	2
CS24-08	Solar/Storage	Franklin	WA	199
CS24-09	Solar	Adams	WA	9.5
CS24-10	Solar/Storage	Spokane	WA	80
CS24-11	Solar	Whitman	WA	70
CS24-12	Solar	Whitman	WA	40
CS24-13	Solar	Whitman	WA	95
CS24-14	Solar	Spokane	WA	40
CS24-15	Wind/Storage	Lincoln	WA	300

Future Transmission Projects Under Consideration

Blue Bird – Garden Springs 230 kV Project

Avista's system planning through the 10-year assessment planning horizon identified transmission system needs for load growth across the south and west of Spokane. Studies show system operability is strained and results in reduced system flexibility, affecting safety, system resiliency, and ultimately service to Avista customers. Continued load growth only amplifies this situation in the future.

The Blue Bird - Garden Springs 230 kV project was identified as the backbone piece of a broader West Plains Transmission Reinforcement. The project's primary goal is to develop a new and independent 230 kV source west of Spokane. This goal will be addressed by sourcing 230 kV from BPA Bell - Coulee #5 230 kV Transmission Line to improve contingency performance and increase system stability. The new 230 kV source will provide the required reliability and operational flexibility to serve current and forecasted loads.

Increased transmission service capability is an additional benefit of developing a new and independent 230 kV source west of Spokane. The location of this new 230 kV connection is anticipated to increase power transfer capability between Avista and BPA by 10-30% depending on the season.

North Plains Connector

This IRP considers a proposed regional transmission project to connect the Western Interconnect with the Eastern Interconnect as a resource option. The project consists of developing a 3,000 MW capacity direct current line between Colstrip, Montana, and North Dakota with an on-line date of 2033. The end points in North Dakota would give Avista access to both the Midcontinent Independ System Operator (MISO) and Southwest Power Pool (SPP) markets to buy or sell power and provide access to generation resources in the mid-continent with different weather patterns. This IRP evaluates this resource as a 300 MW share utilizing the transmission path as a capacity only resource limited by the qualifying capacity credit (QCC) from Montana located generation.

Colstrip Transmission System Upgrade

Avista and the other owners of the Colstrip Transmission System are evaluating upgrades to the existing 500 kV transmission lines and supporting 230 kV and 115 kV infrastructure. These upgrades would increase power transfers out of Montana by approximately 900 MW. The purpose of this study is to better identify the simultaneous increase in transfer capability across the Montana to Northwest and West of Hatwai WECC rated paths. Montana to Washington 500 kV transmission system upgrades were last studied by NorthWestern, BPA, and Avista in May 2012, as part of the Colstrip to Mid-Columbia Upgrade Project Study.

Lolo - Oxbow Upgrade and Optimization

Avista, as a prime recipient, in partnership with Idaho Power Company, is seeking grant funding for their Lolo - Oxbow Transmission Upgrade and Optimization project. This project will upgrade the Lolo - Oxbow 230 kV Transmission Line with high-capacity conductors, wildfire resilient designs and materials. Additionally, the project includes integrating Idaho Power's new Pallette Junction Station and two SmartValve technology deployments. These improvements will increase interregional transfer capability by 450 MW between the Pacific Northwest and Mountain regions, presenting an opportunity to increase the build of renewable energy resources in the region.

The Lolo - Oxbow Upgrade and Optimization project would bring innovative technologies together resulting in improvements to interregional transfer capability by 450 MW from Avista to Idaho and up to 185 MW in the opposite direction. The two innovative technologies planned for this project are:

1) SmartValve technology opens the door to dynamically controlling and optimizing power flows, and

2) Infravision technology speeds transmission line construction with drone pull-line stringing instead of helicopter use.

The local communities and region would benefit from capacity upgrades enabling future generation interconnection opportunities to the Lolo - Oxbow 230 kV Transmission Line. If awarded, there will be community benefit funding available for up to $3.3 million. Additionally, through these upgrades, Avista will work towards further workforce development in energy-supportive roles, such as on-site equipment training, special operator training, and other job skill opportunities.

Distribution Resource Planning

Avista continually evaluates its distribution system for reliability, level of service, and future capacity needs. The distribution system consists of about 380 feeders covering 30,000 square miles, ranging from three to 73 miles. Avista serves 414,000 electric customers on its distribution grid.

