2021 Integrated Resource Plan (Draft)

2022-2045 Study Period

Snohomish PUD

DRAFT

Power Supply Department

Acknowledgements

The Integrated Resource Plan benefits from the insights of a diverse team of subject matter experts, and company and community leaders. This team has strived to understand, study, and quantify the needs of Snohomish PUD and set forth a flexible, achievable plan to serve our customers with safe, affordable, and environmentally responsible electricity.

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1 - Executive Summary

Integrated resource planning is a comprehensive process that considers how a utility will provide reliable electric service to its customers at the lowest reasonable cost while adhering to the policy requirements of electric utilities. This process must also consider the risks and uncertainties inherent in a rapidly changing and complex industry. Accordingly, an integrated resource plan (IRP) must be flexible, allowing the utility to adapt to changing circumstances without adverse financial or operational impacts.[1] To achieve this objective, a range of alternatives are considered and evaluated, from which a preferred plan is established.

Key steps and elements in an IRP include:

1. Understand the planning environment and establish guiding principles;

2. Determine the potential range of future energy and capacity needs;

3. While considering potential future needs and the PUD's current position, establish a variety of scenarios the utility could face based on variations under the planning environment;

4. Define the types of demand- and supply-side resources considered to be reliable and commercially available over the study period to meet the needs identified in scenarios;

5. Craft optimized portfolios for each scenario that identify the mix of reliable and available resources best suited for meeting future energy and capacity needs, based on lowest reasonable cost criterion;

6. Find commonalities and themes across scenarios, selecting a portfolio or Long-Term Resource Strategy that best positions the utility to meet future needs while addressing potential risks; and

[1] Revised Code of Washington, Chapters 19.280 and 19.285 prescribe the statutory requirements of an integrated resource plan

7. Establish a near term action plan with steps the utility can take to implement the plan over the next two to four years.

The PUD’s 2021 IRP covers the 24-year planning horizon of 2022 through 2045. This unusual planning horizon length is to enable study of how the PUD will transition to 100% clean energy by 2045, as prescribed by Washington State’s Clean Energy Transformation Act.

Guiding Principles for 2021 IRP

The guiding principles for the PUD's 2021 IRP effort are to:

1. Meet load growth first by pursuing all cost-effective conservation;

2. Understand the probabilistic range of available energy and capacity from the PUD's existing resources and the overall impact on the load resource balance across the 24-year study period;

3. For future load growth not met by the PUD's existing/committed resources and new conservation acquisitions, pursue clean, renewable resource technologies whenever possible. Planning must take into consideration resource options "that provide the optimum balance of environmental and economic elements."[2]

4. Comply with all applicable Board policies, regulations, state laws, and established IRP planning standards; and

5. Preserve the PUD's flexibility to adapt to changing conditions.

PUD Portfolio Needs

The portfolio needs of a utility are generally classified into two categories: energy needs and capacity needs. Energy needs are measured as the capability to generate electricity, whereas capacity needs are measured as the capability to vary generation output on-demand. Based on the forecasted needs of the PUD, the 2021 IRP evaluates potential portfolios that can meet both categories of need, the results of which can be summarized below.

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[2] The Board of Commissioners adopted its Climate Change Policy and Strategies in March 2007. Full text available at http://www.snopud.com/AboutUs/environment/climate.ashx?p=1233

No Expected Annual Energy Needs after New Conservation until 2043

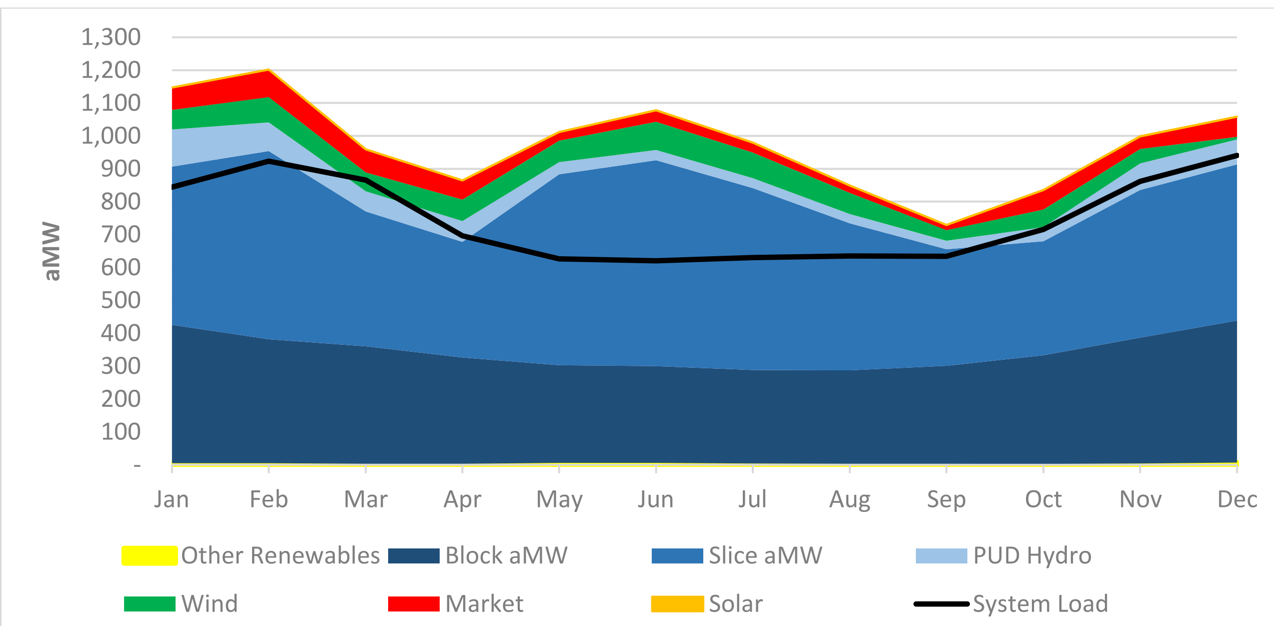
Under the 2021 IRP planning assumptions for the PUD's existing resources,[3] the PUD expects that the acquisition of new cost-effective cumulative conservation across the 2022 to 2045 study period will allow the PUD to maintain a surplus average annual energy position until 2043. In limited scenarios with high load growth trajectories, the PUD has small average annual energy deficits in the late 2030's. Due to the PUD's surplus position on an average annual basis, resources whose primary contribution is annual average energy do not help meet a forecasted need.

Figure 1-1 shows the PUD's 2020 actual monthly load and generation from its existing and committed resources.

Figure 1-1

2020 Actual Snohomish PUD Load and Existing and Committed Resources

(by Month, in aMW)



Seasonal Capacity Needs Persist

Historically, the PUD experiences its highest peak customer demand during the winter months of November through February (known as a "winter-peaking utility"). The highest customer

[3] The 2021 IRP establishes four planning standards against which potential resource portfolios are evaluated. More detail can be found in Section 5 – Analytical Framework.

demand typically occurs on-peak in the months of December or January. The PUD's highest peak winter demand occurred in December 2008 reaching 1560 MW**,** considerably higher than the December 2020 peak demand of 1364 MW. Even so, the December 2020 winter peak is over 180% of the 2020 actual average annual system demand of 749 aMW.

In addition to its winter capacity needs, it is expected that the PUD will have a growing summer capacity need due to climate change and customer's changing preferences for air-conditioning. To illustrate this need, the PUD's previous all-time summer peak occurred in July 2009 with a system demand of 946 MW but was eclipsed in June 2021 by a new record of 1134 MW.

These trends help to inform the 2021 IRP analysis, which shows that after all cost-effective conservation is acquired, a long-term capacity need exists in every scenario. These findings are consistent with the 2013 IRP, 2015 IRP Update, 2017 IRP and 2019 IRP Update. The 2021 IRP analysis also indicates an immediate capacity need, which is addressed by short-term market capacity products.

Regarding the PUD's long-term capacity needs, the 2021 IRP analysis finds that the acquisition of new cumulative conservation reduces the scale of capacity needs and defers the PUD's need for new long-term capacity resources until the mid-2020s. Acquiring a long-term capacity resource at that time will meet the PUD's seasonal and peak load needs, while serving to limit the PUD's exposure to price volatility and delivery risk in the short-term energy market.

While previous IRPs did not identify a specific long-term capacity resource, the 2021 IRP proposes that this capacity need be addressed with long-duration energy storage, augmented by cost-effective demand-side load shifting programs such as demand response and new "smart rate" programs. Other renewable resources predominantly available in the Northwest today, such as wind and solar energy, do not possess the operating characteristics necessary to meet the PUD's on-peak capacity need in a reliable and cost competitive manner at this time.[4] Long-

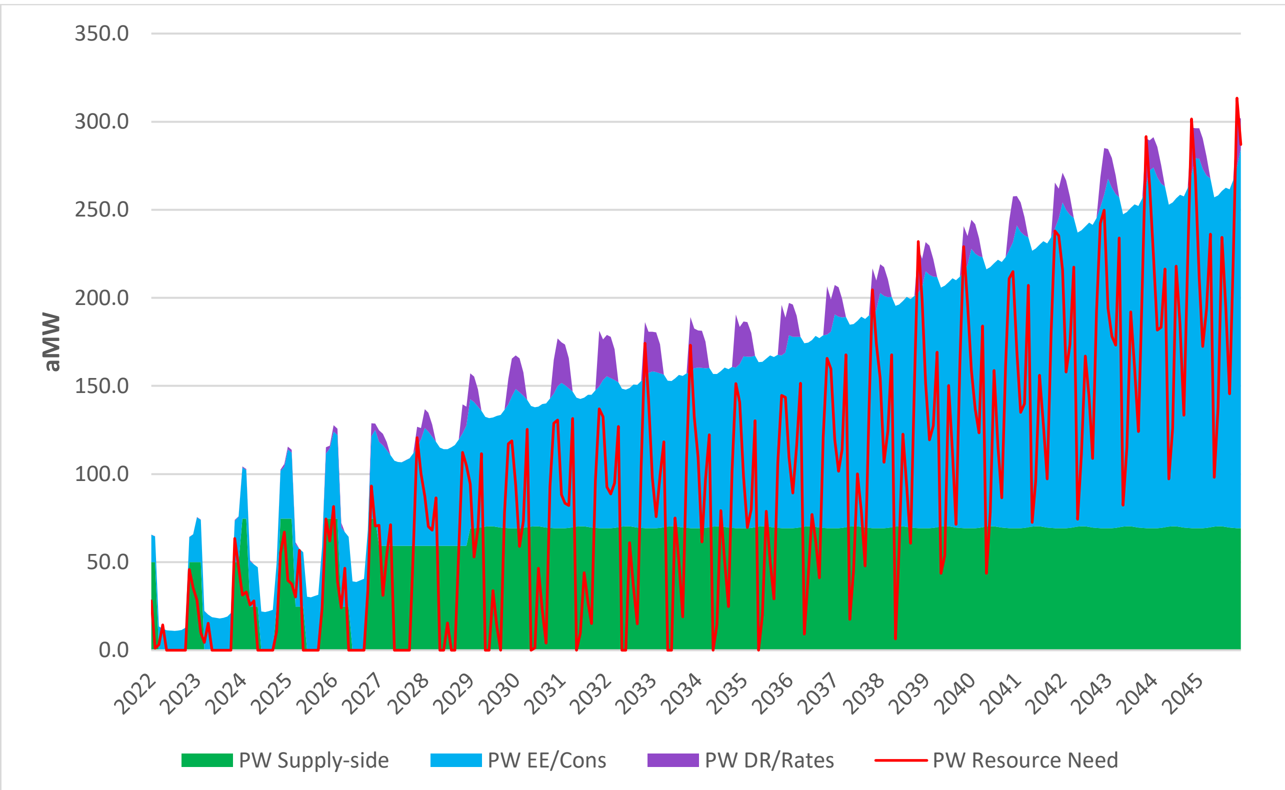
[4] See Section 5 for more discussion on Resource Options available to the District.

duration energy storage also carries a compliance benefit, being an eligible resource under Washington clean energy requirements.

For each scenario's portfolio, the 2021 IRP selected varying amounts of new conservation and supply-side resources to provide capacity for meeting the PUD's future seasonal and peak loads. Figure 1-2 displays one measure of the PUD's capacity needs (the red line) before new resource additions, and how proposed resource additions would "stack" to meet these needs. The chart reflects a portfolio in adverse water supply conditions.[5] Planning toward adverse outcomes helps create portfolios that are able to respond to likely (and unlikely) risks.

Figure 1-2

Snohomish PUD's Peak Week Needs and Proposed Resolutions for the Base Case Scenario under Adverse Conditions (P5) (in aMW)[6]



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[5] The PUD's load resource balance for Peak Week periods were modeled probabilistically across multiple scenarios and time periods. Section 5 details the Probabilistic Load Resource Balance Model.

[6] For more information on these planning metrics, see Section 5 – Analytical Framework

Key Findings of the 2021 IRP

The 2021 IRP is the first to consider how the PUD will plan for compliance with the Clean Energy Transformation Act (CETA), and the impacts to the regional supply mix and market environment that are expected to come with this policy change. Due to the PUD's history of investing in clean resources, the PUD's current carbon-free portfolio of resources is well-positioned to meet CETA requirements without incurring significant additional cost. More discussion on CETA compliance can be found in Section 6, Portfolios and Long-Term Resource Strategy.

Key Findings:

- **The PUD does not need to acquire additional clean or renewable resources in order to meet CETA compliance thresholds for clean energy.** CETA requires utilities to have at least 80% clean energy by 2030 and 100% by 2045. Because the PUD is expected to be surplus clean energy in most scenarios from 2022 to 2045, and because the PUD does not intend to acquire any emitting resources for its portfolio, it is anticipated that the PUD will be able to satisfy all CETA standards. Further discussion of how the PUD performed this analysis is given in Section 5 (Analytical Framework).

- **New energy efficiency and conservation is the single largest resource addition for every portfolio for each scenario**. Conservation is estimated to serve over 100% of the PUD's future load growth on an annual basis until 2043 for the Base Case as demonstrated in Figure 1-3 below, resulting in the PUD having only a small additional annual energy need toward the tail end of the study period under average hydrological conditions.[7] Certain scenarios include load growth trajectories that outpace available, cost-effective conservation, resulting in additional net load growth.

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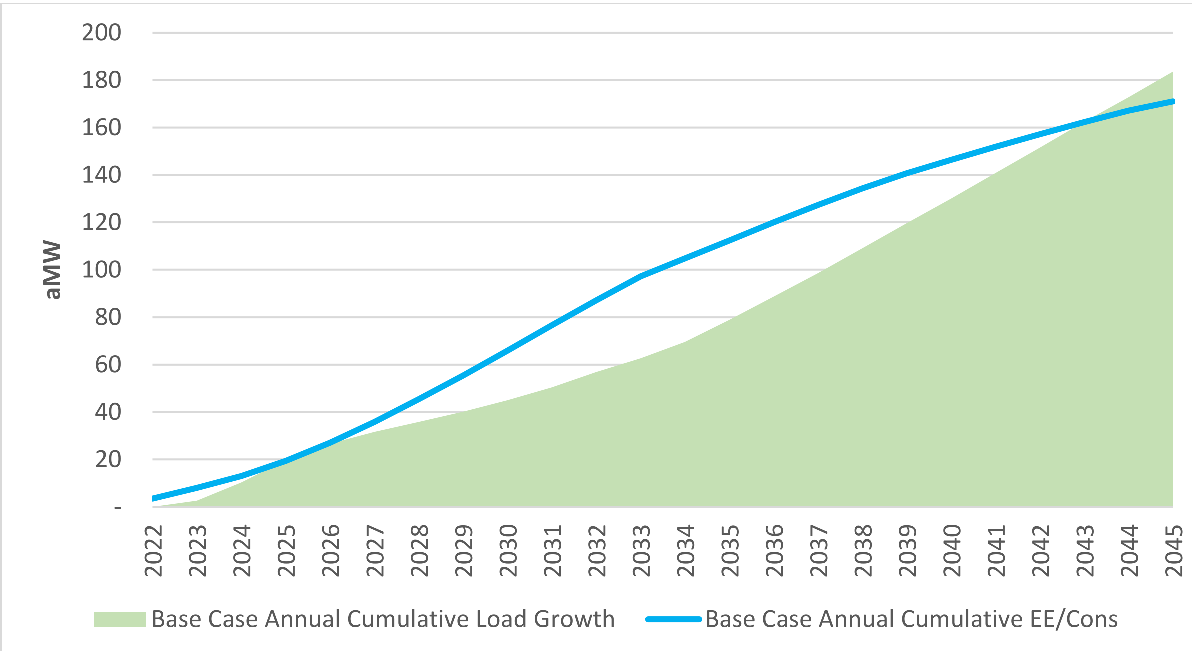
[7] After new conservation additions, the PUD forecasts no average annual energy need until 2043 unless 1) poor hydrological conditions occur/persist; 2) there is a fundamental change in Federal hydro operations that affect the PUD's long-term BPA power contract; 3) the post 2028 BPA products differ from existing product offerings.

Figure 1-3

Base Case Cumulative Load Growth Before New Conservation and New Annual Cumulative Cost-Effective Conservation



- **The need for capacity resource additions over the study period in all scenarios is driven by the Monthly On-Peak and Peak Week planning standards**.

- **Short-term and long-term capacity resource[8] acquisitions provide seasonal and peak load matching capabilities to augment the PUD's owned and contracted resources.** This augmentation ensures the winter planning standards are met in 95% of cases, resulting in the lowest cost portfolios. The lowest cost long-term capacity resources were found to be long-duration (8+ hour) storage resources in all scenarios.

- **Climate change analysis shows impacts to both the PUD's existing resource portfolio and its future resource needs**. Climate change analysis identifies expected changes to

[8] A capacity resource refers to a generator or source of electricity that can be turned on or off, or otherwise adjusted up or down as needed (or "dispatched") at the request of power grid operator or plant owner.

regional precipitation and temperature patterns across the study period. Winter needs are expected to gradually decline as a result of increased hydro production during the November through February period. Summer needs will increase over time with warmer temperatures and increased air conditioning load, while spring and summer hydro production levels decline due to reduced snowpack. The 2021 IRP considers a High Climate Change scenario in addition to the base climate change included in every other scenario and found measurable but modest incremental changes to the base climate change findings.[9]

- **The PUD will continue to meet its Washington state annual Energy Independence Act (EIA) renewables requirement through a combination of renewable energy credits (RECs) from existing PUD renewable resources, incremental hydro, and RECs allocated through the BPA long-term power contract and acquired from the market**. Post-2030, CETA's provision for 100% clean utilities to be deemed in compliance with the EIA's Renewable Portfolio Standard (RPS) provides significant incentive for the PUD to reach 100% ahead of the 2045 requirement date[10]; all scenarios indicate this is a high plausibility occurrence. Given the PUD's forecast surplus annual energy position under average water conditions, procuring some portion of compliance RECs from third parties in the 2020 - 2029 period was identified to be the most cost-effective way to meet the EIA's RPS requirements at this time.[11]

- **CETA's impact on the regional resource mix is expected to have significant implications for the wholesale market, putting downward pressure on average annual energy prices and increasing hourly price volatility.** These wholesale market effects provide economic opportunities for load-shifting or energy storing technologies, which are identified as core parts of the PUD's Long-Term Resource Strategy. Further discussion of the market price environment is discussed in Section 4, the Planning Environment.

[9] Additional discussion on the methodology used is provided in Section 5: Analytical Framework.
[10] RCW 19.285.040(2)(m)
[11] The 2021 IRP Action Plan contains an action item to develop a least cost approach to meet the PUD's annual state renewables requirement, including monitoring applicability of the no load growth and financial cost cap methods, and procuring RECs from third parties for eligible renewable resources situated in Washington, Oregon, and Idaho.

Scenarios

The 2021 IRP utilized eight scenarios that considered the range of possible futures the PUD could face for the 2022 through 2045 study period. Figure 1-4 below summarizes key variables considered by the scenarios evaluated in the 2021 IRP analysis:[12]

Figure 1-4

Snohomish PUD's 2021 IRP Scenarios

	Average Annual Net Load Growth	**Average Electricity Prices ($/MWh) [2022 & 2045]**[13]	**Natural Gas Price ($/MMBtu) [2022 & 2045]**	**Highest Peak Week Electricity Prices ($/MWh) [2022 & 2045]**[14]	**Short description of unique consideration**
Base Case	0.93 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Expected Case
Low Growth	0.72 %	24.49 to 23.70	2.60 to 4.54	40.54 to 68.47	Lower load growth
High Growth	1.32 %	28.05 to 27.50	3.32 to 8.28	45.71 to 96.42	Higher load growth
Less BPA	0.93 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Lower Post-2028 BPA allocation
High Policy	1.28 %	54.30 to 27.37	2.68 to 6.36	83.06 to 92.95	Market price analysis of clean energy policy across Western United States
High Climate Change	0.93 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Higher climate change impact on PUD (RCP 8.5)
High Technology	0.93 %	25.53 to 28.63	2.68 to 6.36	40.33 to 81.18	High storage penetration across WECC market footprint
High Electrification	1.46 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Higher PUD rates of EV adoption and all-electric buildings

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[12] The 2021 IRP scenarios are described in Section 4 – *Scenario & Planning Assumptions*.
[13] Section 4 – *Scenarios & Planning Assumptions* describes the planning assumptions associated with the natural gas, carbon, and regional electric market price forecasts.
[14] The Peak Week Planning Standard considers hours 7-10 and 17-20 of days Monday-Friday for every month. As such, Highest Peak Week MWh prices represents the highest monthly average price for those hours on an annual basis for 2022 & 2045.

Long-Term Resource Strategy

The PUD's Long-Term Resource Strategy must be flexible enough to yield reasonably low costs for customers across a wide variety of potential futures but contain enough definition for the PUD to take specific actions, especially as it relates to the PUD's well-documented need for capacity resources.

Portfolio Development

For every scenario, each of which addresses a unique risk, the 2021 IRP leverages an integrated portfolio approach to determine a set of resource additions to meet the individual needs of that scenario. The integrated portfolio approach evaluates demand-side resources, supply-side resources, and market resources (including the market for environmental attributes) in a single economic optimization allowing the PUD to observe multiple dimensions of potential resource value. This approach helps quantify the peak capacity contributions of conservation relative to other resources, while simultaneously valuing its regulatory compliance value of reducing load subject to regulatory compliance obligations and seasonal energy value. Supply- and demand-side resources are evaluated using the same measurements, creating the best mix of resources to meet future needs based on the least-cost criterion.

From these scenarios and portfolios, each of which addresses a unique risk, commonalities and trends were analyzed to help select a set of actions and resources that would address needs across many futures and deliver benefits to the PUD regardless of which future may come to pass. The collection of these resource choices forms the basis for the PUD's Long-Term Resource Strategy.

Risk Factors

To address the challenge of developing a single resource strategy that is appropriate for several uncertain potential futures, the IRP considers a wide range of potential risk factors. By crafting scenarios that reflect these articulated risks, the IRP can identify the most economic portfolio combinations that satisfy the scenarios and seek commonalities to inform the preferred portfolio.

The risk factors studied in the IRP were identified collaboratively with customers and a cross-departmental team of PUD staff during a four-month Visioning Process. Those principal risk factors, and the scenario that most directly considers them is depicted in Figure 1-5 below.

Figure 1-5

Identified Risk Factors and Scenario Assignment

Risk	Scenario
Low Economic Growth and load	Low Growth
High Economic Growth and load	High Growth
High Rate of Electrification (including EVs and local policies requiring building electrification)	High Electrification
Less BPA resources available to the PUD (either through operational changes or the Post-2028 contract renegotiation process)	Less BPA
Higher rate of Climate Change	High Climate Change
Market Disruption due to Federal Policy changes, or proliferation of State energy policy changes across the WECC	High Policy
Market Disruption due to high penetration of Storage Resources across the WECC	High Technology

Scenario Results

Through comparative analysis, the IRP identifies a similar set of economically viable resource acquisitions to meet PUD needs across scenarios. While the scale and timing of some resource acquisitions varied modestly between scenarios, the majority of portfolio actions remained at similar scales and similar timings. The most significant deviation across portfolios is found in two areas:

1. The highest load growth trajectory scenarios
2. During the latter portion of the study periods, specifically 2030 and beyond.

The timing of these potential deviations suggests that the PUD is likely to have additional time to address the unique needs of those scenarios and will be revisited in future plans. The stability of results across scenarios, came be seen in the similarity of results as expressed in Figure 1-6 below.

Figure 1-6

Portfolio Additions in Years 1-10 Across Scenarios

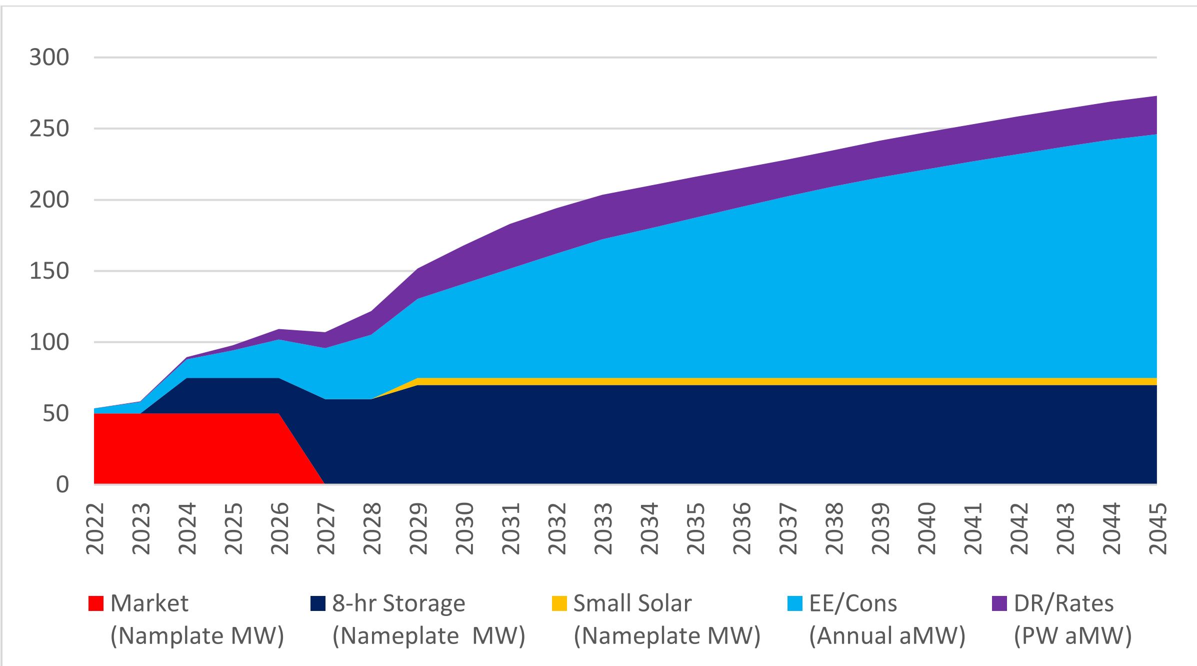
	Market Contract (Nameplate MW)	EE/Cons (Cumulative Annual aMW in Year 10)	8-hr Storage (Nameplate MW)	Local Small Solar (Nameplate MW)	Large Utility-scale Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (Cumulative Peak Week aMW in Year 10)
Base Case	50	77	70	5	0	0	31.6
High Growth	50	78	35	0	50	25	38.1
High Policy	75	81	70	5	0	0	30.9
Less BPA	50	81	70	5	0	0	36.6
High Technology	25	73	45	5	0	50	38.4
Low Growth Case	50	69	60	0	0	0	25.1
High Climate Change	25	77	50	0	0	0	32.2
High Electrification	50	77	45	5	0	75	26.2

Long-Term Resource Strategy Components

The stability of results across scenarios suggests that the resources added will provide value and meet portfolio needs across a wide range of possible futures. This stability allowed the PUD to select the Base Case scenario[15] to assign specific scale and timing estimates for planning. The Long-Term Resource Strategy is shown in Figure 1-7 and its component parts are described in the narrative sections that follow.

Figure 1-7

Base Case Portfolio Additions



Conservation

Conservation provides the foundation for the PUD's resource plan, providing multiple value streams for meeting portfolio needs. Conservation provides the PUD value by reducing load that otherwise would have occurred during peak hours, thus reducing capacity needs. Conservation also reduces pressure on the PUD's current portfolio of generating resources, helping to stretch within the load-based contractual ceiling for BPA power products. Further, conservation reduces load associated with regulatory obligations for the EIA and CETA, reducing regulatory costs. Two-year, four-year, and ten-year conservation targets are given in the table below.

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[15] The Base Case scenario represents the expected load, market, and existing portfolio resource generation outcomes at the time of publication.

Figure 1-8

Conservation Targets (Annual aMW)[16]

2023 (2-year)	2025 (4-year)	2031 (10-year)
7.96	19.35	76.59

Demand Response and Smart Rates

Demand Response and the development and adoption of Smart Rate programs provides the PUD with low-cost resources to meet time-limited capacity needs. The development of these programs is highly contingent upon the timing, rollout, and leveraging of the PUD's Advanced Metering Infrastructure (AMI) program. That infrastructure will facilitate developing the lowest cost load-shifting programs.

This interdependency necessitates some assumptions about the availability and development of these programs. The IRP makes a conservative assumption that AMI rollout will begin in 2025 and the PUD can incrementally develop programs on an annual basis after launch.

A comprehensive Demand Response Potential Assessment was developed in support of this IRP and additional details are contained therein. While AMI provides the capability and infrastructure to take advantage of many Demand Response programs, the technical potential of these programs is not forecast to meet all of the PUD's capacity needs, necessitating the acquisition of additional resources. The PUD's two-year, four-year, and ten-year demand response and smart rates targets (combined as DR targets) are given in the table below and are expressed in Peak Week aMW[17].

Figure 1-9

Demand Response Targets (Peak Week aMW)[18]

2023 (2-year)	2025 (4-year)	2031 (10-year)
0.6	3.6	31.6

[16] Conservation targets are expressed at the BPA busbar, cumulatively, such that the 2023 target is the targeted conservation acquired in 2022 & 2023 added together.

[17] Peak Week aMW is the average contributions across Hours 7-10 and 17-20 of Monday-Friday during the highest load week of each month, or 40 hours across a business week. The Peak Week Planning Standard is discussed in more detail in Section 5.

[18] DR targets are expressed at the BPA busbar, cumulatively, such that the 2023 target is the targeted DR capacity acquired by 2023.

Market Capacity Product

Consistent with both current practice and previous IRPs, the PUD finds a continued need for Market Capacity products to augment the existing portfolio and serve as a bridge while conservation, demand response, and long-duration energy storage are being acquired. The IRP finds that 50MW of winter-serving capacity would serve this need. Market capacity products include a broad array of products that can be acquired on a short-term basis from regional providers at a market rate.

Figure 1-10

Market Capacity Targets (Nameplate MW)

2023 (2-year)	2025 (4-year)	2031 (10-year)
50	50	0

Long-Duration Energy Storage

Long-duration energy storage has been identified as the utility-scale resource acquisition best able to meet the size, seasonality, and persistence of the PUD's long-term capacity needs. As Washington utilities act to comply with CETA, the expected market impact of those actions create significant value for energy storage. Downward pressure on average market prices decreases the cost of charging a storage project. Increased hourly price volatility provides increased opportunity for charging storage at low prices. Further, as the Pacific Northwest's regional resource mix becomes incrementally cleaner due regional clean energy policies, the storage inputs would also be expected to have an increasingly higher environmental quality over time. The IRP does not specify the underlying technology of the storage resource; rather, the study focuses on the specific characteristics needed to meet the PUD's needs.

Figure 1-11

Energy Storage Targets (Nameplate MW)

2023 (2-year)	2025 (4-year)	2031 (10-year)
0	25	70

Small-Scale Solar

The PUD has found a 5-MW, Snohomish-sited utility-scale solar resource would add value to the PUD's portfolio. The value this resource would provide is two-fold: 1) the resource would help to meet increasing summer energy needs driven by climate change, and 2) RECs created by the resource would count double when used for regulatory compliance with the EIA's RPS requirement.

Figure 1-12

Utility-Scale Solar Targets (Nameplate MW)

2023 (2-year)	2025 (4-year)	2031 (10-year)
0	0	5

Renewable Energy Certificates

In advance of the 2030 compliance window where utilities may be considered in compliance with the EIA RPS by virtue of being considered 100% clean, the PUD anticipates a need to augment its portfolio of renewable resources with Renewable Energy Certificates (RECs) to meet RPS requirements. This is because the considerable hydro resources in the PUD's portfolio are not eligible for EIA compliance. There is considerable uncertainty in the volume of needed RECs due to the potential for the PUD to qualify for the "No-Load Growth" RPS compliance mechanism due to the effects of additional conservation acquisition. The following targets represent the estimate for the PUD under a combination of compliance methodologies across the years, given forecast load and conservation. The PUD plans to carefully monitor these amounts in future studies and within the operational timeframe.

Figure 1-13

Renewable Energy Certificate Targets (Cumulative REC MWhs)

2023 (2-year)	2025 (4-year)	2031 (10-year)
0	0	969,873

Summary

The totality of the PUD's Long-Term Resource Strategy is summarized below in Figure 1-14. Supporting description and documentation can be found in Sections 6 & 7.

Figure 1-14

Long-Term Resource Strategy Targets

	2023 (2-year)	2025 (4-year)	2031 (10-year)
Conservation (Cumulative annual aMW)	7.96	19.35	76.59
Demand Response (Cumulative Peak Week aMW)	0.6	3.6	31.6
Market Capacity Product (Nameplate MW)	50	50	0
Long-Duration energy Storage (Nameplate MW)	0	25	70
Small Local Solar (Nameplate MW)	0	0	5
Renewable Energy Certificates (Cumulative MWh)	0	0	969,873

CETA Compliance

This is the PUD's first IRP with CETA requirements and includes the PUD's analysis of its compliance obligations and the forecasted outcomes of those obligations. In summary, the PUD projects that under its interpretation of statute it is already meeting the 100% clean energy requirement on a planning basis, and because the PUD does not plan to make any investments in fossil-fueled resources, it has a clear pathway to maintaining that status in 2045. Section 3 details CETA's policy goals and utility compliance obligations and Appendix C provides a crosswalk of how those requirements were embedded within this IRP.

Action Plan

The 2021 Integrated Resource Plan has identified several near-term actions that enable the PUD to meet the needs of its customers well into the future, even in a rapidly changing environment:

1. **Pursue all cost-effective conservation** and further explore programmatic conservation portfolio optimization, to include consideration of capacity-value, distribution-segment value, and BPA reimbursement.

2. **Pursue acquisition of significant long-duration utility-scale storage** in order to help meet the PUD's capacity needs.

3. **Develop a roadmap to significant, lowest-cost Demand Response programs** leveraging AMI, including dispatchable demand response programs and smart rate constructs. Further explore programmatic demand response portfolio optimization, to include consideration of capacity-value, and distribution-segment value.

4. **Further develop geospatial modelling capabilities of demand-side resource potential** with the intention of refining the ability to capture avoided Transmission & Distribution system costs from demand-side investments, and to better understand the geographic distribution of planned investments. Refine analytical methodology for applying geospatial analysis to measure plan effects on highly impacted communities and vulnerable populations.

5. **Continue to enhance and leverage short and long-term resource portfolio modeling capabilities**; expand cost and risk tradeoff analyses.

6. **Continue to participate in regional forums and assess impacts associated with climate change**, reduction in greenhouse gas emissions, clean energy policy compliance, and regional power and transmission planning efforts.

7. **Continue to participate in the development of a regional resource adequacy program**, in order to further limit reliability risks to customers.

8. **Continue to participate in regional forums discussing the formation of organized markets** in the Pacific Northwest in order to ensure hydropower is appropriately valued, that the economic opportunities and risks of planned dispatchable resources are accounted for, and to appropriately forecast future cost of service.

9. **Continue to participate in the Post-2028 contract negotiation process with the Bonneville Power Administration** in pursuit of a low-cost, high environmental quality, and reliable post-2028 contract.

Organization of the Document

The organization of the 2021 IRP document is as follows:

- Section 1 is this Executive Summary.
- Section 2 describes the PUD, including current load forecast and trends, existing and committed power supply resources, and demand side programs.
- Section 3 discusses the industry's planning environment and changing dynamics, including recently adopted or proposed legislation that may affect utility operations and costs. These inform and contribute to the IRP planning process.
- Section 4 details the scenarios, range of forecasts, and planning assumptions incorporated in the 2021 IRP analysis.
- Section 5 summarizes the analytical framework and planning standards used to examine the PUD's load/resource balance and identify future resource needs.
- Section 6 describes the portfolio results for the scenarios and the selection of the Long-Term Resource Strategy.
- Section 7 describes the key insights of the 2021 IRP analysis and the near-term Action Plan to implement the selected Long-Term Resource Strategy.

2 - Who We Are

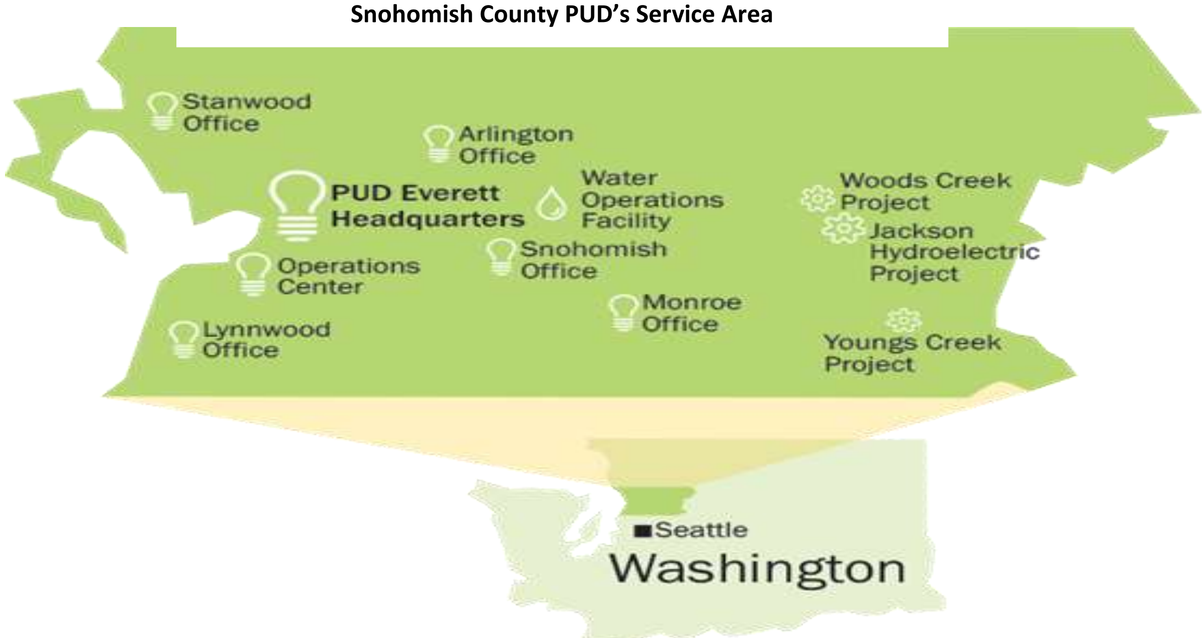
The Public Utility District No. 1 of Snohomish County (the PUD) began utility operations in 1949 by purchasing the electric distribution facilities for Snohomish County and the Camano Island portion of Island County from Puget Power & Light. The PUD is the 12th largest public utility in the U.S. and the second largest in Washington state serving more than 361,000 electric customers and approximately 20,000 water customers.

The PUD is committed to delivering the best possible service, keeping rates low and maintaining the highest levels of reliability for our customers. As stewards of critical community resources, the PUD takes these responsibilities seriously.

The PUD is governed by a Board of Commissioners, which is composed of three members. They represent separate commissioner districts and are elected at-large for staggered six-year terms. The legal responsibilities and powers of the PUD, including the establishment of rates and charges for services rendered, reside with the Board of Commissioners. The PUD is a not-for-profit utility and takes great pride in serving our customers in our community.

Figure 2-1

Snohomish County PUD's Service Area

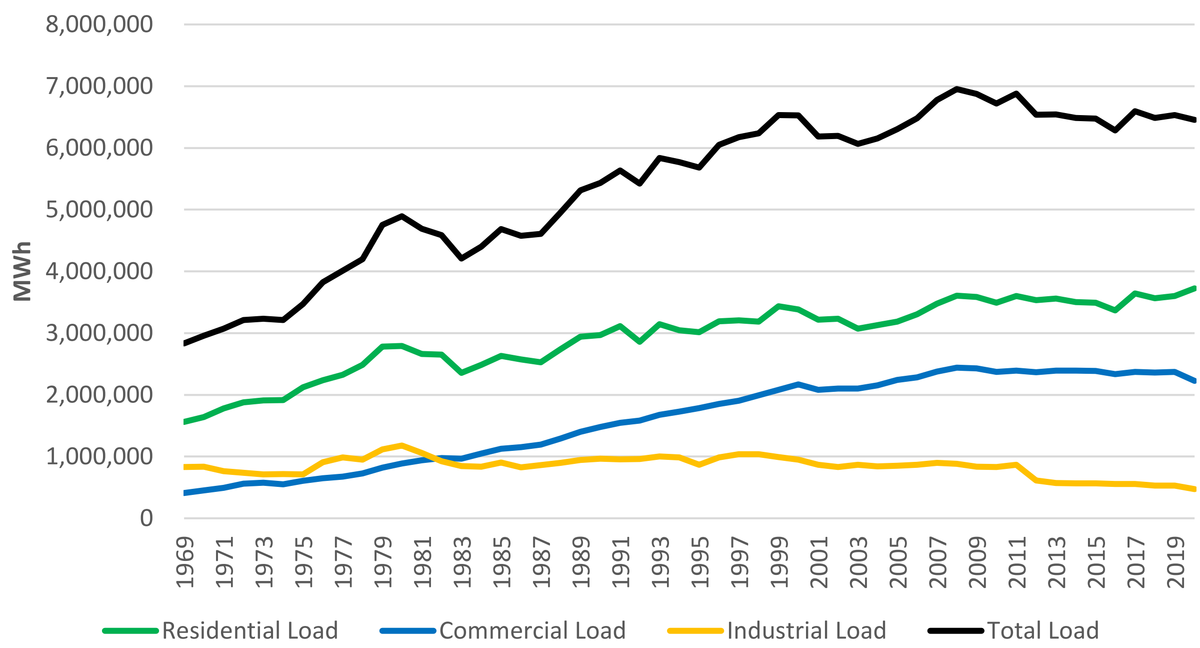


Load Growth

Understanding how the electric needs of PUD customers may grow over time is a vital component of establishing a resource plan. The PUD's load growth from 1970 to 2020 averaged 1.7% annually, with residential, commercial, and industrial loads growing at average annual rates of 1%, 5% and -0.8% respectively, as shown in Figure 2-2. When looking at historical trends, it is important to note that the acquisition of conservation has played a critical role in controlling costs and managing the PUD's portfolio. From 2010 through 2020, the PUD acquired 108 average megawatts of new conservation. Adjusting for that acquired conservation, the PUD's average annual rate of load growth declined by 0.34% between 2008 and 2020, despite considerable population growth and economic development in Snohomish County. The flattening effect over this period can be seen below in Figure 2-2.

Figure 2-2

Snohomish PUD's Historical Annual MWh Retail Sales



Current Trends influencing Load Growth

The current economic environment in Snohomish County and Washington State is one of recovery. Still rebounding from the effects of the Covid-19 pandemic on the local economy, the unemployment rate for the Snohomish County has dropped from a height of nearly 20% at the height of the pandemic in 2020 to 5.9% in July 2021. Industries that make up leisure and hospitality saw the most severe impacts, while many of the region's high tech and professional workers were able mitigate Covid-19's effects on employment by temporarily shifting their work environments by relocating employees to work-from-home.

Despite the economic hardships imposed by the pandemic, the PUD connected approximately 5,000 new premises in 2020. This is slightly higher than the recent trend of roughly 4,000 new premises per year since 2015. Going forward, the PUD expects this long-term trend to slow to approximately 3,000 new connections per year.

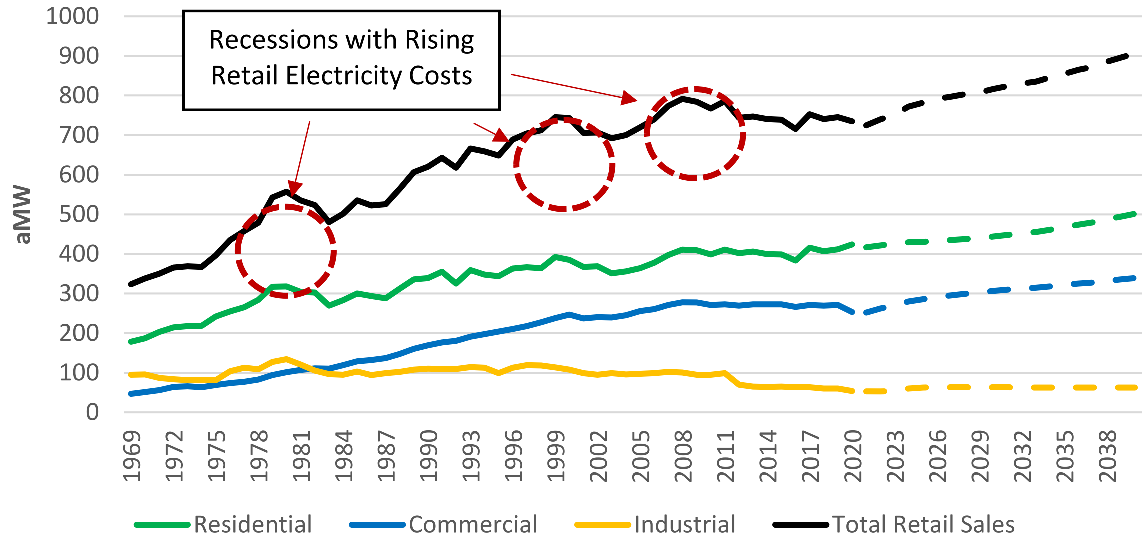
Snohomish County's main employment base is provided by aerospace manufacturing centered around Boeing's Everett Plant, and the hundreds of small aerospace companies delivering parts for the 747, 767, 777, and 787 programs. Naval Station Everett, Snohomish County and Providence Hospital are also major employers in the region. The biotech sector continues to see growth in South Snohomish County, and there are ongoing changes to the manufacturing sector in the Everett area and North Snohomish County, such as new manufacturing entrants. The Cascade Industrial Center, which spans from Marysville to Arlington, will be the second largest manufacturing-industrial center in the county. The Port of Everett is expecting to provide jobs and easy access to the waterfront through development of the "Waterfront Place Central and Riverfront." This effort, located east of downtown Everett, will transform the waterfront into a sustainable and unique commercial, recreational, and residential community.

Comparing Current Trends to Historical on Load Growth

Figure 2-3 shows that, historically, following recessionary periods the PUD's total retail sales rebound and resume their prior, upward slope (see first two recession periods circled). Similarly, customer demand bounced back to meet or exceed pre-recessionary loads. However, recovery from the previous "Great" recession has been markedly different for the PUD, with retail sales generally flat even after recovery. This creates uncertainty regarding the degree to which structural growth in demand should be expected following the economic impacts of Covid-19. Flattening retail sales in recent years is likely due to several factors, such as the cumulative benefit of energy efficiency acquisitions, and the growing effect of building codes and standards improvements.

Figure 2-3

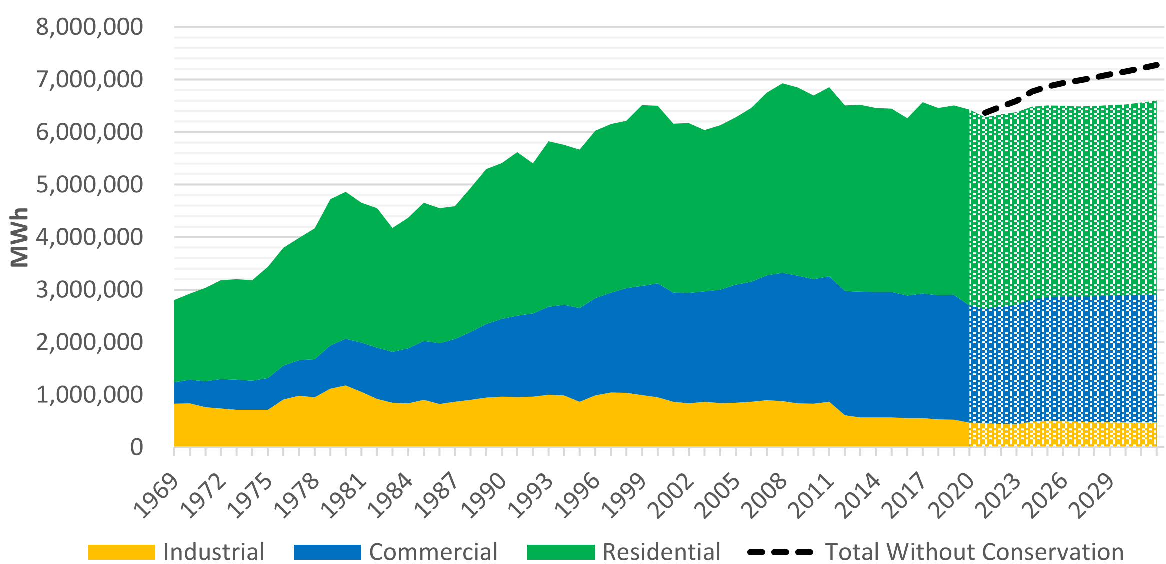
Historical and Base Case Demand Forecast Retail Sales by Sector Before New Conservation (in aMW)



Despite these downward pressures on loads, the PUD does expect to experience positive growth for the foreseeable future. This reflects population inflows and strong economic conditions in the Puget Sound area. When new cost-effective conservation is layered on top of projected load growth however, analysis suggests the recent trend of flat to declining retail sales will persist, as detailed in Figure 2-4.

Figure 2-4

Historic Snohomish PUD Load by Sector in Annual MWh

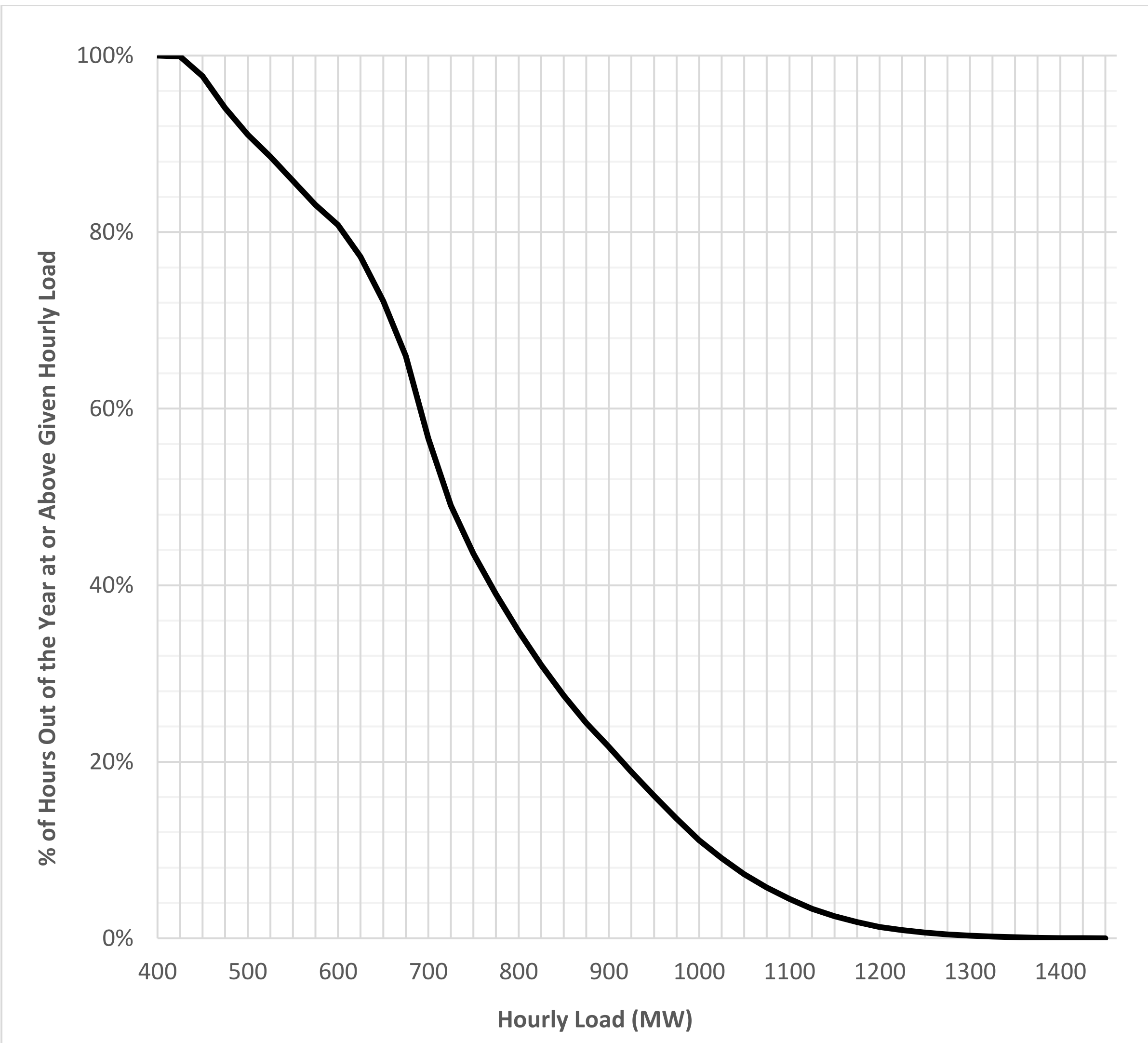


Load Distribution

Snohomish PUD continues to be a winter peaking utility with the winter peaks being approximately 80% to 100% larger than the annual average load, and 50% larger than a typical summer peak. Figure 2-5 below shows the percentage of hours that the PUD experienced a particular level of load (called an average load duration curve) on an annual basis for the period 2016 through 2019, with an average hourly load of approximately 720 MW. As an example, the PUD experienced loads in excess of 900 MW for only 20% of hours over the period.

Figure 2-5

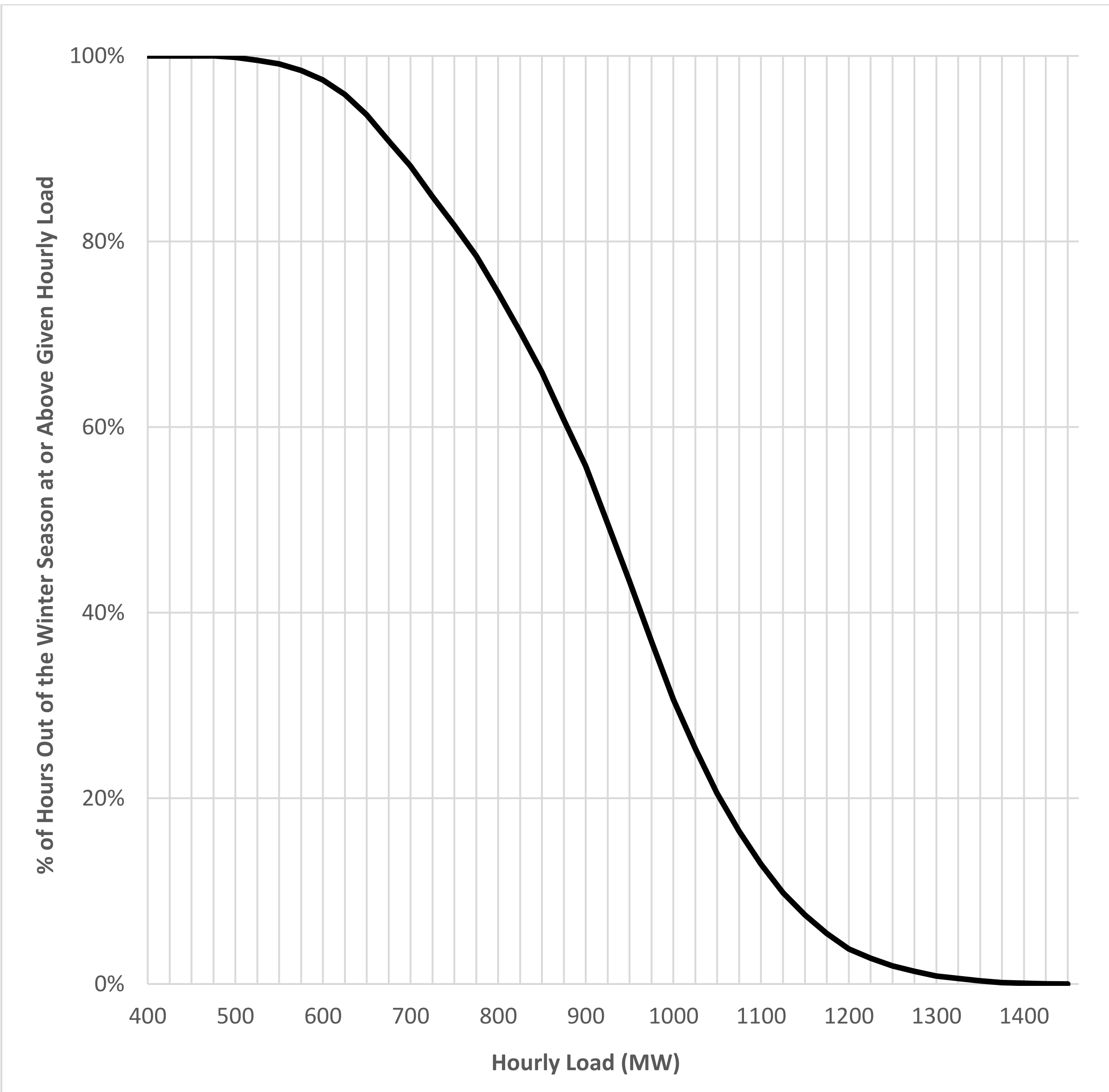
Average Annual Load Duration Curve 2016 through 2019



The winter season is the most demanding on the PUD's resource pool, especially during extreme weather events such as cold snaps. In 2017, the PUD saw a peak of 1448 MW, approximately double the annual average and 50% greater than the winter average hourly load of 925 MW. This can be seen in the average load duration curve for winter, as displayed in Figure 2-6.