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.

Over the last several IRP cycles, Avista has continuously developed and improved its processes and analytical abilities to allow distributed energy resources (DERs) to be fairly evaluated for their stacked benefits as a resource and their impact to the distribution grid. The growth of DERs on Avista's system has reached a point where incorporating DER impacts into the upcoming planning assessment (2025) will provide actionable insights.

Overall, the existing impact of DERs on the distribution system has been minimal. However, there are a few feeders approaching impactful levels of DER penetration (Table 8.4). The tools and confidence to analyze the future DER impacts has arrived just as the uptake of DERs is becoming significant. In addition, the DER Potential Study provides substantial pieces of missing data. These study results give Avista a reasonable estimate of future DER penetration of where new generation or even electric vehicle load could locate. The study is available in Appendix F.

As a point of reference, Idaho and Washington has about 4,500 generators and a total of 40 MW of installed generation on the distribution system. Total generation's nameplate capacity whereas actual generation will be less. A majority of the generators are net metered PV solar.

Table 8.4: Existing Generator (Top 10 Feeders)

Feeder ID	Total Feeder Generation (kW)	No. Installations	Total No. Customers	Penetration (%)
TUR112	1,041	44	2,483	1.8
BKR12F1	794	83	2,481	3.3
GRA12F2	604	63	1,997	3.2
MIL12F3	495	57	2,173	2.6
FOR12F1	495	42	672	6.3
SUN12F2	477	61	2,154	2.8
F&C12F2	473	65	2,274	2.9
BLD12F4	473	45	1,991	2.3
LIB12F2	464	36	827	4.4
EFM12F1	457	44	1,461	3.0

Currently, Avista's third-party integration requests are few with only four small integrations in the cluster study process ranging in size from 0.5 MW to 9.5 MW. The final disposition of projects remains to be seen.

The above summarizes the existing state of resources on the distribution grid. As more DER resources arrive in the future, the grid may become constrained. The extent of the constraints, if any, will be revealed during the next system assessment as the measures fitting the definition of DERs are hypothetically added to the system in future years based on the DER Potential Study results.

Regardless of the cause of the grid constraint/deficiency (load growth, DER uptake, etc.), it will need a mitigation plan. Mitigation projects may include "poles and wires" or possibly another DER commonly referred to as non-wire alternatives. Where it makes financial sense, non-wire alternatives have value such as the deferral of capital expenditures for upgrading the system.

Deferred Distribution Capital Investment Considerations

New technologies such as energy storage, photovoltaics, and demand response programs may help defer or eliminate capital investments to increase capacity of distribution and transmission systems. 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 a particular distribution feeder or at a 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 helpful 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 distribution planning process needs to identify the deficiency well in advance of it becoming a performance issue. Longer evaluation periods provide enough time 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 not lending 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 manner is 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 next system assessment, Avista will use tools and data previously unavailable for the last assessment. The additional results will help facilitate the evaluation of DERs as mitigation options for any deficiencies identified.

Currently, Distribution Planning has not identified any projects meeting the criteria for an economic non-wire alternative. The identified near-term distribution projects require capacity increases and duration requirements exceeding reasonable DER capacity. However, the process is maturing and will identify system needs farther out in time and provide a longer runway needed to fully evaluate reasonable solutions including non-wire alternatives.

Reliability Impact of Distributed Energy Storage

Utility-scale batteries may offer benefits to grid operations including, but not limited to, reliability. 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. As discussed above, these solutions are typically referred to as 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 supply 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 energy 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 a 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 probability of failure 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 automatically be assumed with non-wire alternatives.

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 IRPs concentrate on the power supply and transmission requirements of these new loads, but do not estimate additional 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 the IRP planning horizon (discussed in Chapter 10). The scenarios use alternative forecasts for higher rates of electric vehicle (EV) adoption and a transition to using electric space and water heat of existing customers from natural gas. Additional load requirements by existing customers will have an impact to the distribution system as the system was not designed for the additional load. The system changes and costs to accommodate 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 the other 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. For this analysis, the second option is used to estimate the system costs.