Figure 2-6

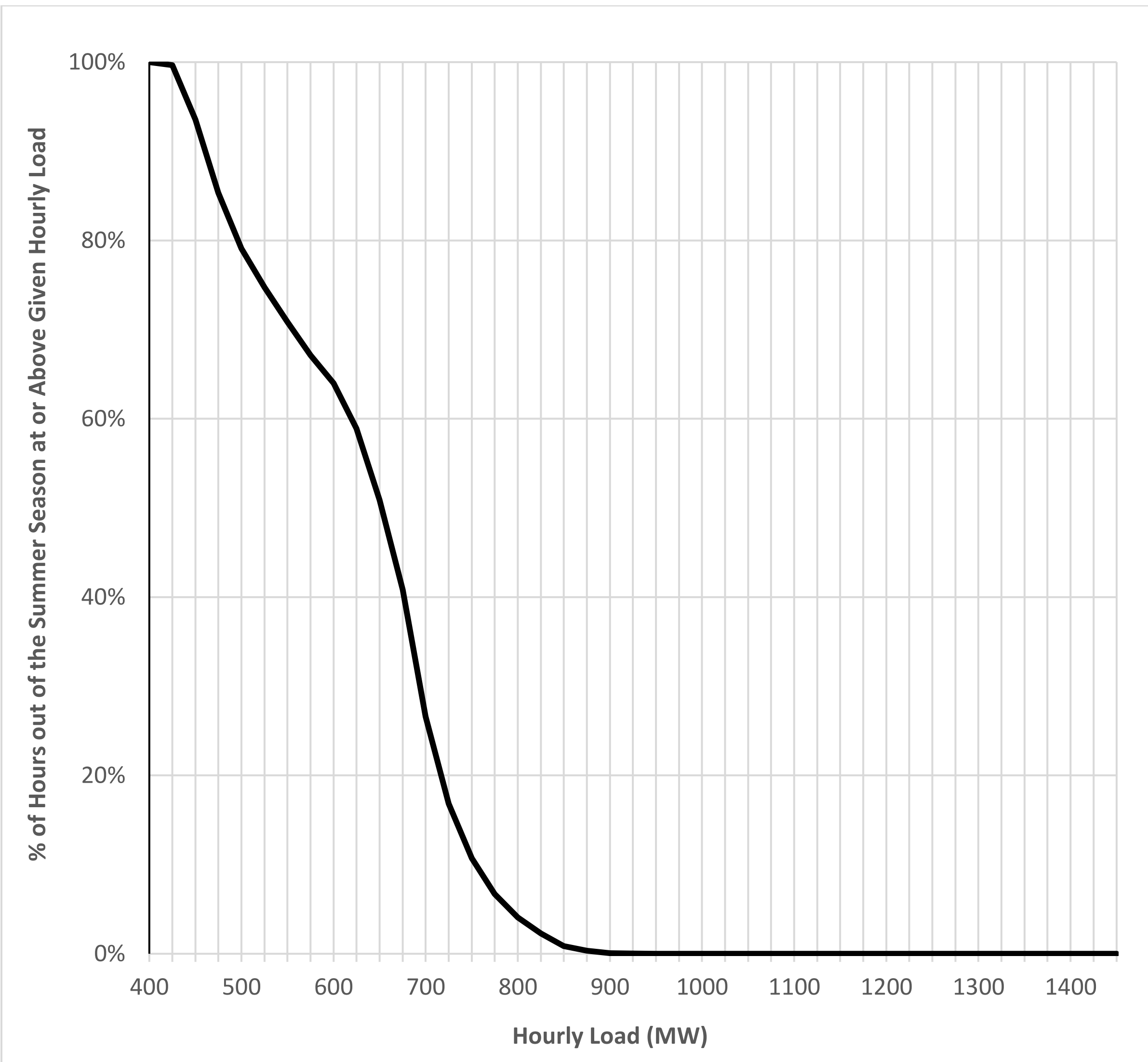
Average Winter Load Duration Curve 2016 through 2019



Summer peaks, in most years, rarely exceed 950 MW in any given hour. In June of 2021 this was not the case. The 2021 summer saw a record-breaking peak of over 1,130 MW during a heat wave, exceeding the typical summer peak by almost 200 MW. That said, even the record-breaking summer peak is well under typical winter peaks by over 250 MW. Figure 2-7 displays the average load duration curve for summer, with the average summer hourly load at approximately 650 MW.

Figure 2-7

Average Summer Load Duration Curve 2016 through 2019

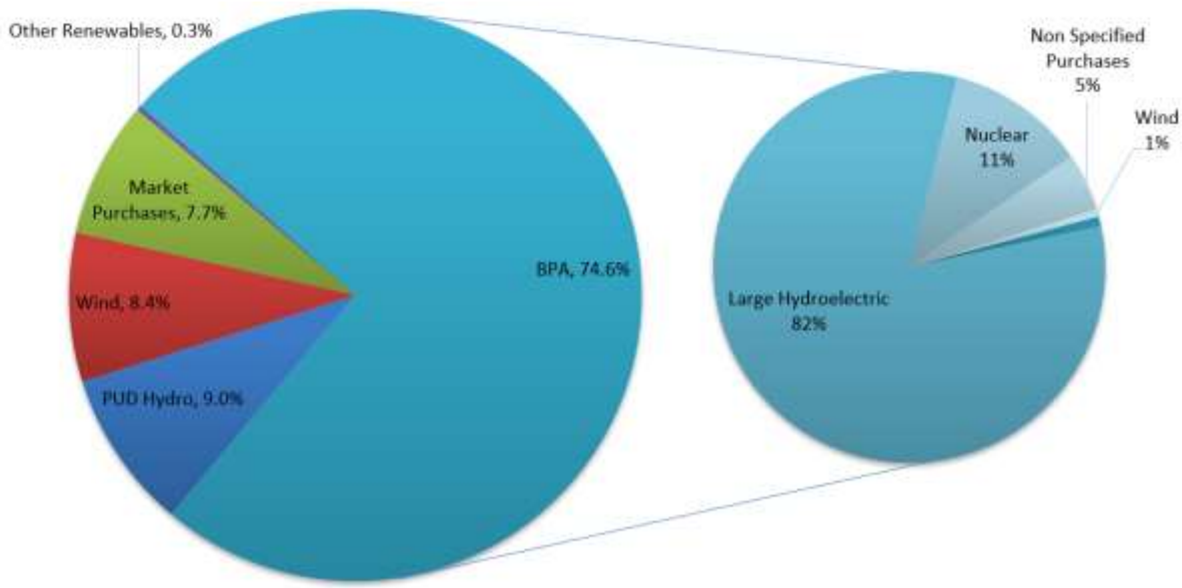


Overview of the PUD's Portfolio

The PUD relies on a diversified power portfolio consisting of conservation and energy-efficiency programs, a long-term power supply contract with the Bonneville Power Administration (BPA), PUD-owned hydroelectric projects, and several long-term renewable power supply contracts. The PUD buys and sells power in the short-term energy market to balance daily and seasonal variations in its customer loads and its owned and contracted resources. In 2020, the BPA contract provided over 74% of the PUD's power needs[19], primarily sourced from the Federal hydro system;[20] nearly 9% from the PUD's owned hydroelectric resources;[21] approximately 9% from a combination of long-term wind contracts and customer-owned, renewable distributed energy resources; and 7.7% came from short-term market purchases (Figure 2-8).

Figure 2-8

2020 Snohomish PUD Portfolio



The PUD's 2019 Fuel Mix is 97% carbon free by MWh, and has a carbon content of .0215 Metric Tons of CO2 equivalent per MWh, using the Washington State Department of

[19] After conservation

[20] BPA markets the output of the Federal Columbia River Power System and delivers firm power to the PUD at cost, under a long-term power contract for the Block and Slice products.

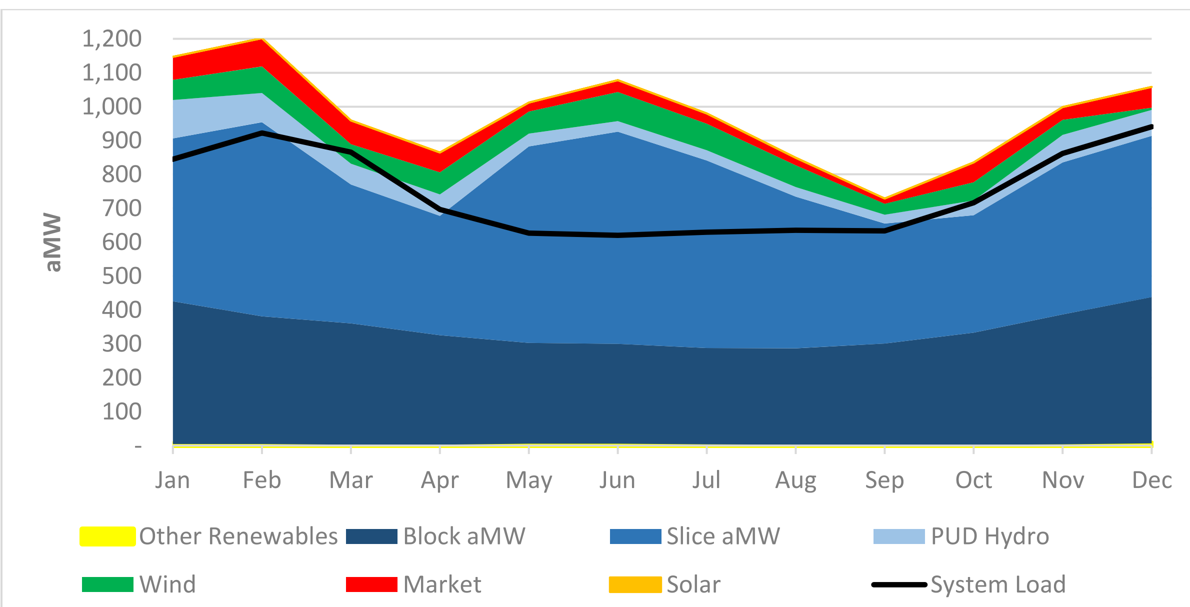
[21] PUD-owned hydroelectric resources include: 112 MW Jackson Hydroelectric Project; 7.5 MW Youngs Creek Hydroelectric Project; 6.0 MW Hancock Creek Hydroelectric Project; 6.0 MW Calligan Creek Hydroelectric Project; 0.65 MW Woods Creek Hydroelectric Project; and a 20% share of the 27 MW Packwood Lake Hydroelectric Project, located in Packwood, WA.

Commerce's Fuel Mix methodology. The PUD's 2019 carbon emissions per MWh was roughly 1/20th the carbon content of the national average.[22]

The shape of the PUD's load resource balance is an important consideration in long-term resource planning. The PUD's loads have been historically highest during the winter, while existing resources have produced more energy in the spring. The net result is energy surpluses and deficits the PUD must manage. Figure 2-9 illustrates the shape of the PUD's 2020 actual load and existing resources:[23] The solid line in Figure 2-9 shows the PUD's average load by month during calendar year 2020. The PUD's annual load shape is driven largely by electric heating loads during the winter months. Monthly, daily, and hourly energy imbalances are balanced by purchasing or selling energy from the short-term wholesale power market. Most market purchases in 2020 were made during the winter period when resource supply did not match the increased customer need on an hour-to-hour basis. Though the resource supply may be sufficient on an average monthly basis, the PUD's hourly needs can vary.

Figure 2-9

2020 Actual System Load with PUD's Existing Resources (in aMW)



[22]In accordance with RCW 19.29A.060, the PUD reports its fuel mix annually to the Washington State Department of Commerce. The PUD's 2019 annual fuel mix report and carbon emissions calculations can be found at Carbon Emissions Data | Power Supply | Snohomish County PUD (snopud.com) and http://www.commerce.wa.gov/growing-the-economy/energy/fuel-mix-disclosure/

[23] Water Year 2020 as measured at The Dalles was 81% of average for the Jan-July period, based on the 1981-2010 period. https://www.nwrfc.noaa.gov/water_supply/ws_normals.cgi?id=TDAO3

Existing & Committed Resources

The PUD relies on a portfolio of resources to meet customer demands. These include:

- **Supply side resources**
  - BPA power contract
  - PUD-owned generating resources
  - Long-term renewable power supply contracts
  - Small renewables program and customer-owned generation
  - Short-term market purchases
  - Regional transmission contracts
- **Demand side resources**
  - PUD energy efficiency programs
  - Demand response programs

Existing Supply Side Resources

BPA Power Contract

The PUD meets its load obligations by managing the energy available from the BPA power contract in concert with its owned resources and other long-term power supply contracts.

The BPA is a revenue-financed federal agency under the Department of Energy that markets wholesale electricity to more than 140 utility, industrial, tribal, and governmental customers in the Pacific Northwest. Its service area covers more than 300,000 square miles with a population of approximately 14 million in Idaho, Oregon, Washington and parts of Montana, Nevada, Utah, and Wyoming.

The BPA sells, at wholesale rates, electric power generated from 31 federal hydroelectric projects in the Columbia River basin, including one nonfederal nuclear plant and several other smaller nonfederal power plants. The federal hydroelectric projects and the related electrical system are known collectively as the Federal Columbia River Power System (the "Federal System"). The Federal System has an expected aggregate output of approximately 9,089 annual average megawatts under average water conditions and approximately 8,135 annual average megawatts under adverse water conditions. The Federal System produces more than one-third of the region's electric energy supply.

Block-Slice Product

The PUD currently purchases the "Block-Slice" product from BPA for the contract term of October 1, 2011 through September 30, 2028. Under this long-term power contract, the PUD historically purchases more than 80% of its power supply from the BPA on an annual average basis. The Block-Slice product is a combination of two energy products:

Block Product: The Block product provides the PUD with power in flat monthly amounts that are determined based on the PUD's average monthly load. This means that for each hour of the month, the PUD receives the same amount of energy, but that amount changes month by month in rough alignment with the PUDs seasonal load shape. To illustrate the monthly adjustments, in 2021 the Block product provided the PUD with 424 aMW in January when customer heating demand is seasonally high, while in June when temperatures are more moderate the Block amount was 296 aMW. Aggregate Block amounts from 2020 totaled 2,986,843 MWh.

Slice Product: The Slice product provides the PUD with variable amounts of power that reflect the output of the Federal System. The PUD takes responsibility for managing this product within the hourly contractual constraints and physical limits of the Federal System. Because the Federal System has a significant amount of energy capacity through its hydro projects, Slice provides the PUD with the ability to follow its customer loads and resources by storing and dispatching its share of that energy.

Most of the PUD's short-term wholesale market sales originate from Slice energy that is surplus to the PUD's needs. The amount of energy received from the PUD is contingent upon the amount of hydro power available in any given period; if snowpack and water conditions are above average in the region, the energy output is also above average. If snowpack and water conditions are low, the PUD's energy supply is correspondingly reduced. This varying amount of energy can cause year-to-year variation in the amount of revenue generated by short-term wholesale market sales.

Block and Slice quantities: Every two years, BPA determines the total of its customers' loads and the size of the Federal System that is to be allocated at-cost (called the "Tier 1 System,") to set rates for the next two-year rate period. This allocation process, called the Rate Period High Water Mark process, establishes the maximum amount of energy the PUD is eligible to purchase from the BPA at cost (called the "Tier 1 rate.") The size of the Tier 1 System varies due to changes in BPA's system obligations, customer load growth, and maintenance outages and refurbishments to the Federal hydro system. Figure 2-10 shows the actual BPA Tier 1 System Size and Tier 1 contract allocation amount to the PUD for the 2012 through 2023 period:[24]

Figure 2-10

BPA Tier 1 System Size and Contract Allocation to Snohomish PUD

Fiscal Year	BPA Tier 1 System Size (in aMW)	Maximum Tier 1 Available to PUD Rate Period High Water Mark (in aMW)	Actual BPA Tier 1 Contract Allocation to Snohomish PUD (in aMW)
2012	7181	811	785
2013	7181	811	788
2014	7240	811	753
2015	6992	811	755
2016	6983	791	759
2017	6983	791	778
2018	6945	786	725
2019	6945	786	729
2020	6955	795	723
2021	6955	795	724
2022	6667	762	718
2023	6667	762	720

24 The BPA Slice product is allocated contractually based on the customer's Slice percentage with monthly output based on critical water; actual amounts will vary.

Figure 2-11 shows the actual annual average megawatt hours (aMW) provided to the PUD by BPA under the long-term Block-Slice contract by fiscal year, and December average aMW, for 2012 through 2020:

Figure 2-11

Snohomish PUD BPA Contract Actual Annual and December aMW

(Block and Slice Combined)

Fiscal Year	Annual aMW	December aMW
2012	941	1,076
2013	859	886
2014	859	1,016
2015	824	924
2016	868	1,032
2017	903	948
2018	848	868
2019	768	840
2020	821	916

PUD-Owned Generating Resources

Jackson Hydroelectric Project

The Jackson Hydroelectric Project (Jackson Project) is located on the Sultan River, north of the City of Sultan, and is owned and operated by the PUD. The project has two large 47.5 MW nameplate Pelton generating units and two small 8.4 MW Francis generating units for a total nameplate capacity of 111.8 MW. The firm energy for the project, based on the 1940-41 water year, is ~29.5 aMW. The average annual or expected output is approximately 49 aMW. Project output is delivered directly into the PUD's electric system.

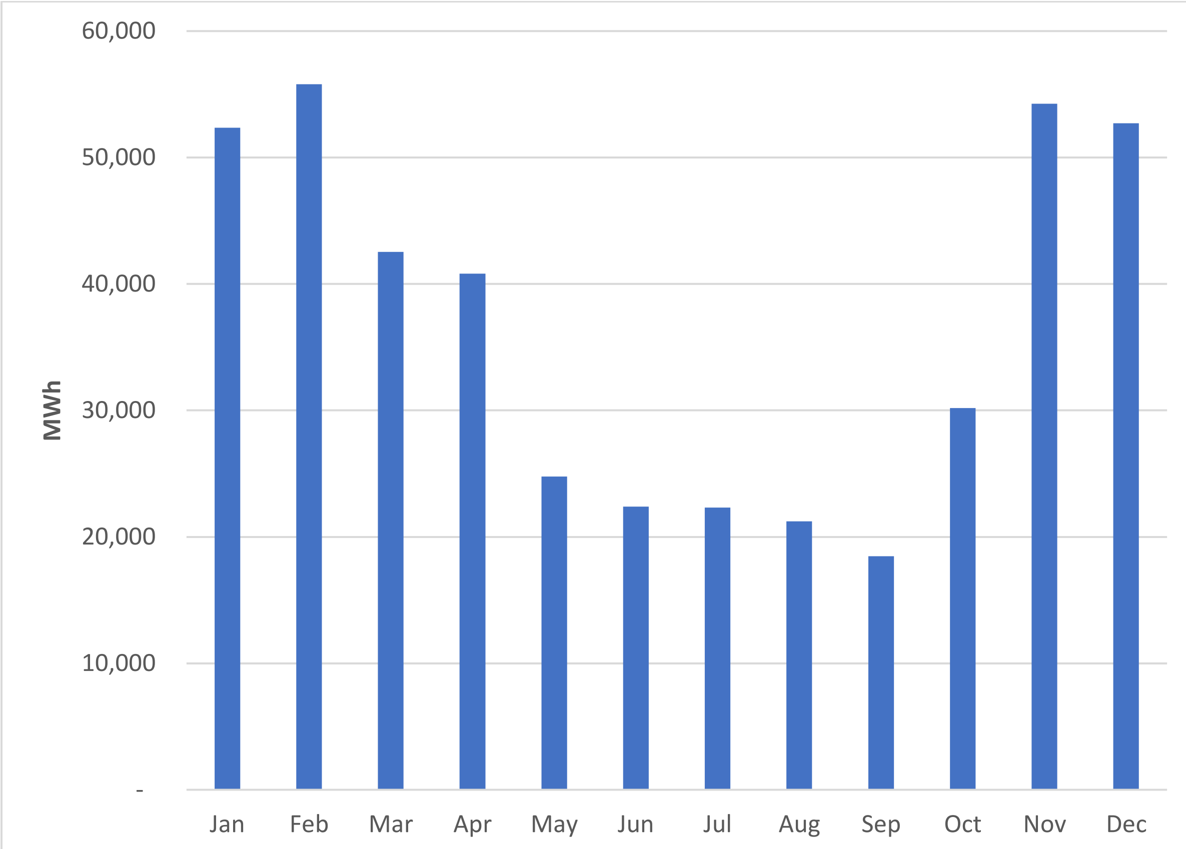
The Jackson Project is operated to produce the optimum amount of electrical energy, subject to specified minimum releases of water into the Sultan River for maintenance of fish and the diversion of water into the City of Everett's water reservoir system. An agreement from 1961, with subsequent amendments, established the rights and duties of the City of Everett and the PUD to the uses of water from the project. The City of Everett receives its water supply from Lake Chaplain Reservoir, which the project feeds through the two 8.4 MW Francis units. The PUD received a new 45-year project license as the sole licensee in September 2011. The new license did not materially alter how the project is operated.

Historical output for the project varies with the amount and timing of rainfall that affects stream flows that fuel the project. Power production is typically highest in the late fall through late spring periods due to precipitation and snowmelt. The shape of the project's output roughly matches the PUD's seasonal load shape. The project has some seasonal ramping capability, depending on time of year, and some ability to be dispatched in conjunction with storage in the Spada Lake Reservoir. License requirements to maintain stream flows and supply the City of Everett's potable water supply do limit the project's ability to follow the PUD's load within a day.

For the 2016 through 2020 period, the Jackson Project generated an annual average of 437,847 MWh, with a minimum of 306,344 MWh in 2019 and a maximum of 486,417 MWh in 2020. Figure 2-12 denotes the project's average generation by month for this period:

Figure 2-12

2016-2020 Monthly Average Jackson Hydroelectric Project Actual Production (MWh)



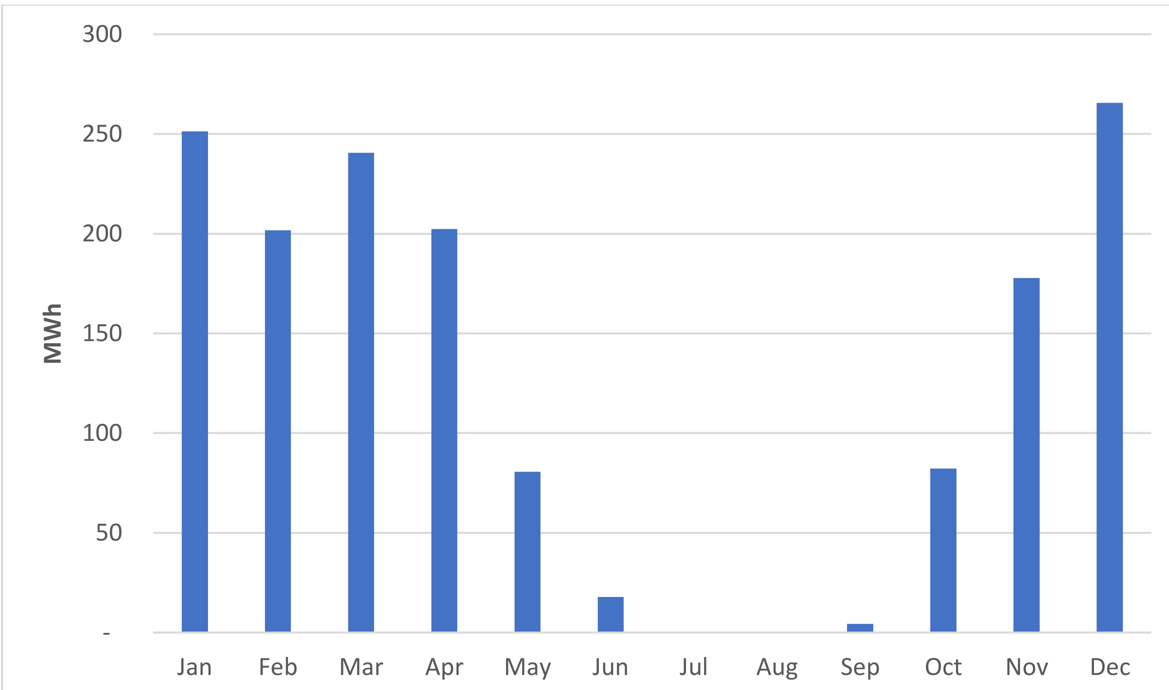
Woods Creek Hydroelectric Project

The Woods Creek Hydroelectric Project is located in Snohomish County, north of the city of Monroe, with a nameplate capacity of 0.65 MW. The project is adjacent to Woods Creek, a tributary of the Skykomish River, with the powerhouse located at the base of a natural impassible barrier to anadromous fish, and typically produces most of its generation during the November through April period. The PUD purchased the powerhouse and adjoining acreage in February 2008. Prior to its acquisition, the PUD had been purchasing only the project's output. This project has a license exception from the Federal Energy Regulatory Commission allowing it to operate indefinitely under existing operating conditions.

Since acquiring the project, the PUD has made numerous engineering and efficiency improvements which has increased annual production from the historical 10-year average production of 497 MWh to just under 1,800 MWh, depending on hydrological conditions. Any improvements to the project that increase production without increasing diversion or impoundment are considered to be "incremental hydro" for purposes of the EIA RPS. While most hydro generation is considered ineligible for compliance with the RPS, incremental hydro qualifies and can be applied toward the PUD's annual renewables requirement.[25] For the 2016 through 2020 period, Woods Creek has generated an annual average of 1,525 MWh. Figure 2-13 shows the generating profile for this resource:

Figure 2-13

2016-2020 Monthly Average Woods Creek Hydroelectric Project Actual Production (MWh)



Youngs Creek Hydroelectric Project

In 2008, the PUD purchased the unconstructed Youngs Creek Hydroelectric Project located on Youngs Creek, a tributary of Elwell Creek near Sultan in Snohomish County. The project is situated above a natural impassable barrier to anadromous fish. Commissioning of this new run of river resource, with a single Pelton unit at 7.5 MW nameplate, occurred in November 2011.

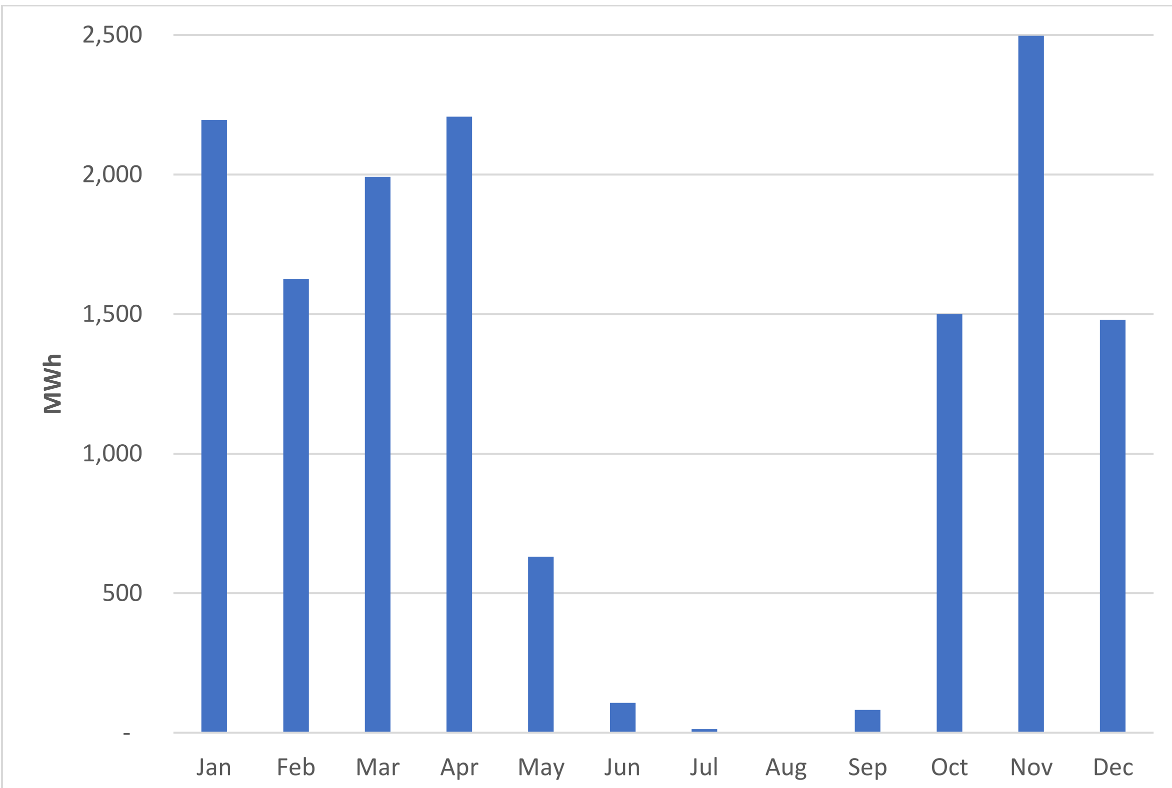
[25] Washington Administrative Code (WAC) Section 194-37-040 (13)(b) provides: "Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to a hydroelectric generation project owned by one or more qualifying utilities [see definition of qualifying utility in RCW 19.285] and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional electricity generated in either case is not a result of new water diversions or impoundments."

Youngs Creek acted as a project base for other PUD small hydroelectric projects Hancock Creek and Calligan Creek and all three projects have similar designs.

Youngs Creek was the first new hydroelectric resource to be constructed in the region in more than 17 years. It is licensed through 2042. For the 2016 through 2020 period, the project generated an annual average of 14,091 MWh, with the majority generated during the winter and spring months (Figure 2-14). Peak generation occurred in 2016 with 18,552 MWh.

Figure 2-14

2016-2020 Monthly Average Youngs Creek Hydroelectric Project Actual Production (MWh)



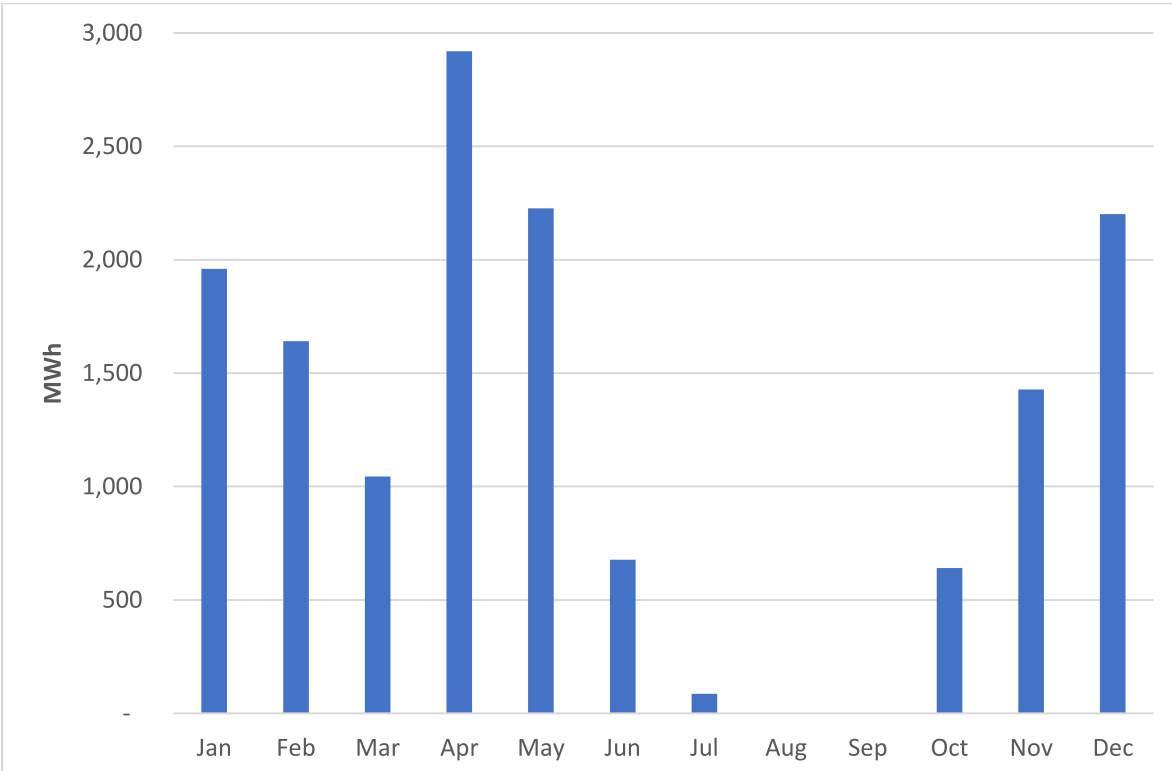
Calligan Creek Hydroelectric Project

In 2015, the PUD received a 50-year license for the Calligan Creek Hydroelectric Project located on Calligan Creek, a tributary to the North Fork Snoqualmie River in King County. The project is located above Snoqualmie Falls, a natural barrier to anadromous fish. Construction on this 6.0 MW Pelton unit began in 2015 and began commercial operation in February 2018. The project is considered "run-of-river" and has little to no ability to shape its output. For the 2019 through

2020 period, the project generated an annual average of 14,826 MWh, with the majority generated during the winter and spring months (Figure 2-15).

Figure 2-15

2016-2020 Monthly Average Calligan Creek Hydroelectric Project Actual Production (MWh)

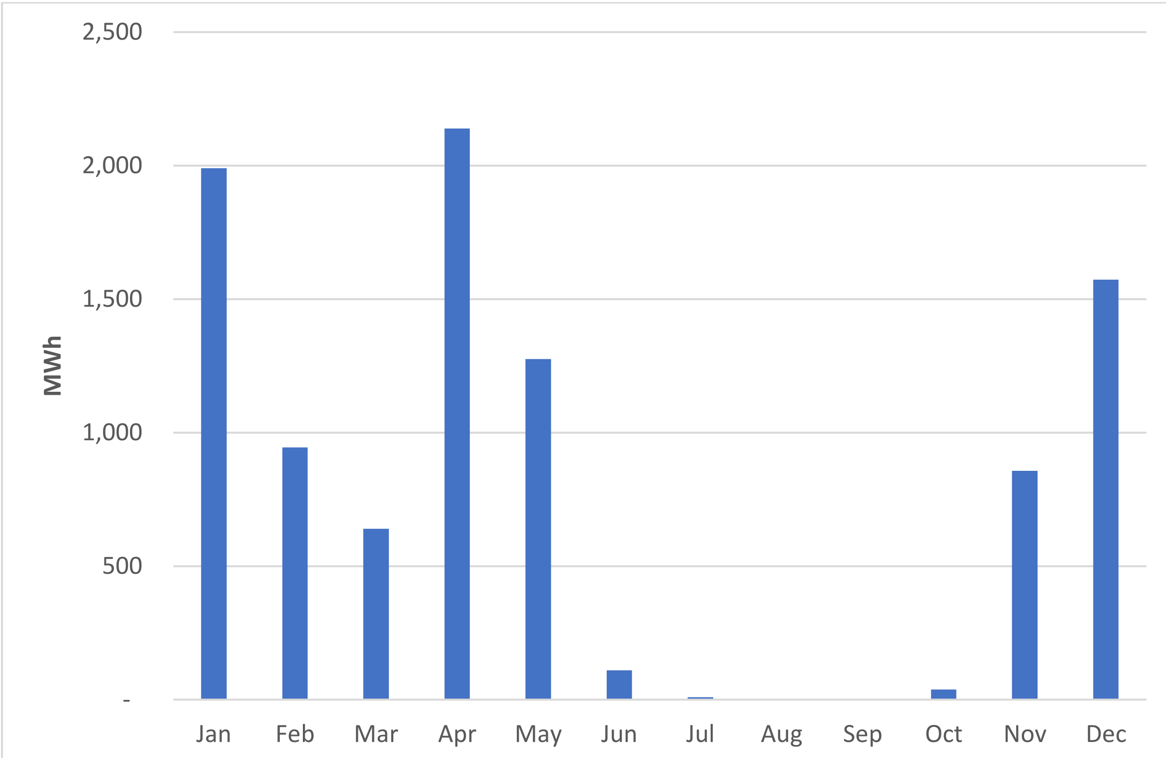


Hancock Creek Hydroelectric Project

In 2015, the PUD received an original 40-year license for the Hancock Creek Hydroelectric Project located on Hancock Creek, a tributary to the North Fork Snoqualmie River in King County. The project is located above Snoqualmie Falls, a natural barrier to anadromous fish. Construction on this 6.0 MW facility began in 2015 and began commercial operation in February 2018. Similar to Calligan Creek, this project is considered "run-of-river." The powerhouse has a single 6 MW Pelton unit. For the 2019 through 2020 period, the project generated an annual average of 9,578 MWh, with the majority generated during the winter and spring months (Figure 2-16).

Figure 2-16

2016-2020 Monthly Average Hancock Creek Hydroelectric Project Actual Production (MWh)



Arlington Microgrid (AMG)

The PUD announced plans in 2017 to build the Arlington Microgrid Solar Array, as part of its new local office complex in Arlington, Washington. Located east of the Arlington Municipal Airport, this facility is a demonstration testbed for several interconnected distributed energy technologies that are constructed to be self-sustaining if disconnected from the electrical grid at large.

The project was funded in part through a Clean Energy Fund II grant provided by the Washington State Department of Commerce (Department of Commerce). The microgrid project consists of:

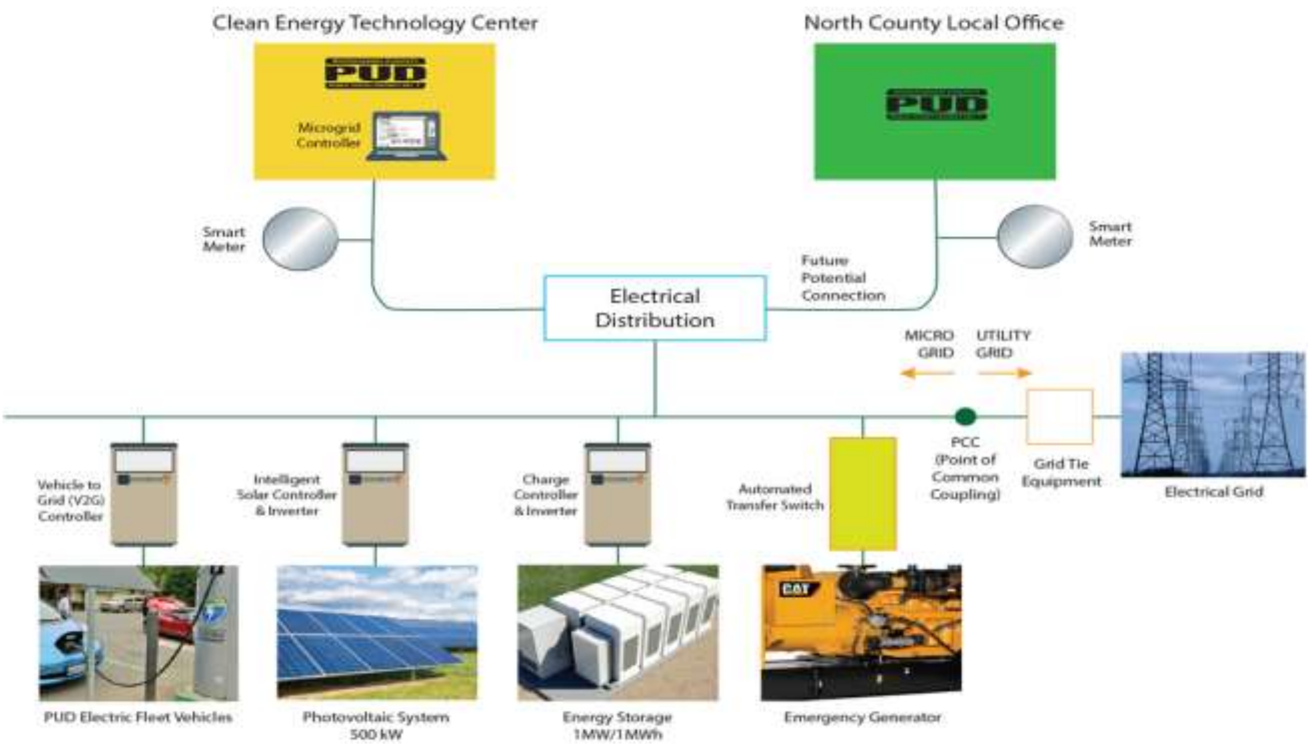
- A 500 kW utility scale solar array;
- A Modular Energy Storage Architecture (MESA) compliant 500 kW/1000 kWh lithium-ion battery;

- Two vehicle-to-grid (V2G) charging systems with connected electrical vehicles;
- The Clean Energy Center (CEC) to provide the load and demonstration area;
- A backup data center supporting PUD information technology resilience.

These components are interconnected and controlled via a central control system for microgrid operations and connected to the PUD's Distributed Energy Resource Optimizer (DERO) scheduling system. The battery storage system may be called upon by DERO when needed and will support microgrid operations in the event the system is isolated from the grid. The V2G chargers provide an additional source of energy and provide testing for larger scale V2G applications. Figure 2-17 shows an overview of the design and components that will be integrated at the Arlington Microgrid Solar Array:

Figure 2-17

Diagram of the Arlington Microgrid Components



The key milestones for the Arlington Microgrid have been:

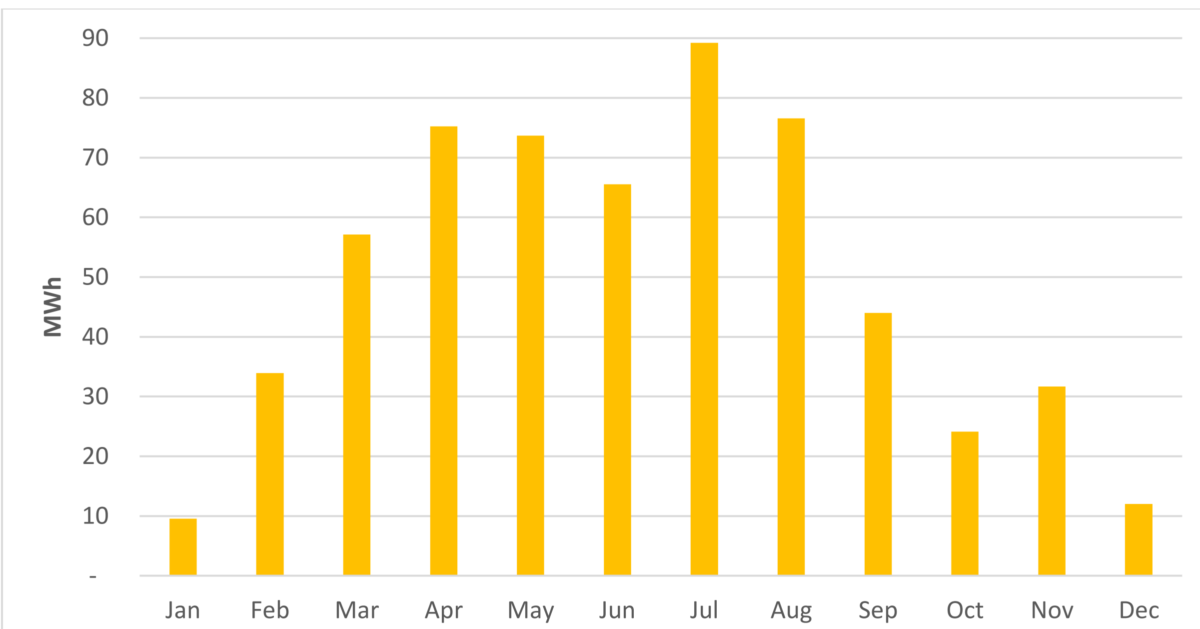
- Design & Equipment Procurement - 2018
- Site Preparation & Construction – 2019-2020
- Commissioning & Reports – 2021

As of 2021 a new North County local office is being built on the site of the AMG with the vision to combine field offices from the Stanwood and Arlington locations. This office will serve the entire North county and act as a staging area for recovery in the event of a large-scale disruption of electric service.

The solar array at the AMG was designed and built as a community solar project to support the PUD's clean and renewable energy development efforts, while providing opportunities for PUD customers to participate and benefit from solar energy generation. Customers were given the opportunity to purchase or lease "shares" of the output of the solar project without requiring their own rooftop or fund or install their own solar panels. This offering was highly successful; the PUD offered 8100 units, each representing 1/5 of a panel. All units were sold over the course of several weeks, with over 500 customers participating. The community solar project is expected to last 20 years.

Figure 2-18

Arlington Microgrid – 2020 Monthly Output 500 kW Community Solar Array (MWh)



MESA 1 Battery System

The MESA 1 project was installed in 2015 and 2016 in the PUD's service territory. It has a nameplate of 2 MW and is comprised of two types of lithium-ion battery systems. The first battery system is a 1 MW, 0.5 MWh, utilizing GS Yuasa batteries. The second is a 1 MW, 0.5

MWh system utilizing LG Chem batteries. Both systems use a power conversion system from Parker-Hannifin. Since completion the project has:

- Undergone use case testing with Pacific Northwest National Laboratories;
- Participated in demand response program with the BPA;
- Been used in a BPA Technology Innovation Fund project studying the sharing of energy storage between transmission and distribution use cases.

The battery has also been utilized by the PUD for energy shifting and energy imbalance mitigation. The Department of Commerce provided $2.4M to help fund this project. As of this report the MESA-1 project is undergoing retrofitting for fire safety in response to several incidents involving other lithium-ion battery storage systems.

Distributed Energy Resource Optimizer (DERO)

The DERO project was installed in 2017 and consists of controls integration to allow the PUD's Power Schedulers to remotely manage energy storage. DERO automatically provides optimized schedules for review and deployment by Power Scheduling and allows for schedules to be remotely loaded into individual energy storage systems. The software and integration were provided by Doosan GridTech. The Department of Commerce provided $1.8M to help fund this project. DERO was upgraded in 2021 to accommodate the Arlington Microgrid and associated functionality.

Long-Term Power Supply Contracts

The PUD has several long-term contracts for energy, each associated with a specific generating resource. The PUD has no ability to shape deliveries under these contracts.

Hampton Lumber Mill – Darrington Cogeneration Contract

In 2006, the PUD executed a 10-year contract with Hampton Lumber Mills-Washington, Inc., for 100% of the electrical output from Hampton's 4.5 MW cogeneration project utilizing wood waste from the co-located lumber mill. The Hampton Lumber Mill is a primary employer for residents in the town of Darrington, WA. The cogeneration project began commercial operation in February 2007 and produces approximately 2 aMW on an annual basis. The contract has since been extended and is due for further extension discussions in 2021. This project is recognized as an eligible renewable resource under the EIA and qualifies for the distributed generation multiplier, doubling the compliance value for each MWh generated.

Packwood Lake Hydroelectric Project

This small hydroelectric project located 20 miles south of Mount Rainier at Packwood Lake in Packwood, Washington, began operating in 1964. The Packwood Hydro Project has a nameplate capacity of 27.5 MW and is managed and operated by Energy Northwest. This project was recently relicensed with FERC in 2018 with a 40-year license term. The PUD is a project participant and contracts for a 20% share, which represents an average output of 17,504 MWh for 2016 through 2020 period. The PUD plans to maintain its 20% share into the foreseeable future.

Contracted Wind Purchases

The PUD purchases wind energy and their associated environmental attributes (represented through Renewable Energy Credits or "RECs") from three wind projects under four long-term contracts. The White Creek, Hay Canyon and Wheat Field wind projects are situated in the Pacific Northwest and have a combined nameplate rating of 217 MW. Historical production for the contracted wind fleet is reflected in Figures 2-14 and 2-15. Capacity factor, or the average amount of actual energy generated compared to the project's nameplate, is approximately 24% for the PUD's aggregate contracted wind resources between 2016-2020.

The wind contracts were modelled in the 2021 IRP analysis as a single fleet based on their aggregate historical actual production by month. These long-term contracts expire at different points through the 2024 - 2029 period.

Figure 2-19

2016-2020 Monthly Average Wind Fleet Actual Production (aMW)

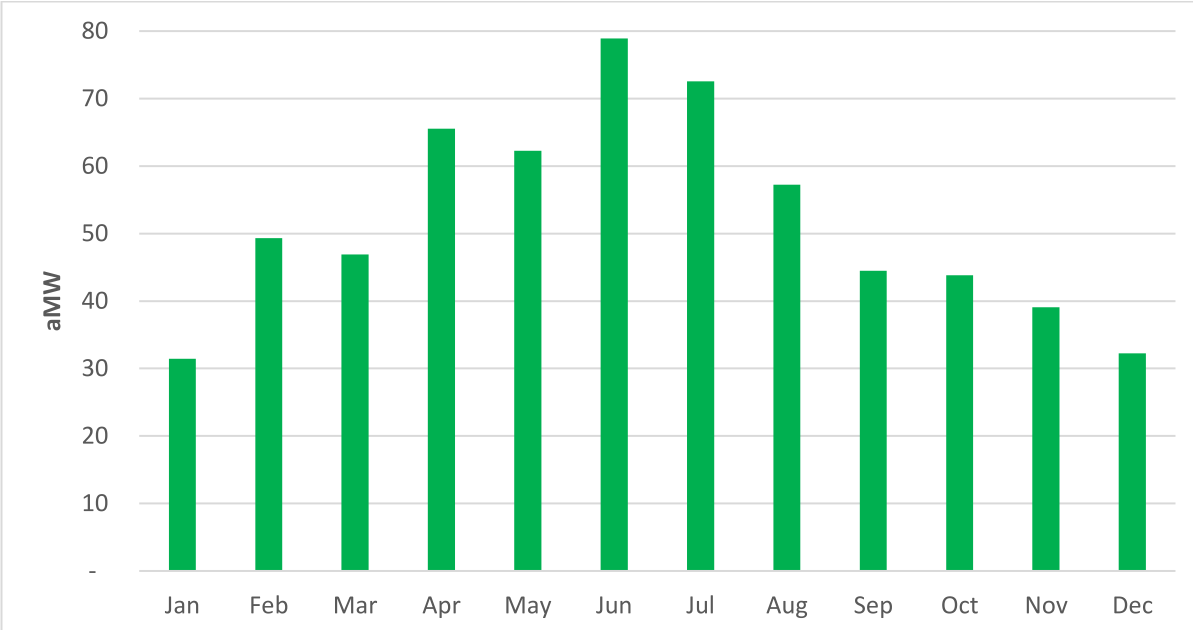
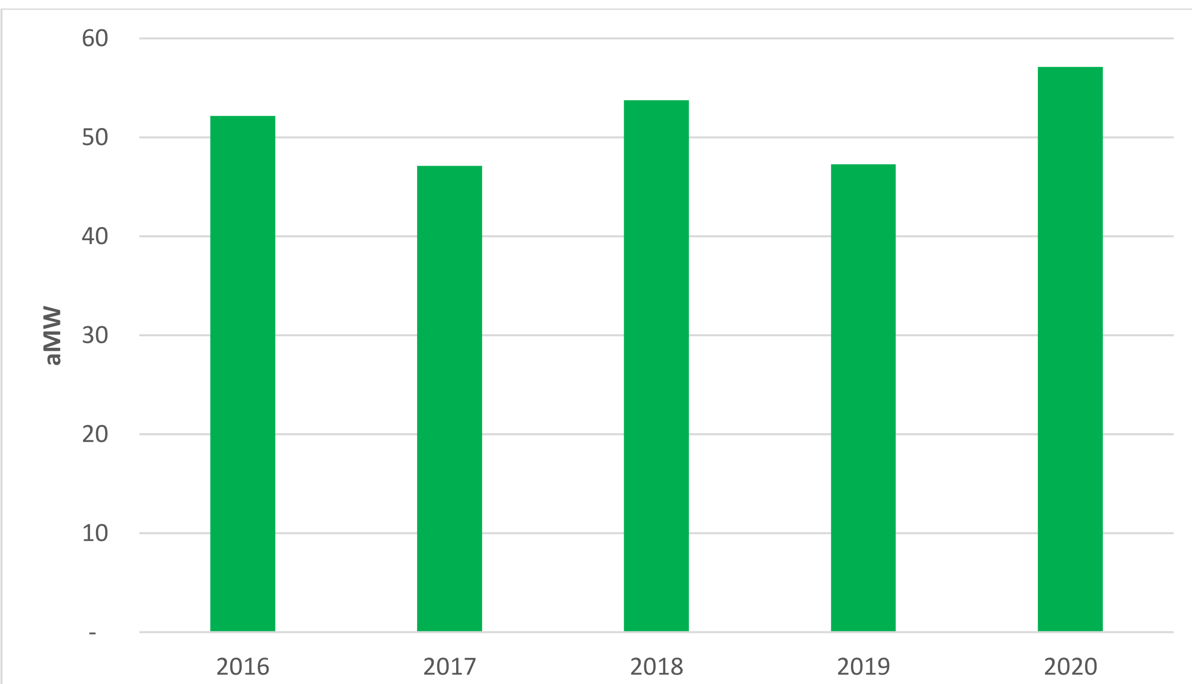


Figure 2-20

Actual Average Annual Wind Fleet Production 2016 - 2020 (aMW)



White Creek Wind Project

In 2007, the PUD executed a 20-year power purchase contract with LL&P Wind, a wholly owned subsidiary of Lakeview Light and Power in Tacoma, Washington for approximately 10% of the output and associated RECs from the White Creek Wind Project. The project is located in south-central Washington along the Columbia River Gorge. The PUD's share of White Creek's output is equivalent to 20 MW of wind capacity, with 6 aMW of wind energy forecasted each contract year. The project is an eligible renewable resource under the EIA RPS and began commercial operation in November 2007; the PUD began taking output from the project in January 2008. The agreement expires in 2027.

Hay Canyon Wind Project

The PUD executed two power purchase agreements in February 2009 for 100% of the wind energy and RECs from the Hay Canyon Wind Project. This 100.8 MW nameplate project is located in north-central Oregon along the Columbia River Gorge. It was developed by Hay Canyon Wind, LLC, a subsidiary of Avangrid, Inc.[26] The PUD contracts for 50% of the project's output under a 15-year power purchase agreement, and 50% under an 18-year power purchase agreement. These contracts expire in 2024 and 2027, respectively. The Hay Canyon Wind Project is an eligible renewable resource under the EIA RPS. The PUD began talking delivery of the project output in March 2009.

Wheat Field Wind Project

The PUD signed a 20-year power purchase agreement for the entire output and associated environmental attributes of the 97 MW nameplate Wheat Field Wind Project in 2008. The project is located in north-central Oregon and interconnects to the BPA's transmission system. The project was developed by Wheat Field Wind Project, LLC, in conjunction with Horizon Wind Energy, LLC, a subsidiary of Energías de Portugal.[27] The Wheat Field Wind Project is an eligible renewable resource under the EIA RPS; the PUD began taking delivery of output from the project in April 2009. The agreement expires in 2029.

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[26] In December 2015, Iberdrola USA finalized acquisition of UIL Holdings to create a new company, Avangrid. The Hay Canyon contracts are now managed by Avangrid out of its Portland, OR offices.

[27] In July 2011, Horizon Wind Energy changed its name to EDP Renewables North America LLC.

Small Renewables Program

The Small Renewables Program was adopted by the Board of Commissioners in August 2011 to encourage development of customer-owned, distributed generation inside the PUD's service area. The program establishes a standard methodology for determining the price the utility may pay for the energy and associated environmental attributes produced by a given customer-owned resource. Potential contracts terms range from one to five years. Participation in this program is limited to renewable resource technologies with a nameplate between 100 kilowatts and 2 megawatts (MW), with a total program limit of 10 MW aggregated nameplate capacity.

Customer-owned Renewables

The PUD has offered a variety of programs promoting and enabling the installation of rooftop solar by its customers. PUD customers have responded with significant growth in installed nameplate, from 1.73 MW in 2012 to 109 MW nameplate forecast by December 2045. The PUD forecasts 2022 production of installed customer-owned solar will be 22,080 MWh, from roughly 23 MW nameplate, equal to roughly 0.101% of forecast annual load.

Short Term Wholesale Power Market Purchases and Sales

To help balance the PUD's energy needs with the production of its portfolio in any given hour, the PUD may engage in purchases or sales from the short-term wholesale power market. Power Scheduling staff make short-term energy purchases when demand is expected to exceed the available output of the PUD's owned and contracted resources, and as needed to balance seasonal variations in loads and resources. Sales are made when the PUD's contracted resources and surpluses exceed the PUD's need. The PUD's short-term market purchases and sales fluctuate each year, reflecting variations in customer demand, weather, and hydrological conditions.

When considering purchases and sales on an annual basis, the PUD is a net seller of energy when annual snowpack and precipitation results in at or above average water years. Between 2016 and 2020, the PUD purchased an annual average of 395,655 MWh of energy and sold an annual average of 1,985,256 MWh in the short-term wholesale power markets; a ratio of sales exceeding purchases nearly 5 to 1.

Firm Transmission Contracts

The PUD relies on long-term firm transmission capacity across the BPA transmission system through its long-term firm point-to-point agreement (PTP contract) with BPA. This firm transmission is used to schedule and deliver output from the PUD's various portfolio resources to the PUD's distribution system. The PUD currently directly contracts for 1,969 MW of firm point-to-point capacity with BPA, with an additional amount to facilitate deliveries from its wind contracts. The PUD's PTP contract includes 16 different points of receipt (where the PUD can receive energy on BPA's transmission system) and six points of delivery (where the PUD can deliver energy on BPA's transmission system).

From the PUD's total transmission capacity, 1,365 MW is designated for delivery directly to the PUD's service territory. The remaining 601 MW is used to transport generation that is surplus to the PUD's needs to the wholesale power market. When the PUD needs more than 1,365 MW delivered to its service area, the PUD has the contractual right to "redirect" portions of its capacity normally used for surplus transactions to other points of delivery or receipt on BPA's transmission system. In this way, the PUD can use its full contract capacity for supporting deliveries to the PUD's system. These "redirect" requests are generally granted, except in cases where there is no available capacity on the requested path.

The contract term expiries for the PUD's firm transmission contracts with BPA range from 2026 through 2043; under BPA's transmission business practices, said contracts and their associated PORs and PODs are eligible for the PUD to request renewal with the first right of refusal. This process is known as exercising the PUD's rollover rights.

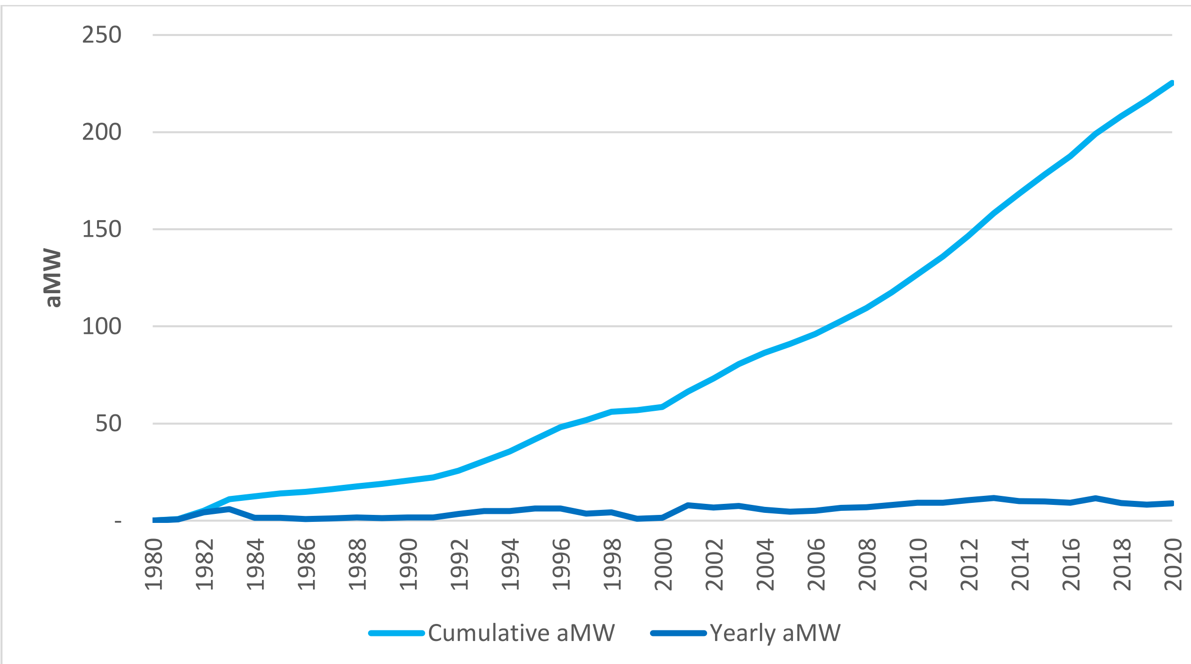
Existing Demand Side Resources

Conservation

The PUD has actively engaged in conservation and demand-side management for over forty years. Since 1980, conservation and energy efficiency programs have resulted in the cumulative acquisition of more than 217 aMW of conservation resources – enough energy to annually power more than 75,000 homes. Figure 2-21 shows the gross annual and cumulative savings accomplishments for the PUD through 2020:[28]

Figure 2-21

PUD Gross Annual and Cumulative Conservation Savings in aMW



Conservation is a low-cost resource with few detrimental environmental impacts. Encouraging customers to use energy more efficiently has numerous benefits, including:

- Deferring the acquisition of new supply side resources;
- Deferring the need for new transmission and distribution system upgrades;
- Creating direct value for customers;
- Increasing affordability for households, and;
- Reducing operating costs for businesses.

[28] As illustrated here, the cumulative savings calculation does not include degradation of savings as energy efficiency measures reach the end of their useful life.

To facilitate energy efficiency, the PUD offers financial incentives, technical assistance, and educational services for all customer classes. For residential customers, the PUD provides a comprehensive set of programs targeting single and multi-family residences, new construction, and income-qualified households. Financial incentives are offered for efficiency-improving products including new heating systems, window and insulation upgrades, LED lighting, and home appliances. For commercial and industrial customers, the PUD offers financial incentives and technical assistance to help reduce energy use and annual operating costs. Efficiency products include HVAC, high-efficiency lighting, insulation, process load efficiencies, motors, and equipment controls. Figure 2-22 highlights key programs and the sector served:

Figure 2-22

PUD Energy Efficiency Programs by Target Sector

Program Description	**Target Sector**			
Residential	**Residential**	**Multi-Family**	**Commercial**	**Industrial**
Single Family Weatherization	X			
Multi-Family Weatherization	X	X		
Retail Platform	X	X	X	
New Home Construction	X	X		
Income-Qualified Weatherization				
Commercial & Industrial				
Custom Projects			X	X
C&I Strategic Energy Management			X	X
Commercial Kitchen Equipment			X	
Lighting Incentives			X	X
Strategic Energy Management			X	X
Energy Design Assistance			X	X

Program Innovation

In addition to the PUD's traditional conservation programs, the PUD actively seeks out new approaches to markets and emerging technologies. Examples include:

- In partnership with Snohomish County, the PUD matches funds to improve efficiency for Income Qualified customers

- Responding to market transformation in the area of efficient lighting, by revising the PUD's incentives to focus on how best to increase other efficiency opportunities for its commercial and industrial customers. Savings from these other areas can reduce peak demand periods and aid in reducing the PUD's winter capacity needs.

- Energy Design Assistance works with customers at the design phase of Commercial and Multi-Family new construction to help them maximize the efficiency benefits at inception, instead of incentivizing costly retrofits later.

- Developing the PUD's retail online platform. Marketplace provides customers a resource to research the purchase of energy efficient home appliances and products. The site serves as an aggregate location that allows customers to compare the energy efficiency, price, customer reviews, operating cost, and utility incentives for models. The platform delivers an Amazon-style experience and has helped many of our customers improve the efficiency of their homes or small businesses.

- Adding numerous new technologies to the PUD's program offerings. Emerging products such as direct outside air systems for HVAC, electric hybrid water heaters, high efficiency control systems, and advanced lighting controls provide exciting new opportunities for energy savings and often provide important secondary benefits to customers.

Community Programs

The PUD places high value on offering programs and measures to serve all customers in our community. Recently, staff worked with the Northwest Power and Conservation Council (NWPCC or Council) to study whether the PUD's programs were reaching all customers and markets. Specific attention was given to traditionally harder-to-reach populations, such as low-income customers, moderate income customers, multifamily tenants, manufactured home dwellers, small business owners, commercial tenants, and industrial customers.

In general, the study showed that most of the hard-to-reach markets were well served by the PUD's energy efficiency programs. Low- and moderate-income residential customers participated at rates roughly proportional to their distribution in the customer population. Manufactured home dwellers and rural residential customers had proportionally high participation rates. As a group, small business owners, commercial tenants, and industrial customers, participated proportionally throughout PUD's service territory.

Regional and National Efforts

The PUD remains actively engaged in regional and national conservation activities to identify new technologies, develop new delivery strategies, and influence policy related to energy efficiency and conservation. Some examples of this engagement include:

- The PUD actively participating and providing financial support for market transformation efforts through the Northwest Energy Efficiency Alliance, Consortium for Energy Efficiency, and the Electric Power Research Institute.

- Being an active member of the Regional Technical Forum and the Snohomish County Sustainable Development Task Force and supporting the Pacific Northwest Integrated Lighting Design Labs.

- Actively participating in the development and review of the conservation supply curves developed by the Council for its 2021 Power Plan. The PUD supports establishing achievable energy efficiency targets and recognizes the need to conduct research, development, and demonstration activities for ensuring a sustainable pipeline of future energy efficiency resources.

Demand Response Program and Strategy

Demand response involves the development of programs, pricing structures, and technologies that can influence when and how customers use electricity. By shifting customer demand for electricity away from periods when the cost of supplying that energy is high into periods of lower loads and prices, the PUD can reduce its overall energy costs. This action also has the potential to contribute to system reliability.

Demand response programs can take multiple forms: dispatchable load controls, scheduled load controls, voluntary calls to action, and price incentives. Dispatchable load control programs give utilities the ability to call on resources without any action by the customer. Dispatchable resources are often available within 10 to 15 minutes after being requested (or “dispatched”) by a utility.

The PUD’s adopted 2013 IRP included an action item for staff to conduct a situational scan of demand response technologies and applications. This action item was completed in 2014 and found that the Northwest lacked a well-established capacity market to determine the value of demand response and that demand response technologies in general were still evolving. Subsequent IRPs recognized the potential value of Demand Response and the PUD has since been interested in developing programs promoting demand response.

At the present time, the PUD is piloting several Demand Response style programs with residential customer signups ending in late 2021. These residential pilots include:

- The FlexTime program, utilizing time-of-day rate designs to encourage load shifting.

- FlexResponse, utilizing incentives to call on demand response for load reduction during critical times.

- FlexPeak, utilizing critical peak pricing notifications to reduce peak load in critical conditions.

In addition to these residential programs, the PUD has operated a pilot Commercial Time of Day program for interested customers.

3 - The Planning Environment

Part of the process for determining the best way to meet future customer needs and demands involves establishing an environment in which the PUD sees itself operating. This environment must consider both the current landscape of policy and trends, and how they may evolve over time. To evaluate these trends, the more significant factors have been categorized by their sphere of influence on the PUD:

- The PUD's Strategic Priorities
- The Puget Sound Economy
- Electric Industry Regional Trends
- Energy Policy and Regulatory Requirements
- Climate Change

PUD's Strategic Priorities

The Board of Commissioners expects the PUD to deliver power and water to its customers in a safe, sustainable, and reliable manner while successfully navigating complex change in our industry. The PUD accomplishes this by empowering its teams to provide quality service to its community and prudently managing costs while investing for the future. The Strategic Priorities, developed in 2016-17 and updated annually, are designed to support the PUD's missions of providing quality water and electric energy products and services and include a distinct focus on 5 key areas: Team PUD, Customer Experience, Delivering Now & For the Future, Responsible Cost & Fiscal Management, and Continual Improvement.

The IRP process incorporates these strategic priorities in a number of ways, with the table below providing some highlighted examples:

Strategic Priority	
Team PUD	The IRP process is deliberately collaborative, using cross-functional teams of subject matter experts from across the PUD for scoping, steering, and technical peer review.
Customer Experience	The IRP was scoped collaboratively with customers over a 4-month period in order to capture customer perspectives on priorities in the study scope
Delivering Now and For the Future	The IRP is a 24-year study period that considers how to best position the PUD to provide outstanding value to customers now and in the future
Responsible Cost & Fiscal Management	The IRP manages and quantifies risks, and seeks to develop an evolving power portfolio at the lowest reasonable cost
Continual Improvement	The 2021 IRP leverages new data science platforms and machine-learning models to utilize larger datasets and provide a more robust analytical environment for determining a long-term resource strategy.

The Economy – Puget Sound and Beyond

The 2021 IRP was largely developed before and during the Covid-19 pandemic that saw the first diagnoses arrive in Snohomish County. The effect of Covid-19 on the local economy has been significant, and the transition to a "new normal" post-pandemic is still somewhat uncertain at this time. The IRP looks to long-term economic trends to set its forecast for future needs, but it should be noted that in this unprecedented period, there may be a need to examine and adjust forecasts in future IRP Updates.

The Puget Sound region saw a 5.5% decrease in employment in 2020 relative to 2019 but is expected to gain 1.8% in 2021 from those levels[29]. It is anticipated that the region will return back to historic job levels at some point in 2022, though much of this depends upon the course of the Covid-19 pandemic.

[29] Western Washington University Center for Economic and Business Research. The Puget Sound Economic Forecaster. July 2021.

Despite changes in employment levels, retail sales in the region grew during the pandemic, with 2020 levels exceeding 2019 levels by 4.4%, and 2021 retail sales are expected to exceed 2020 sales by 13%[30]. Much of this activity may be attributed to the fiscal stimulus offered by the federal government, and 2022 sales are expected to be roughly in line with 2021 as the effects of the fiscal stimulus fade but employment levels rebalance.

The Snohomish County unemployment rate in July 2021 was at 5.9%, well below the July 2020 rate of 9.8%, but far exceeding the 2019 rate of 2.9%[31]. This July 2021 unemployment rate was slightly higher than the Washington State average (5.2%) and the national average (5.4%).

Electric Industry – Regional Trends

The electric industry in the Pacific Northwest is facing dynamic changes. When assessing the state of the industry, several anticipated developments relevant to utility resource planning stand out and must be considered when considering future actions. These include the regional Resource Adequacy Program, Post-2028 contract discussions and strategic planning at the Bonneville Power Administration, the Northwest Power and Conservation Council's Power Plan, and the potential for newly forming markets.

Resource Adequacy Program

In early 2019, the Northwest Power Pool and 19 of its members began the development of a regional resource adequacy program. At its core, the program would provide value to the region by compelling participants to plan to uniform capacity measurements, ensuring the region has adequate resources available in advance of a winter or summer season, and allows for resource sharing across participants if a potential loss-of-load event should occur, pooling regional resources to increase regional reliability. Participation in the resource adequacy program is envisioned to be on a voluntary basis – with participating utilities bound by the requirements of the program, once the program has finalized its design, which it has not yet done.

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[30] Western Washington University Center for Economic and Business Research. The Puget Sound Economic Forecaster. July 2021.
[31] US Bureau of Labor Statistics. Retrieved September 10, 2021. https://fred.stlouisfed.org/series/WASNOH0URN

The PUD has been a participant since program inception and has also participated in interim Summer and Winter resource sharing programs that act as a “stop-gap” measure for the program as it prepares for launch. The PUD called upon resources during the 2021 Summer period, and the program successfully matched the PUD with available regional resources to meet its need.

The PUD is a participant in the voluntary Phase 3A portion of the program, the final phase before the program’s conceptual design is finalized and the program seeks Federal Energy Regulatory Commission (FERC) approval. It is expected that the Winter of 2023 will be the first binding season for potential participants, who at this time have grown to 29, spanning from British Columbia to the north and Nevada to the south, with interest from as far east as Colorado.

Because the program is not yet finalized, planning metrics are not incorporated in the 2021 IRP. The PUD will retain local control and authority over long-term planning metrics and IRP methodologies even when the program is fully operational.

The Bonneville Power Administration

The Bonneville Power Administration (BPA) is a significant supplier of power to the region. As such, its success and long-term viability is of great importance to its customers. BPA’s current power contracts are 20-year agreements, signed in 2008 and expiring in 2028. In 2020, BPA launched the Provider of Choice initiative to provide a process and framework for Post-2028 BPA power contracts with its customers, and the PUD has been actively engaged as it considers its resource portfolio in the Post-2028 landscape. The IRP expects that the current BPA power contract will be replaced with BPA contracts of a similar nature.

In January 2018, BPA released its Strategic Plan for the 2018 through 2023 period. This Strategic Plan focuses on how to strengthen the agency’s financial health, modernize the grid, and provide competitive power and transmission products to “deliver on (BPA’s) public responsibilities through a commercially successful business.”. The Strategic Plan’s financial management processes are the subject of a Financial Plan Refresh, which kicked off in September 2021, and is expected to enhance previous efforts. Snohomish is engaged in these efforts with the hopes of helping BPA chart a long-term path to cost-effective resource management and keeping the BPA portion of the PUD's resource portfolio, considered here in this 2021 IRP, low-cost for customers for years to come.

Northwest Power and Conservation Council

The Northwest Power and Conservation Council (NWPCC or Council) is a public agency created by the Pacific Northwest Electric Power Planning and Conservation Act of 1980. The agency's three primary functions are to:

1. Develop 20-year electric power plans for the Northwest that guarantees adequate and reliable energy at the lowest economic and environmental cost;

2. Develop programming to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and

3. Educate and involve the public in the Council's decision-making processes.

Due to the nature of the Council's work and its structure within the Northwest Power Act, its five-year power plan serves as a regional reference for resource planning in the region. Many utilities, as well as BPA, look to the Council's Power Plans as a key source of information for their own planning needs.

The Council is currently in the process of drafting and adopting the 2021 Power Plan, expected to be complete in 2022. The plan is expected to provide results heavily influenced by the passage of recent state energy policies, the use of a new modelling methodology, and the incorporation of climate change on its modeling.

Highlighted findings for the 2021 Power Plan analysis are expected to include:

- A large influx of renewable energy (as much as 3,500 MW nameplate in additions) throughout the region by 2027. This influx decreases wholesale energy prices by increasing the supply of resources at a rate faster than the growth in demand, as well as reducing regional emissions.

- Regional acquisition of at least 2,400 aMW of energy efficiency and conservation by 2041, with at least 750 aMW by 2027. This is reduced conservation acquisition relative to the past power plans, due to low energy price environment as well as relatively inexpensive conservation having already been acquired.

- Demand response assessment showing 720 MW available by 2027; 200 from residential time-of-use rates and 520 from demand voltage regulation.

- A somewhat controversial perspective that the low market price environment may lead to operational challenges resolved by committing more of the region's thermal fleet in advance of need so their output is available should renewable resources not generate as forecast in the day-ahead time period. There has been considerable regional pushback on the appropriateness of this assumption.

Energy Markets

The PUD, like other electric utilities, regularly buys and sells energy on the wholesale power market in order to balance power supply and demand on a variety of time horizons (e.g., hourly, daily, monthly, longer-term). Traditionally energy trading in the Northwest has occurred on a bilateral basis, meaning buyers and sellers of energy must directly negotiate and implement energy trades. Utilities in much of the rest of the country participate in organized markets, typically known as Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs), that manage most day-ahead and real-time energy trading on behalf of their participants. In the organized market framework, power suppliers submit supply offers to a central market operator that dispatches the lowest cost resources available to serve the load needs of market participants. Resources with the flexibility to increase and decrease output in response to market dispatch signals are generally better suited for participation in an organized market.

The Energy Imbalance Market (EIM) is an organized market operated by the California Independent System Operator (CAISO). While the Northwest real-time energy market has traditionally traded on an hourly basis, the EIM is designed to balance energy on a sub-hourly basis correcting the "imbalance" between generation and loads. Since 2014, fifteen Western utilities have joined the EIM and another seven have signaled their intention to join. BPA closely examined the costs and benefits of joining the EIM in a multi-year decision process and made a final decision to join the EIM in March 2022. Due to the potential impact upon BPA customers, the PUD actively engaged in BPA's study and decision process, ultimately supporting BPA's decision. The PUD recognizes the anticipated benefits of participation, such as reducing BPA power rates and improving management of BPA's transmission system.

Many utilities in the region are looking beyond the EIM to a more comprehensive organized market that would include both day-ahead and real-time trading. This market could take several forms, including a proposal by CAISO to expand the existing EIM to a day-ahead market (EDAM), or the establishment of a separate day-ahead market or RTO operated by an entity other than CAISO. Several western states have recently passed legislation requiring utilities located in their states to join an RTO or for state agencies to study RTO formation. While no such legislation has passed in Washington State to-date, these actions by other states may accelerate the development of regional organized markets. The PUD will continue to explore these options through internal analysis, early-stage discussions with peer utilities and industry groups, and participation in any formal stakeholder processes that arise.

NorthernGrid

The PUD is a member of the NorthernGrid regional transmission planning association. NorthernGrid is currently comprised of 13 members including jurisdictional and non-jurisdictional entities who own and/or operate transmission systems or facilities in the west. NorthernGrid, through its vender the Northwest Power Pool ("NWPP"), facilitates regional transmission planning and interregional transmission planning for its Members.

The Federal Energy Regulatory Commission ("FERC") approved the NorthernGrid Funding Agreement in October of 2019 and the FERC jurisdictional member tariffs in April of 2020. The first NorthernGrid Regional Transmission Plan is scheduled to be completed in December of 2021 (www.northerngrid.net).

Energy Policy & Regulatory Requirements

Future legislative policy and regulatory requirements can have a profound effect on the PUD's existing power supply and any future resources it may consider, acquire, or operate. For example, the requirements of the Clean Energy Transformation Act (CETA) will help shape the portfolio options and choices available to the PUD over the planning horizon. In addition, there are several ongoing regulatory processes that may have a significant impact on the PUD's existing resources, such as the litigation surrounding the Federal Columbia River Power System, and the discussions over modernizing or terminating the Columbia River Treaty.

Washington State's Energy Independence Act (EIA) - RCW Chapter 19.285

In 2006, the voters of Washington State approved the Energy Independence Act (the EIA) through the state's initiative process. This Act requires electric utilities with 25,000 or more customers to pursue all cost-effective energy conservation measures, and to acquire and include in their portfolios a mandated amount of eligible renewable resources, renewable energy credits, or combination of the two. The amount of eligible renewable resources required scales to the utility's retail load.

Utilities have three methods for complying with the renewables portion of the EIA: meeting the load-based goals with resources or RECs, demonstrating investment of 1% of its retail revenue requirement in eligible renewable resources or RECs without load growth, or demonstrating investment in excess of 4% of the utility's annual retail revenue requirement (commonly referred to as the "cost cap" method) in eligible renewable resources or RECs.

Clean Energy Transformation Act (CETA)

In 2019, the Washington State legislature passed the Clean Energy Transformation Act (CETA). CETA places several new requirements on utilities centered around clean energy targets beginning in 2030. The core clean energy CETA provisions require:

- Elimination of coal from rates by 2026
- Utilities to be 100% carbon-neutral by 2030
    - "Alternative compliance" available for up to 20% of a utility's total retail load amount)
- Utilities to be 100% carbon-free by 2045

Because the PUD relies on a portfolio that is predominantly carbon-free, the PUD anticipates full compliance with CETA's clean energy provisions.

Since its passage, CETA has been subject to rulemaking efforts by the Department of Commerce and the Utilities and Transportation Commission (UTC). These efforts have been focused on developing rules and guidance for utilities about how compliance will be measured, especially regarding the 2030 carbon-neutral standard. Until these rules reach a final state, resource planning for CETA remains uncertain. Varying interpretations of how utilities must demonstrate compliance could produce significantly different resource portfolios.

For the purpose of establishing the scenarios in the IRP, the PUD has made assumptions regarding CETA compliance with the understanding these assumptions will be revisited in future IRP updates based on the outcome of rulemaking efforts. CETA also instituted certain new requirements for utility IRPs, such as the incorporation of a social cost of carbon in any resource cost calculations. The PUD has incorporated all applicable CETA requirements into this IRP.

CETA also contains a provision requiring utilities to engage in CETA-specific planning through a Clean Energy Implementation Plan (CEIP). These CEIPs must be informed by a utility's IRP and are intended to set planning targets for utilities to move toward compliance with the CETA standards. The PUD's CEIP effort is currently underway and is expected to be adopted by the end of 2021.

Cap-and-Invest

In the 2021 legislative session, Washington state passed the Climate Commitment Act (CCA). The CCA establishes a cap on the total allowable amount of carbon in the state and allows for the trading and investment of carbon allowances. This program, known commonly as a "Cap-and-Invest" style program, sets a declining cap on emissions with the goal of reducing overall state emissions to 70% of 1990 levels by 2040.

One of the key provisions in the legislation is the concept that electric utility emissions are already regulated through CETA. While covered utilities must participate in the Cap and Invest program to maintain emission parity, those utilities will receive no-cost allowances to offset the cost of the program. Specific mechanisms for the allocation and distribution of no-cost allowances have yet to be determined as rulemaking is currently underway at the Department of Ecology to help define the scope and design of the program.

For purposes of resource planning in this IRP, the Cap and Invest program still has too much uncertainty to be modeled with any accuracy. While the PUD expects to receive no-cost allowances to help offset its minimal historic emissions, the amount and value of these allowances remains uncertain. The PUD plans to revisit modeling of the Cap and Invest program in future IRP updates.

Regional and Federal State Energy Policies

As the IRP considers its 24-year planning horizon, it is highly likely that there will be changes in regional and federal energy policies. These changes may not directly affect the PUD, such as renewable portfolio standards in other states, but they may have an impact on the larger market for electricity. The PUD has modeled all active regional energy policies when forecasting market prices and availability. These regional policies include, but are not limited to, Oregon's Renewable Portfolio Standard and California's 100% renewable requirement (SB100).

The IRP also considers how the federal government may enact legislation that affects the policy landscape. Current proposals, including a national clean energy standard or the "Green New Deal" could have significant implications for the PUD directly, as well as the price of energy in the west. While the Base Case does not make any assumptions about what legislation may or may not be enacted, the PUD included the “High Policy” Case to help visualize market conditions should significant energy policy be enacted at the federal level. Further information and assumptions made for the High Policy Case can be found in Section 4 of this IRP.

Federal Columbia River Power System

Endangered Species Act and NEPA Litigation

Litigation over the operation of the Federal Columbia River Power System and associated Biological Opinions (BiOp) has been ongoing for the past 40 years. In 2014, parties challenged the sufficiency of the 2014 Supplemental BiOp, alleging that the BiOp violated the Endangered Species Act (ESA) and that adoption of the BiOp by the action agencies — the Bonneville Power Administration (BPA), U.S. Army Corps of Engineers (USACE), and Bureau of Reclamation (Reclamation) — violated the National Environmental Policy Act (NEPA).

In May 2016, the District Court of Oregon concluded that the National Oceanic and Atmospheric Administration (NOAA) Fisheries violated the ESA by adopting the 2014 Supplemental BiOp. The court determined that the mitigation in the BiOp was insufficient to avoid jeopardy of the listed species, particularly for salmon and steelhead in the Columbia and Snake Rivers. In addition to finding the BiOp invalid, the Court also ordered compliance with NEPA. In response, the action agencies launched a public process that started in September 2016 and concluded with a final Environmental Impact Statement (EIS) and Record of Decision (ROD) released in September 2020. The ROD commits the action agencies to "implement actions that support the continued reliable water resource benefits and balances the purposes of the federal dams while specifically supporting ongoing and new improvements for species listed under the Endangered Species Act." A key component of the final EIS is the "flexible spill agreement" that aims to balance the objectives of improved salmon survival and affordable hydropower.

On July 16, 2021, the State of Oregon filed a motion in the Oregon District Court seeking a preliminary injunction against the Federal defendants (National Marine Fisheries Service, US Fish and Wildlife Service, USACE and Reclamation). Oregon argues that the existing configuration of the Columbia River System (CRS) dams limits options for providing conservation actions to address CRS impacts on listed fish. The motion asks that spill be significantly expanded.

The PUD has no capability to predict the outcome of this pending litigation. The 2021 IRP analysis uses existing and known Federal hydro system operating assumptions to model the

PUD's offtake under the Slice product portion of its long-term BPA power supply contract. These assumptions are based on the result of the flexible spill agreement.

Columbia River Treaty

The Columbia River Treaty is a 1964 treaty agreement between Canada and the United States addressing the flood control and power benefits derived from the development and operation of dams in the upper Columbia River basin. Either nation can terminate certain provisions of the Treaty at any time on or after September 16, 2024, having provided at least ten years' notice.[32] In December 2013, the U.S. Entity, consisting of BPA and the USACE, in collaboration with regional stakeholders, developed a "Regional Recommendation" concerning the future of the Columbia River Treaty.

The Canadian and United States governments have undergone a formal review of the Treaty and a series of negotiations for potential changes for the joint operation of the system. However, these negotiations have not yet produced an agreement. These negotiations could result in modifications to the flood control and power obligations for each nation, impacting the hydroelectric power produced by the Federal System that BPA markets. At this time, PUD staff cannot predict with any certainty the outcome of these negotiations, or the implications for the Federal hydro system and by extension the PUD's long-term BPA power supply contract and power costs.

[32] To terminate the treaty effective September 2024, the ten-year notice would be required in September 2014.

4 - Scenarios and Planning Assumptions

Purpose of Scenarios

As the PUD attempts to plan for future needs, scenarios help explain how changes in economic, social, technical, regulatory, and environmental trends could affect the PUD's future load growth and resource forecasts. These scenarios also provide useful insights into potential uncertainties and broad sets of risks the PUD could face under each of these futures. The 2021 IRP evaluated eight scenarios that considered a range of futures the PUD could face for the 2022 through 2045 study period. The primary descriptors for each case are summarized below. Note that all cases include effects caused by climate change, electrification, societal carbon costs (as prescribed by CETA), regulatory obligations to meet CETA and I-937 requirements, and a modest reduction in BPA contract allocation after 2028 caused by a declining federal system size.

All scenarios were developed collaboratively with customers and PUD subject matter experts in a series of working meetings across a four-month period. The scenarios were designed to identify risks, trends, and opportunities, while identifying ways in which these variables could be incorporated into the 2021 IRP. These efforts would ultimately help to create a flexible resource strategy that could work well for a variety of futures the PUD may encounter.

Figure 4-1 provides a summary of the risks identified by customers, and how they were mapped to specific scenarios.

Figure 4-1

Identified Risk Factors and Scenario Assignment

Risk	Scenario
Low Economic Growth, load, and wholesale market energy prices	Low Growth
High Economic Growth, load, and wholesale market energy prices	High Growth
High Rate of Electrification (including EVs and local policies requiring building electrification)	High Electrification
Less BPA resources available to the PUD (either through operational changes or the Post-2028 contract renegotiation process)	Less BPA
Higher rate of Climate Change	High Climate Change
Market Disruption due to Federal Policy changes, or proliferation of State energy Policy changes across WECC	High Policy
Market Disruption due to high penetration of Storage Resources across the WECC	High Technology

Figure 4-2 provides a summary of the key variables across scenarios. These variables help to quantify identified risk elements.

Figure 4-2

Snohomish PUD's 2021 IRP Scenarios

	Average Annual Net Load Growth	**Average Electricity Prices ($/MWh) [2022 & 2045]**[33]	**Natural Gas Price ($/MMBtu) [2022 & 2045]**	**Highest Peak Week Electricity Prices ($/MWh) [2022 & 2045]**[34]	**Short description of unique consideration**
Base Case	0.93 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Expected Case
Low Growth	0.72 %	24.49 to 23.70	2.60 to 4.54	40.54 to 68.47	Lower load growth
High Growth	1.32 %	28.05 to 27.50	3.32 to 8.28	45.71 to 96.42	Higher load growth
Less BPA	0.93 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Lower Post-2028 BPA allocation
High Policy	1.28 %	54.30 to 27.37	2.68 to 6.36	83.06 to 92.95	Market price analysis of clean energy policy across Western United States
High Climate Change	0.93 %[35]	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Higher climate change impact on PUD (RCP 8.0)[36]
High Technology	0.93 %	25.53 to 28.63	2.68 to 6.36	40.33 to 81.18	High storage penetration across WECC market footprint
High Electrification	1.46 %	25.21 to 30.72	2.68 to 6.36	40.61 to 93.06	Higher PUD rates of EV adoption and all-electric buildings

[33] Section 4 – *Scenarios & Planning Assumptions* describes the planning assumptions associated with the natural gas, carbon, and regional electric market price forecasts.
[34] The Peak Week Planning Standard considers hours 7-10 and 17-20 of days Monday-Friday for every month. As such, Highest Peak Week MWh prices represents the highest monthly average price for those hours on an annual basis for 2022 & 2045.
[35] Load growth for the High Climate Change scenario is slightly above that of the Base Case at less than one hundredth of a percent.
[36] More detail on climate change analysis is provided in Section 4

Key Variables for Scenarios

Load Growth Forecast

The range of load forecasts developed for the 2021 IRP rely on a mix of econometric and stochastic approaches. The IRP uses an econometric approach for modeling historical weather, consumption, and customer information to build a baseline from which future years can be predicted. In building this baseline, the PUD relies on actual consumption data from the past several years by sector, and then provides stochastic forecasts of what consumption would be expected under climate-change-modified, historic weather patterns, while holding other variables constant.

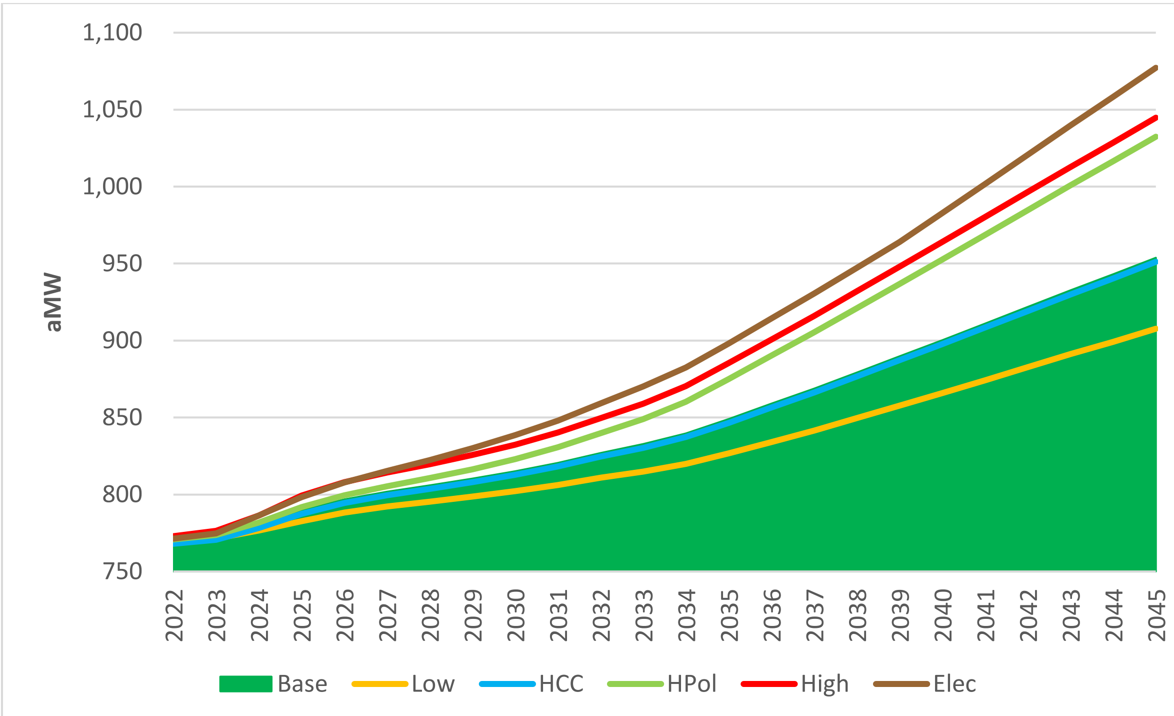
With the baseline established, the IRP adjusts for expected future conditions including changes in: population, housing type and efficiency, electric vehicle adoption,[37] electric water and space heating adoption, assumptions based on permitting by the Washington State Liquor and Cannabis Board on grow or processing locations, county employment and projections in the goods-producing, service-producing and military sectors, known industrial developments, and other factors. These changes are aggregated and net effects are applied over the forecast period.

[37] Estimates for electric vehicle adoption (plug-in electric and battery electric technologies) in the PUD's service territory were derived from a 2017 joint study performed Energy and Environmental Economics (E3), *"Economic & Grid Impacts of Plug-In Electric Vehicle Adoption in Washington & Oregon,"* March 2017. This study was sponsored by Snohomish PUD, Chelan County PUD, Puget Sound Energy, Tacoma Power, Avista Utilities and Seattle City Light.

Figure 4-3 shows the average annual load forecast by scenario for the 2022 through 2045 study period, before new conservation. Note that the Low BPA and High Technology Scenarios share the same load forecast as the Base Case Scenario, and thus are not shown in Figure 4-3.

Figure 4-3

2021 IRP Average Annual Load Forecast by Scenario before New Conservation (in aMW)



Climate Change Forecast

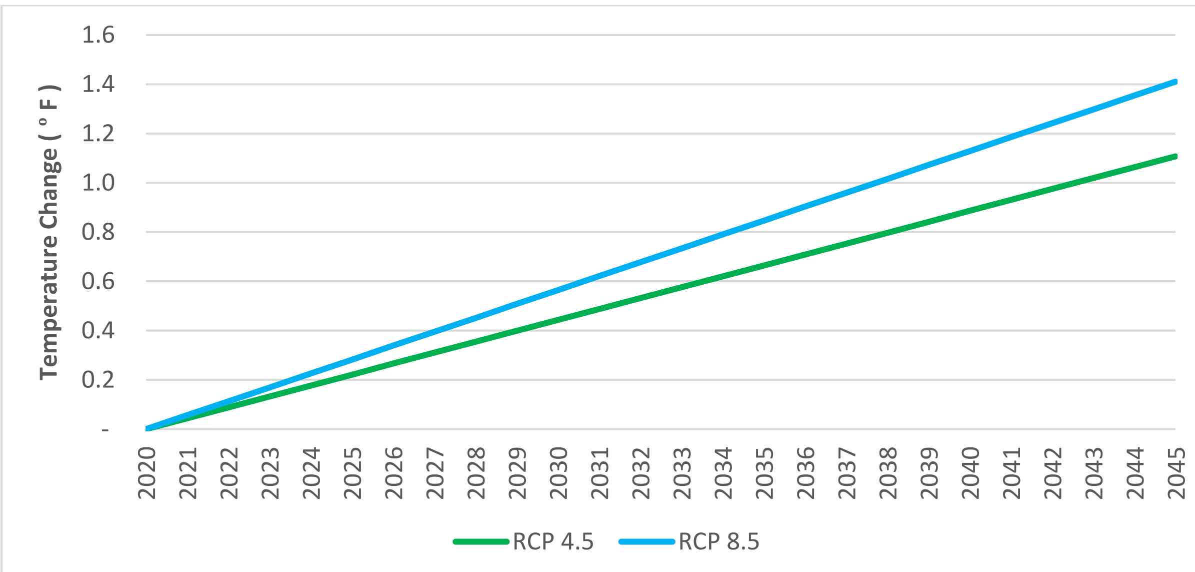
All load forecasts and resource generation forecasts include forecasted impacts of climate change based upon data available through the University of Washington Climate Impact Group and Oregon State University.

There are two climate change pathways used in the 2021 IRP. The default climate change pathway uses the United Nations Intergovernmental Panel on Climate Change's Representative Concentration Pathway (RCP) standards, selecting the 4.5 RCP pathway. This represents an increase in average global temperatures of approximately two degrees Celsius from pre-industrial levels by the year 2100. RCP 4.5 has been used as an estimate of moderate climate change and serves as the baseline climate change estimate utilized by the Council's 2021 Power Plan analysis. RCP 8.5 is used in the High Climate Change scenario and represents an increase in average global temperatures of approximately 3.7 degrees Celsius relative to the global 1986-2005 average.[38] All global climate change estimates are downscaled to the region in studies by the University of Washington and Oregon State University.

Figure 4-4 shows a comparison in average temperature deltas between RCP 4.5 and RCP 8.5. Average annual climate change varies by season and year, and adjustments were fit to stochastic modeling of historic weather patterns.

Figure 4-4

RCP 4.5 and RCP 8.5 comparison: Average Annual Temperature Change Assumptions applied to Stochastic Weather Model, relative to 2020

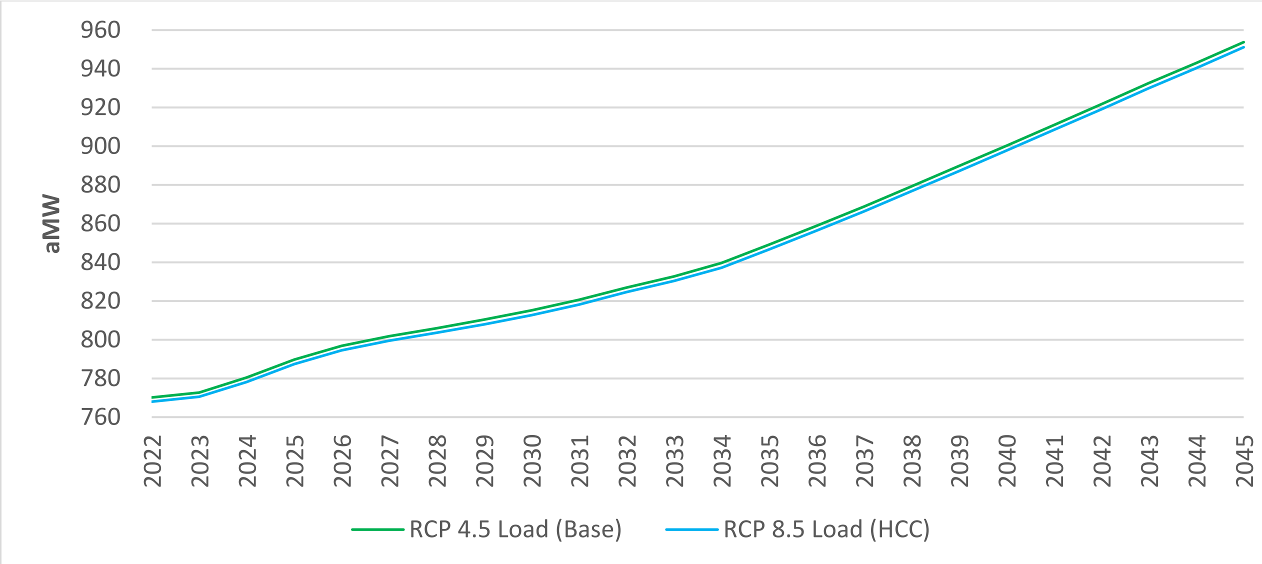


Load forecasts are directly affected by climate change – a key variable in load forecasts, the electricity needed to meet space heating and space cooling needs, are directly affected by variations in climate and temperatures. In addition to forecasts of temperature changes, climate change forecasts also include forecasts of increasing customer adoption of air conditioning. Figure 4-5 shows a comparison between annual average PUD loads with RCP 4.5 compared to RCP 8.5. In general, RCP 8.5 load is slightly lower than RCP 4.5 because the reduced amount of space heating due to climate change in RCP 8.5 relative to RCP 4.5, is greater than the additional amount of space cooling forecast.

Figure 4-5

[38] WG1AR5_SPM_FINAL.pdf (ipcc.ch)

RCP 4.5 and RCP 8.5 Load Comparison



Under current analyses, the effects of climate change on annual forecast loads are relatively small but have a more significant impact on resource output. Climate change impacts resource forecasts for hydropower resources by altering patterns of projected future snowpack runoff and precipitation falling as snow or rain. Figure 4-6 shows a comparison of annual Jackson generation through 2045 under RCP 4.5 modelling compared to RCP 8.5 modelling. Climate change modelling is applied to BPA generation, Jackson generation and all PUD-owned or contracted hydropower generation.

Figure 4-6

RCP 4.5 and RCP 8.5 Jackson Annual Generation Forecast through 2045

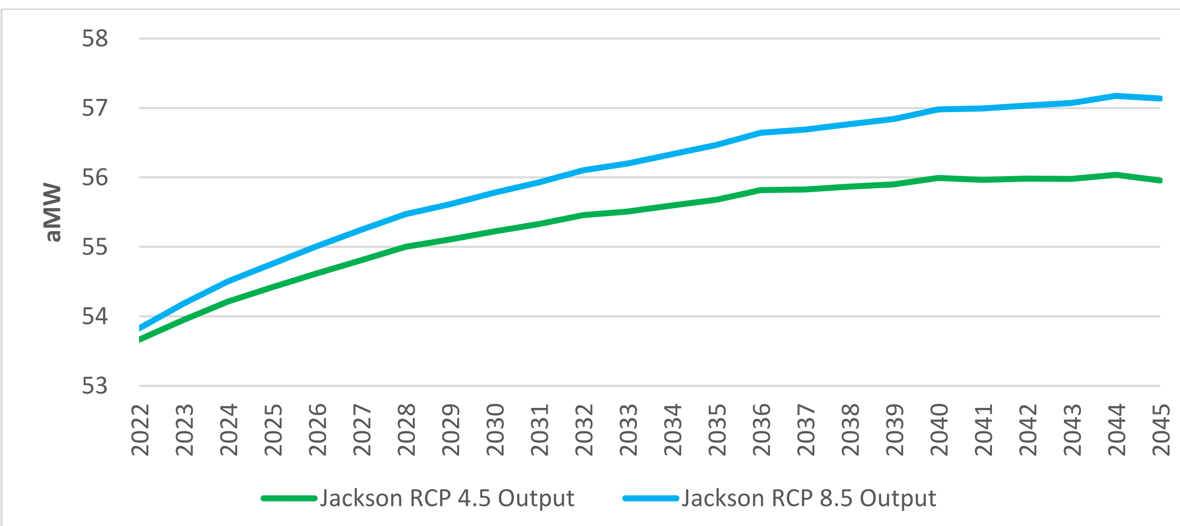


Figure 4-7 shows how Jackson's monthly production output changes over time due to climate change in the RCP 4.5 scenarios. Effectively, production ramps up in winter and down in summer months over the duration of the study period. This is due to increasing temperatures affecting when water is released from snowpack into the generation system; with higher annual temperatures, snow either falls as rain or melts earlier resulting in higher winter generation and a corresponding decrease in summer generation.

Figure 4-7

RCP 4.5 Jackson Evolution of Monthly Generation Forecast through 2045

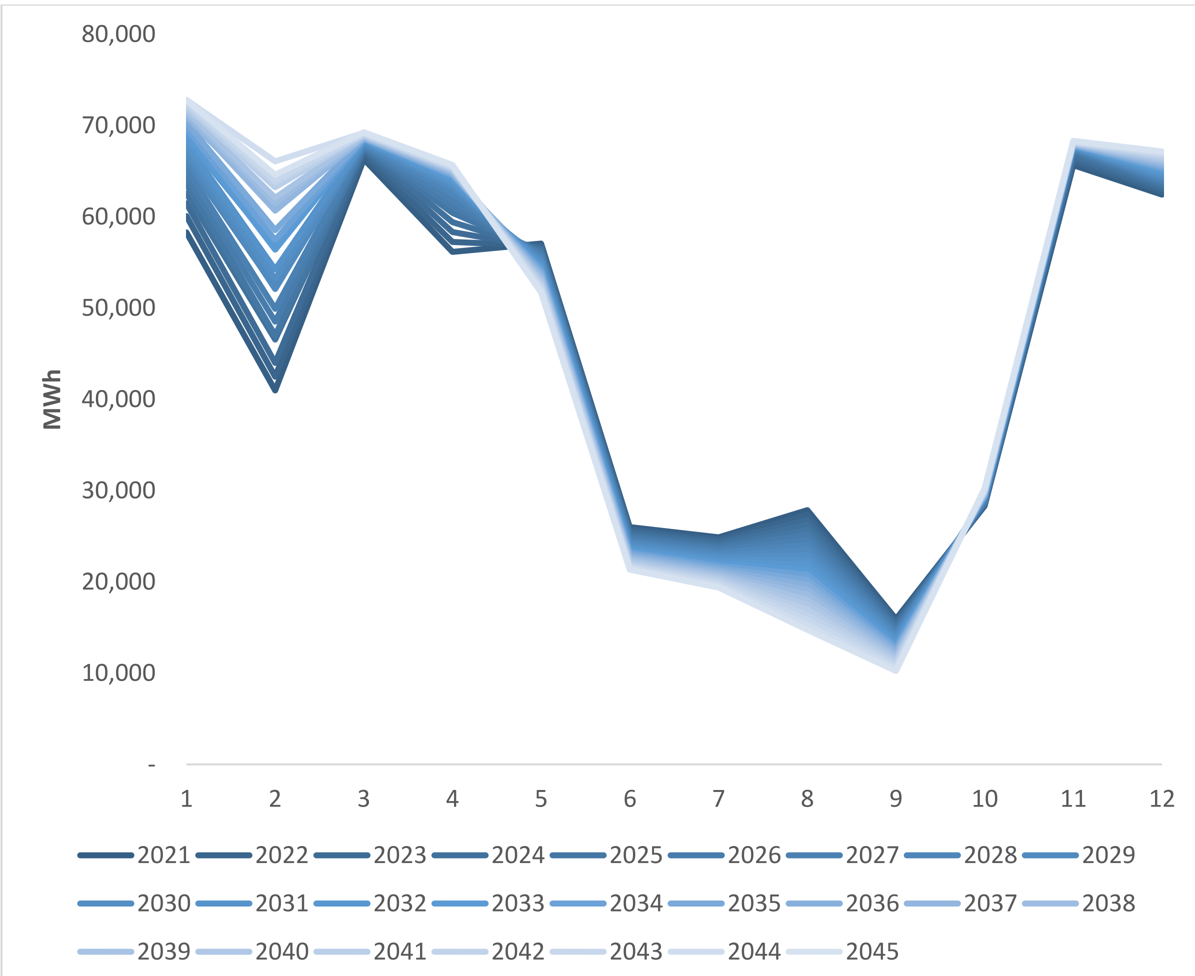


Figure 4-8 Shows how the Climate Change variable was accounted for in scenarios assessed.

Figure 4-8

Table of Climate Change incorporation into Scenarios

Scenario	Variable Treatment
Base Case	RCP 4.5
Low Growth	RCP 4.5
High Growth	RCP 4.5
Less BPA	RCP 4.5
High Policy	RCP 4.5
High Climate Change	**RCP 8.5**
High Technology	RCP 4.5
High Electrification	RCP 4.5

EV Forecast

Electric vehicle (EV) adoption assumptions were built into each of the scenario load forecasts and reflect the PUD's expectation that EV's may become a significant component of future load growth. EV load forecasts examine growth in the service territory, forecast the average load per vehicle on an annual basis, and utilize an Avista study on time and location of charging[39] to estimate the hourly load distribution of electric vehicle load. A Low, Base, and High electric vehicle forecast was developed for use as appropriate across the scenarios.

[39] Avista's study is also used by the Council in the 2021 Power Plan

Figure 4-9 shows the differences in annual electric vehicle counts across the Low, Base, and High EV forecasts.

Figure 4-9

Electric Vehicle Count Forecast

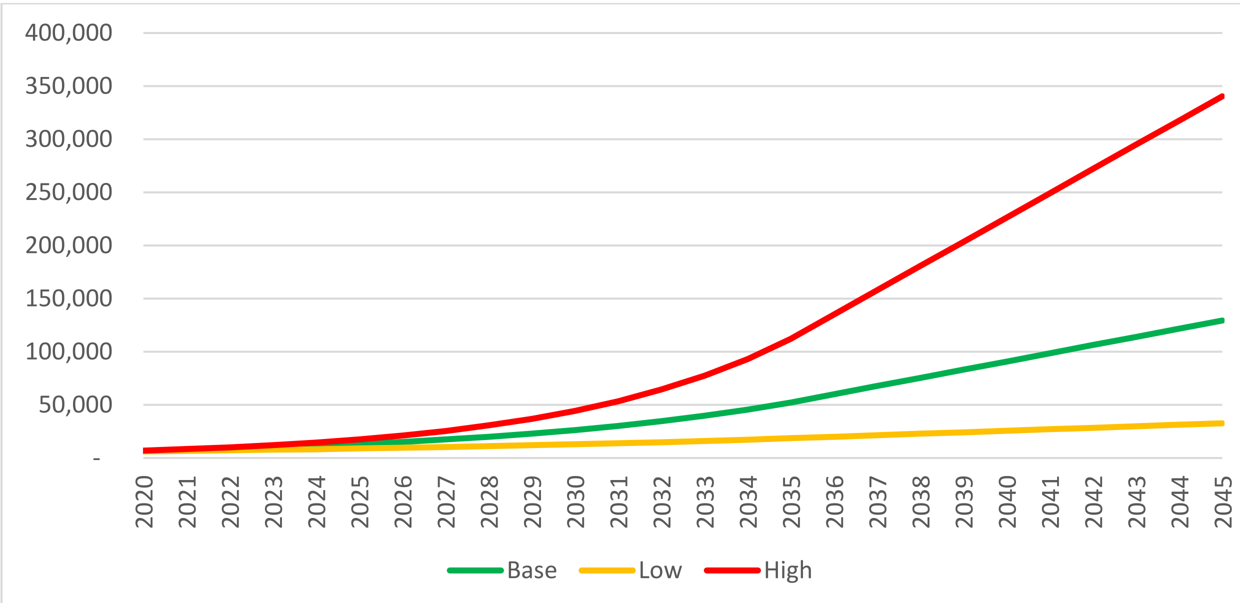


Figure 4-10 shows the differences in annual electric vehicle load across the Low, Base, and High EV forecasts.

Figure 4-10

Annual Electric Vehicle Incremental Load Forecast

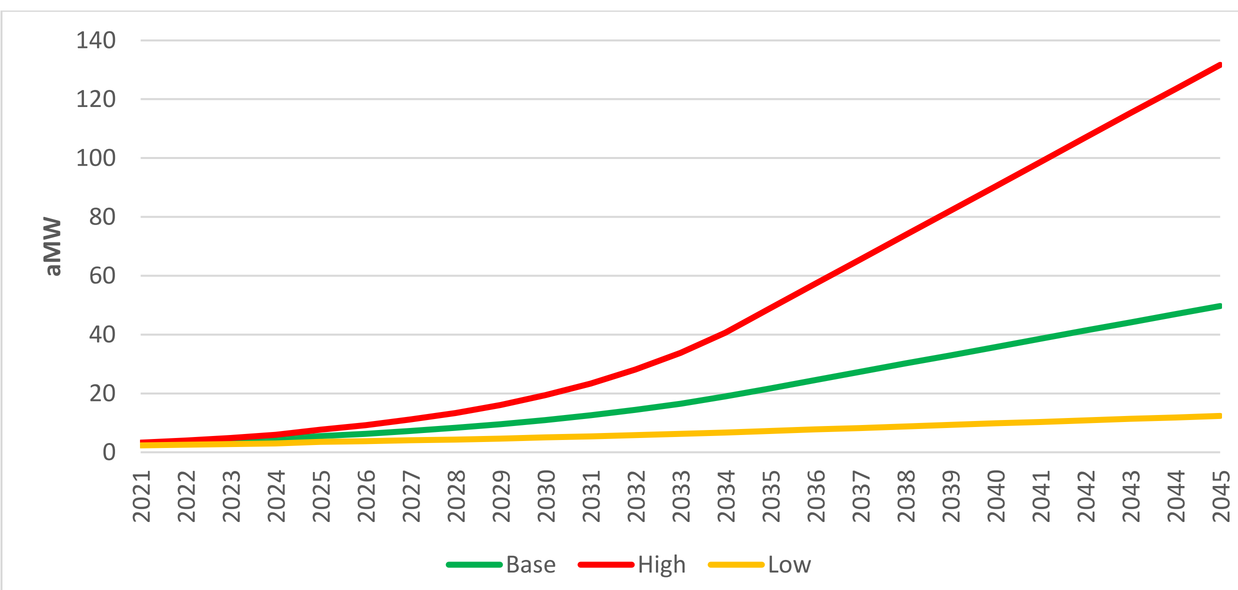


Figure 4-11 shows an example of how hourly load was distributed across weekday hours by location of charger in 2022 for the Base EV forecast. This information is used to help the PUD identify the forecasted hourly capacity needs associated with EVs.