Avista estimated the required replacement components based on the judgement of Avista's planning engineers and construction personnel. The high electrification scenario adds 930 MW of additional winter peak load by 2045, but for system planning purposes this is increased to 1,100 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. To account for new transmission and distribution costs in these high load forecasts $287 per kW of winter peak load on a levelized basis.

Distribution Planning Advisory Group Update

Avista formed the Distribution Planning Advisory Group (DPAG) following the 2021 Clean Energy Implementation Plan (CEIP). There have been five 2-hour long meetings covering various distribution topics including:

- March 2023: Power Delivery 101, Avista's Distribution System Overview
- June 2023: Performance Criteria, Planning Basics, System Assessment
- December 2023: System Needs, Solutions, DER Potential Study Update
- March 2024: DER Potential Study Results
- July 2024: Interconnection Process, Hosting Capacity Maps, DER Potential Assessment Maps

Future meetings and preliminary topics:

- October 2024: Weather models, Virtual power plants
- TBD: 2025 System Assessment kickoff – what it is and is not, modeling approach, performance criteria, outputs.

The meetings have been well attended and the engagement is slowly ramping up as comfort level increases. The results of the next system assessment should provide for interesting and collaborative discussions with DPAG members. The previous assessment was already well underway when the group formed so going through the next assessment should be more fruitful for those attending.

Merchant Transmission Rights

Avista has two types of transmission rights – those owned by Avista and those purchased from third parties. The first type includes Avista-owned transmission which is reserved and purchased by Avista's merchant department to serve its customers. This type of 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 Avista's generation and purchases transmission from the Avista transmission operator to ensure that energy can be delivered to customers. Avista must show a load serving need to reserve Network Transmission on the Avista-owned transmission system to ensure equitable access to the transmission capacity. Appendix J shows the projected need and future use of Avista's owned transmission system.

Avista also purchases transmission rights from other utilities to serve customers as listed in Table 8.5 below. 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 8.5: 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	7/30/2026
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
NorthWestern	Clearwater to AVA-System	100	9/1/2029

9. Market Analysis

This section will be available on October 1, 2024

10. Portfolio Scenarios

This section will be available on October 1, 2024

11. Action Items

The IRP continues to be an iterative and collaborative 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 and regulatory environment changes. This section provides an overview of the progress made on the 2023 Action Items and details the 2025 IRP Action Items for the 2027 IRP.

2023 IRP Action Items

- Incorporate the results of the DER potential study where appropriate for resource planning and load forecasting.

  The DER potential study included a spatial forecast for electric vehicles and customer owned generation. The study results for additional load and load reductions were included in the long-term load forecast used for resource selection within this IRP. The DER potential study is available in Appendix F.

- 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.

  Avista hired Energy Strategies to develop an estimates for capacity reserves to be held by the utility for different levels of VERs such as wind and solar. With these reserve estimates, Avista was able to calculate the incremental cost of holding these reserves. Furthermore, the reserves were also considered in the capacity planning of the system. Additional information about this study can be found in Chapter 5. The analysis concludes a cost of $0.15 to $0.19 per kW-month to integrate existing VER variability on the system, the study evaluated future portfolios with up to 2,500 MW of new wind and/or solar.

- 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.

  For this IRP, Avista utilized Applied Energy Group's (AEG) end use model to estimate future loads. This methodology is critical for modeling potential electrification and efficiency improvements over time. The study was used for the load forecast between 2030 and 2045. This was a drastic modeling change compared to previous methods, highlighting many issues to address in future forecasts, such as weather normalization and how to merge short-term versus *long-term forecasting methodologies. Avista will perform a plus delta review to improve and build upon for the next load forecast.*

- Investigate the potential use of PLEXOS for portfolio optimization, transmission, and resource valuation in future IRPs.

    Avista acquired PLEXOS to test its viability for use in long-term planning. Avista conducted a back-cast to validate performance of the tool. The back-cast found the PLEXOS model can sufficiently model Avista's system and has capabilities other models do not have, such as a more detailed hydro modeling capability. Avista found the tool could be used for resource planning including resource evaluation, capacity planning, and resource adequacy testing. The PLEXOS software comes at the expense of lost customization, added license fees, and additional employee time versus Avista's current modeling methodology. Avista chose not to use PLEXOS during the 2025 IRP for any analysis and will continue to evaluate whether or not to retain the model.