Figure 4-11

Weekday Electric Vehicle Load Forecast in aMW

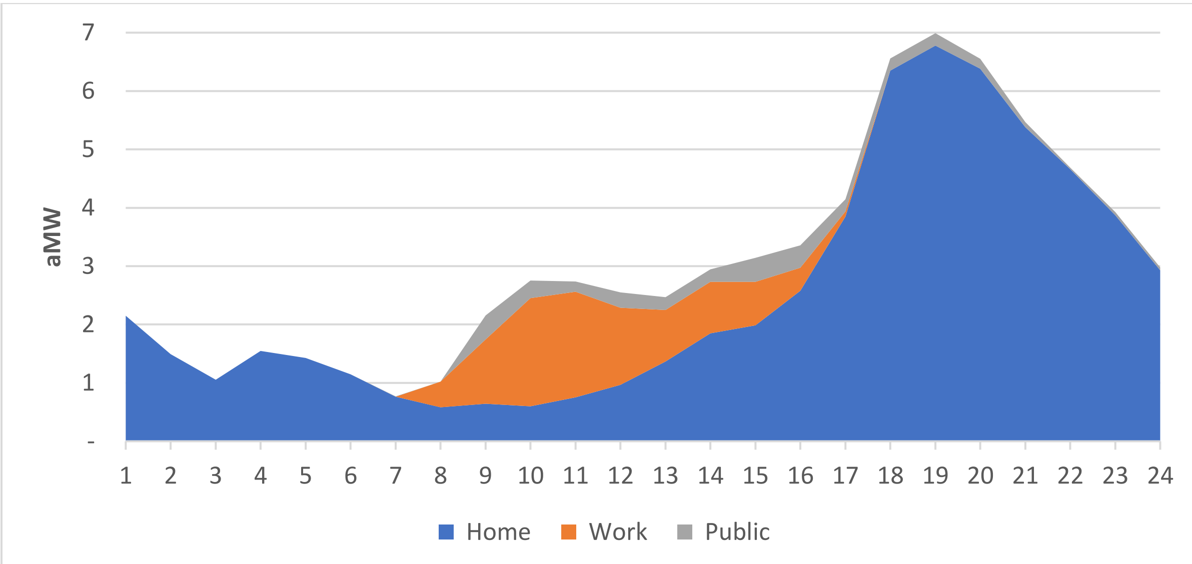


Figure 4-12 shows an example of how hourly load was distributed across weekend hours by charger location in 2022 for the Base EV forecast.

Figure 4-12

Weekend Electric Vehicle Load Forecast in aMW

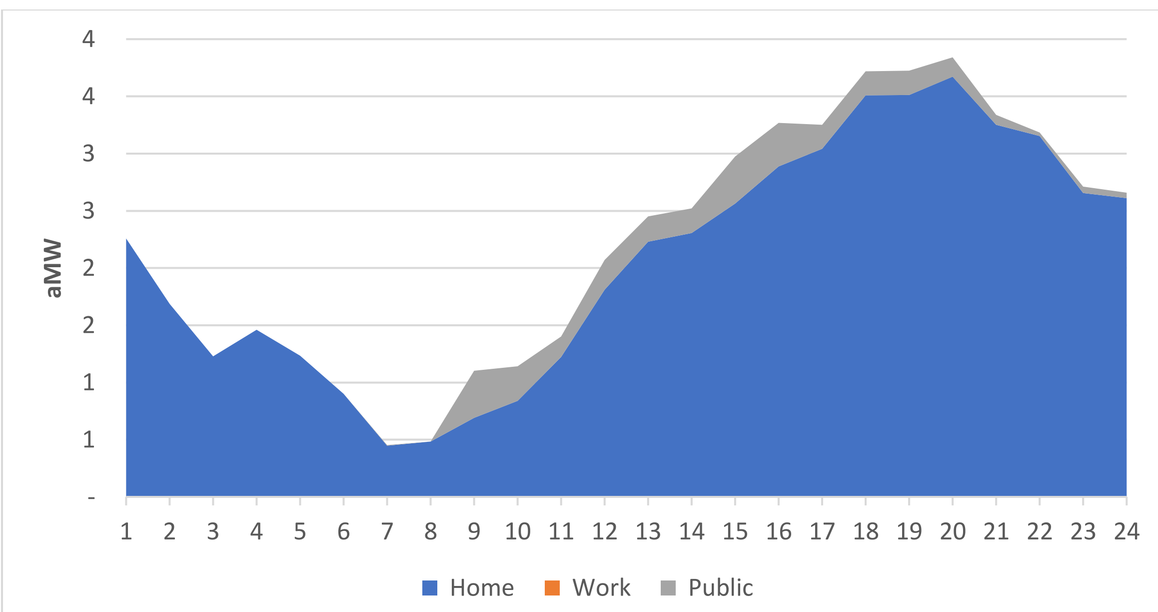


Figure 4-13 Shows how the Electric Vehicle forecast variable was accounted for in scenarios assessed.

Figure 4-13

Table of Electric Vehicle Forecast incorporation into Scenarios

Scenario	Variable Treatment
Base Case	Base
Low Growth	Low
High Growth	High
Less BPA	Base
High Policy	High
High Climate Change	Base
High Technology	High
High Electrification	High

Rooftop Solar Forecast

Rooftop Solar adoption assumptions are built into each of the scenario load forecasts and reflect the PUD's expectation that customer-owned rooftop solar will continue to grow over time, spurred by declining costs. The two key variables when forecasting rooftop solar are installed rooftop solar capacity in the service territory (as measured by aggregated nameplate), and anticipated generation of that aggregated installed capacity on an hourly basis across the study period. A Low, Base, and High rooftop solar forecast was developed for use as appropriate across the scenarios. Given its nature as a "behind-the-meter" resource, the aggregated rooftop solar forecast acts as a reduction to forecasted load.

Figure 4-14 shows the differences in annual installed rooftop solar capacity (as measured by nameplate) across the Low, Base, and High forecasts with the to date installed capacity.

Figure 4-14

Installed Rooftop Solar Nameplate Forecast

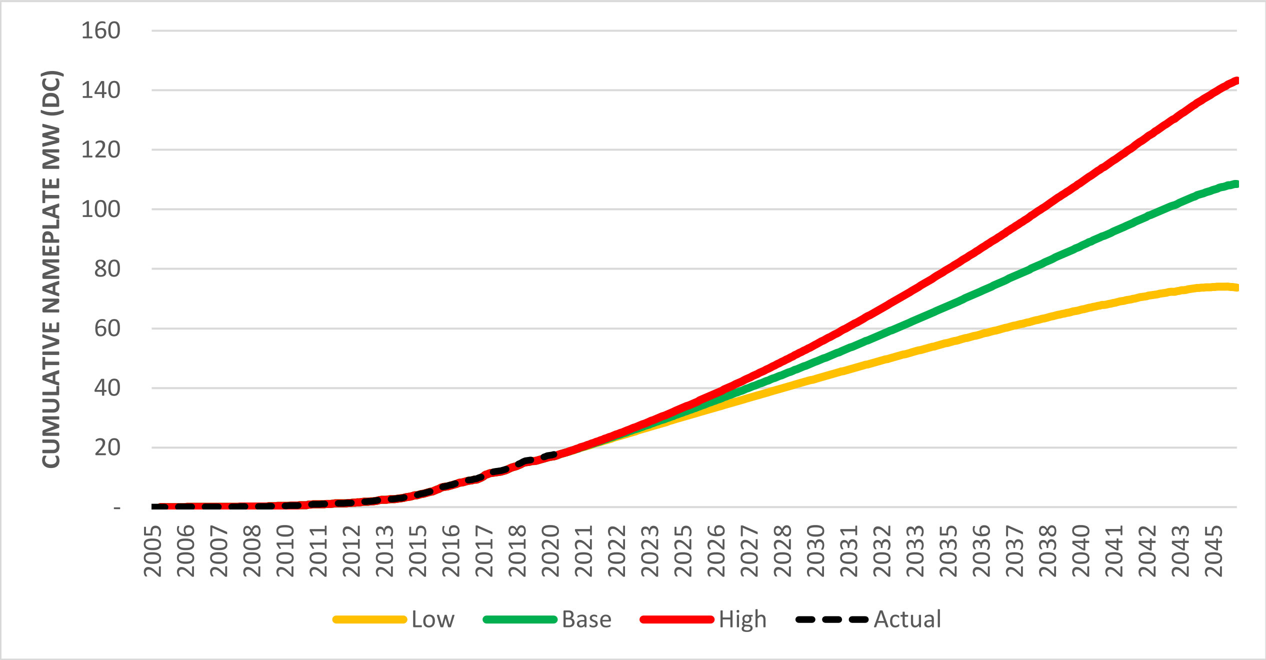


Figure 4-15 shows the differences in annual rooftop solar generation estimates across the Low, Base, and High forecasts.

Figure 4-15

Rooftop Solar Generation Forecast

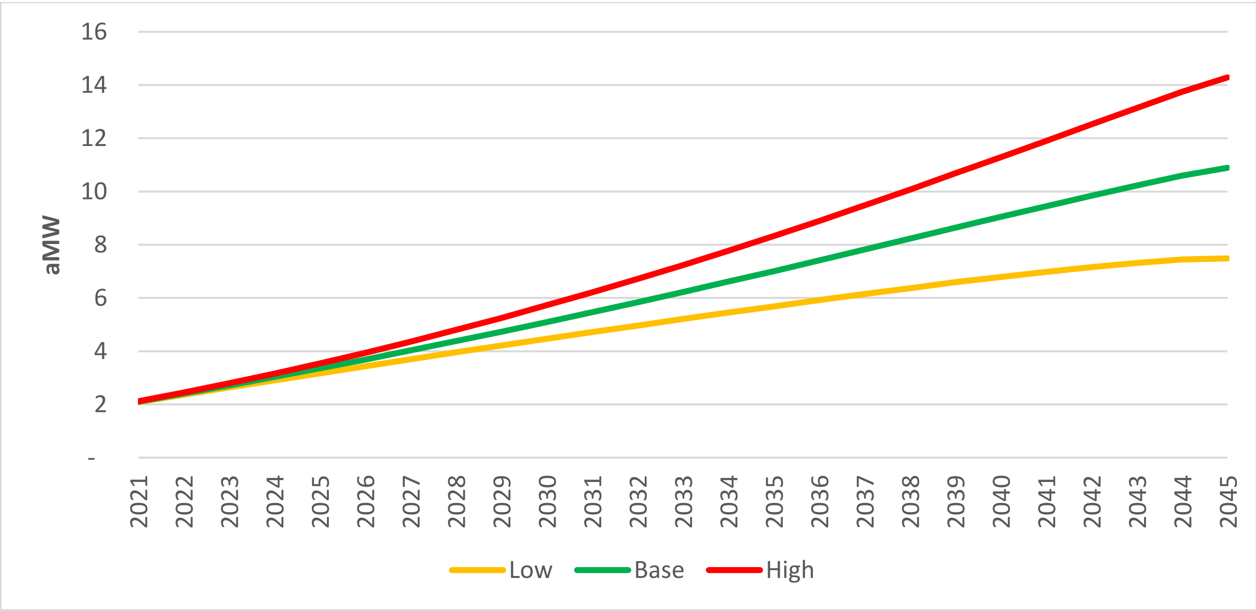


Figure 4-15 Shows how the Rooftop Solar forecast variable was accounted for in scenarios assessed.

Figure 4-15

Table of Rooftop Solar incorporation into Scenarios

Scenario	Variable Treatment
Base Case	Base
Low Growth	Low
High Growth	High
Less BPA	Base
High Policy	High
High Climate Change	Base
High Technology	High
High Electrification	High

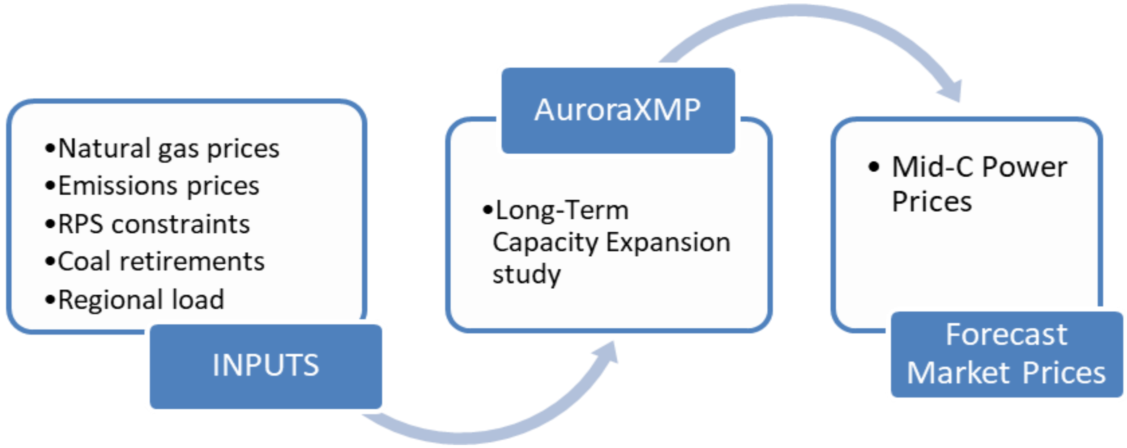
Market Price Forecast

The 2021 IRP forecasts wholesale prices at the Mid-Columbia (Mid-C) price hub using AURORA^{XMP} software. The Aurora model simulates and forecasts the entire WECC-wide resource mix, called a long-term capacity expansion study. This study requires various inputs into the model and is based upon the resource needs across the system and various economic and regulatory signals throughout the footprint. Once the WECC-wide resource mix is determined via the Long-Term Capacity expansion study, the Aurora model simulates how those resources are dispatched in response to forecasted loads across different zones in the WECC, called a standard zonal production model. This production model returns the marginal costs at each hub, thereby producing the forecast wholesale market price at each hub location across time.

Figure 4-16 provides a visual example of how the AURORA modeling framework operates.

Figure 4-16

Diagram of AURORA^{XMP} Modeling



The AURORA^{XMP} model required significant modifications in order to reflect recent changes to State Energy policies. These changes were accomplished by setting resource mix goals for each state specific to their policy. For example, the model reflects the requirement for utilities in Washington to serve their customers with 100% clean energy by 2045, with clean energy defined as renewable energy, hydropower, or nuclear generation.

All policy goals were modeled assuming compliance would be met and progress toward compliance occurred linearly – such that a goal of 80% clean by 2030 and 100% clean by 2045 would be incrementally achieved in a manner where the 2030 mix was 80%, 2033 was 84%, 2036 was 88%, 2039 was 92%, 2042 was 96%, and 2045 was 100%.

Forcing the model to assume all policy goals would be met spurred the model to build a considerable amount of renewable energy to meet policy goals, consistent with the results of the Council's 2021 Power Plan. This large renewable build-out put downward pressure on wholesale energy prices despite inflationary pressure over time and increased hourly market price volatility.

Figure 4-17 compares the resource buildout seen in the Base Case model, for comparison with Figure 4-18, which is the results of the NWPCC's Draft 2021 Power Plan. Relative to the Council, the 2021 IRP takes a more cautious view on the volume of renewables that can be added to the grid over the next twenty years. The IRP acknowledges that an unprecedented volume of new resources are coming, and they are largely variable renewable resources.

Figure 4-17

Base Case WECC Resource Builds

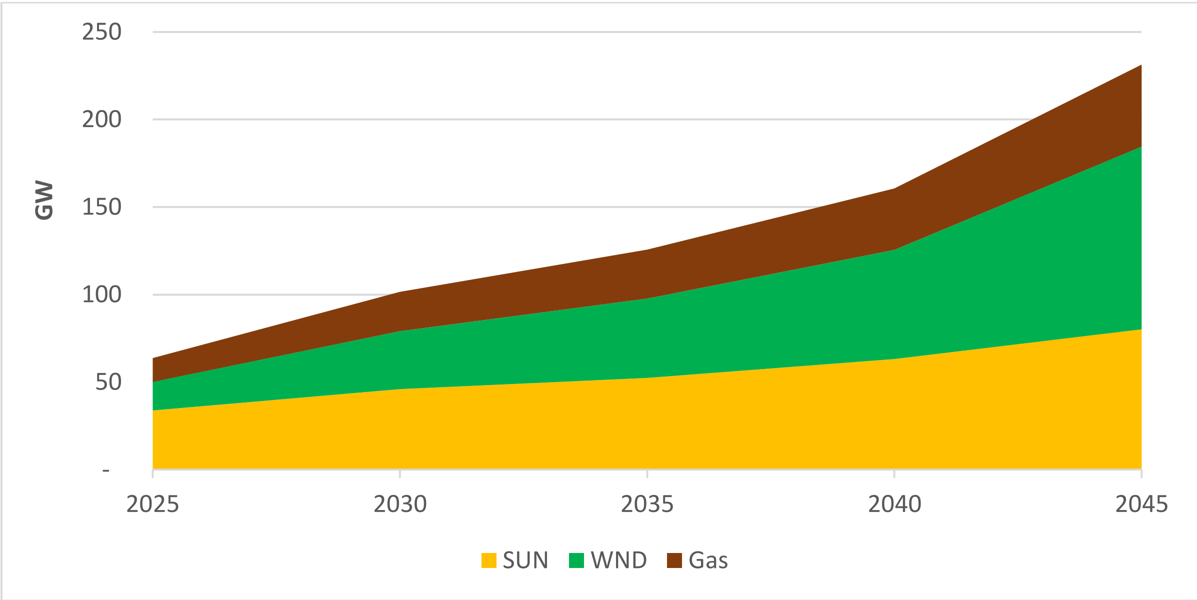
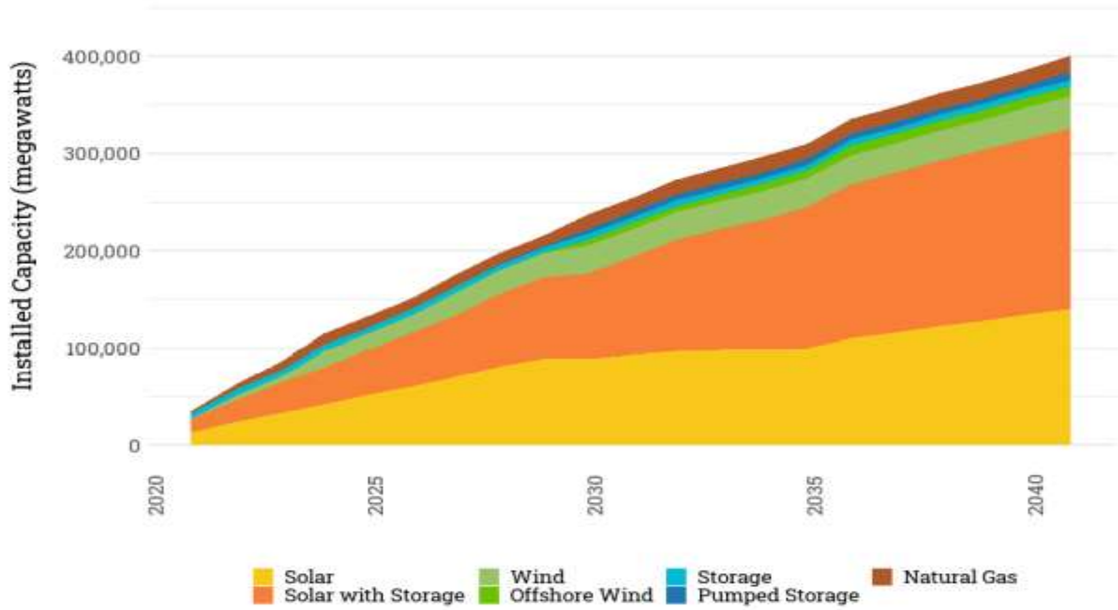


Figure 4-18

NWPCC 2021 Power Plan WECC Resource Builds by 2041[40]



[40] 1,000 MW = 1 GW nameplate. The 2021 IRP expresses nameplate capacity additions WECC-wide in GW, where the NWPPC expresses additions in MW.

Natural Gas

Assumptions regarding natural gas prices served as both an input to the forecast of wholesale electricity prices modeled at the Mid-Columbia trading hub and to the underlying fuel costs associated with certain supply side resource options. These assumptions varied accordingly by scenario. The 2021 IRP analysis calculated natural gas price forecasts using AURORA^{XMP} and the Energy Information Administration's 2020 Annual Energy Outlook. The Societal Cost of Carbon was added to the dispatch of any fossil-fuels in the Zonal Production run and adds additional effective costs to natural gas in the study.

Figure 4-19 shows natural gas prices inputs across scenarios.

Figure 4-19

Natural Gas Price Forecasts

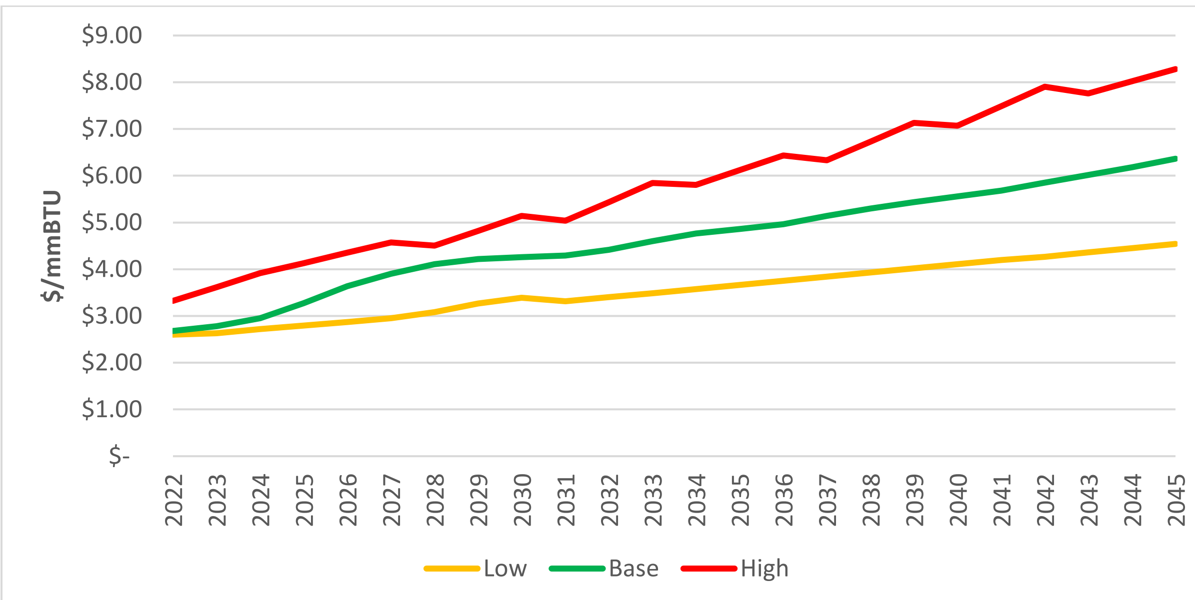


Figure 4-20 Shows how Natural Gas price forecasts were applied in scenarios assessed.

Figure 4-20

Table of Rooftop Solar incorporation into Scenarios

Scenario	Variable Treatment
Base Case	Base
Low Growth	Low
High Growth	High
Less BPA	Base
High Policy	Base
High Climate Change	Base
High Technology	Base
High Electrification	Base

Societal Cost of Carbon

The Clean Energy Transformation Act (CETA) requires utilities to consider the Societal Cost of Carbon (SCC) at a 2.5% discount rate on a planning basis[41]. Because the PUD uses an integrated portfolio approach where market resources, demand-side resources, and supply-side resources are all simultaneously economically co-optimized to identify the PUD's long-term resource strategy, the SCC must be added to the wholesale market price forecast in order to flow through the economic optimization model. Methodologically, the SCC was added in the standard zonal production run of the AURORA model, acting as a "planning basis" carbon tax on fossil-fuel based dispatch. In this way, the SCC increases wholesale market forecast prices consistent with the scale of the price (increasing over time) and the carbon mix in the market for the forecast time period.

[41] RCW 19.280.030(3)(a)

Figure 4-21 shows the Societal Cost of Carbon using the 2.5 percent discount rate in 2020 dollars per metric ton.

Figure 4-21

Societal Cost of Carbon[42]

Year	Social Cost of Carbon Dioxide* (in 2007 dollars per metric ton)	** GDP Index (2007 dollars)	** GDP Index (2020 dollars)	Adjusted Social Cost of Carbon Dioxide* (in 2020 dollars per metric ton)
2010	$50	92.498	113.623	***$61***
2015	$56	92.498	113.623	***$69***
2020	$62	92.498	113.623	***$76***
2025	$68	92.498	113.623	***$84***
2030	$73	92.498	113.623	***$90***
2035	$78	92.498	113.623	***$96***
2040	$84	92.498	113.623	***$103***
2045	$89	92.498	113.623	***$109***
2050	$95	92.498	113.623	***$117***

** Social cost of carbon dioxide in 2007 dollars using the 2.5 percent discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016.*

*** U.S. Department of Commerce Bureau of Economic Analysis Gross Domestic Product Table 1.1.4 Annual Price Indexes (Line 1), Last Revised on: May 27, 2021.*

Price Forecast Comparison

The resulting forecast market prices yield distinctive observations that describe the potential market price environments under which the PUD's Long-Term Resource Plan might operate.

The first observation is that annual average prices at Mid-C appear to be relatively flat over time; the arrival of considerable renewable supply offsets inflationary pressure and increasing natural gas prices. Because wholesale market prices are given nominally, the real cost of wholesale electricity is actually decreasing over time. An interesting anomaly to this observation in the study period is the High Policy Case, which includes WECC-wide limitations on new fossil-fuel resource builds and a WECC-wide clean energy goal of 100% by 2045. Due to these fossil-fuel

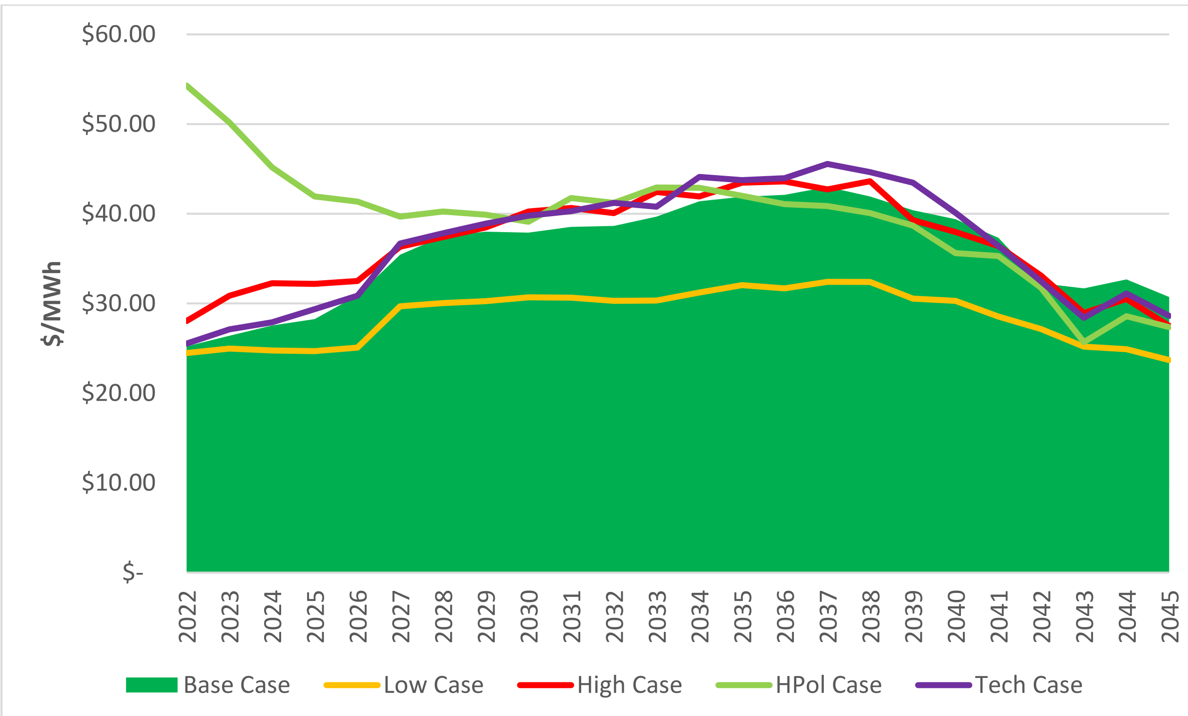
[42] Washington State Utilities and Transportation Commission. https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

build limitations, capacity resource scarcity forces high near-term prices but ultimately approaches a near-consensus price trajectory by the 2030's similar to other scenarios.

Figure 4-22 provides a comparison of wholesale market prices on an annual average basis.

Figure 4-22

2021 IRP Wholesale Market Price Forecast by Scenario



The second observation is that hourly price volatility at Mid-C is accelerating over time, with the delta between the highest price hour and lowest price hour increasing across time and across seasons.

Figure 4-23 shows the increase in price volatility across time on an hourly basis. In general, morning and evening peak prices grow across time. Conversely, mid-day hours decrease due to load shape and an increasing supply of solar generation across WECC. These results are consistent with those found by the NWPCC as seen in Figure 4-24.

Figure 4-23

Average Hourly Price Forecast at Mid-C (Base Case shown)

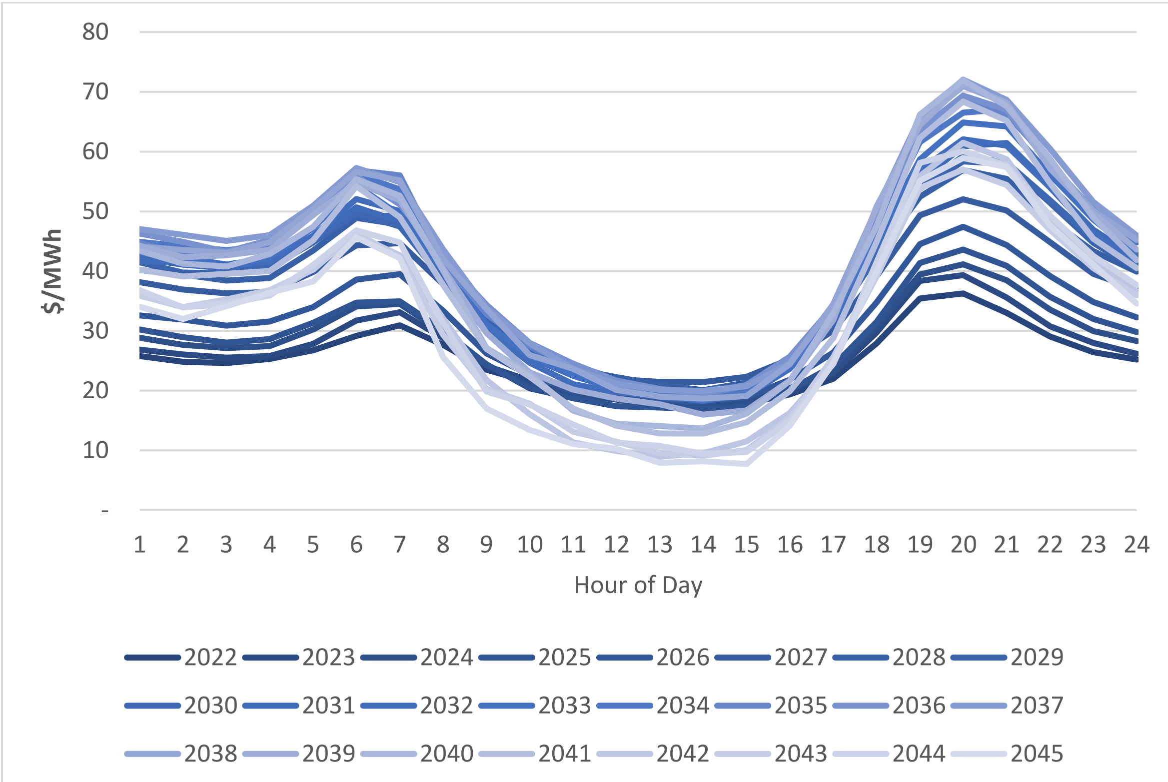
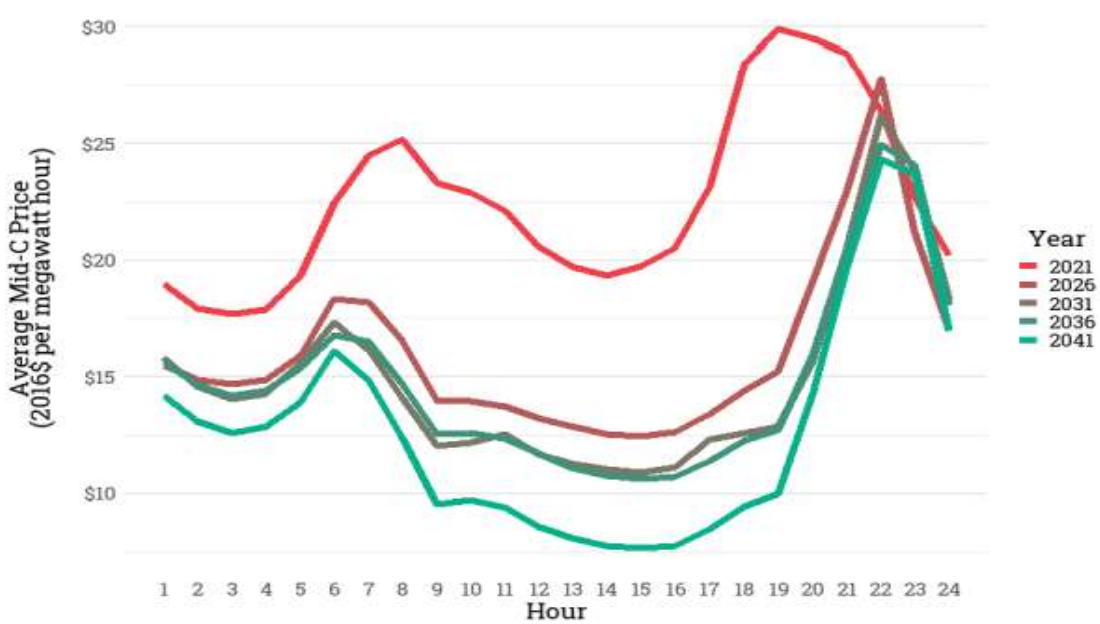


Figure 4-24

NWPCC 2021 Northwest Power Plan Mid-Columbia Average Hourly Prices (expressed in 2016 real dollars)



BPA Assumptions

The PUD contracts with the Bonneville Power Administration (BPA) for the Block and Slice products under a long-term power supply agreement. The Block product supplies the PUD with firm energy in flat monthly amounts based on the PUD's average monthly load shape. The Slice product provides the PUD with variable amounts of energy that depend upon the output of the Federal System. Under the Slice product, the PUD takes responsibility for managing its share of the output from the Federal System on an hour-by-hour basis, also assuming the risk that in any given hour, the Federal System may not fully meet the PUD's needs. Generally speaking, the amount of energy received through Slice is closely correlated with the snowpack and water conditions in the region. More snow and rain generally indicate more available electricity and vice versa.

For ratemaking purposes, BPA determines the total of its customers' loads scaled to the size of the Federal System for allocating costs over the two-year rate period. This Rate Period High Water Mark process establishes the maximum amount of energy the PUD is eligible to purchase from the BPA at cost, called the Tier 1 rate. Since the new contract term began in October 2011, the size of the Tier 1 System has varied over time due to changes in BPA's system obligations and hydro operations, as well as maintenance outages and refurbishments to the physical equipment of the system.

Figure 4-25 shows the actual BPA Tier 1 System Size and Tier 1 contract allocation to the PUD for the 2012 through 2020 period.

Figure 4-25

BPA Tier 1 System Size

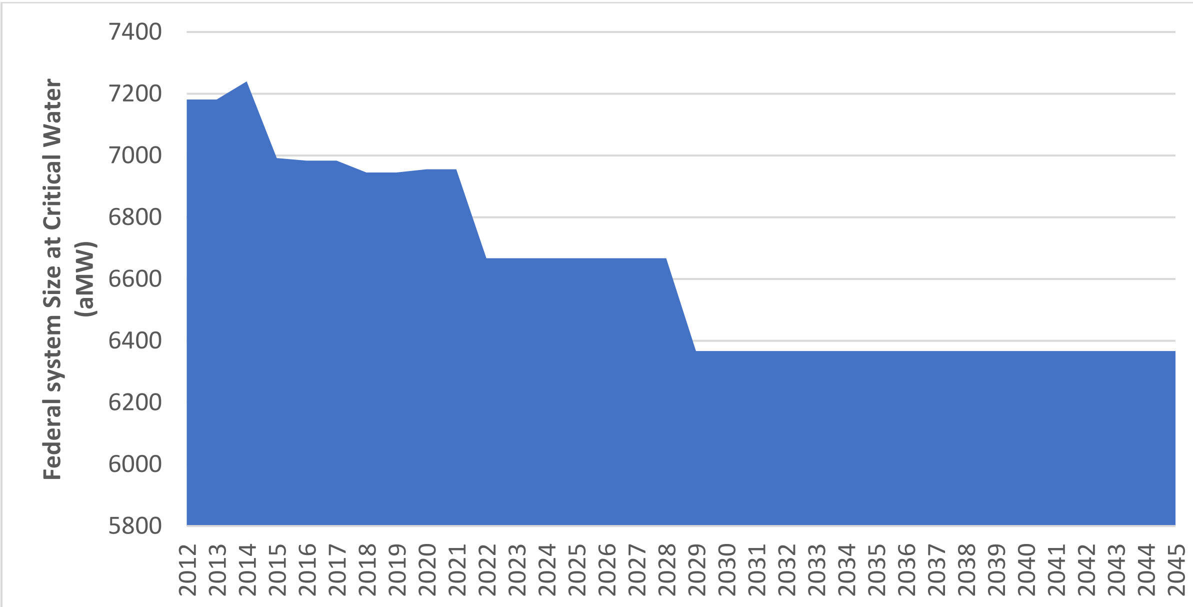
Fiscal Year	BPA Tier 1 System Size (in aMW)
2012	7181
2013	7181
2014	7240
2015	6992
2016	6983
2017	6983
2018	6945
2019	6945
2020	6955
2021	6955
2022	6667
2023	6667

The 2021 IRP assumes that under critical water conditions, the BPA Tier 1 System would decline from 6,667 aMW in 2022 to 6,367 aMW in 2029 This assumption is tied to the shrinking of the Federal System over time and also captures Post-2028 risk of greater demand for BPA resources as Rate Period High Water Mark assumptions are linked proportionally to Federal System Size in PUD models. These generation reductions are primarily caused by operational changes to facilitate other uses of the system such as fish and wildlife.

Figure 4-26 shows how the size of the Federal System has changed over time, and the forecast used to project the size of the Federal System across the study period.

Figure 4-26

BPA Tier 1 System Size Assumptions



The Post-2028 BPA contract renegotiation process is in its nascency, there are limited details about what products, contract allocations, and other terms may be offered. With no other information available at this time regarding what the BPA may offer in the post-2028 period, the 2021 IRP assumes that the current Tiered Rates Methodology is a reasonable stand-in for the eventual post-2028 framework. The IRP assumes the Tier 1 System size would be allocated to customers in a similar fashion as today's contract and uses a continuation of the Block/Slice contract as a default assumption for the PUD's future portfolio needs. Additional analysis on developing BPA product options will be run in the 2023 IRP Update as more information becomes available.

One fundamental assumption in a Post-2028 contract will be the PUD's contractual allocation of the Federal System. In the current contract, the PUD holds a Contract High Water Mark of 811 aMW of firm output across the Block and Slice products. This amount varies in each rate period based on the Net Requirement[43] or Rate Period High Water Mark (whichever is lowest). While

[43] The PUD's Load minus contractually dedicated firm energy resources

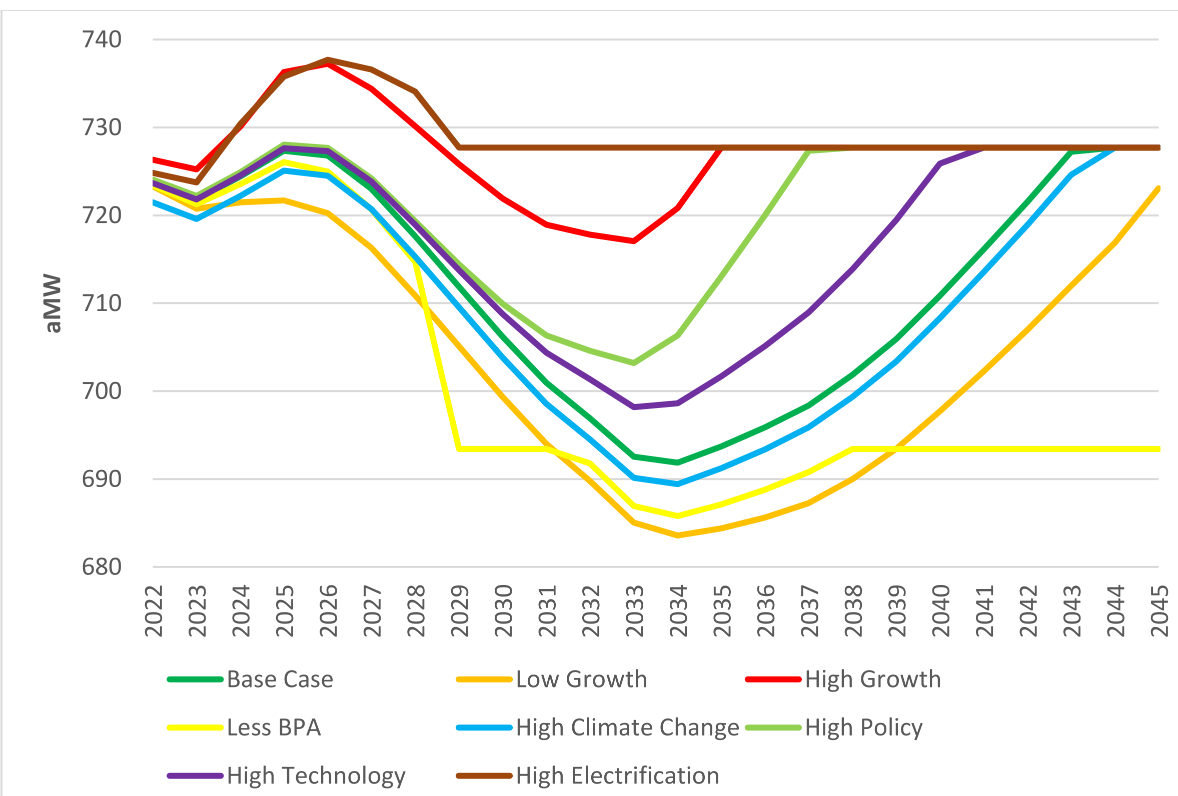
the PUD advocates it is entitled to no less than its current allocation in the Post-2028 period due to its significant conservation investment, the Federal System is a finite set of resources. If more obligations are placed on the Federal System, and if the Federal system size is reduced due to operational constraints, it is possible that the PUD's contractual allocation could be reduced in the next contract.

Given the risk of reduced BPA output, all scenarios include a modest reduction in the RHWM allocated to the PUD starting in 2029 in order to prudently plan for the future. This includes a ceiling of 728 aMW for years post-2028 in all scenarios, though continued conservation defers the point at which the PUD would be expected to reach that ceiling. The IRP also analyzes the resulting portfolio of a contractual allocation that remains the same as the existing contractual allocation, finding the 10-year resource plan remain largely the same.

Figure 4-27 shows the PUD's BPA Contractual Allocation forecast, which is the lower of the RHWM or Net Requirement after new conservation across the various scenarios.

Figure 4-27

PUD Forecast of BPA Contractual Allocation by Year and Scenario



The distribution of the PUD's contract allocation between the Slice and Block products is assumed to remain similar to today's.

While Slice is contractually allocated as firm energy based on the output that would be expected during the Critical Water Year of 1937, Slice output is variable based upon the actual generation of the system. Slice product deliveries were simulated thousands of times using a 66-year regulated hydro study for the water years 1950 through 2015 historical weather, subsequently adjusted for climate change.[44] This probabilistic analysis suggests Slice output will exceed the critical value in 94% of cases on an average annual basis.

Finally, a "Less BPA" scenario has been compiled. The intent of this scenario is to examine a future where there is a significant reduction in the Federal System or Contractual Allocation and determine whether that reduction would significantly change or alter the PUD's Long-Term Resource Strategy. In this scenario, the Federal System is reduced beyond the assumptions in other scenarios by an additional 300 aMW and the PUD's Post-2028 contractual allocation is reduced by about 35 aMW at Critical Water. The scenario results indicate that while the reduction would alter the scale of future resource needs Post-2028, it would not significantly alter the PUD's 10-year Resource Strategy.

Building Electrification

Participants in the PUD's 2021 IRP Visioning Process identified building electrification as a unique risk the PUD may face and need to account for in future resource plans. The "why" behind building electrification was uncertain as participants explored the topic, with ideas ranging from:

- Local policies prohibiting new natural gas;
- State or federal policies incentivizing building conversation, or;

[44] Hydro regulation data reflects operating constraints for the 2019 Water Year, informed by the 2019-2021 Flexible Spring Operation Agreement.

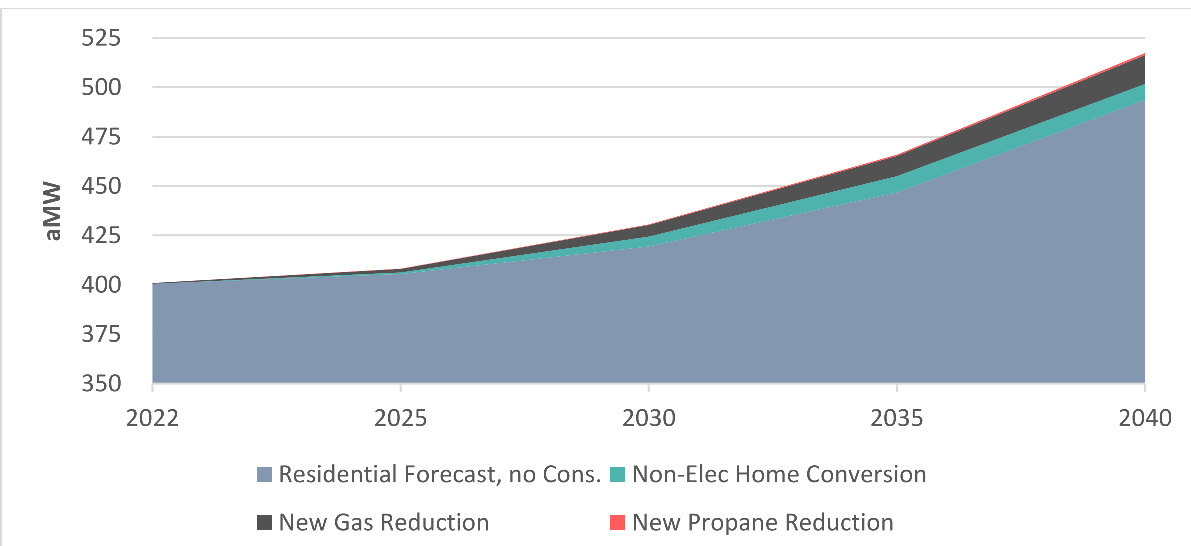
- Building codes and standards gradually shifting the proportion of all-electric buildings and mixed-fuel buildings (such as those that use natural gas or propane for space and water heating) toward electric over time.

Though a specific causality is not identified, the 2021 IRP explores building electrification as a potential cause of load growth in the High Electrification Scenario, where both building retrofits and a higher proportion of all-electric home new connections are modelled.

Figure 4-28 shows the incremental building electrification load across the High Electrification scenario, which contains the highest net load forecast before new conservation, exceeding the High Growth Scenario. Building electrification assumptions include that all new homes would be electric by the year 2030, and that 10% of existing propane or natural gas heating homes would be converted to all-electric homes by the year 2035. Cumulatively, this would add ~25aMW of additional load by 2040, before new conservation.

Figure 4-28

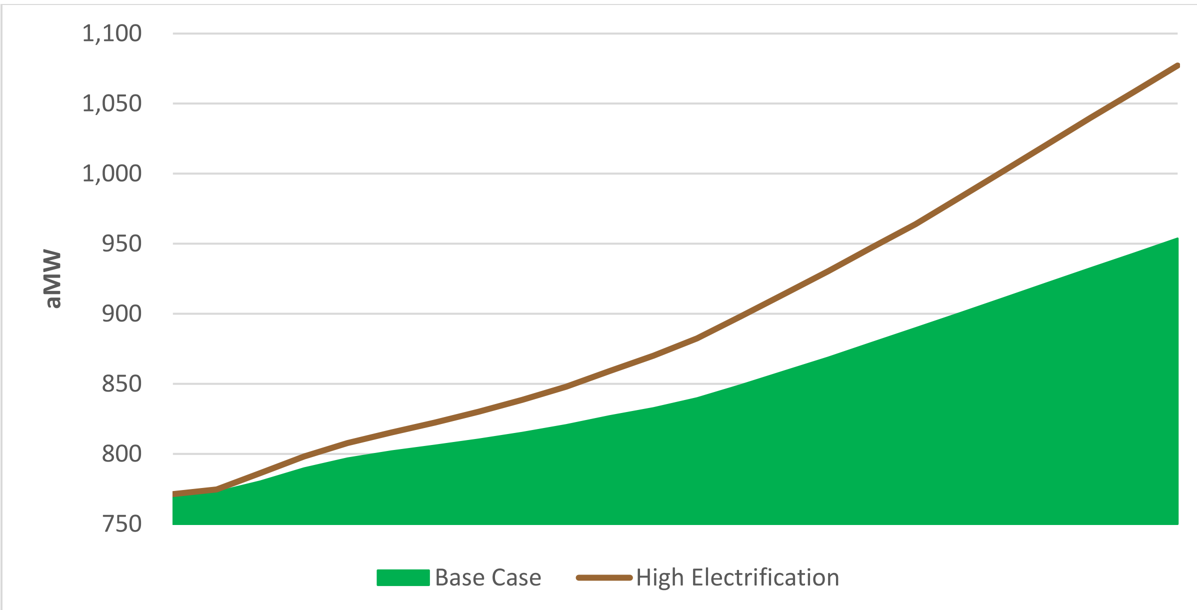
Incremental Building Electrification Load by Source in High Electrification Scenario



To better illustrate the magnitude of load growth forecasted in the High Electrification case refer to Figure 4-29, which shows the aggregate differences between the Electrification Case and Base Case Scenario annual load forecasts. In addition to the ~25 aMW of building electrification, the remaining divergence is attributable to differing vehicle electrification assumptions, accounting for an additional 109 aMW of load growth in the High Electrification case.

Figure 4-29

Comparison between Electrification Scenario and Base Case Scenario Load Forecast



Scenario Descriptions

Base Case Scenario

The future under the Base Case reflects moderate load growth due to expected economic growth and conditions. Market energy price forecasts incorporate the progressively decarbonizing WECC region due to legislation such as Washington State's Clean Energy Transformation Act and various other regulatory and legislative mandates set by other states throughout the Western Interconnection.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	Base
Rooftop Solar Forecast	Base
Market Price Forecast	Base
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

Low Growth Scenario

The Low Growth Scenario reflects a future where economic growth, and therefore load growth and demand, are less than expected throughout our service territory and the greater WECC region. This reduction in assumed growth accounts for a wide variety of global or nationwide political, economic, or pandemic related issues such as COVID-19. The Low Growth scenario also assumes lower market energy prices due to lower overall regional demand for electricity and natural gas.

Key Variable	Key Variable Description
Load Growth Forecast	Low
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	Low
Rooftop Solar Forecast	Low
Market Price Forecast	Low
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

High Growth Scenario

The High Growth Scenario is marked by higher relative average annual load growth for the PUD's service territory. Higher economic growth in this scenario is accompanied by higher demand for energy. This effect influences load, market prices, commodity prices including natural gas, and also results in higher consumer adoption of electric vehicles and rooftop solar. When comparing relative resource needs, the High Growth scenario has a resource need second only to the High Electrification scenario.

Key Variable	Key Variable Description
Load Growth Forecast	High
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	High
Rooftop Solar Forecast	High
Market Price Forecast	High
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

Less BPA Scenario

The assumptions made in the Less BPA scenario are largely identical to the Base Case, except that post-2028 BPA contractual allocation is further reduced beginning in 2029.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	Base
Rooftop Solar Forecast	Base
Market Price Forecast	Base
BPA Assumptions	Default (Tier 1 System reduced 600aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

High Policy Scenario

This potential future assumes a national political climate that introduces robust energy policies across the WECC, including some states that do not currently have aggressive energy policy standards for electric utilities. These aggressive energy policy standards directly affect assumptions regarding the cost of meeting local demand in states that otherwise would not have aggressive energy policies. At the beginning of the study period, wholesale energy prices are significantly higher than any other scenario due to these variations but decline significantly in the mid-2020's as renewable resources are developed to meet compliance needs.

Demand assumptions in the High Policy scenario encourage production, purchase, and use of electric vehicles as well as rooftop solar PV.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	High
Rooftop Solar Forecast	High
Market Price Forecast	High Policy
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

High Climate Change Scenario

The High Climate Change scenario assesses the impact a higher rate of climate change may have on load and resource generation forecasts. Assumptions are based on the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report (AR5). In this report, the IPCC describes several different futures for the planet's climate, all of which are considered possible depending on the volume of greenhouse gasses emitted in future years. The High Climate Change scenario uses AR5's Representative Concentration Pathway 8.5 (RCP 8.5), which sees the average global temperature increase by approximately five degrees Celsius and average sea levels rise over half a meter by the end of the century.[45] This is considered by the IPCC to be the most extreme of possible global climate scenarios and best reflects the purpose of the High Climate Change scenario.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 8.5 (High)
Electric Vehicle Forecast	Base
Rooftop Solar Forecast	Base
Market Price Forecast	Base
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)

[45] Relative to pre-industrial levels

High Technology Scenario

The High Technology Scenario is a future where installed energy storage capacity throughout the WECC is exceptionally high. The purpose of this scenario is to examine the hourly price volatility due to state energy policy-driven renewable resource development, and whether that price volatility could be lessened by significant storage resources distributed across the WECC footprint. The analysis predicts that while hourly price volatility is reduced over time, volatility would still be present.

While the amount of achievable demand response in all scenarios is capped based on the PUD's 2021 Demand Response Potential Assessment, this potential future assumes demand response technology and smart rate structures can be implemented more rapidly than the Base Case.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	Base
Rooftop Solar Forecast	Base
Market Price Forecast	High Technology
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	Base (current rate of New Electric Homes)
Demand Response Technical Potential Rate	Accelerated

High Electrification Scenario

The High Electrification scenario considers a future where electrification of vehicles and of space and water heating is significantly accelerated above current expectations. The causality of this change could be local, state, or federal policy changes, or changing consumer and developer preferences. While the economic framework for the load forecast remains the Base Case, the additional increments of electric load result in load growth in this scenario that outpaces all other scenarios.

Key Variable	Key Variable Description
Load Growth Forecast	Base
Climate Change Forecast	RCP 4.5 (Base)
Electric Vehicle Forecast	High
Rooftop Solar Forecast	High
Market Price Forecast	Base
BPA Assumptions	Default (Tier 1 System reduced 300aMW in 2029)
Building Electrification	High Electrification

5 - Analytical Framework

Section 5 addresses the analytical framework used to identify the PUD's forecasted resource needs for each case before new resource additions are considered. This framework exists within established planning standards, evaluates new energy efficiency measures, demand response, and supply-side resource options, and includes how portfolios are modeled on a case-by-case basis.

Planning Standards

The probabilistic approach to the PUD's load resource balance provides the analytical platform upon which the 2021 IRP planning standards are derived. Planning standards use standardized risk thresholds combining the likelihood of portfolio insufficiency in a given time period and a standard determining at what threshold potential deficits exceed risk tolerance. This threshold informs the PUD's ability to meet some potential portfolio deficits on a short-term basis through the wholesale electricity market. As such, the deficit thresholds are consistent with current operating practices and significantly less than anticipated market depth and liquidity determined by prior analysis. The four planning standards established in the 2021 IRP analysis provide an objective comparison of the impacts of various scenario assumptions on future resource needs, and are listed below:

1. The **Annual Energy Planning Standard** measures the ability of the PUD to meet average annual energy demand across the entire year. The PUD is deemed to have an energy need if the P50 load resource balance is below zero on an annual average basis.

2. The **Monthly On-Peak (HLH) Planning Standard** measures the ability of the PUD to meet monthly on-peak demand, 19 out of 20 times, with its existing resources. Given that the PUD's existing portfolio is predominantly hydro based, the Monthly On-Peak standard is reflective of exposure to the combination of high load and poor or adverse water hydro conditions. This planning standard also limits the quantity of on-peak energy/capacity purchased from the short-term wholesale energy market to no more than 100 aMW in a given month to satisfy portfolio deficits. Combined, this standard requires a Monthly HLH Load Resource Balance of no less than negative 100 aMW under P5 conditions.

3. The **Peak Week (PW) Planning Standard** measures the ability of the PUD to reliably meet its highest on-peak[46] demand during the most deficit week of the month, 19 out of 20 times, with its existing resources. Peak Week aMW metrics measure the average surplus or deficit of all hours on average in a given risk condition (such as P5). The highest on-peak demand has historically occurred during December.

   The PUD's existing portfolio is predominantly hydro based and as such the Monthly Peak Week standard for on peak hours is reflective of exposure to the combination of high load and poor or adverse water hydro conditions. This planning standard limits the quantity of on-peak energy/capacity purchased from the short-term wholesale energy market to no more than 150 aMW in a given month to satisfy portfolio deficits. Combined, this standard requires a Monthly Peak Week Load Resource Balance of no less than negative 150 aMW under P5 conditions.

4. The **Regulatory Compliance Standard** generally assures that no portfolio will be considered meeting the PUD's portfolio needs unless the portfolio would comply with all regulatory compliance standards to which the PUD must comply. These standards include conservation requirements, the EIA RPS, and CETA clean energy standards. Other regulatory requirements including consideration of over-generation and renewable and nonrenewable resources are also addressed through this planning standard.[47]

Planning Standards, Resource Adequacy, and Resource Adequacy Metrics

The Planning Standards used by the PUD in the 2021 IRP were developed by staff to reflect the unique needs and position of the PUD and constitute the resource adequacy standards for the PUD for the 2021 IRP. The PUD is not a Balancing Authority itself but rather operates within the BPA Balancing Authority Area. As a result, the planning standards used by the PUD are consistent with the standards used by BPA in their own resource program, are reflective of a

[46] . Peak Week hours are defined as hours-ending 7-10 and 17-20 on days Monday through Friday, for a total of 8 hours per day and 40 hours per week.
[47] RCW Chapter 19.285 details conservation and renewables' compliance requirements and RCW Section 19.280.030 addresses developing a resource plan and considering overgeneration events.

hydro dominant portfolio, and do not reflect the Loss-of-Load planning metrics sometimes employed by utilities that operate their own balancing authority areas.

The Clean Energy Transformation Act requires utilities to make "a determination of resource adequacy metrics for the resource plan…" The planning standards established in the 2021 IRP are a balanced collection of metrics that appropriately measure adequacy risk.[48]

The PUD is a participant of the regional resource adequacy program under development by the Northwest Power Pool. While that program will ultimately yield regional resource adequacy metrics and provide an additional overlay into the PUD's long-term planning efforts, the program was still under development at the time of 2021 IRP analysis, and a binding program with a finalized design is not expected until 2023.

Identifying Future Resource Need

Determining the ability of the PUD's existing portfolio to meet forecast customer demand across a wide range of scenarios is a core component of the 2021 IRP. This analysis relies upon stochastic methods, assessing a variety of weather conditions that could affect both customer demand and output from the PUD's variable renewable resources. The objective of the stochastic analysis is to determine the timing, scale, and frequency (or likelihood) of the existing portfolio's sufficiency for meeting needs.

The PUD's existing power supply portfolio is predominantly comprised of hydroelectric generation with over 80% of its energy provided via a long-term power supply contract with the Bonneville Power Administration (BPA). The most significant portfolio risk the PUD faces in meeting its customer needs is the effect that low water conditions may have on hydro generation.

Probabilistic Load

The PUD uses an in-house econometric load forecast developed by the Rates Department as the basis for the load forecast model in each scenario. This load forecast model provides a forecast

[48] RCW Chapter 19.285.030 (1)(g). https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030

of customer demand based upon weather conditions throughout the study period. The stochastic model provides a range of load forecasts for every future time period by examining historical weather volatility based upon the weather Snohomish County and Camano Island and modifying those conditions to account for the effects of climate change.

The load forecast is described as a “hourly net load forecast” because the model forecasts load for every hour of the study period (2022 to 2045), net of behind-the-meter solar[49]. The load forecast includes residential, industrial, and commercial load forecast components adjusting for rooftop solar (modeled as a reduction to load) and electric vehicle load (modeled as an increase to load). The stochastic methods produce the range of weather outcomes and provides a probability distribution of load for every hour. This data provides probability distributions for aggregated time periods as well, such as annual average load. The 2021 IRP primarily focuses on the following time periods:

1. <u>Annual Average</u>: Annual average load provides an annual standard across scenarios and is important for load-based regulatory compliance obligations, such as the Energy Independence Act Renewable Portfolio Standard (EIA RPS) and Clean Energy Transformation Act (CETA. Annual load is also useful for forecasting the PUD’s BPA allocation, which is determined in part by annual load.

2. <u>Monthly Heavy-Load Hours (HLH):</u> Monthly HLH load is a seasonal forecast that provides insight into the PUD’s seasonal energy needs. HLHs are defined as hour-ending 7:00 (6:00 AM) through hour-ending 22:00 (10:00 PM) Monday through Saturday, with the exception of weekday holidays. The PUD uses the California Independent System Operator (CAISO) HLH calendar for determining which hours constitute HLH hours. Average HLH measurements include the average of all load across qualifying HLH hours in each month.

3. <u>Monthly Peak Week:</u> This metric, developed by the PUD, provides insight into capacity needs by focusing on the average of all hours between hour-ending 7:00 and hour-ending

[49] Behind-The-Meter Solar assumptions are provided in Section 4.

10:00, plus all hours between hour-ending 17:00 and hour-ending 20:00, Monday through Friday. This metric totals 8 hours per weekday, totaling 40 hours.

Annual Net Load Forecasts

Figure 5-1 shows the range of Annual Net Load Forecasts at P50 (or expected) across scenarios, before New Conservation. The Base Case load forecast (shown as a green area) increases at an annual average rate of 0.93%. The High Technology and Less BPA cases have the same load forecast as the Base Case before new conservation. The High Climate Change case has a slightly different average annual load forecast than the Base Case, despite looking identical in the graph.

Figure 5-1

2021 IRP Average Annual Load Forecast by Scenario

before New Conservation (in aMW)

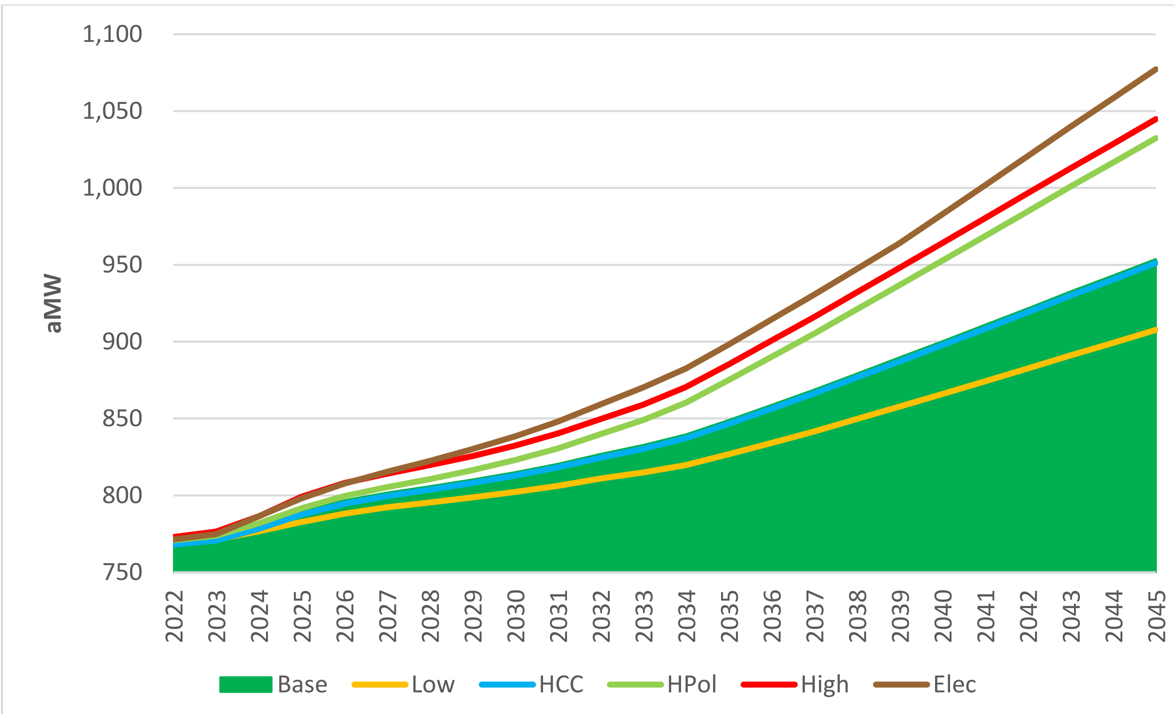
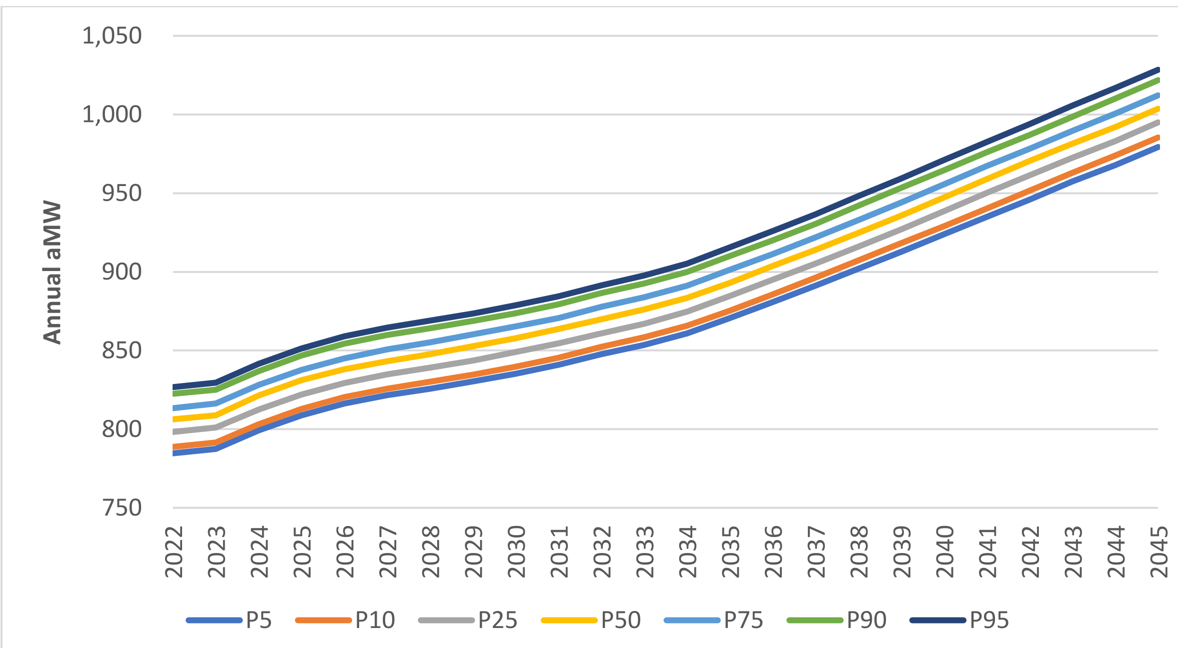


Figure 5-2 shows the probabilistic range of annual average load forecasts (before new conservation) for the Base Case. To interpret the graph, it is important to understand probabilistic notation. In the case of load forecasting, probabilistic range notation indicates the chances that actual loads will fall below the given value. In the case of a "P5" load forecast, there is a 5% chance that actual loads will fall below the given forecast. Similarly, a "P50" load forecast provides values that reflect a 50% chance that actual loads will fall below the given forecast. Each unique colored curve in Figure 5-2 represents a probabilistic load forecast, ranging from "P5" to "P95." Given the nature of these forecasts, it is possible to deduce the chance that a given future load would fall between two given lines. For example, there is a 90% chance that actual load would be between the "P5" and "P95" lines, or a 45% chance that actual load would fall between "P5" and "P50."

The probability distribution provides the weather-induced range of load outcomes for the annual time-period for the Base Case, reflecting expected loads given 65 years of climate change-adjusted historical weather volatility and assuming identical economic growth assumptions. The same underlying data supports the time-period forecasts for all scenarios, providing the PUD with a data-rich environment to identify and mitigate risks.

Figure 5-2

2021 IRP Probabilistic Range of Annual Energy Load Forecast for Base Case Scenario before New Conservation (in aMW)

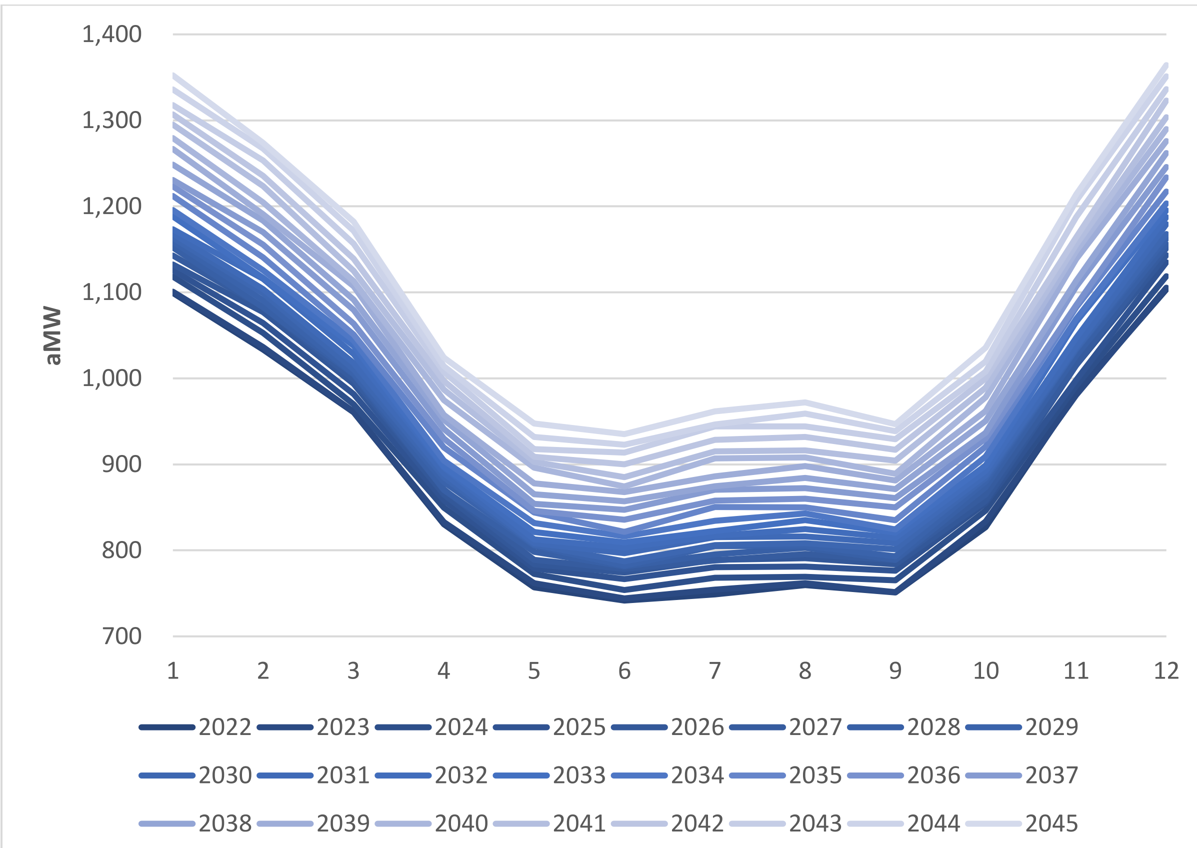


Seasonal Net Load Forecasts

Figure 5-3 shows the range of Monthly HLH Net Load Forecasts at P50 (or expected) for the Base Case, before New Conservation. The PUD remains a winter peaking utility for the duration of the study period across all scenarios in this IRP.

Figure 5-3

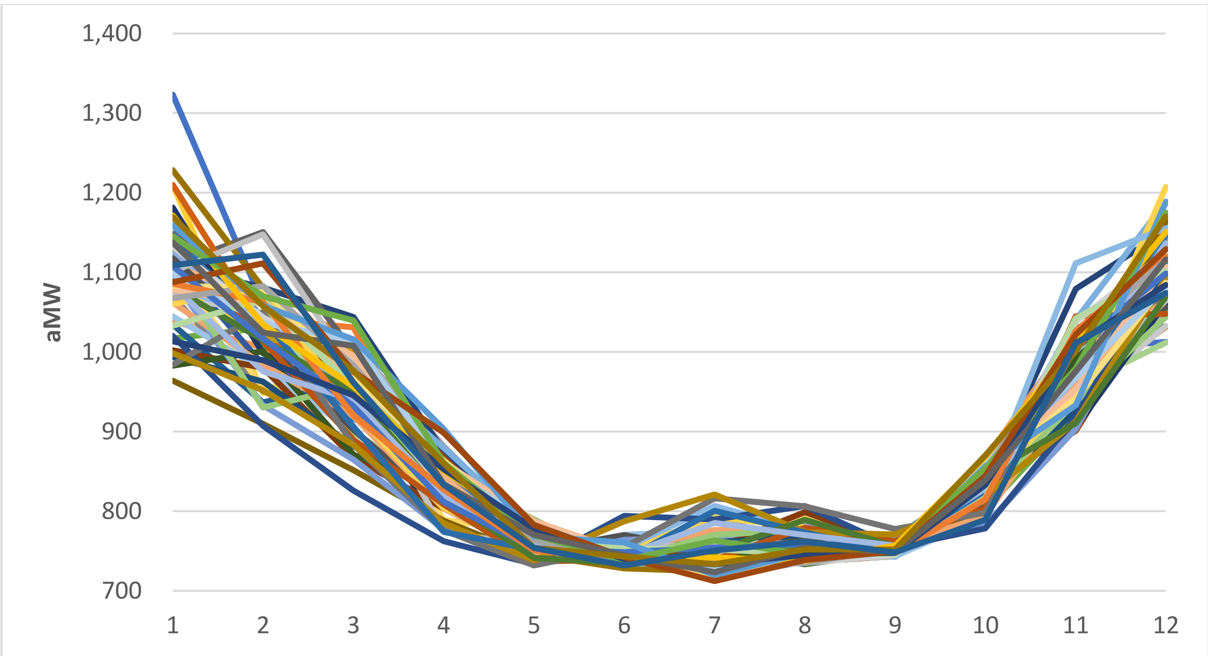
2021 IRP Monthly Average HLH Net Load Forecast for the Base Case before New Conservation (aMW)



The PUD's load resource balance model runs multiple "games" of historic weather patterns modified by climate change expectations. Figure 5-4 shows the range of unique monthly average HLH net load forecasts (before new conservation), varied by historical weather (and climate change) for the Base Case in the year 2022. This graph represents 65 simulated deliveries of 2022 given historical weather patterns with climate change adjustments.

Figure 5-4

Base Case 2022 Monthly Average HLH Net Load Forecast before New Conservation (in aMW)



Seasonal Peak Week Net Load Forecast

Figure 5-5 shows the range of Monthly Peak Week Net Load Forecasts at P50 (or expected) for the Base Case, before new conservation. The PUD's Peak Week needs are highest during the winter period for the duration of the study period across all scenarios.

Figure 5-5

2021 IRP Monthly Average Peak Week Net Load Forecast for the Base Case before New Conservation (in aMW)

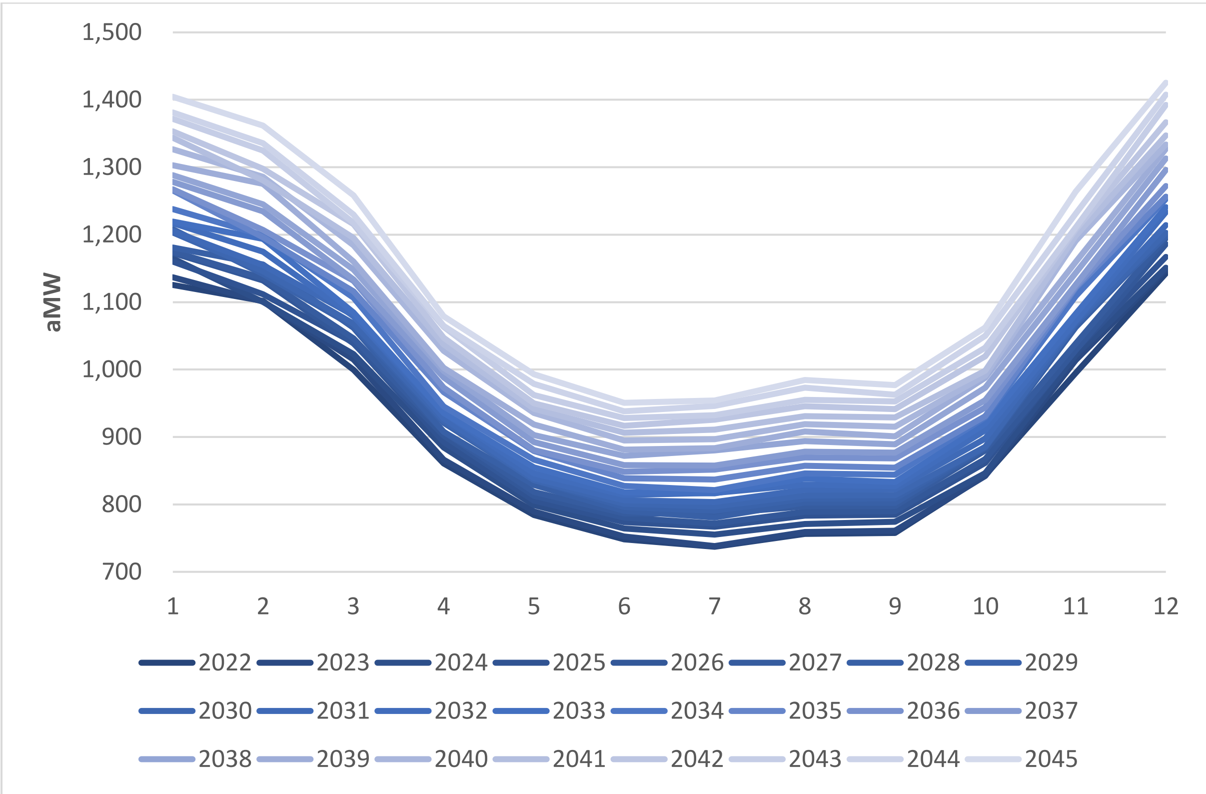


Figure 5-6 shows the range of unique monthly average peak week net load forecasts before new conservation varied by historical weather (and climate change) for the Base Case in the year 2022. Each curve represents one of the 65 simulated deliveries of 2022 given historical weather patterns and climate change adjustments.

Figure 5-6

Base Case 2022 Monthly Average Peak Week Net Load Forecast before New Conservation (in aMW)

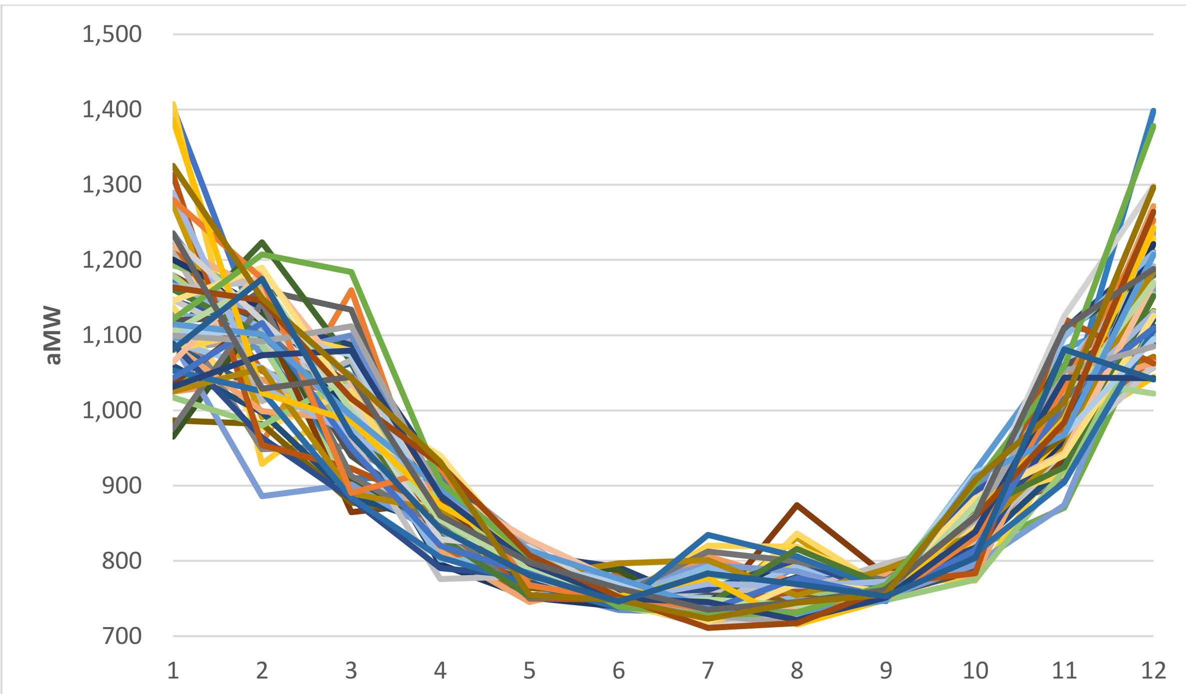
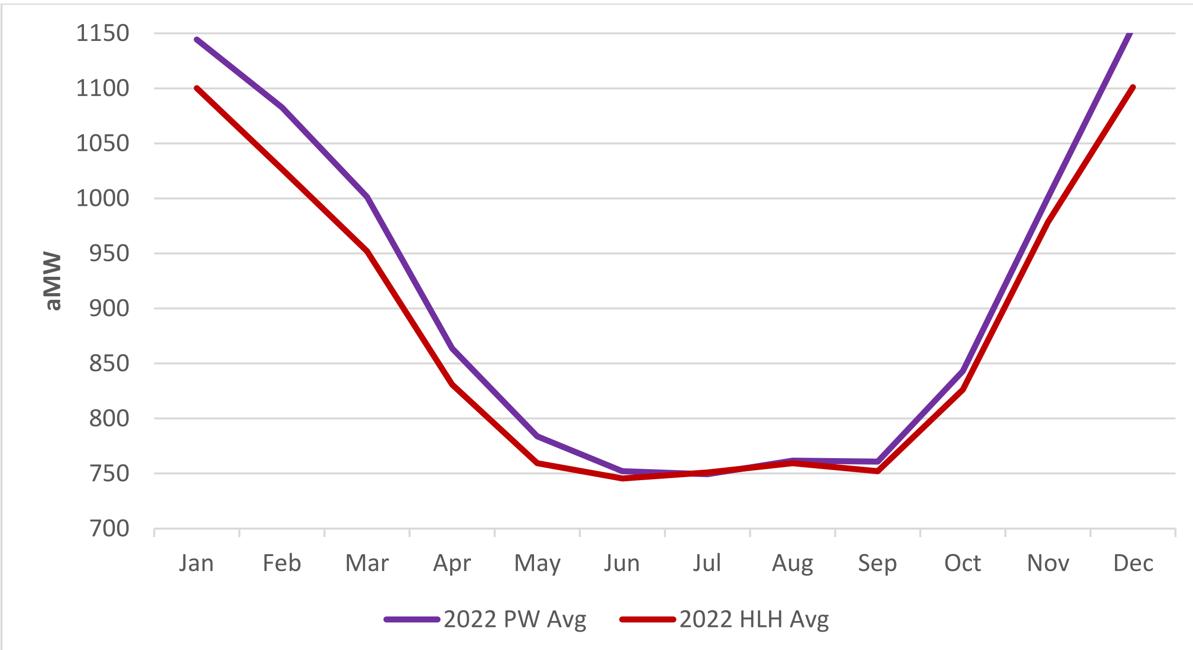


Figure 5-7 compares the P50 (or expected) Monthly HLH Net Load Forecast with the P50 (or expected) Monthly Peak Week Net Load Forecast and shows that Peak Week loads are significantly higher than Monthly HLH needs. This is because the Peak Week time period focuses on the hours where the PUD has the highest loads (HE7-10, and HE 17-20).

Figure 5-7

Base Case 2022 Comparison of Monthly Average Peak Week with Monthly Average HLH Net Load Forecasts before New Conservation (in aMW)



Hourly Load Duration Curves

Figures 5-8 through 5-10 show the Base Case P50 forecast load duration curve over the study period on an annual, winter seasonal, and summer seasonal basis, respectively before new conservation.

Figure 5-8

Base Case Forecast P50 Annual Load Duration Curve throughout Full Study Period before New Conservation

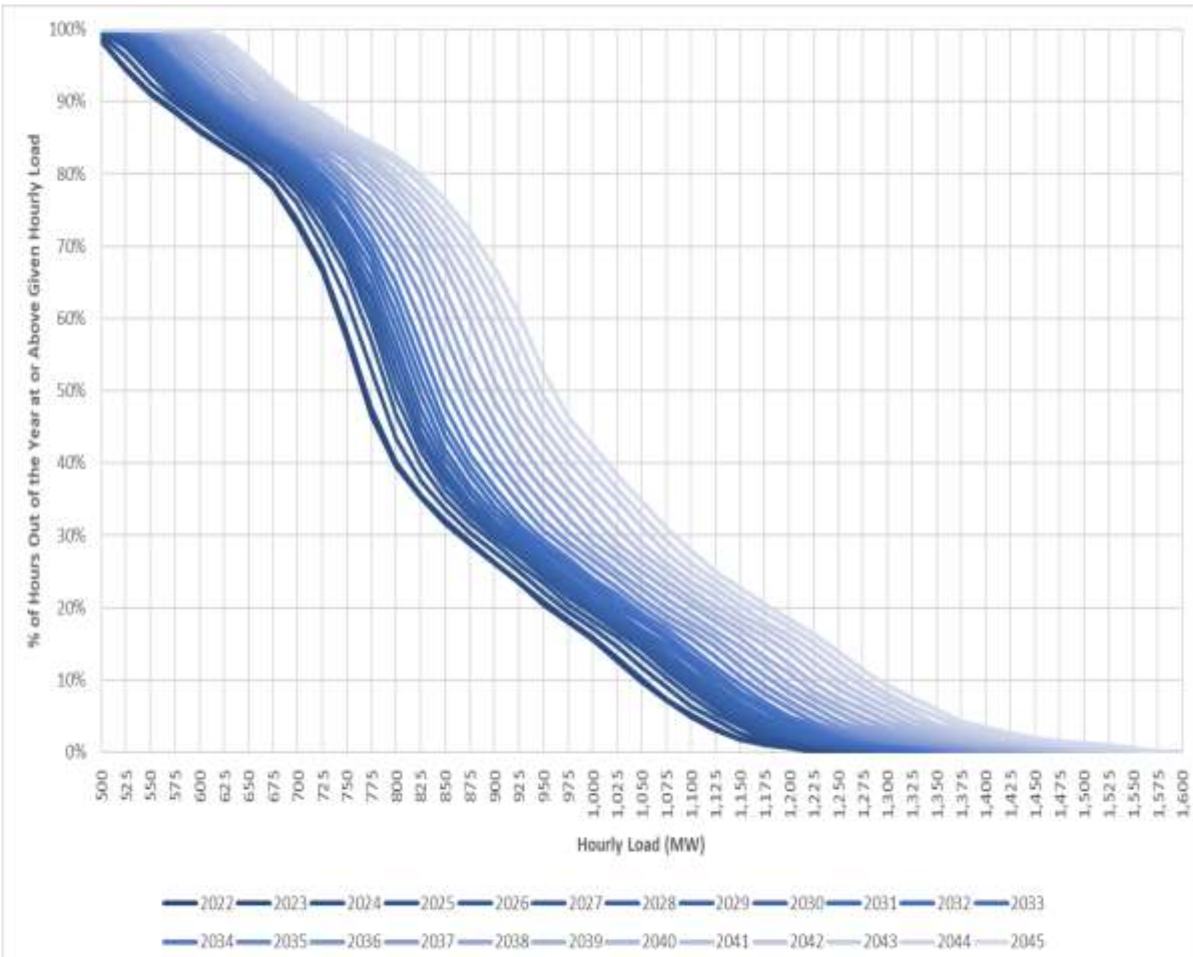


Figure 5-9

Base Case Forecast P50 Winter Season Load Duration Curve throughout Full Study Period before New Conservation

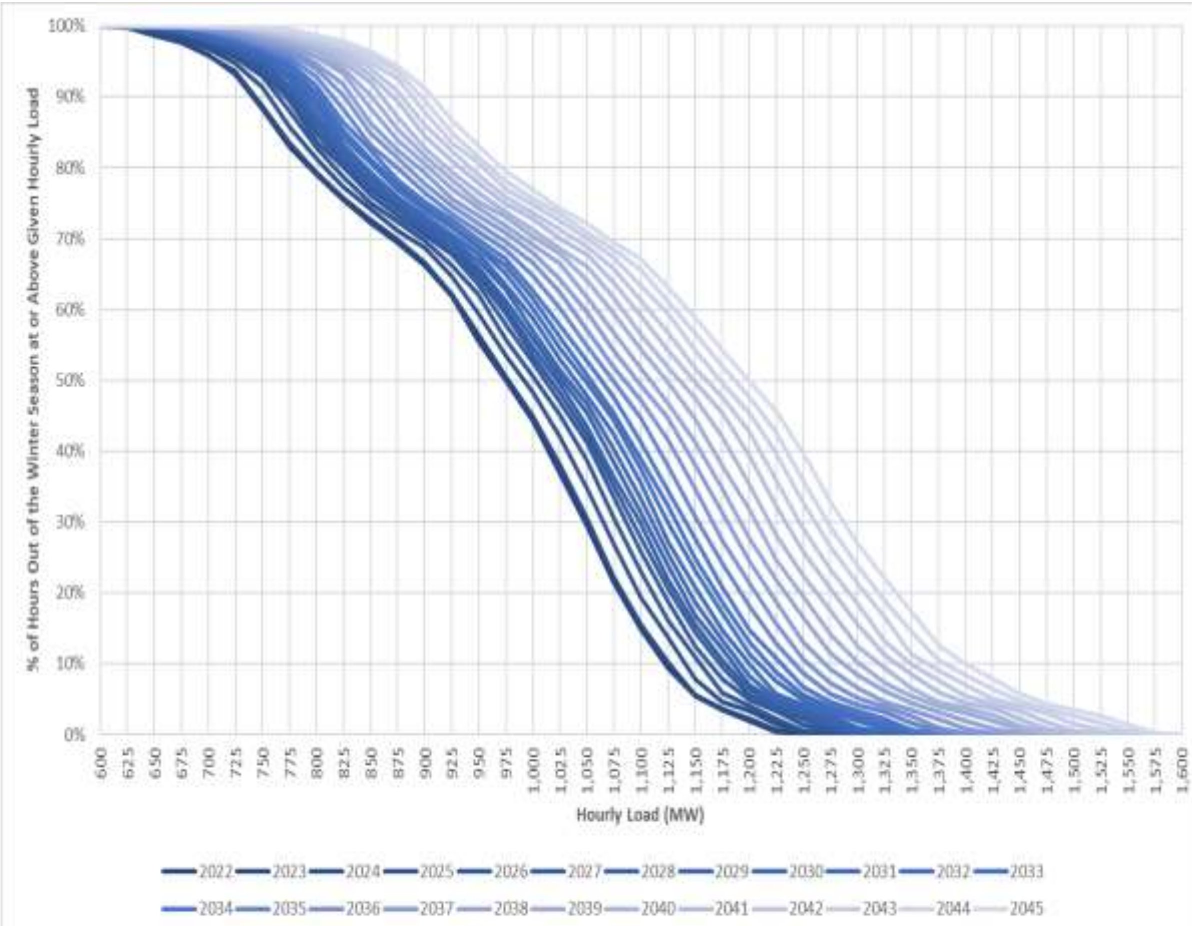
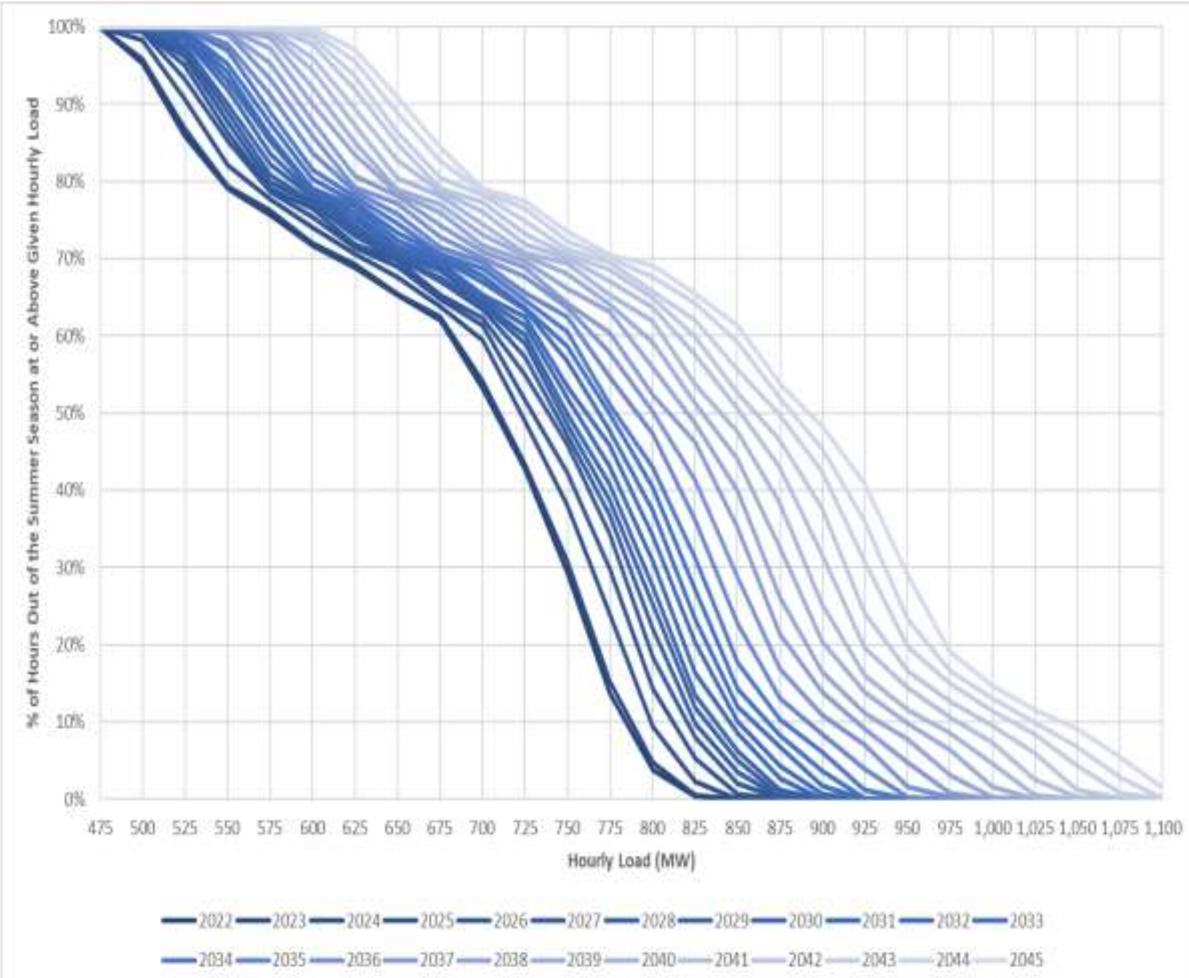


Figure 5-10

Base Case Forecast P50 Summer Season Load Duration Curve throughout Full Study Period before New Conservation



Probabilistic Resource Generation

Resource Generation forecasts use the same stochastic methodology to produce probabilistic estimates of resource generation for the targeted time periods. However, the PUD's resource portfolio is subject to change in composition over time. This is because some current PUD resources, such as the PUD's wind contracts, are set to expire over the study period. In addition, the PUD's BPA contractual allocation is also subject to change, based upon forecasted loads across the study period, and due to new contract structures that begin in 2029. The resource portfolio reflects these changes, resulting in declines across the study period.

Annual Resource Generation Forecasts

In order to understand potential cost and portfolio impacts, the PUD has chosen to reflect a risk-mitigated view of the BPA contract renegotiation in 2029 including an assumption of a reduced allocation. Figure 5-11 shows expected resource generation across the study period in the Base Case along with annotations of key changes.

Figure 5-11

Base Case Annual Resource Generation Forecast (in aMW)

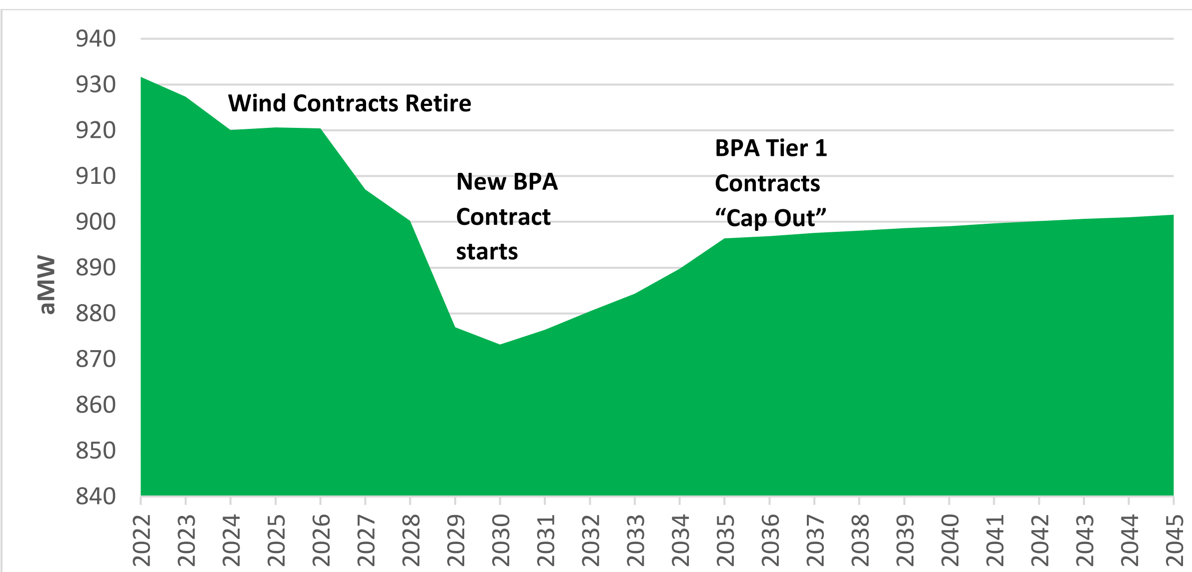


Figure 5-12 compares Annual Resource generation forecasts across scenarios. The High Technology Case has the same existing annual resource generation forecast as the Base Case.

Figure 5-12

Annual Resource Generation Forecast Across Scenarios (in aMW)

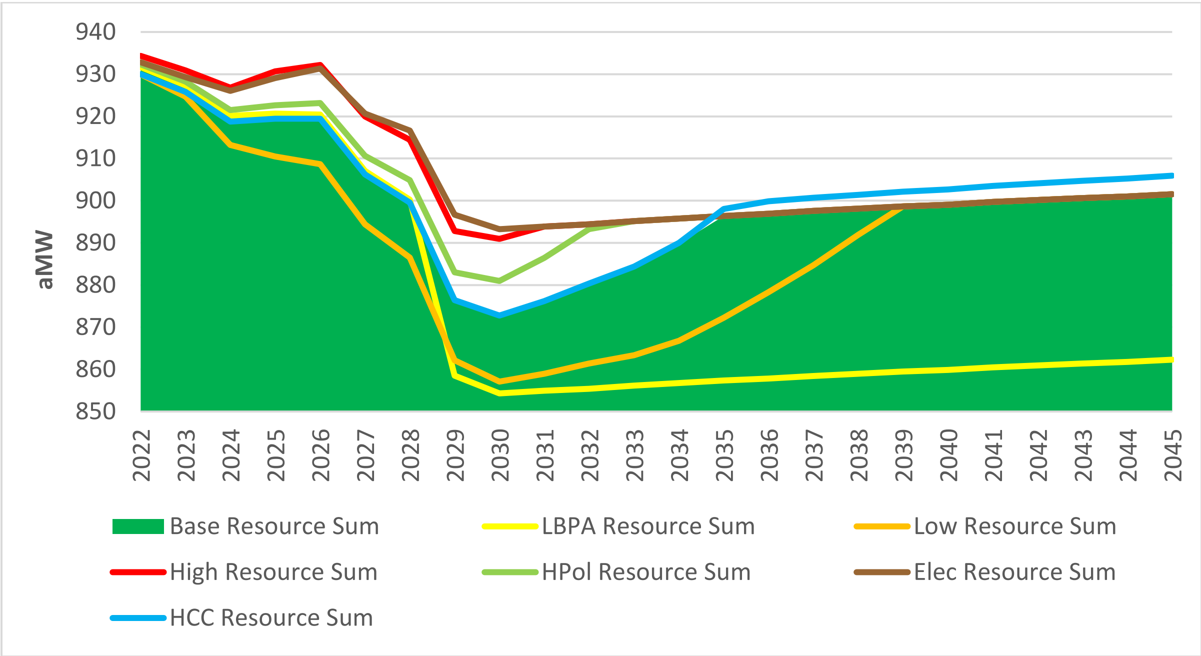
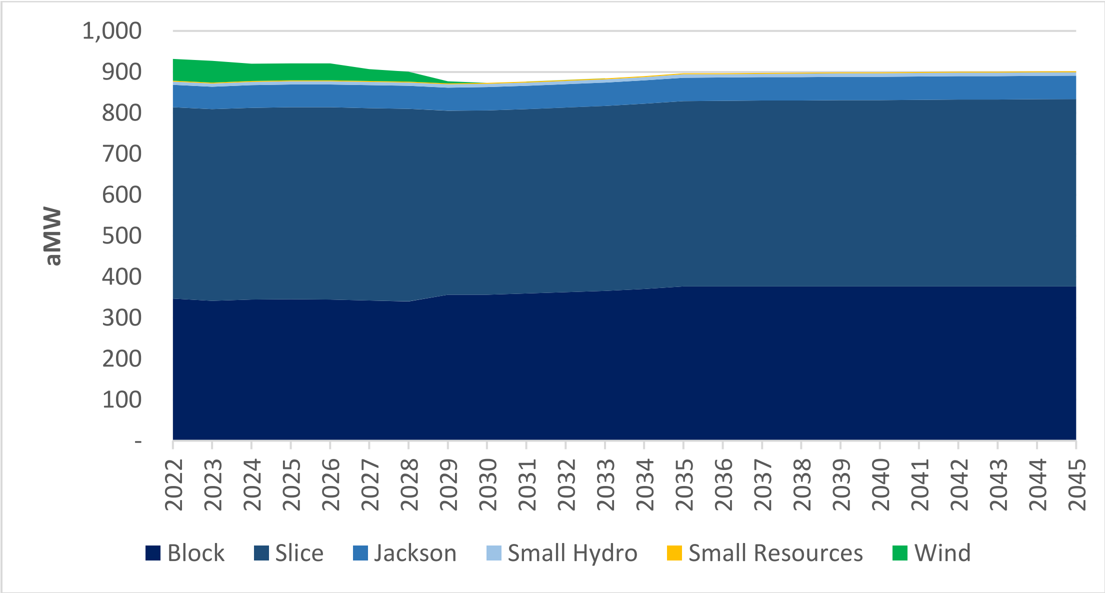


Figure 5-13 displays the Annual Resource generation forecast by resource type for the Base Case.

Figure 5-13

Base Case Annual Resource Generation Forecast by Resource Type (in aMW)



Forecast Renewables Requirement under EIA

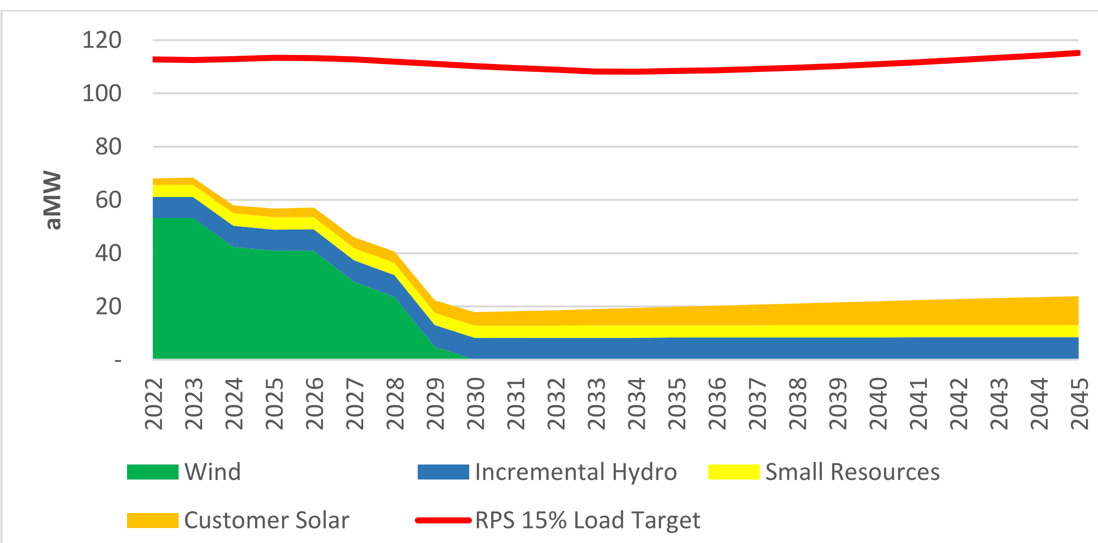
The Energy Independence Act Renewable Portfolio Standard (EIA RPS) assigns resource eligibility for policy compliance to a narrow set of renewable resources, excluding existing hydropower. The primary compliance methodology requires utilities to acquire RECs equal to 15% of their total retail loads over a given period. RECs claimed for compliance are eligible if generated in the compliance year, and one year before or after the compliance year.

In addition to this "target" compliance methodology, there are alternative compliance mechanisms. The 2021 IRP finds that because of these alternative compliance mechanisms and the expected low costs of eligible RECs, that it is more cost-effective for the PUD to explore alternative compliance methodologies and use acquisition of RECs in any year in which an alternative compliance mechanism is not feasible.[50]

Figure 5-14 displays the RPS qualified resource generation expected across the study period in the Base Case, set against the expected EIA RPS target, which is determined by Retail Load forecasts. This chart displays only the annual eligible resource production; while the chart appears to show a compliance deficit, it does not capture the PUD's ability to "shift" RECs between compliance years nor exercise alternate compliance methodologies.

Figure 5-14

Base Case Annual RPS-Eligible Resource Generation (in aMW)



[50] Further description can be found in Section 6.

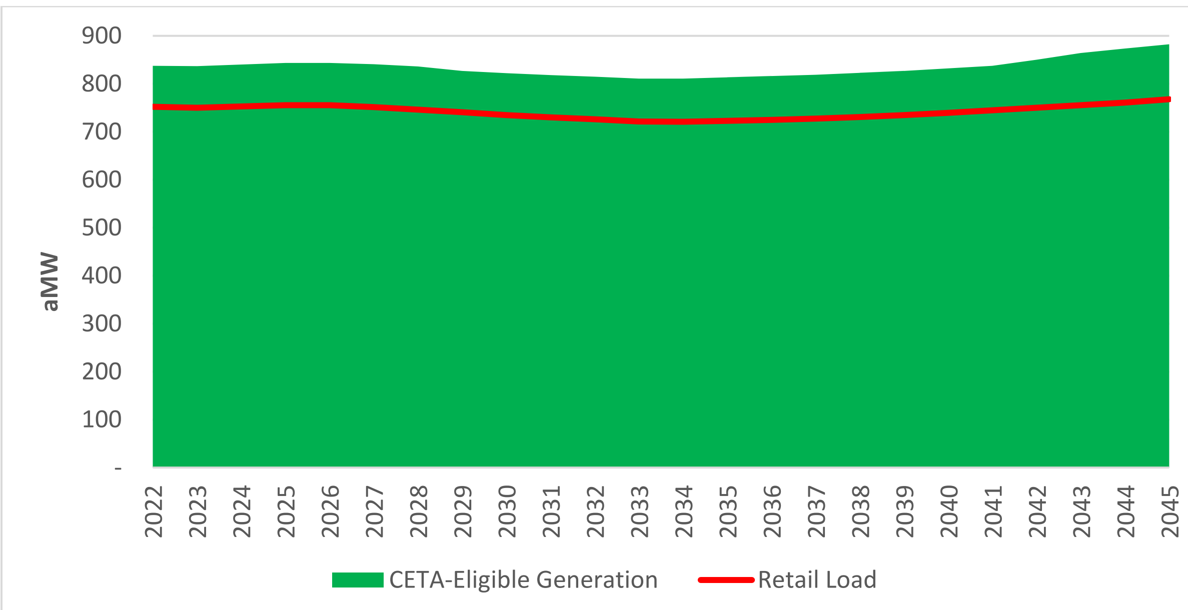
Forecast Renewables Requirement under CETA

The Clean Energy Transformation Act (CETA) applies a broader definition of qualifying resources, including existing hydropower and non-emitting resources such as the PUD's share of Columbia Generating Station through BPA.

Figure 5-15 displays the CETA qualified resource generation forecast for the Base Case, set against the implied CETA threshold of 80% beginning in 2030, and linearly increasing to 100% by 2045. As shown in the chart, the PUD expects to have surplus qualifying resources on an annual average basis, and therefore, expects to meet the 100% standard by 2030.