- 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.

    Avista continues to participate in the Western Power Pool's WRAP and continues to include the QCC estimates in this IRP. As the program develops and more information comes from the various studies conducted by Southwest Power Pool (SPP), Avista will follow the progress and incorporate study results as appropriate.

- Evaluate long-duration storage opportunities and technologies, including pumped hydro, iron-oxide, hydrogen, ammonia storage, and any other promising technology.

    Generic long-duration storage opportunities and technologies were included in this plan as resource options, a discussion of technologies included and can be found in Chapter 7. Avista will continue to participate in webinars, consultations with vendors and developers, and participate in other educational forums to follow developments in long duration storage technologies as they develop.

- Determine if the Company can estimate energy efficiency for Named Communities versus low-income.

Avista met with its energy efficiency consultant to understand the requirements for dividing energy efficiency savings potential by geographic area. Conducting such a study will require significant data currently not available for individual neighborhoods. Given the expense of developing useful estimates, Avista recommends keeping the current methodology by estimating the low income share of total energy efficiency potential and using these values as a proxy for Named Community potential. Avista still commits to exploring alternative means to estimate energy efficiency on the local level. One option, discussed in Chapter 6, is to validate if energy efficiency could offset the need for system improvements in specific communities when a potential distribution constraint may exist in the future.

- Study transmission access required to access energy markets as surplus clean energy resources are developed.

As mentioned in Chapter 2 and Chapter 8 of this plan, Avista has an opportunity to explore access to new markets such as Midcontinent Independent System Operator (MISO) and SPP, along with adding capability to southern Idaho resources. Avista will continue to evaluate the cost and benefit of this opportunity to include arbitrage. Further information regarding transmission can be found in Appendix D.

- Further discuss planning requirements for Washington's 2045 100% clean energy goals.

Avista is awaiting final rules for the Clean Energy Transformation Act (CETA) as it relates to the "use" of clean energy. Until final rules are approved, Avista is planning its system to generate enough clean energy on a monthly basis to cover Washington load (including losses). Furthermore, the Company is including an hourly analysis based on dispatch of resources in future markets and if the markets do not exist, to identify if it can meet load on an hourly basis in Chapter 2. Another issue regarding the 100% clean energy goal is related to the cost cap and how it will be applied.

2025 IRP Action Items

To prepare for the 2027 IRP planning process, the 2025 Action Plan considers input from Commission Staff, Avista's management team, and members of the IRP Technical Advisory Committee (TAC) regarding additional analysis and further development of projects for inclusion. These action items include both Company actions related to results of this plan and planning items to enhance the 2027 IRP.

Company Actions

- Determine the Northeast CT's retirement date and develop a plan for replacing the lost capacity.
- Pursue transmission expansion opportunities within Avista's service territory and those connecting to Avista's transmission system.
- Develop an all-source Request for Proposal (RFP) for the new resources needed to meet future capacity deficiencies and determine if renewable energy is cost effective as estimated in the PRS.
- Determine if a separate RFP should be conducted for Demand Response (DR) resources or incorporated within the all-source RFP.
- Investigate options to increase natural gas availability for existing and potential natural gas generation.

IRP Planning Actions

- Incorporate future policy requirements regarding CETA and/or the Climate Commitment Act (CCA) implementation as directed by the Washington Commission, legislature, or voter initiatives.
- Explore best practices for production cost, reliability, and capacity modeling, including utilizing enhancements to the Aurora model.
- Explore how end use load forecasting should or should not be included in the 2027 plan by reviewing lessons learned from the new load forecast process completed in the 2025 IRP.
- Consider combining natural gas and electric capacity expansion models to ensure the connection between energy uses are aligned for potential building electrification.
- Increase coordination between resource and distribution planning to ensure customers have the lowest cost investments to ensure a reliable delivery of energy.

- Work with the TAC to determine the best strategy for engagement, such as more frequent meetings (as experimented in this IRP), along with best available technologies to facilitate communication and data availability.

- Incorporate any new Customer Benefit Indicators (CBIs), targets, or directives from the 2025 Clean Energy Implementation Plan (CEIP).