Figure 5-15

Base Case Annual CETA-Eligible Resource Generation (in aMW)



In order to model CETA compliance, some assumptions about the content of the PUD's BPA allocation were required in order to characterize the PUD's share of qualifying MWhs of BPA generation. The 2020 BPA Asset Controlling Supplier carbon emissions rate for BPA (.0211 MT of CO2 per MWh) applied to the PUD's BPA allocation to produce an estimate of MT of CO2 for the MWhs the PUD received[51]. Because BPA does not have emitting resources in its portfolio, these emissions came from market purchases. The volume of emissions was then

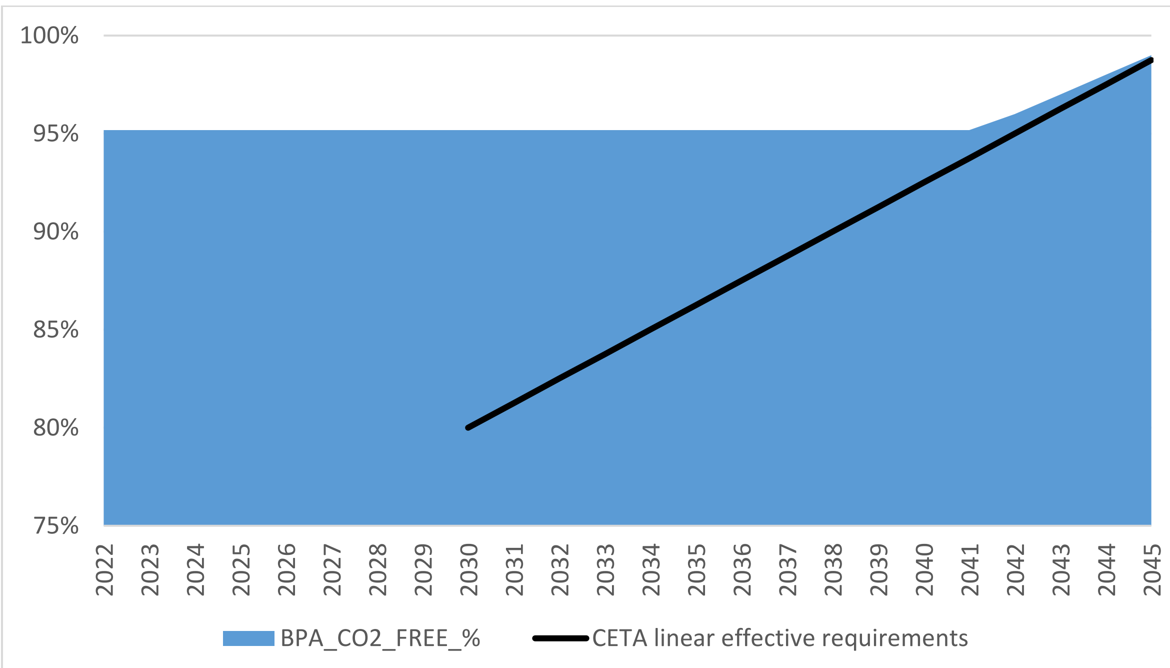
[51] The Asset Controlling Supplier emissions rate is determined by the California Air Resource Board on an annual basis and is recognized in programs across multiple western states.

divided by the Clean Energy Transformation Act emissions rate assignment for unspecified market purchases (0.437 MT/MWh), yielding an estimate of market purchase MWh. This MWh was then deducted from the total BPA MWhs to arrive at an estimate of carbon-free MWhs by percentage, which was found to be 95.2%. This formed the "starting point" for BPA emissions for the study period. It was assumed that at the point the wholesale market, by virtue of utilities complying with CETA, became cleaner than 95.2%, that the BPA clean energy % would also increase at the same rate, approaching 100% by 2045.

Figure 5-16 shows the assumption for BPA's percentage of qualifying resource on a per-MWh basis, arrived at by applying the methodology described above.

Figure 5-16

BPA CETA-Eligible Resource Generation Assumptions (in % of BPA MWh)



Seasonal Monthly Generation Forecasts

The PUD's existing portfolio is characterized by the seasonality of its generation. In most years, a large portion of generation is received during the spring, when precipitation and snowpack melt provide water for hydropower production.

Figure 5-17 shows the probabilistic generation profile across all months of 2022 for the HLH period.

Figure 5-17

Base Case Probabilistic Monthly HLH Generation for 2022 (in aMW)

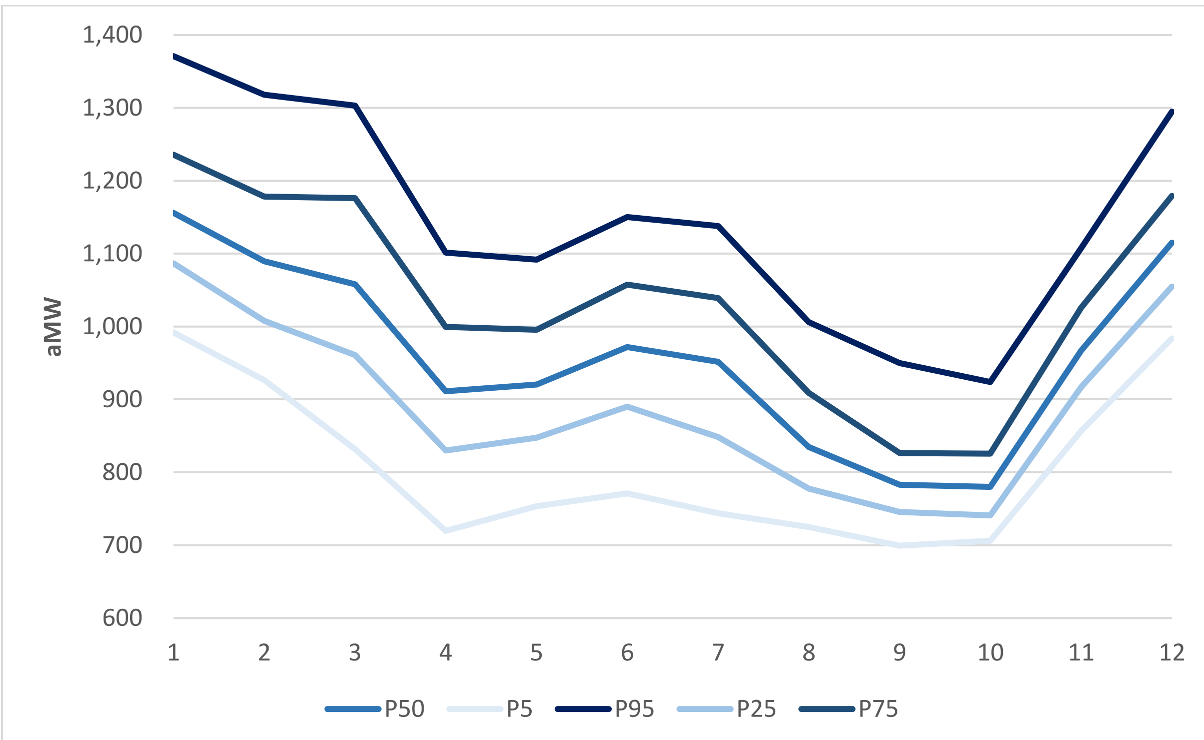
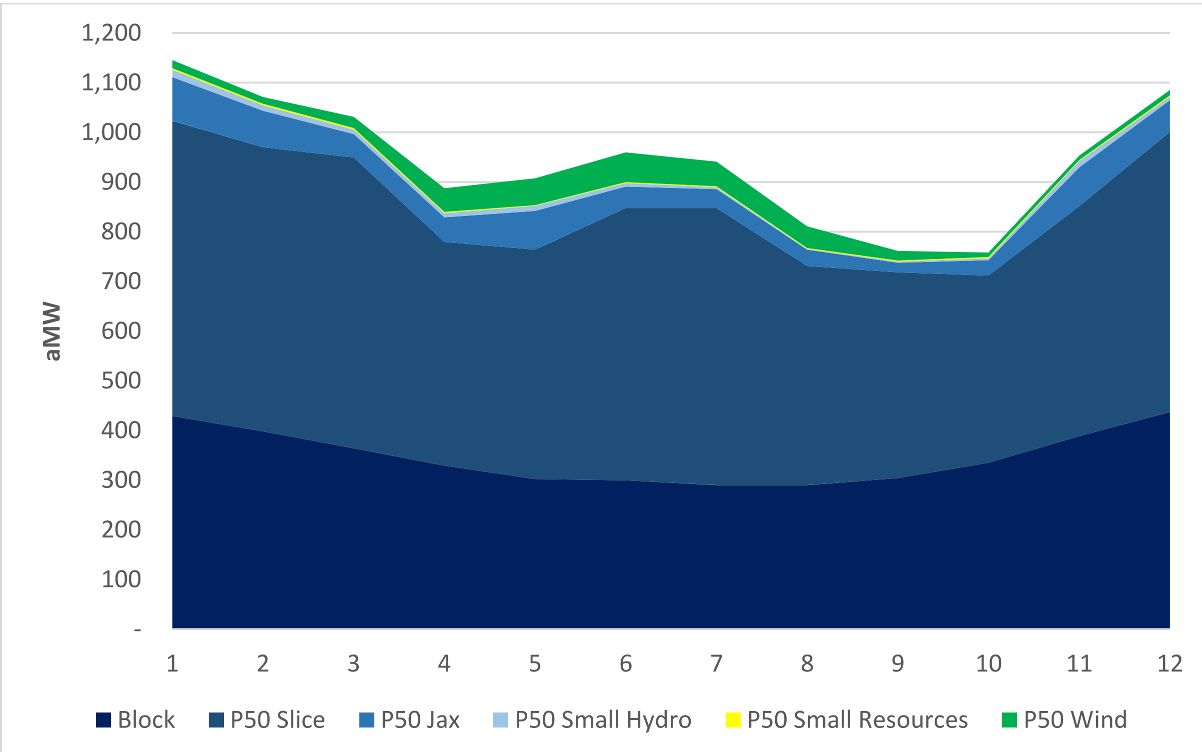


Figure 5-18 shows the resource attribution for Monthly HLH generation at P50 for 2022, under the Base Case.

Figure 5-18

Base Case Monthly HLH Generation by Resource for 2022 (in aMW)[52]



52 "Jax" is an abbreviation for the Henry M. Jackson Hydroelectric Project, which is the PUD's largest owned generating facility at 112 MW nameplate.

Seasonal Peak Week Resource Generation Forecasts

The Peak Week period reflects the PUD's portfolio under the highest load hours across a business week, also capturing some of the flexibility of the PUD's hydro system. The PUD's allocation of the BPA Slice product can be shaped into certain hours to help meet needs, reflected in the increased generation of the portfolio under peak week conditions relative to Monthly HLH conditions.

Figure 5-19 shows the probabilistic generation profile across all months of 2022 for the HLH period.

Figure 5-19

Base Case Probabilistic Monthly Peak Week Generation for 2022 (in aMW)

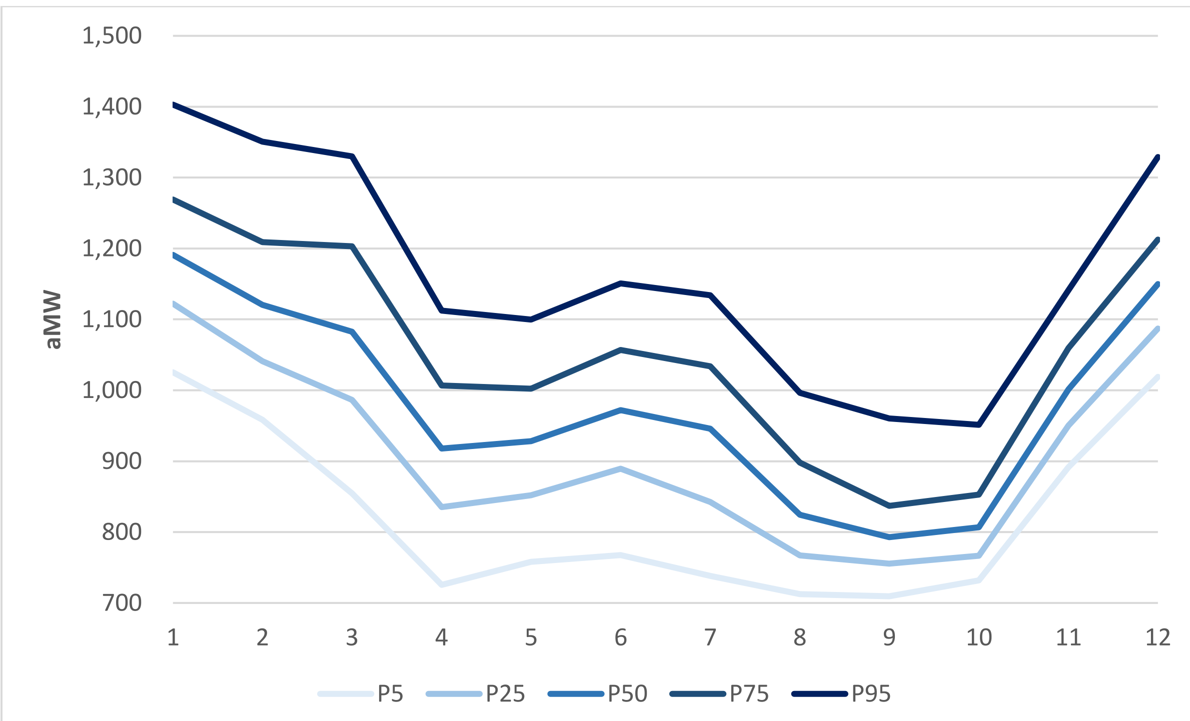


Figure 5-20 shows the resource attribution for Monthly Peak Week generation at P50 for 2022, under the Base Case.

Figure 5-20

Base Case Monthly Peak Week Generation by Resource for 2022 (in aMW)

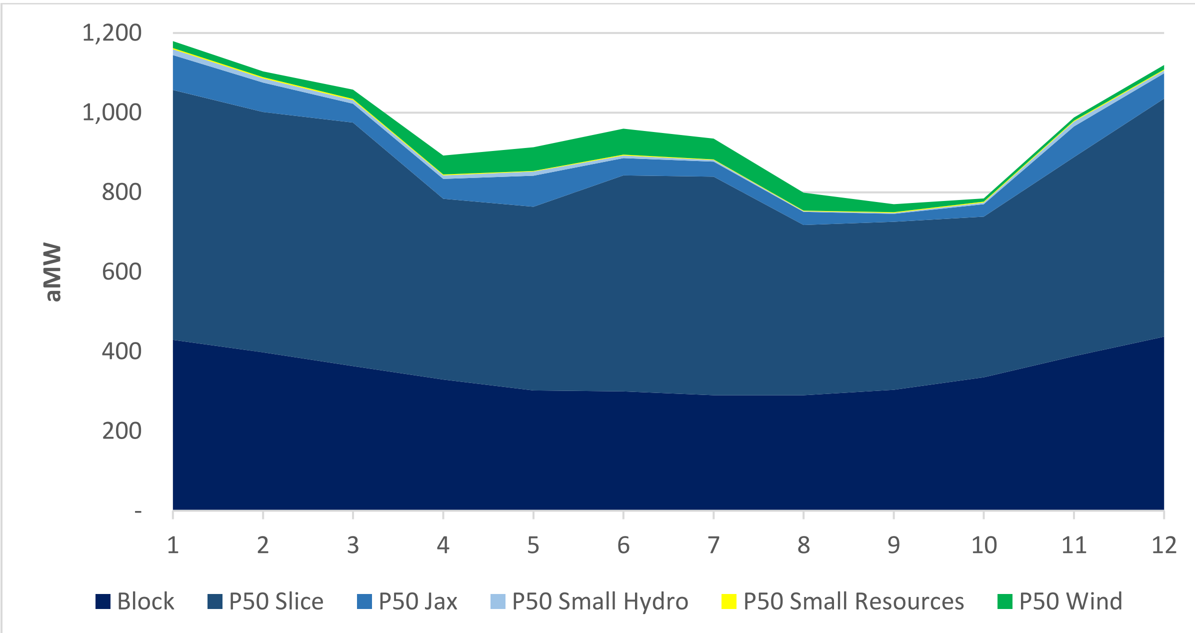


Figure 5-21 shows a comparison of Monthly HLH and Monthly Peak Week generation at P50 for 2022, under the Base Case.

Figure 5-21

Base Case Monthly Peak Week and Monthly HLH Generation 2022 (in aMW)

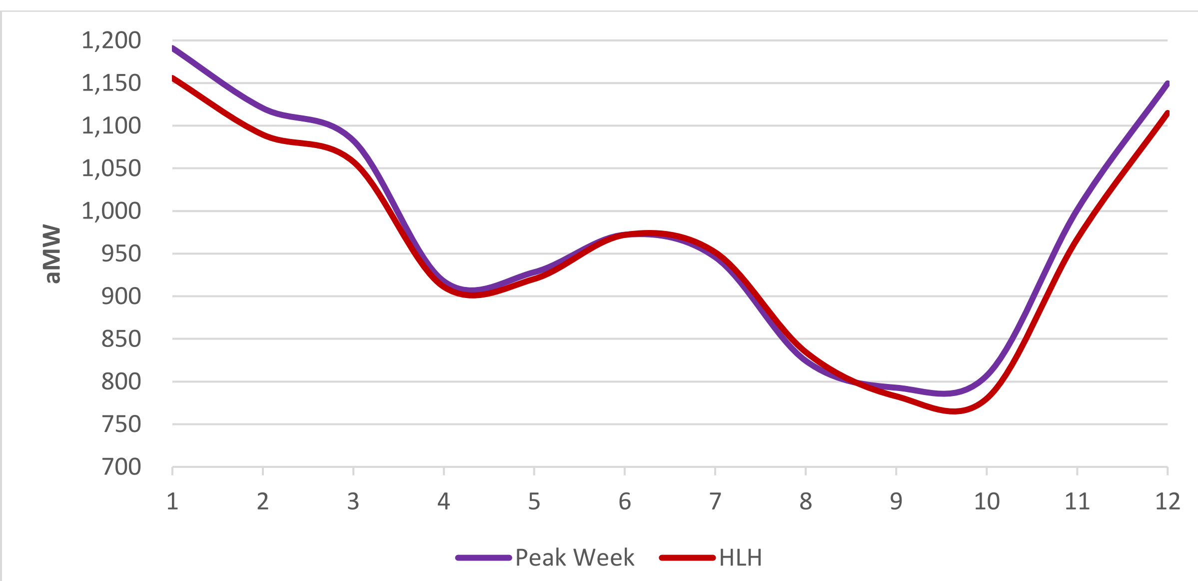
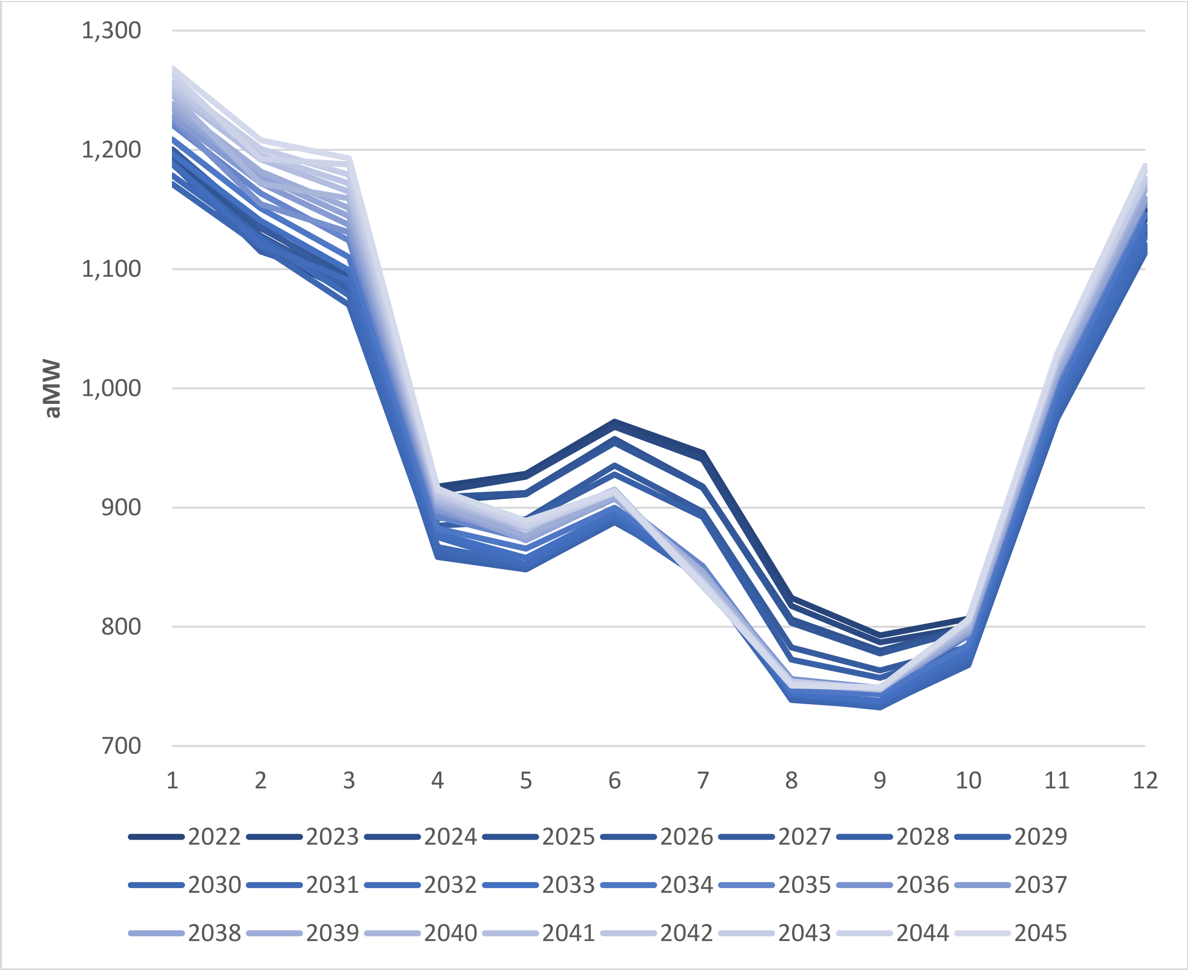


Figure 5-22 shows how Peak Week generation at P50 is expected to change seasonally over time as wind resources retire and climate change shifts hydro generation, on average, earlier into the calendar year.

Figure 5-22
Base Case Monthly Peak Week Generation by Year (in aMW)



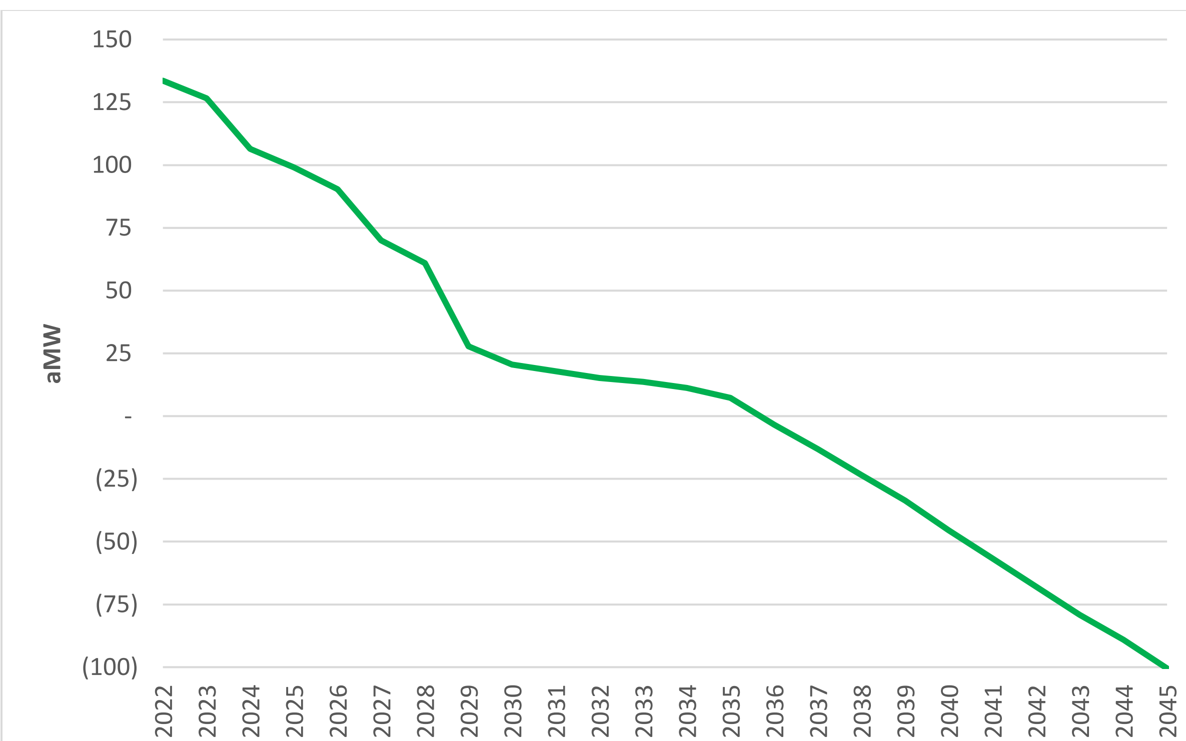
Probabilistic Load Resource Balance

The PUD's probabilistic modeling framework is designed to compare and study hourly load forecasts against hourly generation profiles. This analysis helps determine the scale, timing, and likelihood of circumstances where the PUD's needs may exceed its available portfolio resources. Subtracting the PUD's range of annual customer loads from its forecast of existing and committed resources under the same conditions results in what is referred to as the "load resource balance" or "net position." This Load Resource Balance is calculated for every hour, using the historic weather volatility adjusted for climate change over the course of the study period.

Figure 5-23 shows the annual net position under the Base Case scenario before the acquisition of any new conservation over the 24-year study period. The Y-Axis depicts the amount of energy surplus or deficit (also called "long" and "short" positions). The data forecasts that the PUD will have an annual energy surplus through 2035; beginning in 2036, the trend line falls below zero, depicting annual energy deficits.

Figure 5-23

Base Case Annual Load Resource Balance at P50 across Study Period before New Conservation (in aMW)

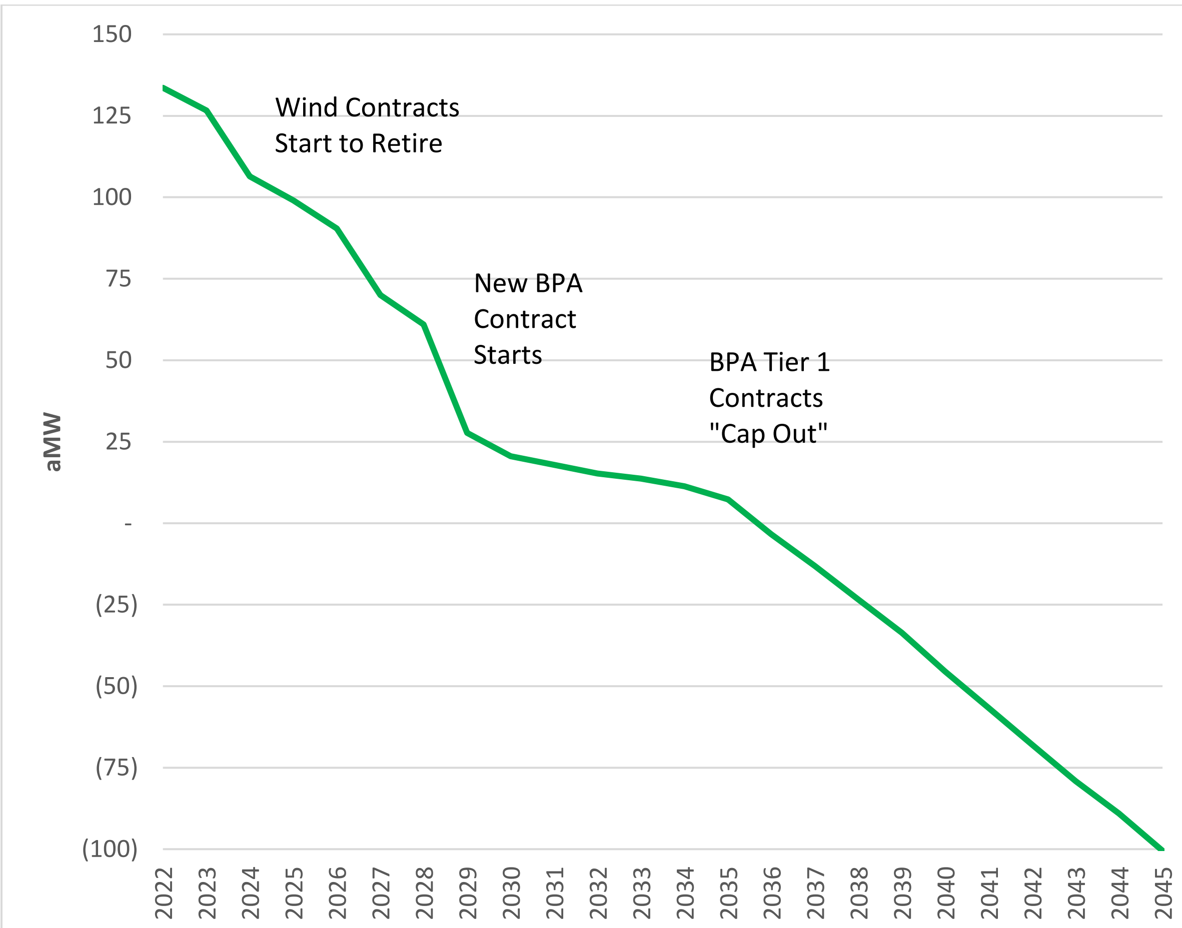


Annual Load Resource Balance Forecasts

The Annual Load Resource Balance provides a snapshot to assess the combination of changes in the PUD's portfolio over time as new loads enter the service territory before new conservation. Figure 5-24 annotates selected, high-impact changes for the Base Case.

Figure 5-24

Annotated Base Case Annual Load Resource Balance at P50 across Study Period (in aMW)

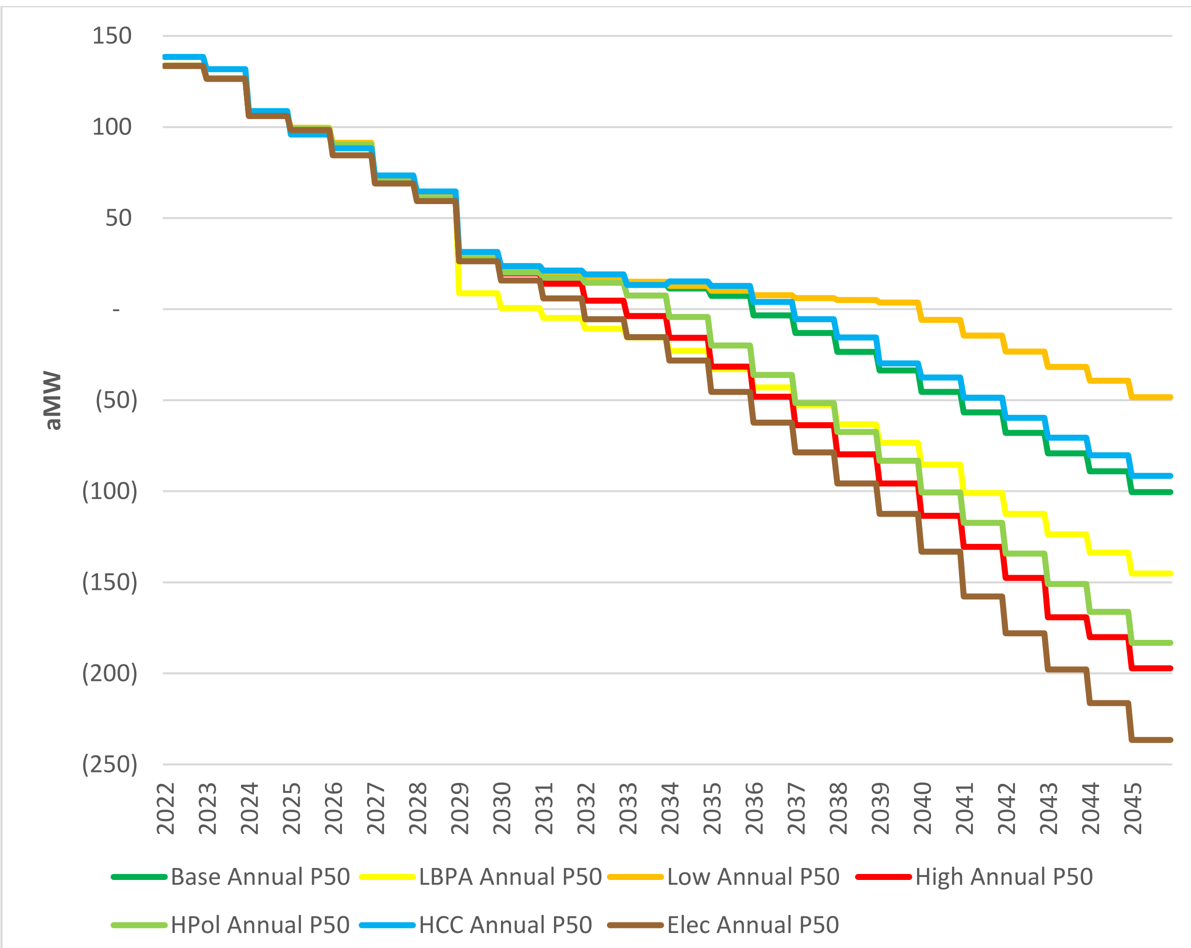


Because the PUD's BPA contract allocation is based on load, the annual load trajectory of a given scenario also influences the trajectory of the annual load resource balance. As PUD load increases, the BPA contractual allocation also increases at an approximate 1:1 ratio, until the PUD reaches its full contractual allocation.

This can be seen in Figure 5-25, where load resource balance is charted for multiple scenarios. The point of divergence on the graph is where the PUD would reach its full contractual allocation, based on the scenario assumptions for load and BPA. This point generally occurs after 2028. Because the PUD is forecasting an annual surplus, the IRP does not find a need to procure resources that primarily provide annual average energy.

Figure 5-25

Annual Load Resource Balance by Scenario at P50 (in aMW)



Seasonal Monthly Load Resource Balance Forecasts

The PUD has seasonal load resource balance deficits that begin to appear as early as 2022. In general, the PUD portfolio is most vulnerable to deficits in the winter, when cold temperatures can increase loads and variable generation may not be sufficient to meet all energy needs. Figure 5-26 shows the Monthly HLH Load Resource Balance in the 2022 Base Case before new conservation.

Figure 5-26

Base Case Probabilistic Load Resource Balance for 2022 Monthly HLH periods (in aMW)

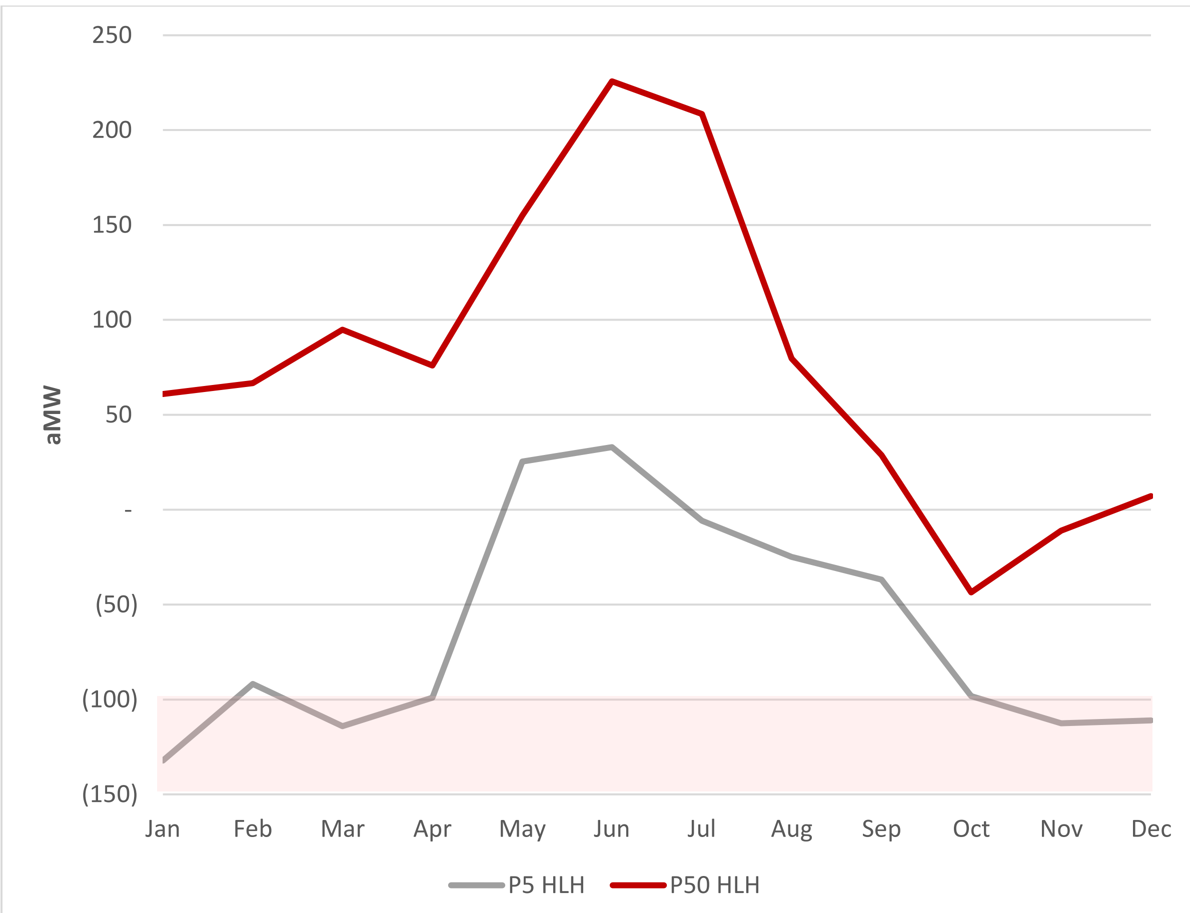
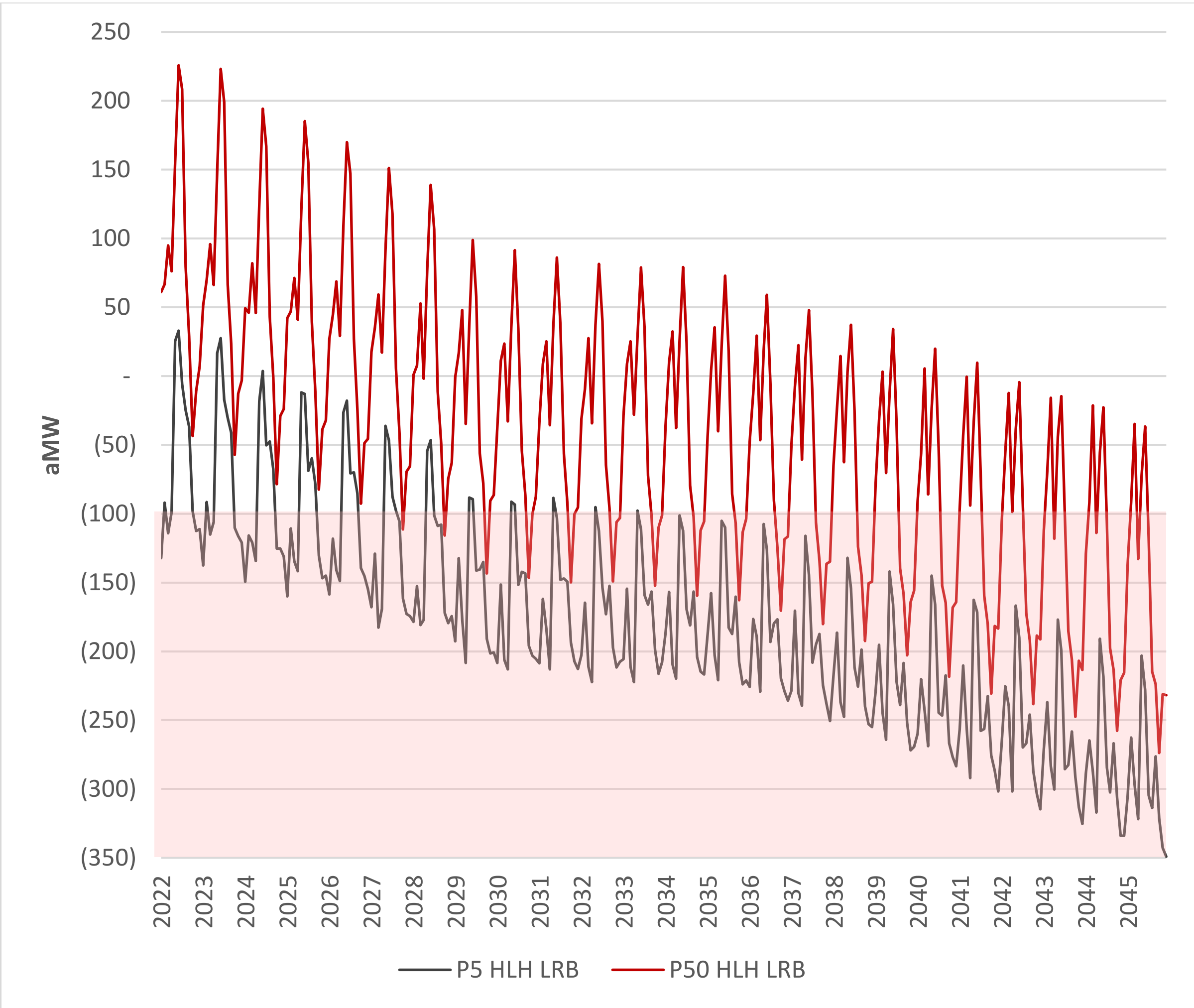


Figure 5-27 shows the Base Case Portfolio Monthly HLH Load Resource Balance at P50 and P5. Generally, Monthly HLH needs grow across time, until there is considerable risk of deficit in all months. The PUD seeks to limit Monthly HLH vulnerability to no lower than 100aMW deficit during P5 conditions - the forecast in Figure 5-27 demonstrates the need to acquire additional resources to maintain this standard.

Figure 5-27

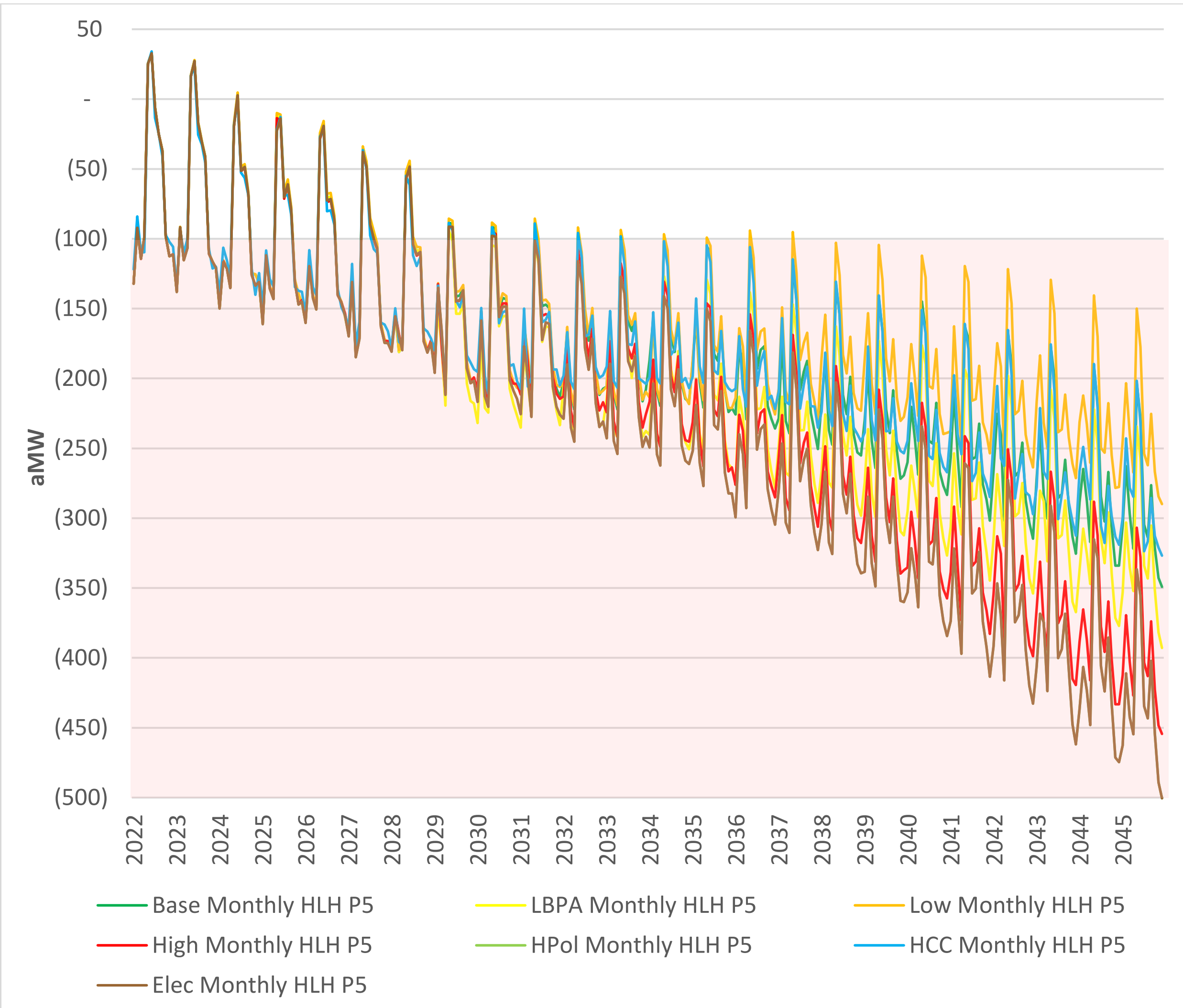
Base Case Load Resource Balance at P50 and P5 for Monthly HLH periods from 2022-2045, before New Conservation (in aMW)



As seen in the divergence point of the annual load resource balances, the load trajectory of a given scenario generally provides the causality of the point of divergence across scenarios. Scenarios with higher load growth trajectories or lower BPA allocation assumptions will have deeper Monthly HLH deficit risks, compared to scenarios with lower load forecasts or higher BPA allocations. Figure 5-28 shows Monthly HLH Load Resource Balance Deficits at P5 by scenario across the study period.

Figure 5-28

Load Resource Balance at P5 for Monthly HLH periods from 2022-2045 for all scenarios, before New Conservation (in aMW)



Seasonal Peak Week Load Resource Balance Forecasts

The IRP forecasts seasonal peak week load resource balance deficits appearing as early as 2022. Generally, the PUD portfolio is most vulnerable to peak week deficits in the winter when cold temperatures can increase loads and variable generation may not be sufficient to meet all energy needs in some weather conditions. Figure 5-29 shows the Monthly Peak Week Load Resource Balance for the 2022 Base Case before new conservation.

Figure 5-29

Base Case Probabilistic Load Resource Balance for 2022 Monthly Peak Week periods (in aMW)

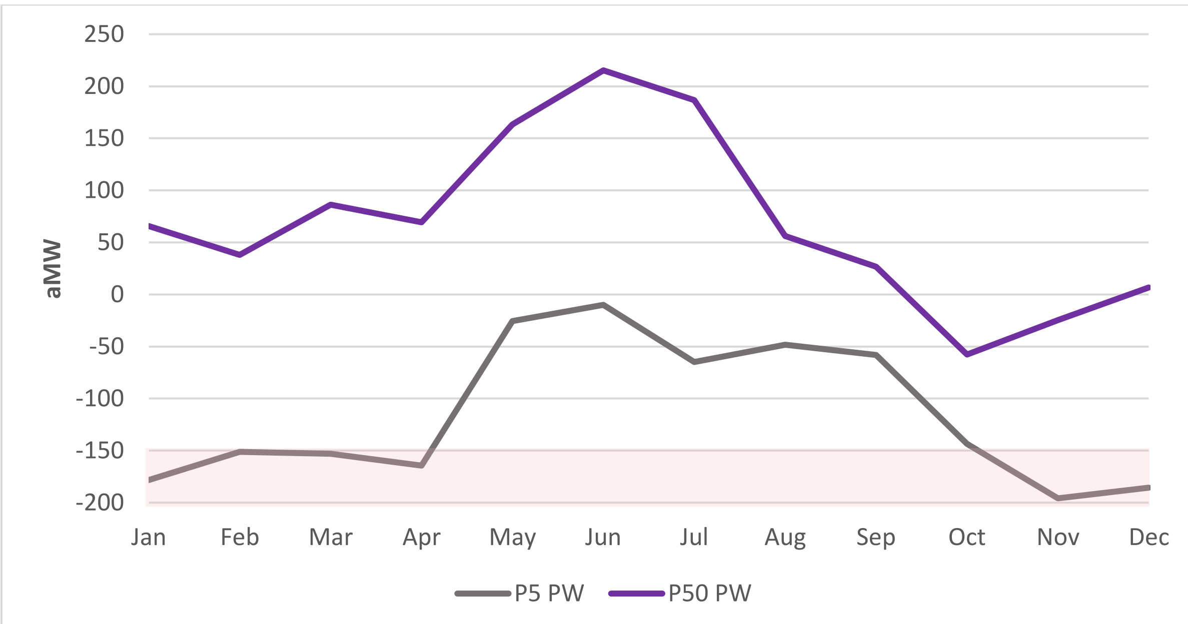
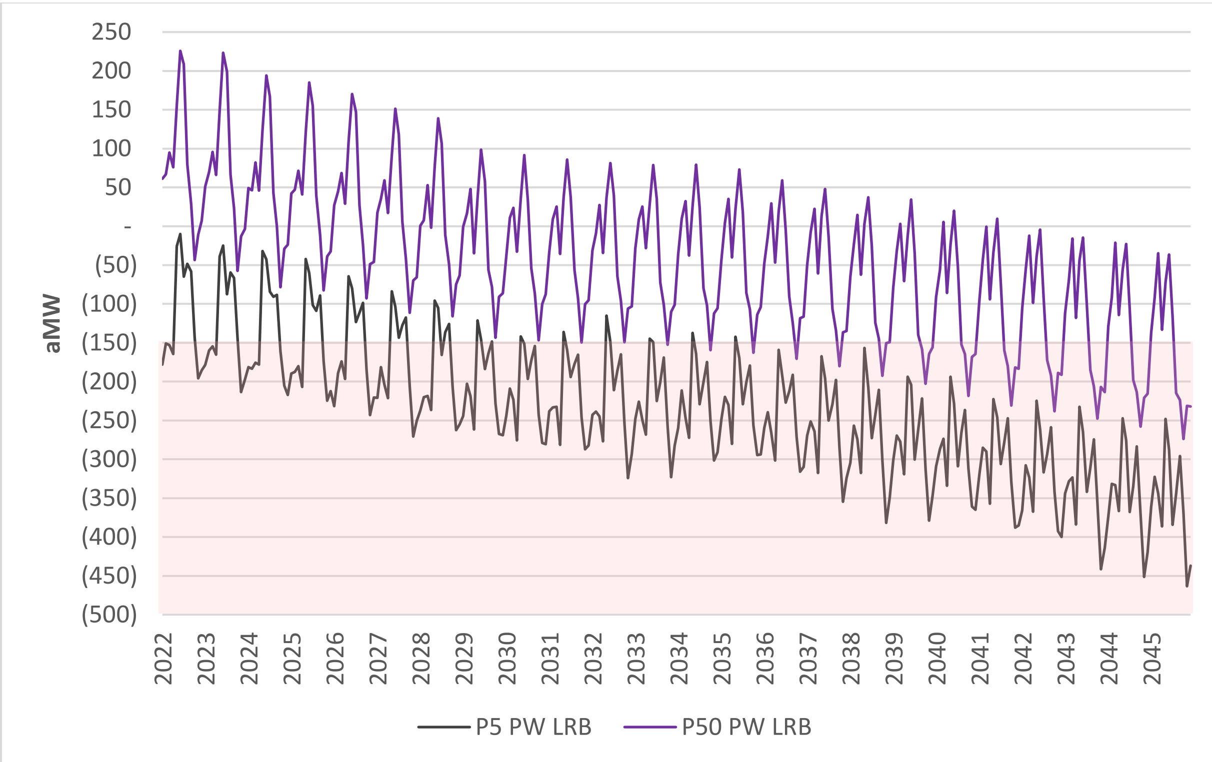


Figure 5-30 shows the Base Case Portfolio Monthly Peak Week Load Resource Balance at P50 and P5. Monthly Peak Week needs grow across time, until there is considerable risk of deficit in all months. The PUD seeks to limit Monthly Peak Week vulnerability to no lower than 150aMW deficit during P5 conditions - Figure 5-30 demonstrates that the PUD needs to acquire additional resources to maintain this standard.

Figure 5-30

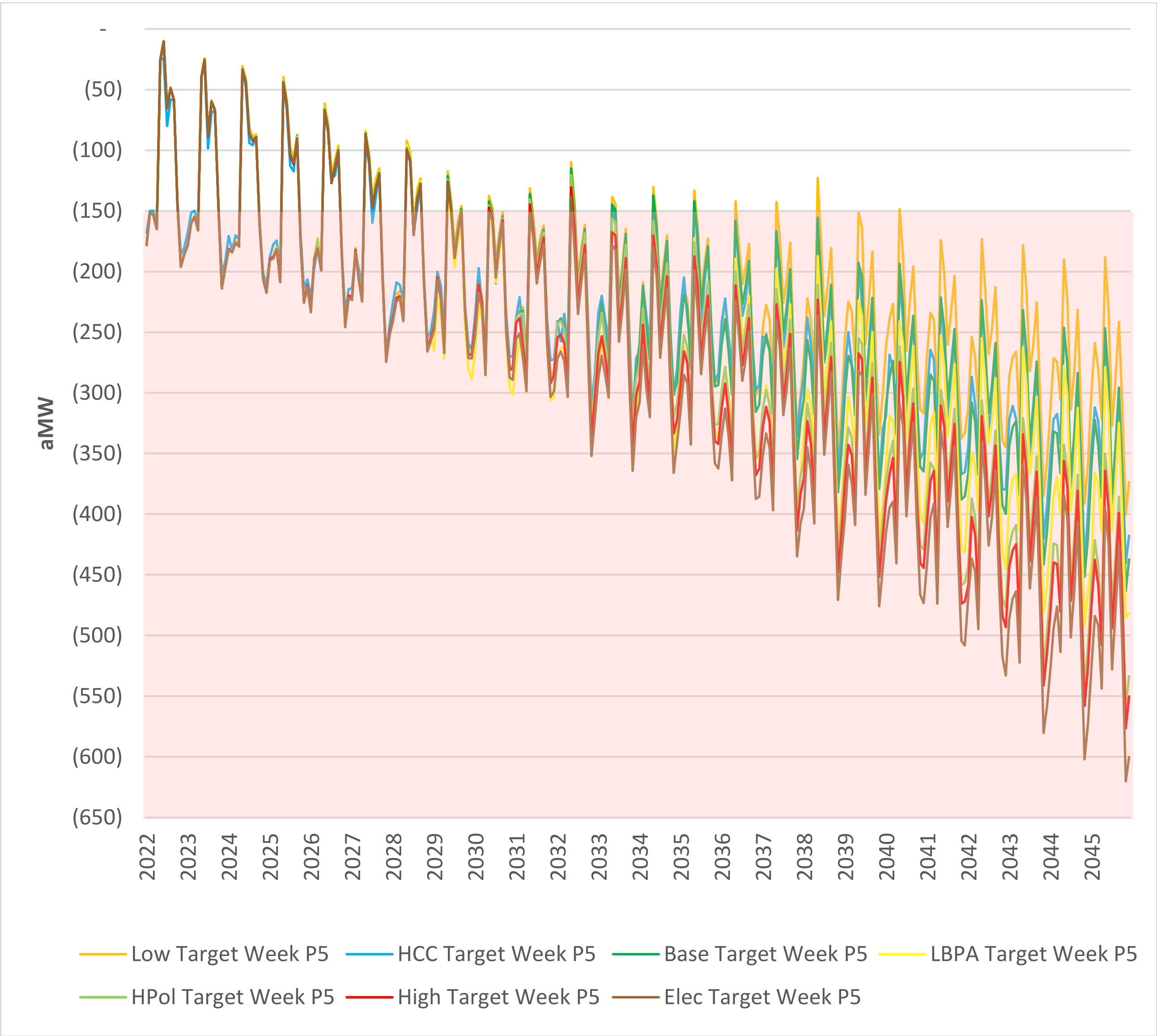
Base Case Load Resource Balance at P50 and P5 for Monthly Peak Week periods from 2022-2045, before New Conservation (in aMW)



As seen in the preceding graphs comparing scenarios, scenarios with higher load growth trajectories or lower BPA allocation assumptions have deeper Monthly Peak Week deficit risks, compared to scenarios with lower load forecasts or higher BPA allocations. Figure 5-31 shows Monthly Peak Week Load Resource Balance Deficits at P5 by scenario across the study period.

Figure 5-31

Load Resource Balance at P5 for Monthly Peak Week periods from 2022-2045 for all scenarios, before New Conservation (in aMW)



Resource Options

The analytical approach taken to identify resource gaps helps identify the timing, scale, and likelihood of resource needs, and it's important that the PUD's evaluation of available resources take a similar view in assessing resource outputs. The PUD uses an integrated portfolio approach to finding the most cost-effective portfolio additions. The integrated portfolio approach evaluates demand-side resources, supply-side resources, and market resources (including the market for environmental attributes) in a single economic optimization allowing the PUD to observe multiple dimensions of potential resource value. This approach helps quantify the peak capacity contributions of conservation relative to other resources, while simultaneously valuing its regulatory compliance value of reducing load subject to regulatory compliance obligations and seasonal energy value.

Supply side and demand side resources are evaluated using the same measurements: their potential contributions to capacity, energy, and satisfying regulatory requirements. In this way, the PUD was able to use an integrated portfolio approach for each scenario, creating portfolios that combined the best mix of demand and supply side resources to meet that scenarios future need, based on least-cost criterion.

Demand Side Resource Options

Conservation

The PUD contracted with Lighthouse Energy Consulting for a utility-specific 2021 Conservation Potential Assessment (CPA) study. The CPA identified all achievable potential conservation within the PUD's service territory over the 24-year study period.[53] The CPA used measures' savings, costs, and other characteristics based on the measures included in the Northwest Power and Conservation Council's (NWPCC) draft 2021 Power Plan, with updates from the Regional Technical Forum (RTF) and additional customizations to make the measures specific to the PUD.

[53] A full description of the conservation resources available to the PUD can be found in the PUD's 2021 CPA Report prepared by Lighthouse Energy

The 2021 IRP incorporates the results of the CPA into its integrated portfolio approach. The portion of achievable potential found to be economic, also called "cost-effective conservation," is identified through portfolio optimization in each scenario, analogous to the NWPCC methodology. Further discussion of the cost-effective conservation found in each portfolio and in the Long-Term Resource Strategy is given in Section 6.

Figure 5-32 illustrates the differences in technical potential, achievable potential, and economic potential.

Figure 5-32

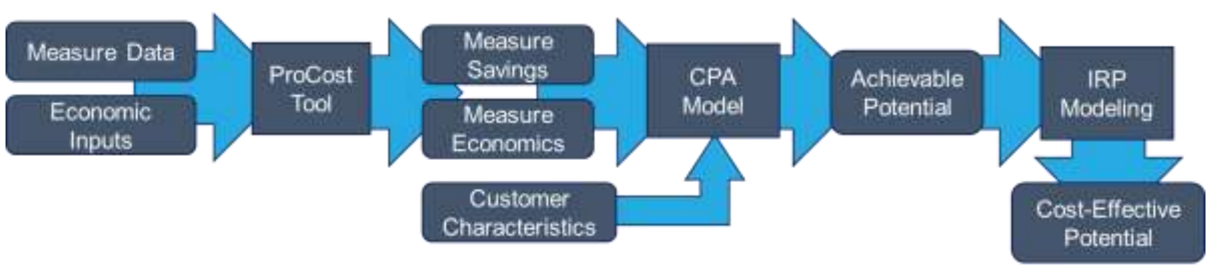
Types of Energy Efficiency Potential

Not Technically Feasible	Technical Potential		
Not Technically Feasible	Market and Adoption Barriers	Achievable Potential	
Not Technically Feasible	Market and Adoption Barriers	Not Cost Effective	Economic Potential

Figure 5-33 displays the general process used to develop achievable technical potential estimates, and the IRP's role in identifying cost-effective potential.

Figure 5-33

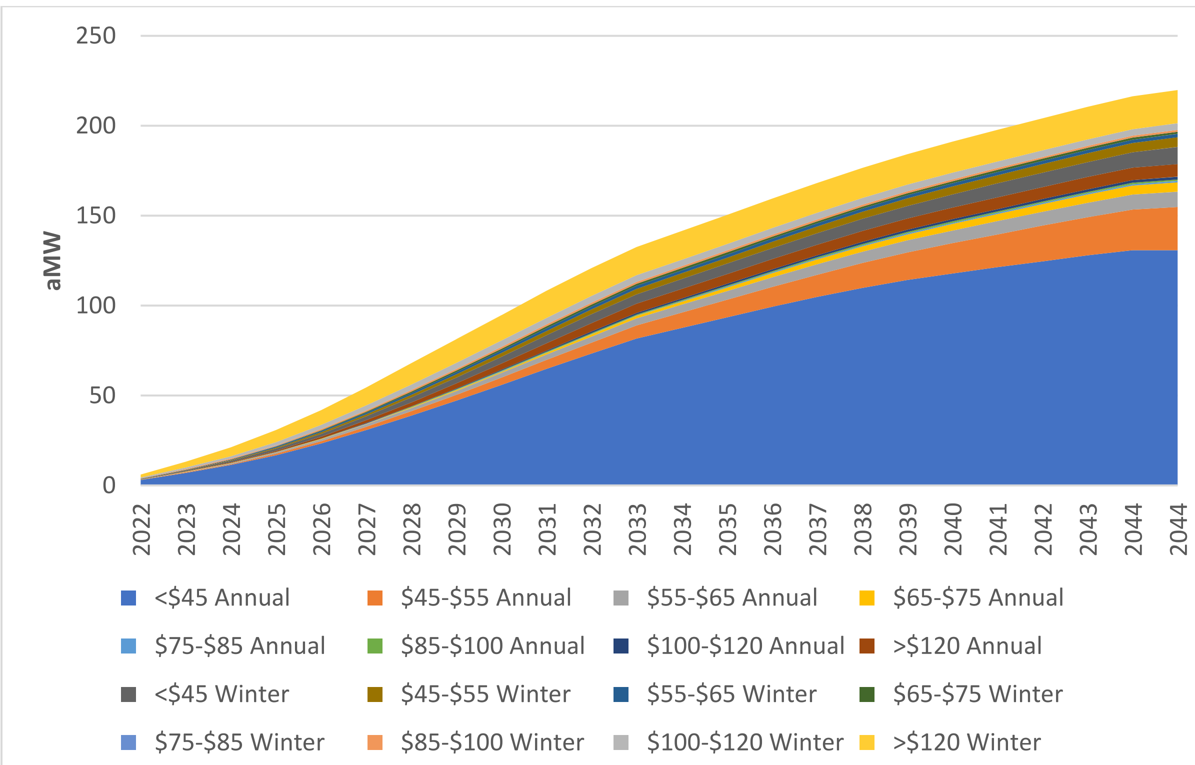
Conservation Potential Assessment Methodology



The CPA assessed each achievable technical conservation measure and sorted the measures into two seasonal bins each with eight different sub-bins organized by levelized cost. The two seasonal bins are annual measures and winter measures, where annual measures reduce load on an annual basis, and winter measures generally reduce load only in the winter months of November through February. This organization produces a total of 16 bundles of conservation that the 2021 IRP economic optimization model selects from, alongside supply-side resource options, to identify the conservation that most cost-effectively meets that portfolio's needs.

Figure 5-34 illustrates the 2021 CPA's conservation supply curve, separated by bundle and seasonal bin. The last bar on the right represents a total of 220 aMW of cumulative conservation. This represents the maximum amount of annual achievable conservation savings that could be achieved over the 24-year study period.

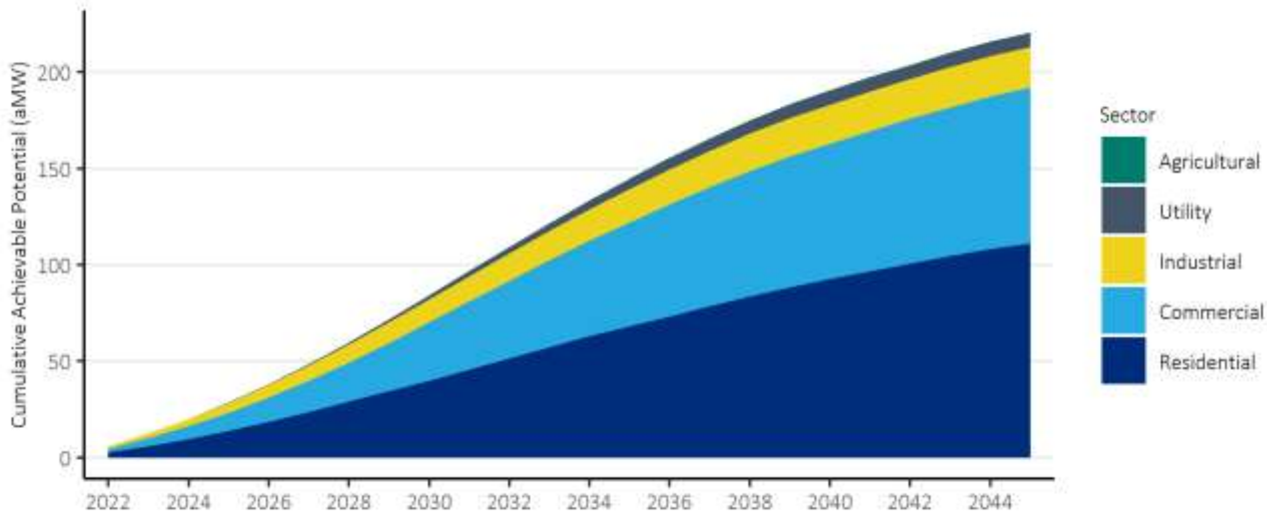
Figure 5-34
24 Year Cumulative Conservation Supply Curve – 2022 through 2045 (Annual aMW)
(Achievable Potential)



The residential sector accounts for approximately 50% of achievable technical conservation potential with the commercial and industrial sectors accounting for 36% and 9%, respectively. The balance of measures is agricultural or distribution system efficiency measures.

Figure 5-35 shows cumulative achievable technical potential across the study period, distributed by sector:

Figure 5-35
24 Year Achievable Technical Potential by Sector



Demand Response

Demand Response programs entail coordination with customers aiming to alter energy consumption patterns and help the PUD defer customer demand from a time period with peak load pressure to a time period with less peak load pressure. An example of this type of program is the recent BPA Commercial & Industrial Load Curtailment pilot program, in which some large-scale customers reduced their energy consumption during peak periods in exchange for monetary compensation.

The PUD contracted with Lighthouse Energy for a 24-year demand response (DR) potential assessment, which would identify DR potential by product and levelized cost. This assessment would also have DR programs included as discrete resource options in the 2021 IRP analysis. The assessment followed the methodology developed by the Northwest Power and Conservation Council (Council) for the draft 2021 Power Plan (2021 Plan) and included many of the same DR products, plus several additional products under consideration by the PUD. The range of DR products included are applicable to the commercial, industrial, and residential sectors. While winter peak demand was the primary focus of considered DR programs, the assessment also included several products that are applicable to both summer and winter peak demands.

Like a conservation potential assessment, the DR potential calculation process began with the quantification of technical potential, which is the maximum amount of DR possible without regard to cost or market barriers. The assessment then considered market barriers, program participation rates, and other factors to quantify the achievable potential. As with the conservation potential assessment, the achievable potential assessment did not include an economic screen to determine cost-effectiveness. Instead, the results of this assessment were provided as inputs to the 2021 IRP process, which determines the level of cost-effective DR resources through economic optimization across a variety of demand and supply-side resources using the integrated portfolio approach.[54]

Figure 5-36 provides an overview of the types of programs, their sector association, and their broad program categorization.

Figure 5-36

Demand Response Products in 2021 DRPA

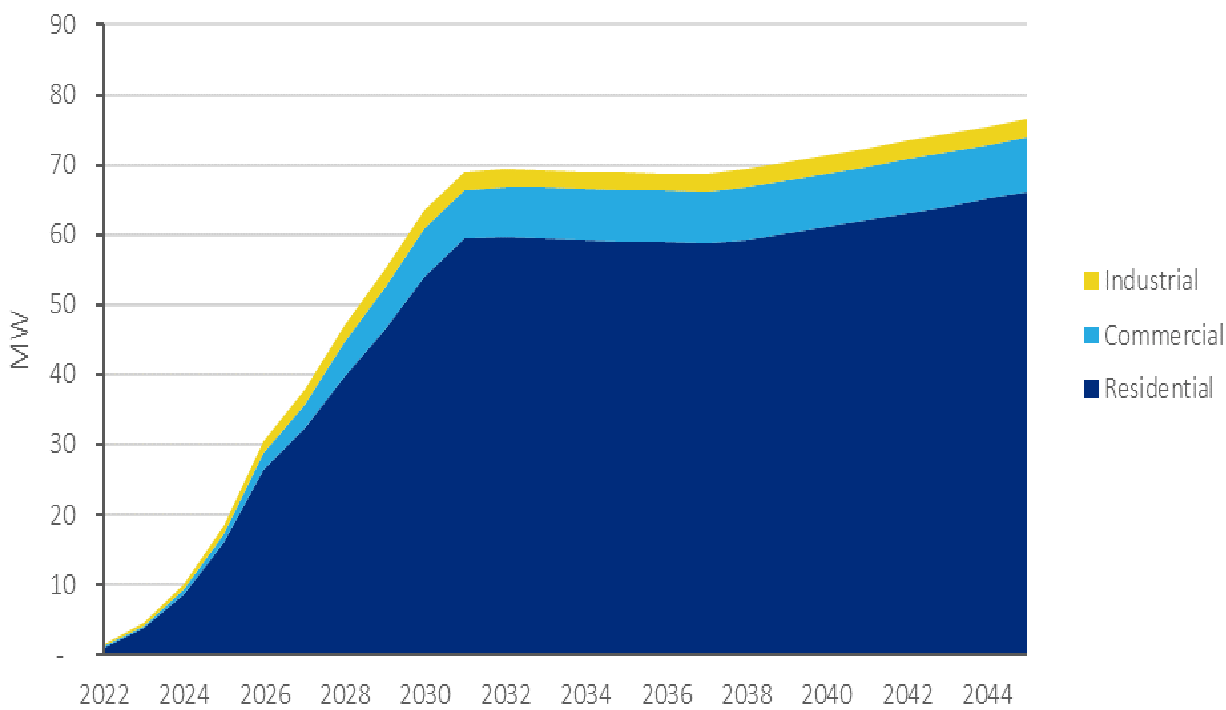
	Commercial	Industrial	Residential
Direct Load Control	Space Heating Switch Smart Thermostat		EV Charging Water Heater Controls Space Heating Switch Smart Thermostat
Demand Curtailment		Demand Curtailment	
Time-Varying Prices	Time of Use Rates Critical Peak Pricing Time of Use + Critical Peak Pricing	Time of Use Rates Critical Peak Pricing Time of Use + Critical Peak Pricing	Time of Use Rates Critical Peak Pricing Time of Use + Critical Peak Pricing

[54] More details on the Demand Response Potential Assessment can be found in the report itself.

The DRPA found the majority of winter achievable potential, originates from the residential sector. The estimated achievable winter DR potential is summarized by sector and year in Figure 5-37. The total winter potential is 76 peak hour MW, which is approximately 5% of the PUD’s estimated 2045 winter peak demand.

Figure 5-37

Annual Achievable Winter DR Potential by Sector in Peak Hour MW



Most of the potential is spread evenly across the categories of space heating, water heating, and pricing and curtailment, which impact all end uses. Second to those categories, a smaller amount of potential is available from electric vehicle supply equipment. The pricing and curtailment category starts slower than the other categories as it is dependent upon the implementation of Advanced Meter Infrastructure (AMI).

Figure 5-37 illustrates this DR potential by end use.

Figure 5-37

Annual Achievable Winter DR Potential by End Use in Peak Hour MW

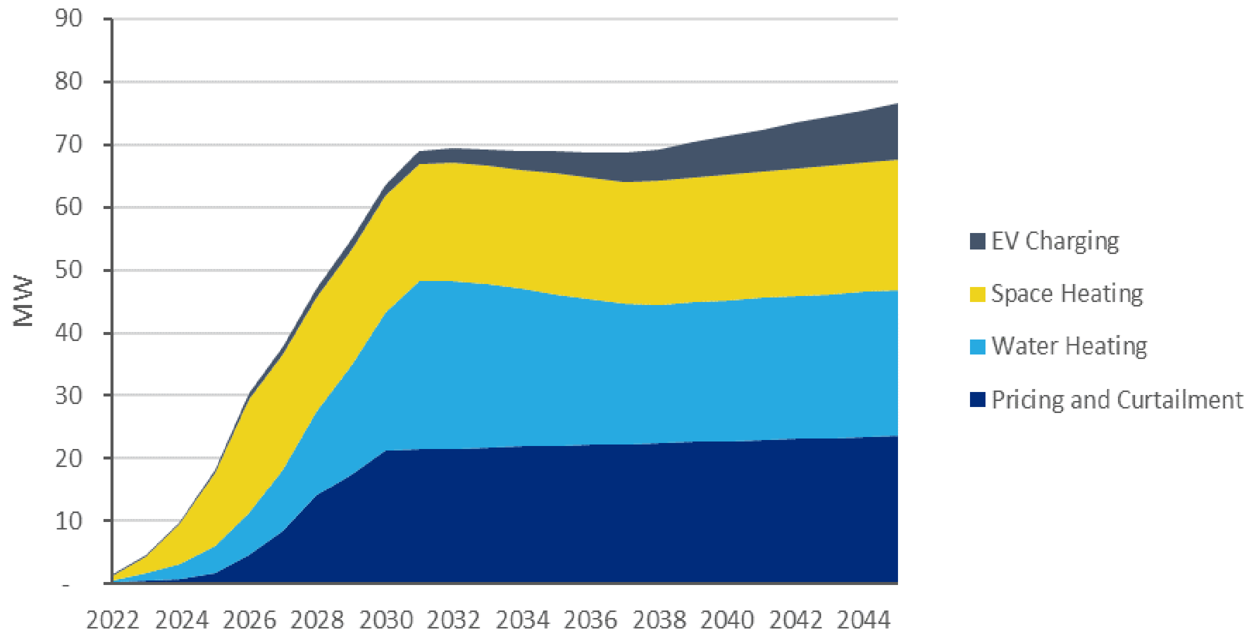
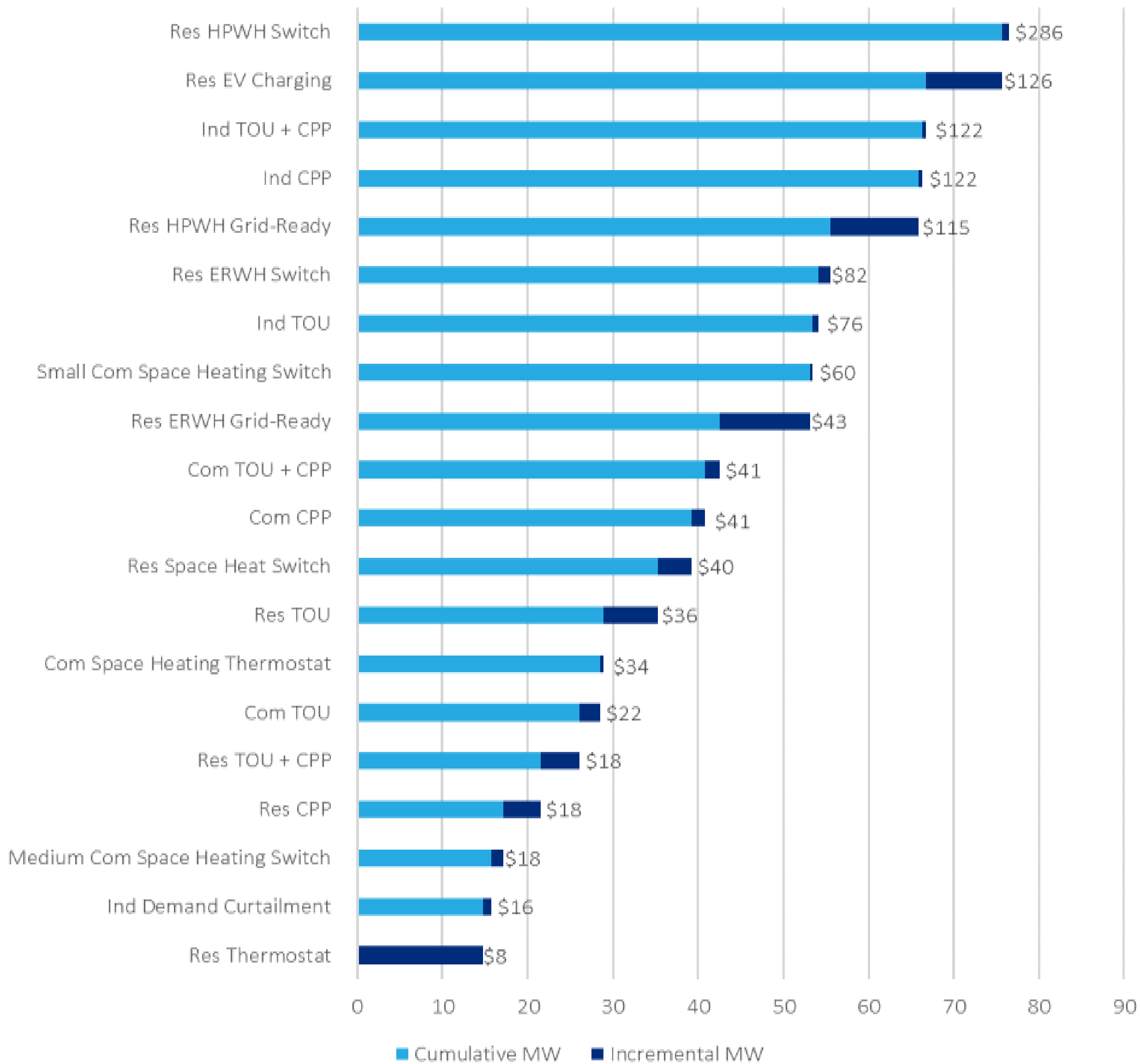


Figure 5-38 shows that the individual products with the highest potential are associated with residential space and water heating systems. In general, many of the residential and commercial pricing programs are low-cost options as these programs do not involve any equipment costs.

Figure 5-38

Winter DR Supply Curve (MW and $/kw-year)

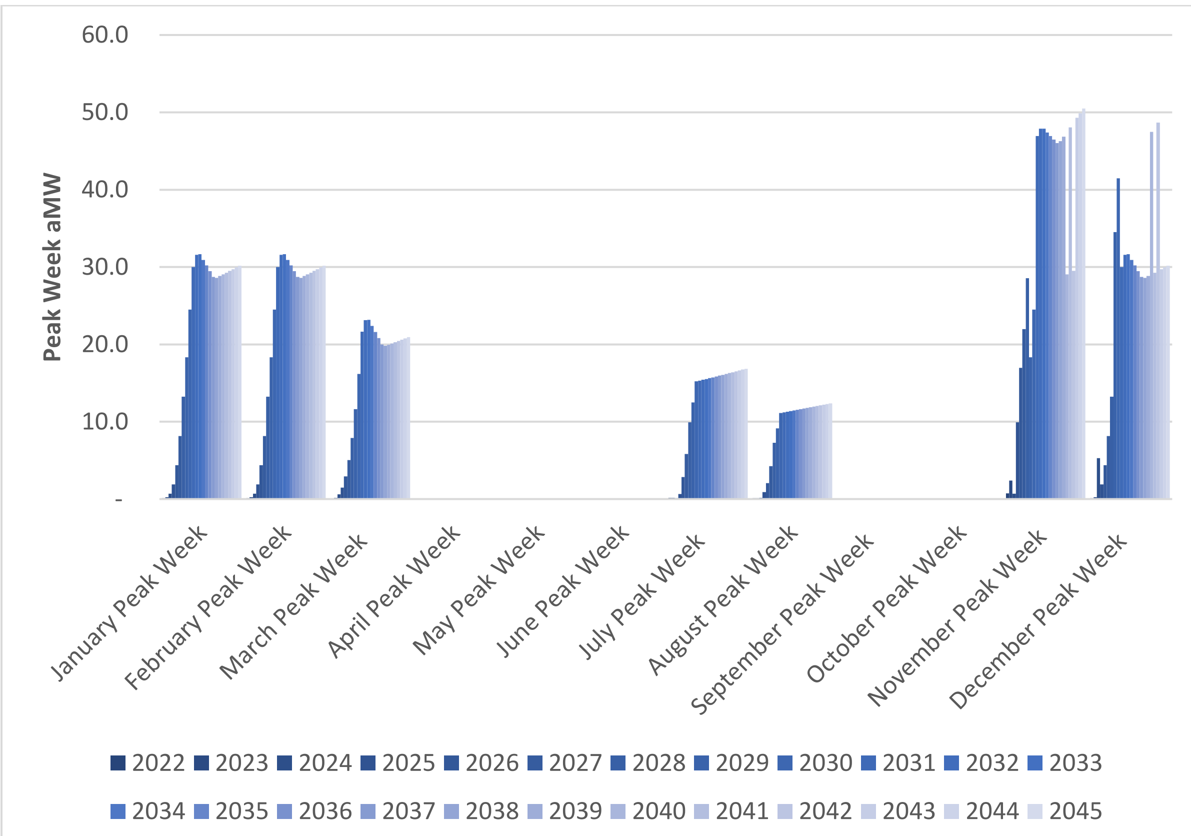


One unique attribute of many demand response programs is that they are call-limited, meaning they cannot be freely called upon. Rather, the programs have a set number of calls that can be made upon participating customers. Due to this limit, the contributions of demand response programs are likely limited to the hours of greatest need but may not cover all of them.

To illustrate this, Figure 5-39 shows how all achievable potential would be dispatched on a forecast basis to meet greatest needs, as measured on a Peak Week aMW basis. Based on this forecast, some months would likely not be served by the program, with the months of November and December expecting to see the largest dispatches.

Figure 5-39

Simulated Optimal Dispatch of All Achievable DR Potential by Month and Year

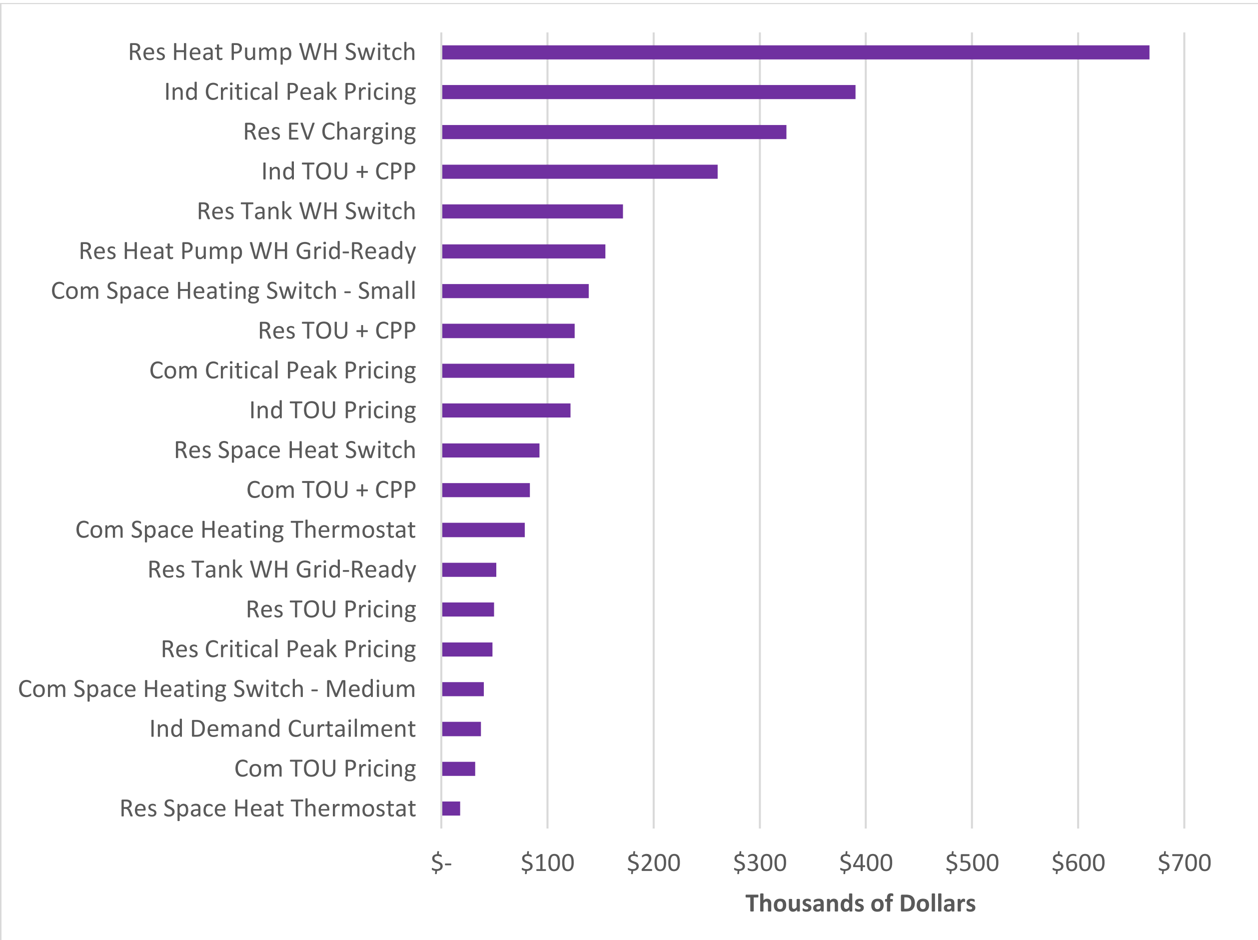


The unique capacity needs of the PUD influence the cost effectiveness of DR programs. Lower cost programs that cover longer periods of time have lower costs per Peak Week aMW.

Figure 5-40 displays all winter programs by Levelized Cost per maximum Winter Peak Week aMW, which is the highest peak week contribution of the program, for any year or month, divided by the Present Value cost of delivering the program across the study period.

Figure 5-40

Winter DR Programs by Levelized Cost per Maximum Winter Peak Week aMW

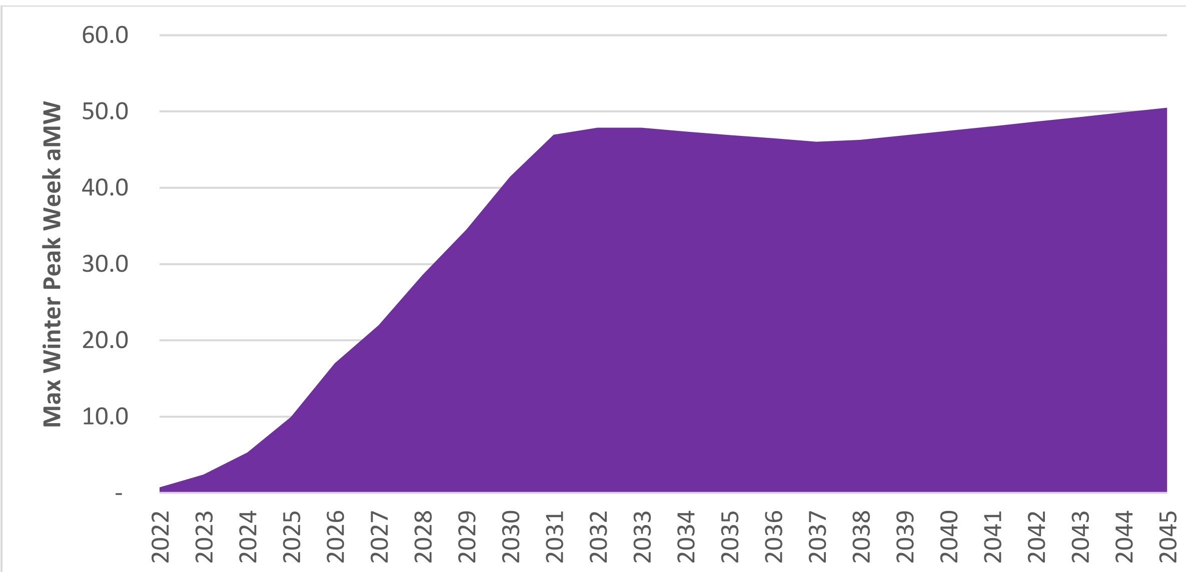


Relative to other available resources, the Levelized Cost per aMW is low for Demand Response programs. This low cost may appear to signify that significant portions of capacity needs could be met in the 2021 IRP with DR alone. However, the achievable potential for demand response programs is limited, with maximum winter peak weak potential forecast at a ceiling of approximately 50aMW and low levels available over the course of the next 10 years. The economic optimization further parses which of this total achievable potential may be economic to acquire, resulting in a smaller still amount.

Figure 5-36 shows Maximum Winter Peak Week Achievable Potential across the study period. One element affecting the timing of achievable potential is the timing of the PUD's Advanced Meter Infrastructure (AMI) rollout. The DRPA modeled a five-year rollout of installed meters, beginning in 2025. Any acceleration of this timeline would shift available DR programs like Time-of-Use Rates (TOU) or Critical Peak Pricing (CPP) forward, increasing DR achievable potential in the earlier portion of the 2020's.

Figure 5-36

Maximum Winter Peak Week Achievable Potential (in Peak Week aMW)



Supply-side Resource Options

The PUD's integrated portfolio approach to planning for the future sets demand-side resources, market resources, and supply-side resources as a menu of options for the IRP's economic optimization model to choose from as it seeks the lowest net cost portfolio to meet the PUD's portfolio needs. Supply-side resources are resources that generate or store energy, as well as long-term energy purchases from third parties or the market. There are a wide variety of available resource types available across the Pacific Northwest, and consideration of these resources requires an assessment of their commercial availability, generating attributes, development costs, and operating costs.

The PUD screens resources for their commercial availability based on a staff assessment of whether a resource could be permitted, built, and have available market cost estimates. Some resources, such as coal plants, are not considered commercially available for the purposes of the 2021 IRP because energy policies create a reasonable doubt as to whether they would be permittable, as well as impose significant regulatory costs. Other technologies, such as small modular nuclear reactors, offshore wind turbines, and enhanced geothermal systems, show promise but are not yet fully commercially available. Any nascent resource not deemed commercially available for use or further analytical consideration the IRP portfolio is deemed an "Emerging Technology" and can be found in Appendix E.

Supply-Side Resource Types

The 2021 IRP classifies supply-side resources into three categories: baseload resources, variable resources, and capacity resources. Baseload resources have a generation profile that is stable and similar across hours of the day and across months of the year. An example of a baseload resource is a biomass generation facility. Variable energy resources have a generation profile that varies throughout the day and may have seasonal differences in the amount of energy that might be produced across months in a year. An example of a variable resource is a solar generation facility. Capacity resources can be controlled to dispatch into targeted hours of the day, and within certain months of the year. An example of a capacity resource is a utility-scale battery.

Baseload Resources

The 2021 IRP evaluates baseload resources with the following characteristics:

Name	Fuel Source	Scale(s) in MW Nameplate	First Year Available
Biomass	Combusted biomass feedstock (such as lumber waste)	10	2025
Solar+ Storage	Solar energy	25, 50, 75	2023
Wind + Storage	Wind Energy	25, 50, 75	2023
Geothermal	Geothermal energy	25	2024
Short-term Market Product	Wholesale Market	25	2022
Run-of-River Hydropower with Storage	Hydropower	7.5	2025

The 2021 IRP includes the first-time evaluation of renewables with integrated storage as a baseload resource. These resources are modeled to contain on-site storage to firm and smooth the output of otherwise variable renewable generation.

Variable Resources

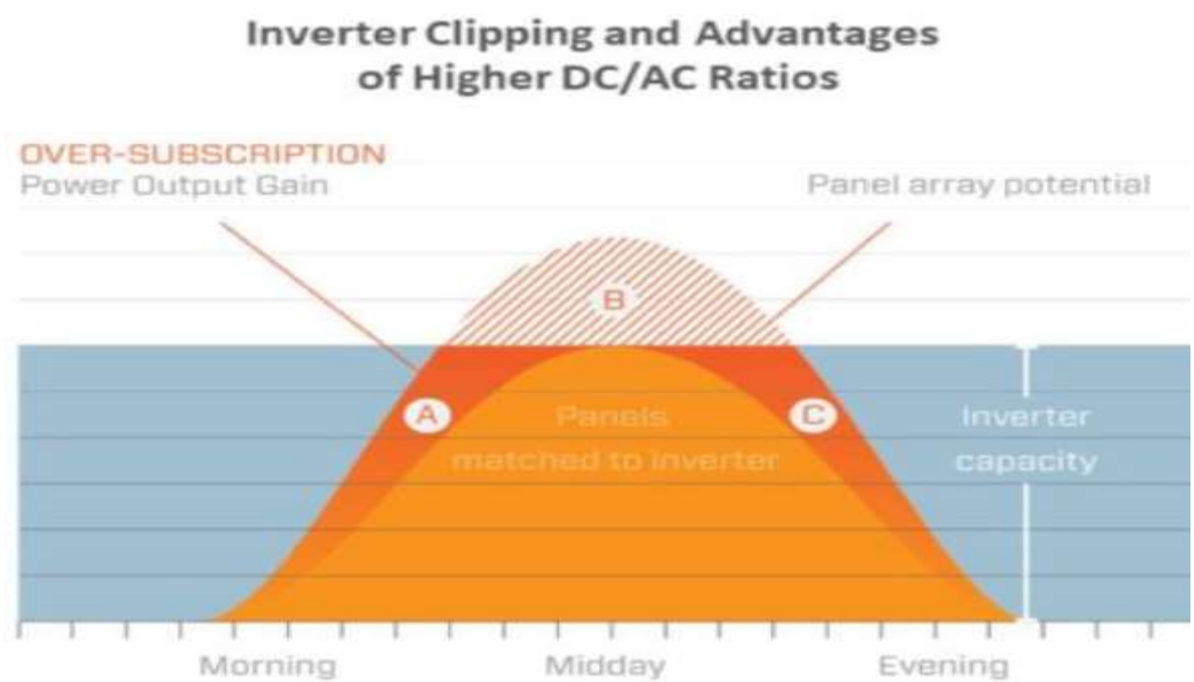
The 2021 IRP evaluates variable resources with the following characteristics:

Name	Fuel Source	Scale(s) in MW Nameplate	First Year Available
Columbia River Gorge Utility Scale Wind	Wind Energy	25, 50, 75	2023
Montana Utility Scale Wind	Wind Energy	25, 50, 75	2023
Eastern Washington Utility Scale Solar	Solar Energy	50	2023
Western Washington Utility Scale Solar	Solar Energy	5	2023
Western Washington Run-of-River Hydro	Hydropower	7.5	2025

For the first time in the 2021 IRP, two inverter loading ratios (ILR) were modeled for utility scale solar projects (1.2 ILR and 1.4 ILR), reflecting a current trend to oversize the panel array with respect to the maximum allowance at the point of interconnection with the goal of providing a firmer resource output. Many solar arrays are sized such that their maximum generating capacity equals the interconnection limit, thus never "losing" generation due to the generating capability exceeding the amount that can be accepted by the interconnection. However, oversizing the array results in a trade-off: "losing" generation when at maximum capacity, but increasing generation in other hours, creating a "flatter" generation profile.

The falling cost of solar panels has driven this oversizing trend, which supposes the wider generation profile provides a higher value than the total costs of the additional panels and the "lost" generation that exceeds what can be accepted by the interconnection to the grid. Figure 5-37 below displays an example of the wider daily generation profile.

Figure 5-37



Capacity Resources

The following variable resources were evaluated, with the following characteristics:

Name	Fuel Source	Scale(s) in MW Nameplate	First Year Available
Short-duration local storage (4hr)	Stored energy (surplus PUD renewables, or market)	5,10,15	2023
Mid-duration local storage (8hr)	Stored energy (surplus PUD renewables, or market)	10,25	2023
Long-duration regional storage (12hr)	Stored energy (surplus PUD renewables, or market)	50,100	2026
Long-duration regional storage (16hr)	Stored energy (surplus PUD renewables, or market)	100,150	2026
Biodiesel Peaker	Liquid Biodiesel	12	2024
Short-term Market Capacity Product	Wholesale market	25	2022

When considering supply-side capacity resources, the 2021 IRP focuses on different durations of storage resources across a wide variety of delivery methods. The evaluation does not discriminate based on technology but is instead based upon the lowest cost commercially available storage resource identified for each storage duration type.

The PUD did not consider natural gas resources in the 2021 IRP as a viable long-term capacity resource. This choice is reflective of the Commission’s stated Climate Change policy, increasing regulatory uncertainty around fossil fuel resources, and analysis that concludes that the PUD could procure lower cost supply-side capacity resources through pursuit of storage resources.

Resource Costs

Supply-side resource costs in the 2021 IRP include the assessed total resource cost of developing and operating a resource. Operating costs include the cost of fuel (if applicable), the cost of transmission if the resource is sited outside the PUD's service territory, and the cost of ancillary services that may be required to support the resource such as Variable Energy Resource Balancing Service through BPA for wind energy.

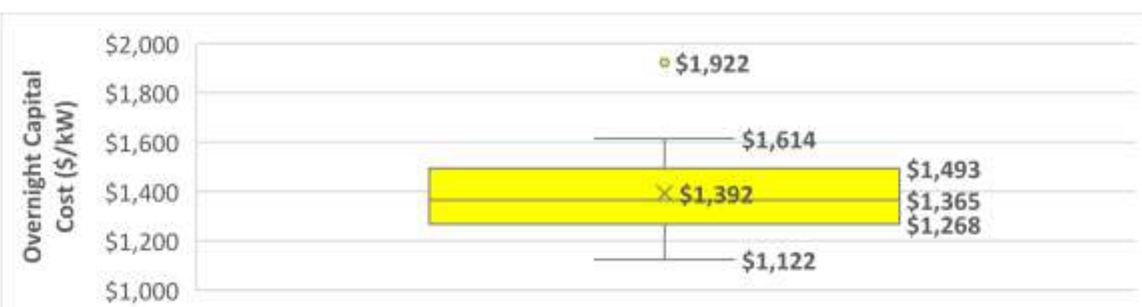
All costs assume a discount rate of 4.5%, are in USD currency, and were converted to a 2018 dollar-year value. All federal tax credits such as the production tax credit and investment tax credit are included where applicable. Cost estimates were made in each feasible delivery year for each resource type, such that the economic optimization model could draw upon present value cost estimates while considering PUD ownership of any given resource.

The PUD's methodology for determining supply-side resource costs was derived by developing a composite of credible, third-party cost estimates for the Pacific Northwest region, and normalizing this value to the scale, dollar year, and cost methodology used by the 2021 IRP. Cost data was derived from other recent regional utility IRPs, the Northwest Renewable Energy Laboratory's (NREL) All-Technology Bulletins (ATB), and the Northwest Power and Conservation Council's 2021 Power Plan.

The 2021 IRP considers the midpoint of a distribution of regional costs to be the composite cost used as an input for the various cost types. Figure 5-38 below shows an example of how a composite cost was derived for the Overnight Cost of Capital (development cost estimate) for utility-scale solar plants.

Figure 5-38

Overnight Capital Cost Composite of Utility-scale Solar PV

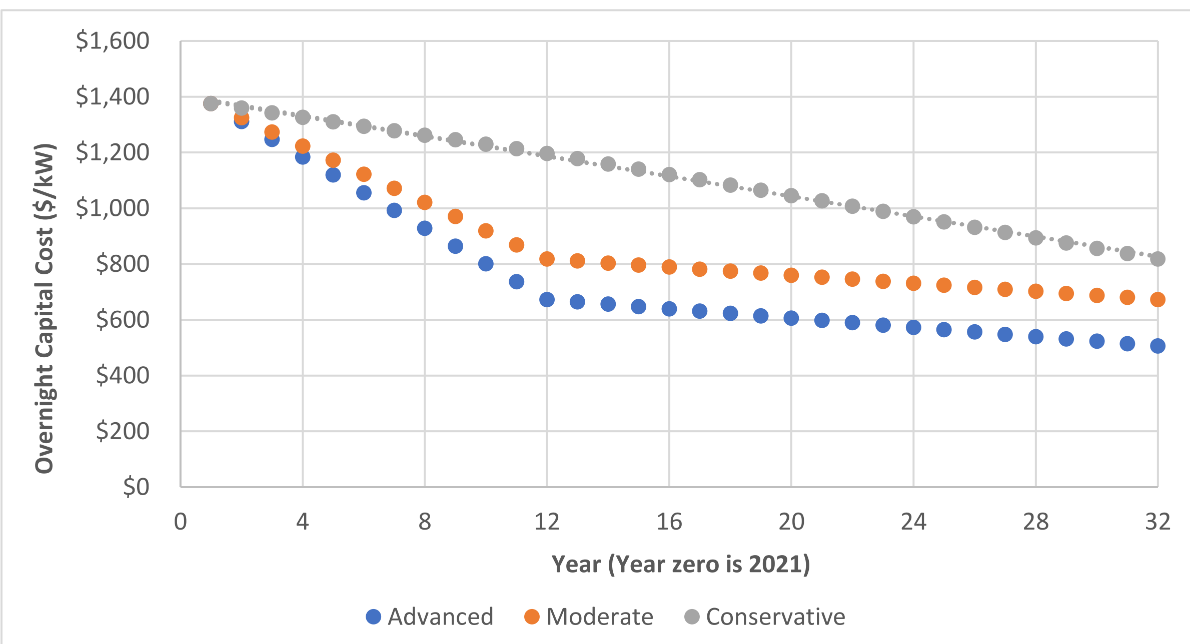


For some resource types where the efficiency of a resource is expected to increase significantly, or costs are expected to decrease significantly, the 2021 IRP applies a modification to the effective cost-per-nameplate of the resource. These modifications are derived from the NREL's 2020 Annual Technology Baseline data forecasts for cost and efficiency changes over time for resources available to the broader Seattle market. The purpose of this practice is to financially account for technology improvements over time, such that the economic value of resource deferral includes consideration of cost decreases or efficiency gains. Cost modifications are made to short-duration storage, utility scale solar, and utility scale wind resources to reflect forecasted technology improvements.

Figure 5-39 below shows an example of how the cost of utility-scale solar PV is projected to decrease over the study period in conservative, moderate, and advanced scenarios derived from the NREL ATB. In all cases where a modification was applied, the IRP uses the conservative trajectory from the ATB as a forecast in order to reflect the considerable future uncertainty.

Figure 5-39

Overnight Capital Cost Projections of Utility-scale Solar PV



Some dispatchable resources, such as utility-scale storage resources must include assumptions of dispatch frequency in order to develop a total cost estimate. This information is needed because fuel cost estimates are based on both the price of fuel expected in a given year, and the volume of fuel needed in a given year. For such resources, a dispatch simulation study is performed using recent historical data to forecast how often a resource might be expected to dispatch in a given year. In order to forecast the MWh of input energy needed to support the volume of dispatch for storage resources, the dispatch rate can be multiplied by the nameplate and hours in a given year, then divided by the return-trip-efficiency of the plant. Because all wholesale market prices include the Societal Cost of Carbon (SCC) in the price estimate, all resources that use the wholesale market as their fuel cost estimate have an embedded SCC cost adder in their total resource cost forecast, including market resources and storage resources. The 2021 IRP utilizes 998 distinct supply-side resource cost estimates for the 53 supply-side resources under consideration across the 24-year study period.

Figure 5-40 provides selected highlights of cost attributes by resource.

Figure 5-40

Selected Highlights of Supply-Side Resource Cost Attributes

	Resource	First Year Available	Levelized Cost of Energy (2018$ /MWh)	Levelized Cost of Winter Peak Week Capacity (2018$/ MW)	Name plate (MW)	OCC (2018$/ kW)	Total First Year Costs (Nominal $ of total costs of first year availability)
Baseload	10 MW Biomass	2025	$ 97	$ 890,354	10	$ 4,000	$ 5,102,405
	25 MW Geothermal	2024	$ 96	$ 888,754	25	$ 6,100	$ 16,083,621
	50 MW Solar PV@1.2ILR + 25 MW 4-hr Storage - Yakima	2022	$ 189	$ 965,671	50	$ 3,655	$ 19,708,762
	50 MW Wind + 25 MW 4-hr Storage - Columbia Gorge	2022	$ 139	$ 9,008,151	50	$ 3,928	$ 21,960,742
	7.5 MW Run-of-the-River + 3.75 MW 4-hr Storage - SnoCo	2025	$ 356	$ 1,741,419	8	$ 10,295	$ 6,022,576
	25 MW Firm Annual Energy Contract	2022	$ 45	$ 392,201	25	N/A	$ 9,295,535
	25 MW Firm Winter Energy Contract	2022	$ 52	$ 83,922	25	N/A	$ 1,793,048
Variable	25 MW Wind - Columbia Gorge	2022	$ 60	$ 7,824,457	25	$ 1,550	$ 4,635,429
	25 MW Wind - Central Montana	2022	$ 60	$ 1,197,589	25	$ 1,550	$ 5,160,729
	50 MW Solar PV@1.2 ILR - Yakima	2022	$ 67	$ 4,827,365	50	$ 1,250	$ 7,059,766
	50 MW Solar PV@1.4 ILR - Yakima	2022	$ 63	$ 4,394,653	50	$ 1,400	$ 7,729,026
	5 MW Solar PV@1.2 ILR - SnoCo	2022	$ 74	$ 8,135,923	5	$ 1,250	$ 557,717
	7.5 MW Run-of-the-River Hydro	2025	$ 212	$ 5,900,019	8	$ 5,700	$ 3,759,096
Capacity	5 MW 4-hr Storage	2022	$ 311	$ 297,512	5	$ 1,554	$ 1,406,687
	10 MW 8-hr Storage	2023	$ 227	$ 161,294	10	$ 1,560	$ 1,483,698
	50 MW 12-hr Storage	2026	$ 210	$ 219,066	50	$ 1,751	$ 10,757,154
	100 MW 16-hr Storage	2026	$ 247	$ 281,325	100	$ 2,785	$ 28,033,684
	25 MW Seasonal Exchange Contract	2022	$ 255	$ 74,353	25	N/A	$ 573,309
	25 MW Winter Capacity Contract	2022	$ 255	$ 223,060	25	N/A	$ 1,865,927
	25 MW Annual Capacity Contract	2022	$ 3	$ 24,229	25	N/A	$ 5,597,780
	58 MW SCCT Plant	2022	$ 172	$ 158,342	58	$ 620	$ 7,309,505
	12 MW Biodiesel	2023	$ 286	$ 217,090	12	$ 1,814	$ 2,441,577

Resource Attributes

The PUD economic optimization model will simultaneously optimize a future PUD scenario for P50 conditions and P5 (adverse) conditions from a Load Resource Balance perspective. For this reason, supply-side resources must be assessed at both their P50 generation estimate and their P5 generation estimate for each time period. The time periods correspond with the planning standards and include annual metrics, Monthly HLH metrics, Monthly Peak Week Metrics across the 24-year study period.

Probabilistic modeling for renewable resources is important because the variable nature of the generation may produce greater amounts of energy in some time periods than in others. To create probabilistic models of variable renewable resources, the 2021 IRP utilizes historic weather data and resource efficiency data to create simulated hourly generation profiles and subsequent probability distributions for every relevant time period.

Dispatchable resources required a simulated study of their expected dispatch to equivalent to their P50 generation estimates. This estimate was created by a dispatch simulation model using historic load and portfolio data. P5 generation attributes, designed to show the resource capabilities of a dispatchable resources under adverse conditions (1 in 20 outcomes or less), utilized the technical capacity of the plant as an estimate, including assumptions of the plants forced outage rate.

Figure 5-41 provides selected highlights of resource generation attributes by resource.

Figure 5-41

Selected Highlights of Supply-Side Resource Generation Attributes

	Resource	First Year Available	Annual Capacity Factor	P50 Annual Average (aMW)	P5 December HLH (aMW)	P5 December PW (aMW)	P5 August HLH (aMW)	P5 August PW (aMW)
Baseload	10 MW Biomass	2025	60.0%	5.70	5.70	5.70	5.70	5.70
	25 MW Geothermal	2024	80.0%	19.00	19.00	19.00	19.00	19.00
	50 MW Solar PV@1.2ILR + 25 MW 4-hr Storage - Yakima	2022	24.7%	12.37	5.54	21.25	24.85	25.61
	50 MW Wind + 25 MW 4-hr Storage - Columbia Gorge	2022	37.7%	18.87	9.64	2.55	20.02	10.02
	7.5 MW Run-of-the-River + 3.75 MW 4-hr Storage - SnoCo	2025	27.1%	2.03	1.93	3.64	0.00	3.64
	25 MW Firm Annual Energy Contract	2022	100.0%	25.00	25.00	25.00	25.00	25.00
	25 MW Firm Winter Energy Contract	2022	18.3%	8.22	25.00	25.00	0.00	0.00
Variable	25 MW Wind - Columbia Gorge	2022	38.4%	9.61	3.84	0.64	8.51	2.46
	25 MW Wind - Central Montana	2022	43.6%	10.90	7.13	4.75	7.13	5.46
	50 MW Solar PV@1.2 ILR - Yakima	2022	25.9%	12.96	5.93	1.58	25.78	15.64
	50 MW Solar PV@1.4 ILR - Yakima	2022	30.0%	15.00	6.95	1.89	29.84	18.22
	5 MW Solar PV@1.2 ILR - SnoCo	2022	17.2%	0.89	0.38	0.07	1.87	0.97
	7.5 MW Run-of-the-River Hydro	2025	28.1%	2.10	1.80	0.66	0.00	0.00
Capacity	5 MW 4-hr Storage	2022	10.4%	0.54	0.97	4.94	0.97	4.94
	10 MW 8-hr Storage	2023	7.7%	0.80	5.20	9.87	5.20	9.87
	50 MW 12-hr Storage	2026	11.3%	5.66	37.50	47.50	37.50	47.50
	100 MW 16-hr Storage	2026	12.4%	12.35	95.00	95.00	95.00	95.00
	25 MW Seasonal Exchange Contract	2022	100.0%	8.22	25.00	25.00	-25.00	-25.00
	25 MW Winter Capacity Contract	2022	3.3%	0.83	25.00	25.00	0.00	0.00
	25 MW Annual Capacity Contract	2022	10.0%	2.50	25.00	25.00	25.00	25.00
	58 MW SCCT Plant	2022	10.0%	5.80	57.25	57.25	57.25	57.25
	12 MW Biodiesel	2023	8.2%	1.02	2.96	11.84	2.96	11.84

Resource Summaries

The 2021 IRP framework takes a holistic view of resource contributions, including a stochastic approach to resource generation forecasting, a composite approach to resource costing, and a forward-looking approach to adjusting expected costs over time. The totality of this information is fed into the PUD's economic optimization model which solves for the lowest-cost, best-fit combination of demand-side, supply-side, and market resources to meet the PUD's needs.

Section 6 will discuss the portfolio optimization process and the results of portfolio optimization by scenario.

Figures 5-43 and 5-44 provide high-level views of relative supply-side resource cost comparisons from an energy and winter capacity perspective.

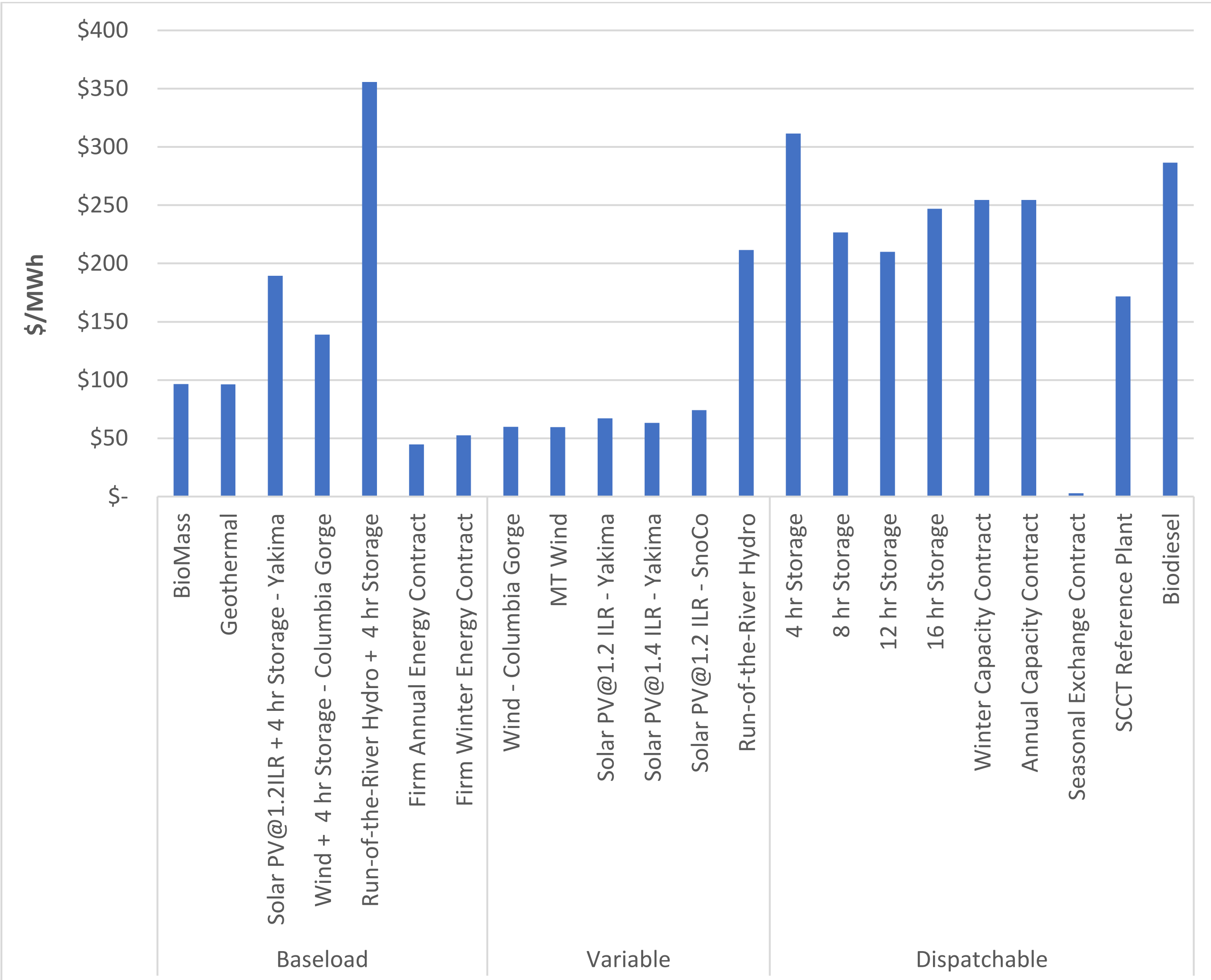
Figure 5-43

Levelized Cost of Winter Capacity ($/December Peak Week aMW @P5)

	Resource	Levelized Cost of December Peak Week Capacity
Baseload	Biomass	$ 890,354
	Geothermal	$ 888,753
	Solar PV@1.2ILR + 4-hr Storage - Yakima	$ 965,671
	Wind + 4-hr Storage - Columbia Gorge	$ 9,008,151
	Run-of-the-River Hydro + 4-hr Storage	$ 1,741,419
	Firm Annual Energy Contract	$ 392,201
	Firm Winter Energy Contract	$ 83,921
Variable	Wind - Columbia Gorge	$ 7,824,457
	MT Wind	$ 1,197,588
	Solar PV@1.2 ILR - Yakima	$ 4,827,365
	Solar PV@1.4 ILR - Yakima	$ 4,394,652
	Solar PV@1.2 ILR - SnoCo	$ 8,135,923
	Run-of-the-River Hydro	$ 5,900,018
Capacity	4-hr Storage	$ 297,512
	8-hr Storage	$ 161,294
	12-hr Storage	$ 219,065
	16-hr Storage	$ 281,324
	Winter Capacity Contract	$ 74,353
	Annual Capacity Contract	$ 223,060
	Seasonal Exchange Contract	$ 24,228
	SCCT Reference Plant	$ 158,342
	Biodiesel	$ 217,090

Figure 5-44

Levelized Cost of Energy



Carbon Emissions

Carbon content is primarily treated financially in the 2021 IRP, consistent the CETA requirement to incorporate the Societal Cost of Carbon (SCC) for direct or indirect emissions. This embedded cost is attributable to all resources that use the market as a fuel, as the PUD is not considering adding any fossil fuel resources to its portfolio. The methodology requires the SCC to be added to all simulated dispatch of an hourly wholesale market simulation model for many scenarios.

In order to capture generic carbon estimates in metric tons of CO2 equivalent for comparative use for resource evaluation, simplifying assumptions were made. These assumptions presume that the 0.437 CO_2 equivalent metric found in state law for Fuel Mix Disclosure purposes is an appropriate estimate of wholesale market emissions on average, and that this rate decreases linearly across time until it is 0 by 2045 as the grid becomes progressively less emitting. For the purposes of creating carbon emissions estimates only, this emissions rate is factored into all market-fueled resources and aggregated for comparison across portfolios. For more information on emissions, refer to Appendix H.

Overgeneration Events

The provisions under RCW 19.280.030 – Developing a Resource Plan, were expanded in 2013 and require IRPs to describe how its resource plan addresses overgeneration events. An oversupply event is an event that historically occurs in the late spring, and is marked by simultaneous:

- Moderate temperatures that reduce demand
- High hydroelectric energy production due to regional snow melt and spring rains
- High seasonal energy production from regional renewable energy projects.

The PUD's service area resides in the Bonneville Power Administration's (BPA's) footprint, also called the BPA Balancing Authority Area (BPA BAA). As the BAA, BPA is responsible for moment-to-moment balancing of loads and resources within its footprint, including for the PUD. BPA mitigates overgeneration conditions and oversupply events on a regional basis through its Oversupply Management Protocol. The PUD's portfolio is subject to BPA's Oversupply Management Protocol and pays the oversupply rate assessed by BPA.[55]

Unbundled Renewable Energy Credits

The cost to purchase the environmental attributes or renewable energy credits (RECs) associated with a renewable resource were modeled and made available in the 2021 IRP analysis as an investment option for meeting the PUD's annual EIA RPS requirement. The environmental attributes or RECs associated with energy produced by an EIA RPS eligible renewable resource can be purchased separately from the energy itself. The modeling assumption for unbundled

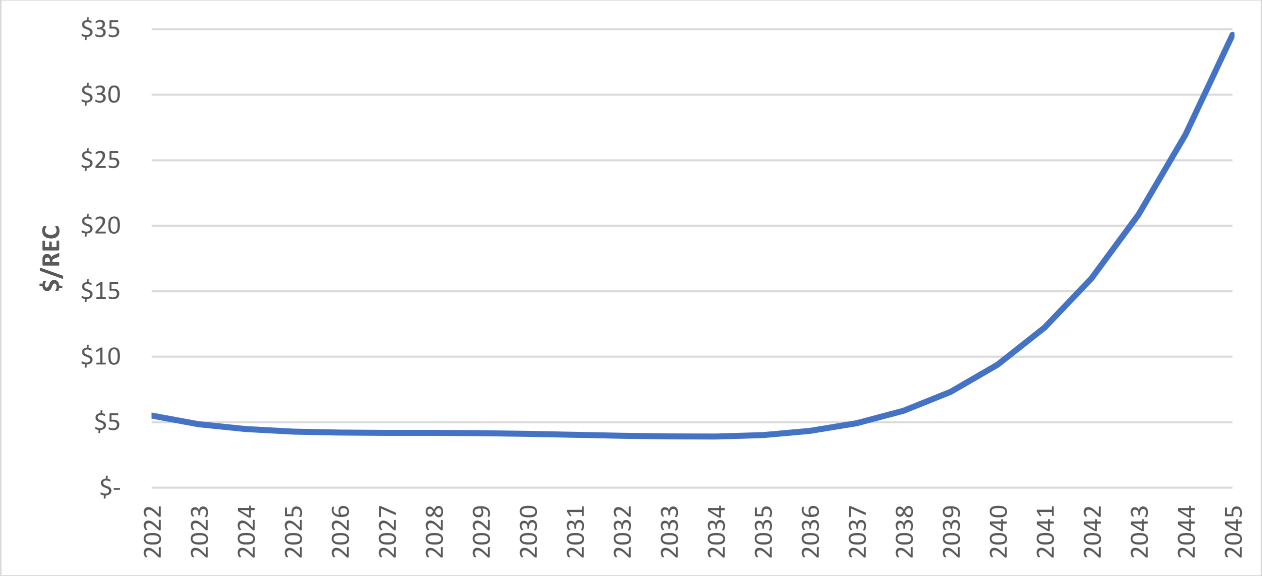
[55] BPA's Oversupply Management Protocol and Oversupply Rate can be found at https://www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx.

RECs was that the seller of the REC owns or contracts for the renewable resource and may have RECs surplus to their own compliance need or are trying to maximize revenue from the energy and REC streams for their project portfolio.

Today, the Northwest has a reasonably liquid bilateral market for unbundled RECs, with REC prices forecast for 2022 near $5.00 per REC for Washington EIA-eligible RECs. Various market forces have stratified the REC market and are projected to put downward pressure on RECs over time. More frequent use of alternative methodologies for meeting EIA RPS requirements, such as the 4% cost-cap mechanism and No-Load-Growth mechanism are creating intermittent surplus REC inventories. These surpluses push down the price of EIA-eligible RECs in real dollar terms. New state energy policies in neighboring states without near-term compliance thresholds serves as an additional supply accelerant. In order to model the average REC prices in the future, the 2021 IRP utilizes the Base Case wholesale market simulation across the WECC and solves for the average shadow price of compliance for all applicable state energy policies. This shadow price is then normalized to the current market price for RECs in the Washington State market. Figure 5-45 shows the REC market price forecast for 2022-2045.

Figure 5-45

REC Forecast ($/REC)



6 - Portfolios and Long-Term Resource Strategy

Previous sections of this 2021 IRP have described the load and resource characteristics of the PUD, the portfolio vulnerabilities, and the scenario-based approach the PUD has employed to understand risk factors. This analytical background provides the framework for portfolio evaluation and the identification of a long-term resource strategy.

The purpose of portfolio analysis is to identify the lowest cost resources to meet forecast portfolio needs, and to compare those results across scenarios. The PUD's integrated portfolio approach considers the cost and revenue implication of demand-side resources, supply-side resources, and market resources simultaneously as the algorithm optimizes portfolios to meet Planning Standard objectives.

Portfolio Development

All scenario portfolios are evaluated using the same portfolio optimization modeling framework. However, the inputs of each portfolio optimization are different and specific to each scenario.

The portfolio optimization model considers P50 (or expected) and P5 conditions for each scenario according to that scenario's unique load, generation, and load-resource-balance results.[56] The optimization model ensures sufficient resources are added to the portfolio to address needs defined by the Planning Standards while considering the expected costs and revenues under P50 conditions. In this way, the optimization model can be considered a simultaneous optimization of P50 and P5 conditions.

The optimization goal is the lowest incremental net cost of portfolio additions, expressed as a Net Present Value estimate in 2020 dollars. This means that the existing portfolio is treated as a sunk cost, and no resource retirements within the existing portfolio are considered. The incremental net cost includes the total costs and revenues of all new resource additions that occur within the study period.

[56] Section 5 details the Analytical Framework and Planning Standards and probabilistic approach to the PUD's existing/committed load resource balance, including the expected (average or P50) and adverse conditions (P5).

The generic optimization equation is given as:

Incremental Net Cost = Incremental Costs – Incremental Revenues

The following table details the components of evaluated incremental costs:

Cost Component	Description	Optimization Logic
Conservation Costs	Total Resource Cost of Conservation, as determined by CPA	Evaluates costs of various levels of conservation
Demand Response Costs	Total Resource Cost of Demand Response Programs, as determined by DRPA	Evaluates costs of various levels of demand response programs
Supply-Side Costs	Total Cost of Supply-Side Resources	Evaluates costs of combinations of supply-side resources
Dynamic Effect of Conservation on incremental BPA Block costs	Conservation lowers load and different levels of conservation create different forecast BPA Block allocations. This can result in a net cost or net benefit.	Apply conservation level to load forecast and calculate incremental effect on expected BPA costs
P50 Market Exposure	Expected forward market purchase costs under P50 conditions	Calculate any Load-Resource-Balance deficits after resource additions and apply market price forecast to volume of market purchases across appropriate time periods
P5 Market Exposure	Additional market purchases that would be expected under P5 conditions (worst 1 in 20).	Calculate any Load-Resource-Balance deficits after resource additions and apply market price forecast to volume of market purchases across appropriate time periods
REC Purchases	Expected REC purchases needed to fulfill EIA Renewable Portfolio Standards requirements or CETA requirements	Calculate balance of environmental attribute needs under applicable policy after new renewable resources are added and apply the REC market price forecast across appropriate time periods

The following table details the components of evaluated incremental revenues:

Revenue Component	Description	Optimization Logic
Incremental Wholesale Revenues	Expected additional market sales after new resource additions. This can occur if a resource additions made to satisfy a Planning standard requirement (P5 Monthly HLH needs in December for instance) creates an incremental surplus in another time period (P50 March HLH for example)	Calculate any Load-Resource-Balance surpluses after resource additions and apply market price forecast to volume of market purchases across appropriate time periods
REC Revenue	Expected additional REC sales after new resource additions. This can happen if conservation creates new surplus REC inventory, or if new renewables exceed regulatory needs in a time period.	Calculate surplus of environmental attribute needs under applicable policy after new renewable resources are added and apply the REC market price forecast across appropriate time periods
Dynamic Effect of Conservation on incremental BPA Block costs	Conservation lowers load and different levels of conservation create different forecast BPA Block allocations. This can result in a net cost or net cost savings, depending how much conservation was added relative to a baseline assumption before the optimization model ran. It was most often a net cost savings.	Apply conservation level to load forecast and calculate incremental effect on expected BPA costs

The portfolio optimization model uses a genetic algorithm[57] which seeks to identify the lowest incremental net portfolio cost by evaluating hundreds of thousands of possible combinations of resources to identify the best combination for each scenario. As the algorithm runs, it evaluates costs, revenues, and whether a resource combination satisfies Planning Standards (including regulatory requirements). Resource combinations that do not satisfy Planning Standards are rejected by the algorithm. The algorithm records the costs of each potential portfolio as it seeks continually lowest cost portfolios in a loop, stopping only when no significant improvements in net incremental portfolio costs can be found. A typical portfolio optimization for a given scenario takes roughly 30 minutes of computational runtime and returns the selected resources that compose the lowest incremental net cost portfolio along with all needed meta-information describing the costs, revenues, and attributes of the resulting portfolio.

Portfolio Results

The purpose of the portfolio optimization process is to understand the differences and commonalities of optimal portfolios across scenarios to inform the selection of a Long-Term Resource Strategy that incorporates cross-scenario risk factors.

[57] A genetic algorithm is a type of algorithm that relies on biologically inspired operators such as mutation, crossover, and selection as it evaluates a population of possible problem solutions to perform efficient search and optimization functions.

Those risk factors are discussed in detail Section 4 but are summarized in Figure 6-1 below.

Figure 6-1

Identified Risk Factors and Scenario Assignment

Risk	Scenario
Low Economic Growth, load, and wholesale market energy prices	Low Growth
High Economic Growth, load, and wholesale market energy prices	High Growth
High Rate of Electrification (including EVs and local policies requiring building electrification)	High Electrification
Less BPA resources available to the PUD (either through operational changes or the Post-2028 contract renegotiation process)	Less BPA
Higher rate of Climate Change	High Climate Change
Market Disruption due to Federal Policy changes, or proliferation of State energy Policy changes across WECC	High Policy
Market Disruption due to high penetration of Storage Resources across the WECC	High Technology

Total Net Portfolio Costs by Portfolio

The optimal portfolio for each scenario represents the lowest reasonable cost combination of resources that satisfy all established planning standards.

Figure 6-2 below denotes the ranking of the cases developed in the 2021 IRP analysis, by net portfolio cost NPV. The portfolios for the eight cases are denoted by their color-coded bars. The lowest cost portfolios have the lowest rates of load growth driving new resource additions, and a low-cost market price environment. The highest cost portfolios had higher load growth trajectories and higher-cost market price environments.

Figure 6-2

2021 IRP Incremental Net Portfolio Costs by Scenario

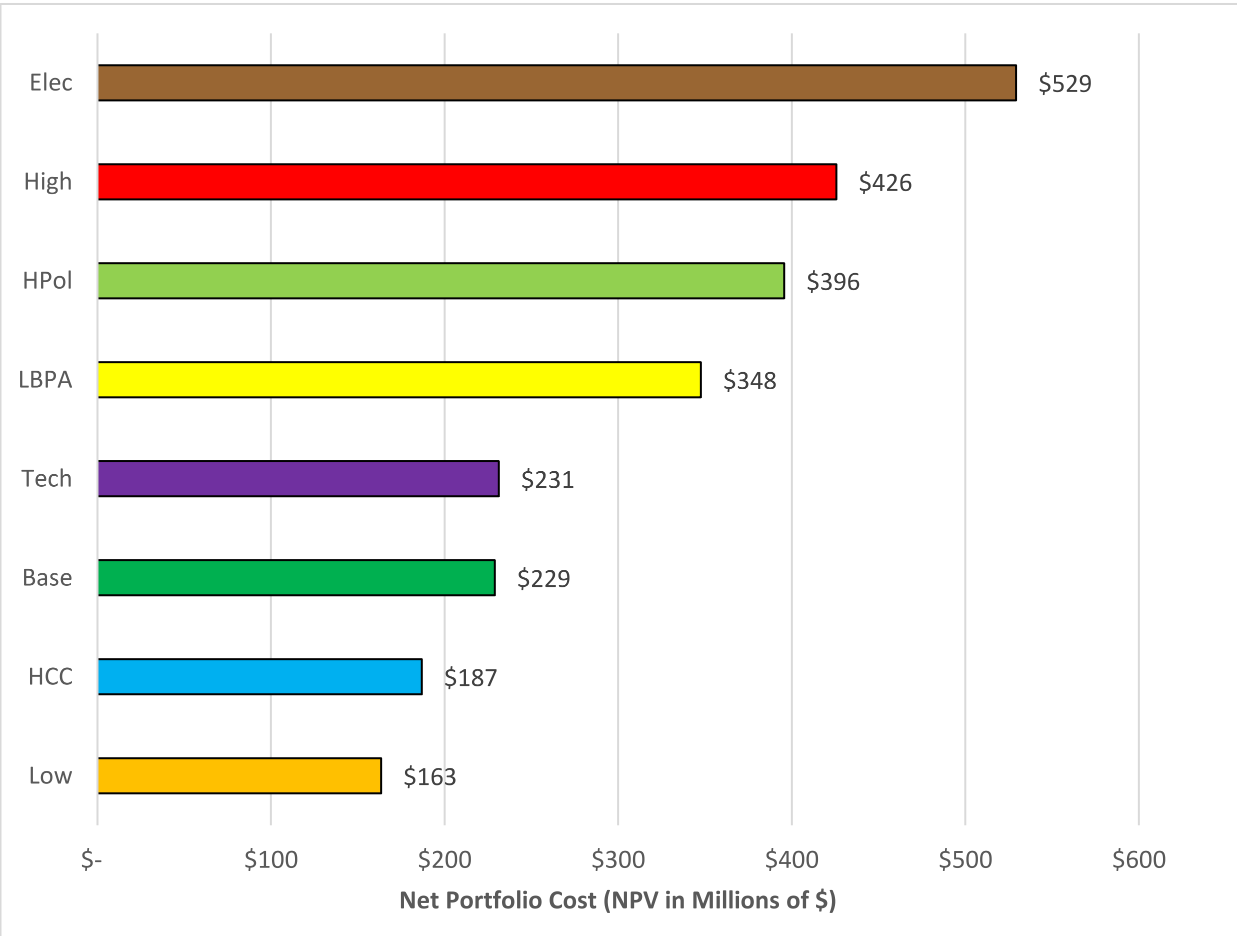
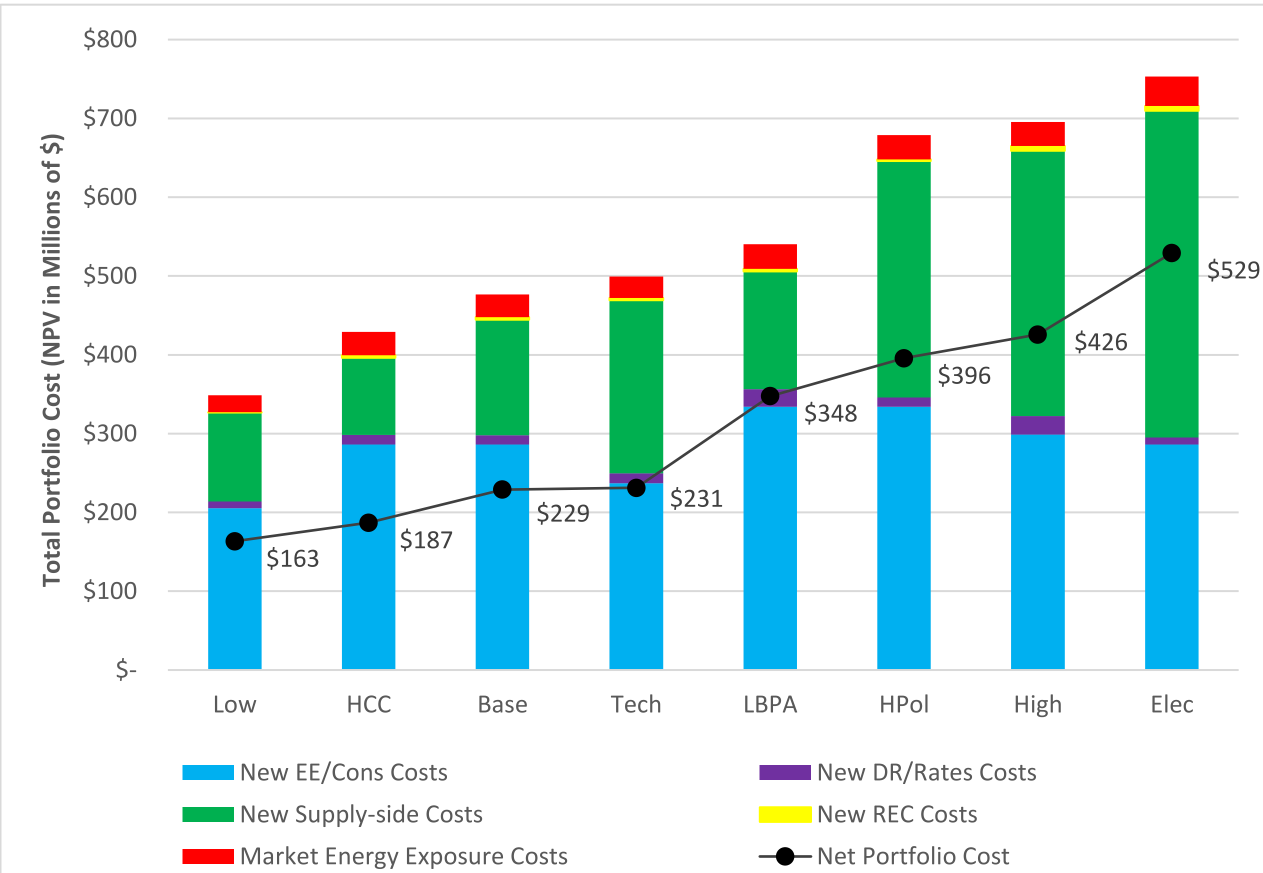


Figure 6-3 below illustrates the net present values (NPVs) of the total and net portfolio costs by scenario and component. Each scenario is represented by a stacked bar, visualizing the total NPV cost values for incremental demand-side and supply-side resource additions, market exposure, and new REC additions. The dotted line represents the net portfolio cost NPV. The net cost NPV incorporates portfolio revenues from surplus portfolio energy sales and REC sales over the study period.

Figure 6-3

NPV Cost Comparison of 2021 IRP Portfolios by Scenario – Total Cost v Net Cost



In general, costs are proportional to the scale of planned additions; conservation is typically the largest cost element, but it is accordingly the largest addition on an average annual MWh basis for most scenarios. It is important to understand the interplay between resource costs and magnitude of acquisition when analyzing model outputs.

Portfolio Resource Addition Comparisons

Despite a variety of underlying assumptions, optimal scenario portfolios shared many commonalities. This suggests that there are a number of actions available to the PUD that would work well in nearly every scenario studied.

These common elements include:

- **Market Capacity Product:** All portfolios identified an immediate need for a market capacity product to augment the PUD's portfolio in the winter for the period of 2022-2025. A market capacity product is a short-term contract the PUD could procure from the bilateral marketplace that would allow the PUD to call on a fixed amount of energy (25MW and 50MW were the two volumes identified in various scenarios) if the PUD was experiencing load pressure and needed the additional energy. The market capacity product is different than a market firm energy contract because a firm energy product is not callable, and the energy would be provided (and the PUD would need to pay for it) in every hour the contract covers. The PUD currently holds a market capacity contract and has for several years. In this way, the finding that a market capacity product is appropriate across scenarios is indicative that the PUD should continue current practice.

- **Conservation.** All scenarios identified a significant amount of conservation as cost-effective and a primary tool for the PUD to manage its portfolio. In addition, the range of conservation added across scenarios over the first 10 years of the study period was narrow, between 69aMW and 81aMW. Conservation provides a number of benefits that drive this finding. First, because energy savings often come in the hourly shape of Snohomish's load (that is, if a significant proportion of PUD load is at 5pm, the PUD would expect a significant amount of conservation would significantly reduce 5pm load), conservation helps reduce portfolio pressure in the hours most needed. Second, many conservation measures are low-cost, many of which can be added at below the wholesale market value of energy. Third, load reduction keeps the PUD within its BPA contractual allocation ceiling, which is based on load. If the PUD exceeds its BPA allocation, additional supply-side resources may be needed. Staying within the low-cost BPA contractual helps the PUD save money. Last, load reductions reduce regulatory compliance costs, which are generally based on retail load. For example, Washington State's Renewable Portfolio Standard under the Target Methodology is 15% of retail load. If that load is reduced by conservation, the cost to comply with the policy will also be reduced.

- **Demand Response.** All scenarios found a significant amount of demand response to be cost-effective with a narrow range of additions over the next 10 years. The range of additions falls between 25.1aMW and 38.4aMW as measured during Winter Peak. The central value proposition of demand response is its relatively low cost for the capacity contribution that it makes to the portfolio. The limitation of demand response is that the relatively low scale of achievable potential and the time required to develop the potential. New programs take some time to develop, and AMI will be required to enable some of the lowest cost programs. In all scenarios, demand response was a significant pillar of the new resource additions, and, in all cases, it needed to be augmented by other resources to reach the scale of the PUD's capacity needs.

- **Long-Duration Storage.** The most fundamental supply-side resource addition across scenarios was long-duration energy storage. Long-duration storage augments conservation and demand response and provides dispatchable capacity at scale to help with peak week needs, while mitigating seasonal energy needs as measured in monthly HLH aMW. The cost-effectiveness of the long-duration storage is driven by the price shape of the long-term market price forecasts. Those forecasts, across scenarios, show the potential for downward pressure on average prices, with increasing hourly price volatility. This means that a storage resource that can choose which hours to charge with, will have access to increasingly low prices in the "valleys" of the hourly price curve over time. Additionally, the long-duration storage option presumes a local siting, utilizing existing transmission service, and avoiding those incremental costs.

- **Local, Small Solar.** In a majority of scenarios, a small (5MW) local solar project is identified. The need for this addition is based upon climate change and clean energy policy. Climate change forecasts for load and hydrogeneration show an emerging summer energy need, which a local solar project could mitigate. In addition, local renewable projects just under 5MW qualify for a 2x multiplier in the volume of RECs it generates. This helps provide additional value as the RECs can help with intermittent regulatory requirement needs or be monetized in the REC market for additional revenue while the energy helps meet local needs

While scenario portfolios have a number of common elements, one notable difference is that some scenarios find significant renewable resource additions were needed. This occurred in the highest load cases (Electrification, High load Growth), lower resource portfolio size case (Less BPA), and in a market price environment with less hourly market price volatility (High Technology). The renewable resources added were generally Montana Wind (25 MW-75 MW nameplate) and Eastern Washington Solar (100 MW nameplate).

Figure 6-4 depicts resource additions across scenarios over the first 10 years of the study period.

Figure 6-4

Portfolio Additions in Years 1-10 Across Scenarios

	Market Contract (Nameplate MW)	**EE/Cons (Cumulative Annual aMW in Year 10)**	**8-hr Storage (Nameplate MW)**	**Local Small Solar (Nameplate MW)**	**Large Utility-scale Solar (Nameplate MW)**	**Wind (Nameplate MW)**	**DR/Rates (Cumulative Peak Week[58] aMW in Year 10)**
High Electrification	50	77	45	5	0	75	26.2
High Growth	50	78	35	0	50	25	38.1
High Policy	75	81	70	5	0	0	30.9
Less BPA	50	81	70	5	0	0	36.6
High Technology	25	73	45	5	0	50	38.4
Base Case	50	77	70	5	0	0	31.6
Low Growth Case	50	69	60	0	0	0	25.1
High Climate Change	25	77	50	0	0	0	32.2

[58] Peak Week is a planning period further explained in Section 5

Figure 6-4 describes resource additions across scenarios over all 24 years of the study period.

Figure 6-4

Summary of Portfolio Resource Additions by Scenario over Full Study Period

	Market (Nameplate MW)	EE/Cons (Annual aMW)	Energy Storage (Nameplate MW)	Local Solar (Nameplate MW)	Large Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (PW aMW)
Low	50	142	60	5	0	0	20
HCC	25	171	60	0	0	0	28
Base	50	171	70	5	0	0	27
Tech	25	149	70	5	0	50	33
LBPA	50	181	70	5	0	25	38
HPol	75	181	170	5	0	0	26
High	50	173	145	5	100	25	40
Elec	50	171	230	5	0	75	21

Scenario Portfolio Results Details

The following section details each scenario’s optimal portfolio and illustrates how the planned resource additions address the PUD’s future monthly HLH and PW needs throughout the full 2022 to 2045 study period and meet the PUD’s integrated resource planning standards on a P5 and P50 basis. Scenarios are presented in order of load growth trajectory, with the lowest load growth trajectories presented first.

Low Growth Case

Figure 6-5 summarizes the Low Growth Case resource additions for the 10-year and 24-year time periods.

Figure 6-5

	Market (Nameplate MW)	EE/Cons (Annual aMW)	Energy Storage (Nameplate MW)	Local Solar (Nameplate MW)	Large Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (PW aMW)
1st 10 Years	50	69	60	0	0	0	25.1
24-year Study Period	50	142	60	5	0	0	20

Figures 6-6 and 6-7 detail how portfolio resource additions in the Low Case address forecast monthly HLH and peak week deficits. Due to forecast low load growth and generally low resource need overall, new cumulative energy efficiency and conservation totaling 142 aMW is limited to the least expensive bundles priced at less than $45 per MWh. Short-term market contracts up to 50 MW address winter deficits until 8-hour energy storage is available as early as 2024, with up to 60 MW available by 2027. Demand response and rate programs help to meet winter deficits starting in the 2027 to 2028 winter season. This case also implements renewables in the form of a small 5 MW local solar PV farm on the tail end of the study period in 2045.

Figure 6-6

Low Case P5 HLH - Resource Additions and Resource Need

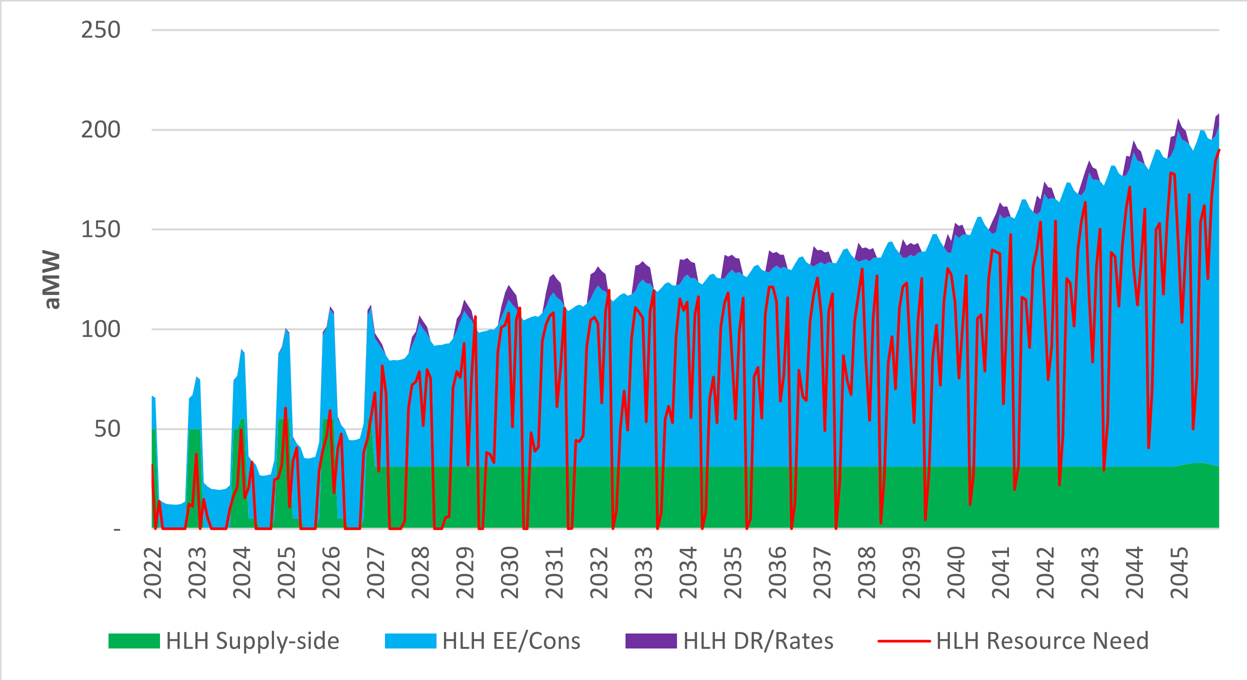
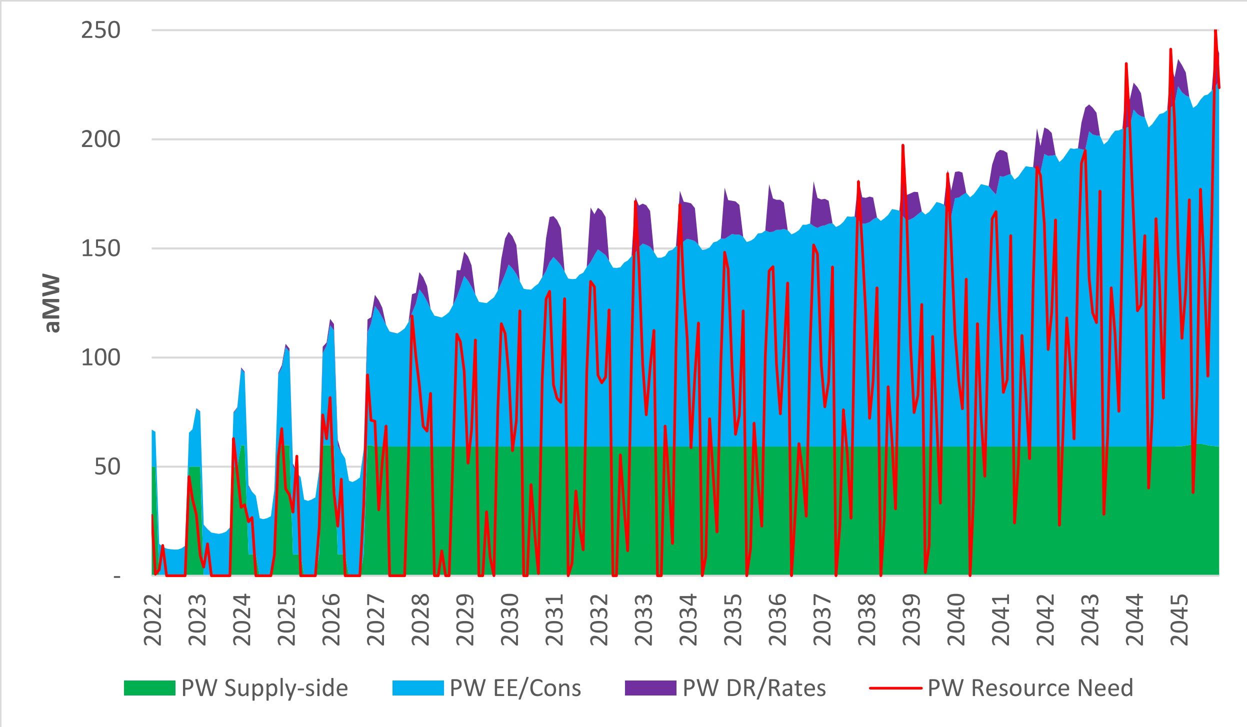


Figure 6-7

Low Case P5 PW - Resource Additions and Resource Need



High Climate Change (HCC) Case

Figure 6-8 summarizes the High Climate Change Case resource additions for the 10-year and 24-year time periods.

Figure 6-8

	Market (Nameplate MW)	**EE/Cons (Annual aMW)**	**Energy Storage (Nameplate MW)**	**Local Solar (Nameplate MW)**	**Large Solar (Nameplate MW)**	**Wind (Nameplate MW)**	**DR/Rates (PW aMW)**
1st 10 Years	25	77	50	0	0	0	32.2
24-year Study Period	25	171	60	0	0	0	28

Figures 6-9 and 6-10 detail how portfolio resource additions in the HCC Case to address forecast monthly HLH and PW deficits. This case assumes many of the same inputs as the Base Case, differing primarily in the acceleration of the effects of climate change.[59] New cumulative energy efficiency and conservation totaling 171 annual aMW are limited to bundles priced at less than $55 per MWh. Short-term market contracts of up to 25 MW are required to meet winter deficits until 50 MW of 8-hour energy storage is available in 2027. Demand response and rate programs help meet winter peak deficits starting early in the 2022 to 2023 winter season.

Effectively, existing resources in the HCC case will better serve forecast load, requiring fewer new additional resources when compared to other cases with moderate load growth such as the Base Case. HCC is also the only scenario that implements no additional supply-side resources other than 8-hour duration energy storage.

[59] HCC Case assumes existing hydroelectric resources are forecast to produce monthly outputs that are better fitting to meet forecast monthly load shape. This is due to modeled accelerated effects of climate change on regional hydrologic cycles.

Figure 6-9

HCC Case P5 HLH - Resource Additions and Resource Need

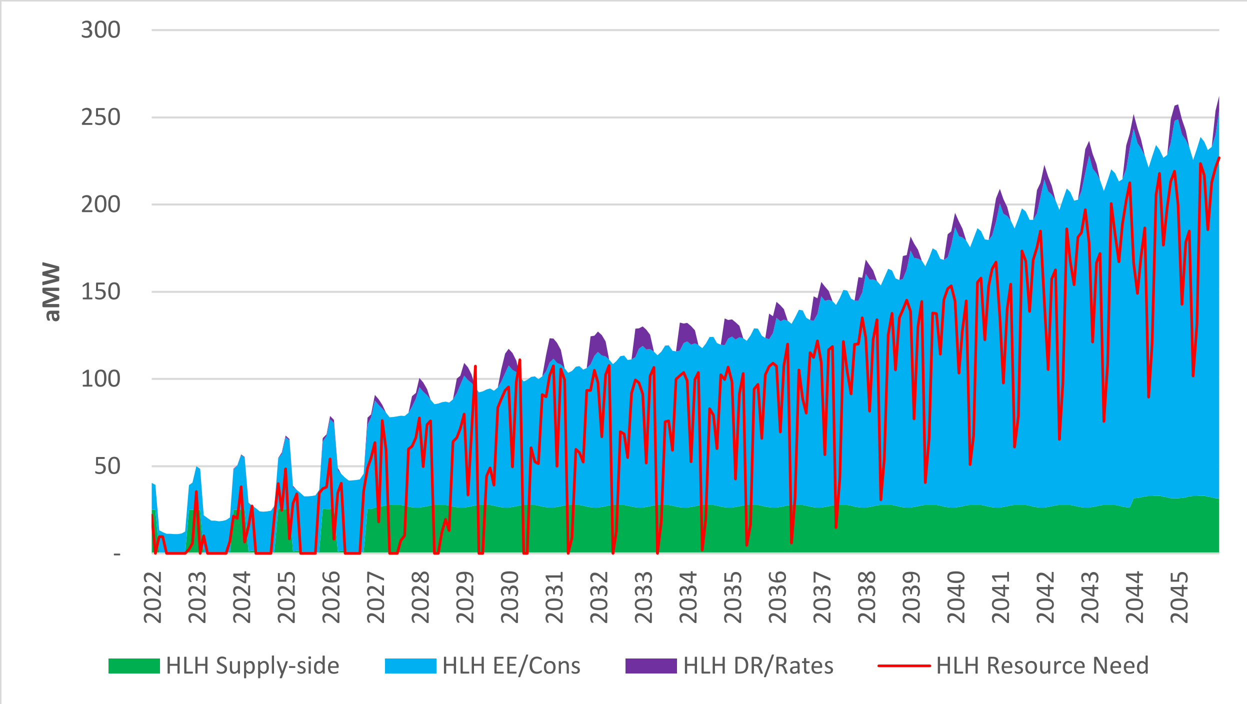
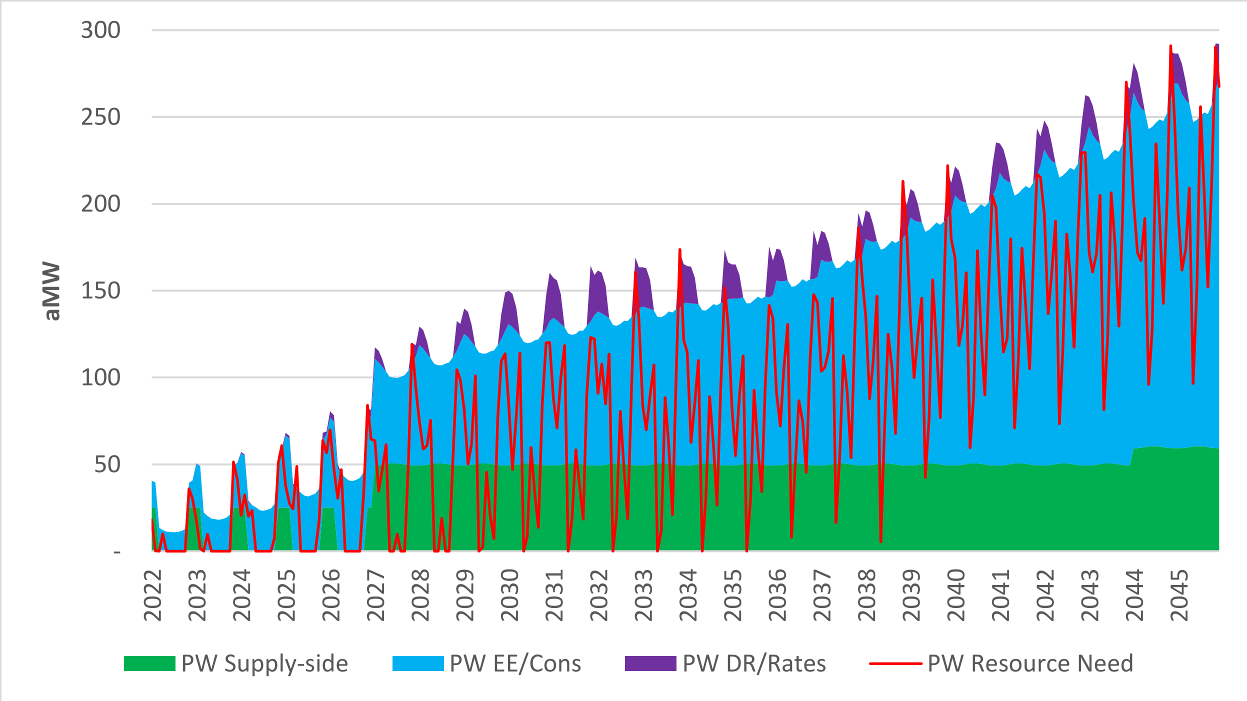


Figure 6-10

P5 PW - Resource Additions and Resource Need



Base Case

Figure 6-11 summarizes the Base Case resource additions for the 10-year and 24-year time periods.

Figure 6-11

	Market (Nameplate MW)	EE/Cons (Annual aMW)	Energy Storage (Nameplate MW)	Local Solar (Nameplate MW)	Large Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (PW aMW)
1st 10 Years	50	77	70	5	0	0	31.6
24-year Study Period	50	171	70	5	0	0	27

Figures 6-12 and 6-13 detail how portfolio resource additions in the Base Case address forecast monthly HLH and PW deficits. This case forecasts moderate load growth and moderate market energy prices. New cumulative energy efficiency totaling 171 annual aMW are limited to bundles priced at less than $55 per MWh. Short-term market contracts of up to 50 MW are required to address winter deficits until 8-hour energy storage comes online as early as 2024, up to 70 MW by 2029. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. This case also calls for new renewables in the form of a small local solar PV farm by 2029.

Figure 6-12

Base Case P5 HLH - Resource Additions and Resource Need

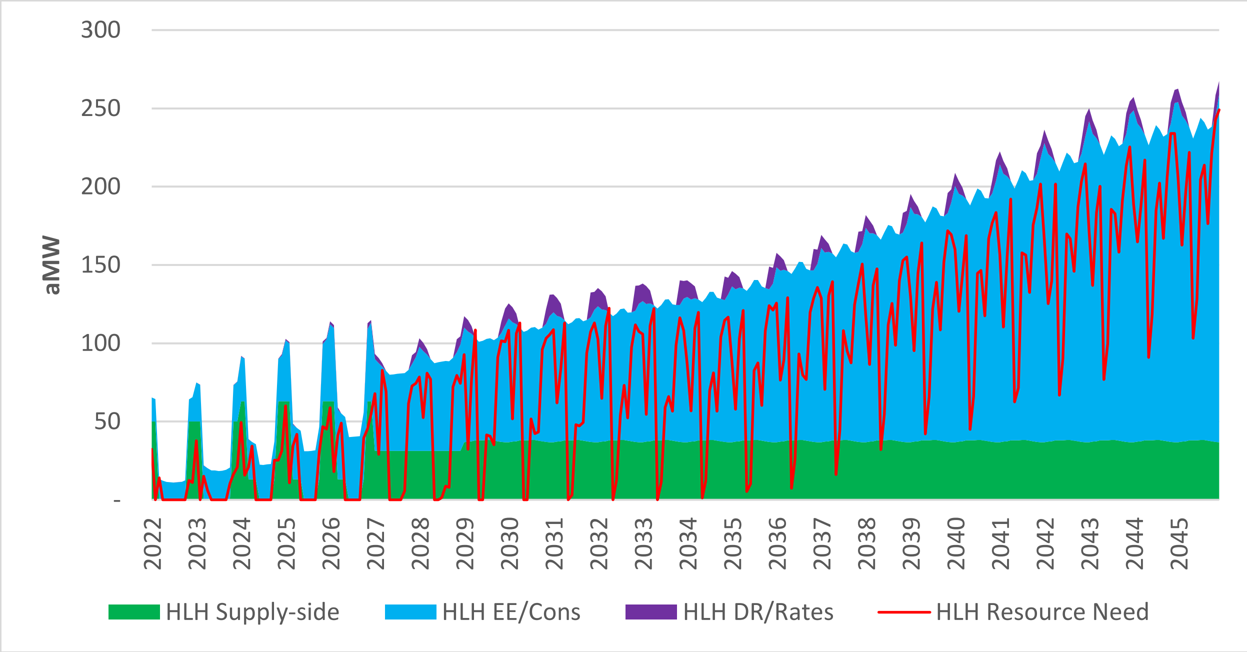
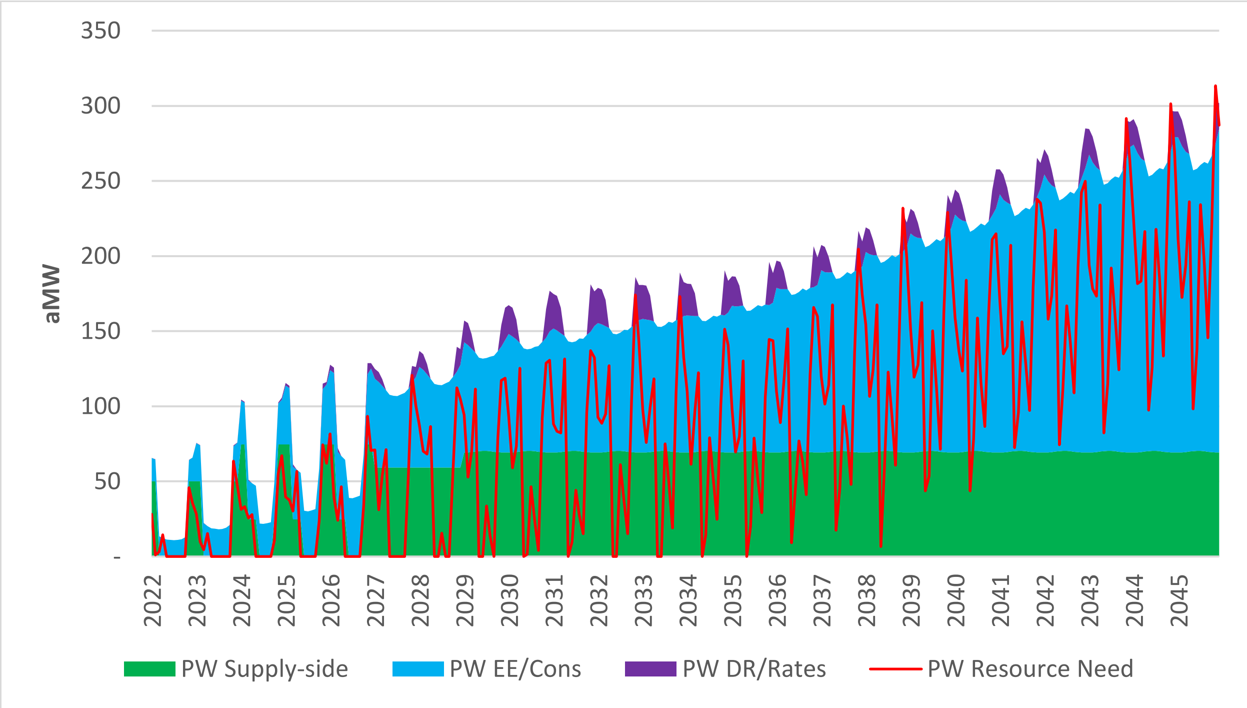


Figure 6-13

Base Case P5 PW - Resource Additions and Resource Need



High Technology (Tech) Case

Figure 6-14 summarizes the High Technology Case resource additions for the 10-year and 24-year time periods.

Figure 6-14

	Market (Nameplate MW)	**EE/Cons (Annual aMW)**	**Energy Storage (Nameplate MW)**	**Local Solar (Nameplate MW)**	**Large Solar (Nameplate MW)**	**Wind (Nameplate MW)**	**DR/Rates (PW aMW)**
1st 10 Years	25	73	45	5	0	50	38.4
24-year Study Period	25	149	70	5	0	50	33

Figures 6-15 and 6-16 detail how portfolio resource additions in the Tech Case address forecast monthly HLH and PW deficits. This case contains many of the same assumptions and forecasts as the base case but differs in two major inputs: market energy price projections[60] and demand response and rates programs.[61] New cumulative energy efficiency and conservation totaling 149 annual aMW are limited to annual bundles priced at less than $45 per MWh, and winter specific bundles priced at less than $65 per MWh. Short-term market contracts of up to 25 MW are required to cover winter deficits until 8-hour energy storage comes online as early as 2023, up to 70 MW by 2029. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. The Tech Case also implements utility-scale renewables in the form of a 50 MW Montana wind contract as early as 2027, and a small local solar PV farm by 2029.

[60] Tech Case assumes a very high capacity of regionally integrated energy storage, where market energy prices start out relatively inexpensive in 2022, but rapidly become expensive over the following years through the study period.
[61] Tech Case assumes a significantly faster availability and deployment of demand response and rates programs after the first year of the study period, but at a slightly increased cost.

Figure 6-15

Tech Case P5 HLH - Resource Additions and Resource Need

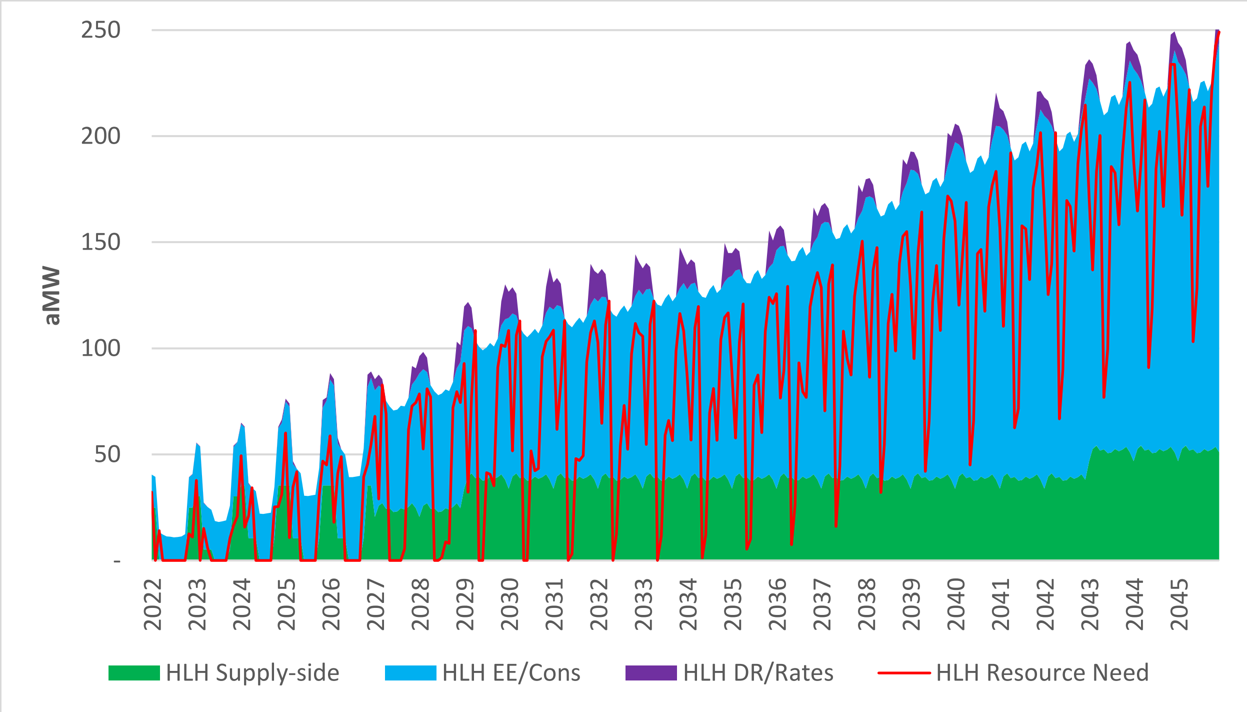
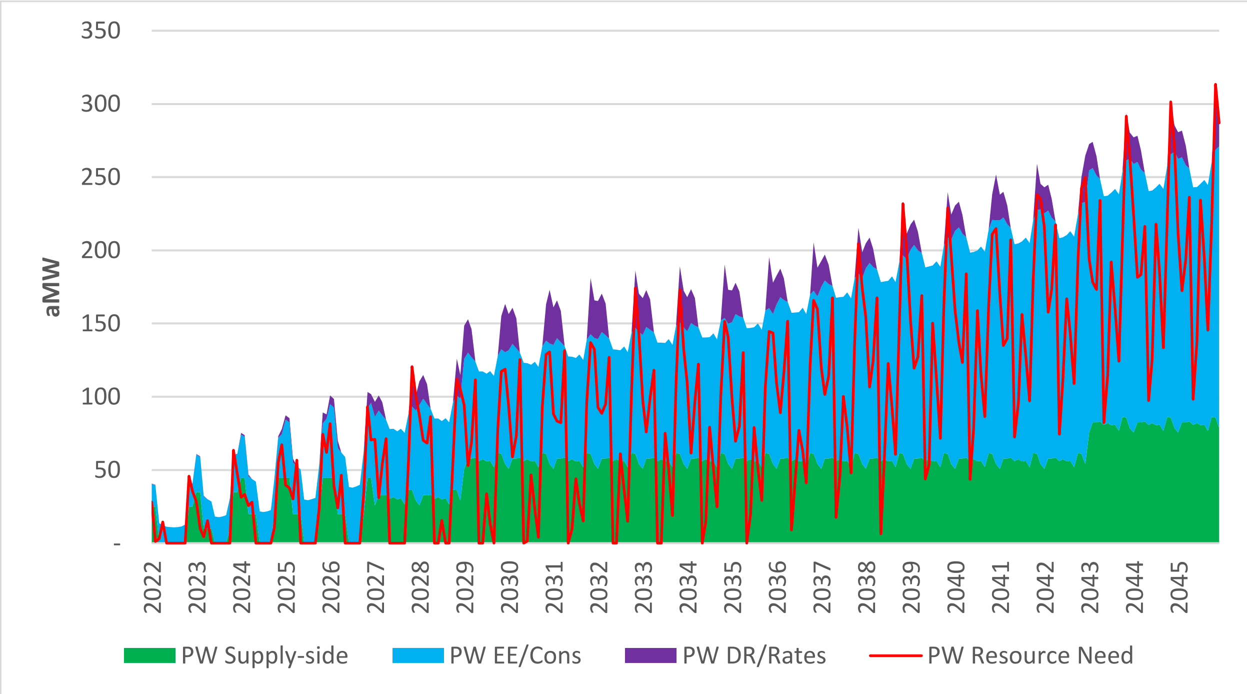


Figure 6-16

Tech Case P5 PW - Resource Additions and Resource Need



Less BPA (LBPA) Case

Figure 6-17 summarizes the Less BPA Case resource additions for the 10-year and 24-year time periods.

Figure 6-17

	Market (Nameplate MW)	**EE/Cons (Annual aMW)**	**Energy Storage (Nameplate MW)**	**Local Solar (Nameplate MW)**	**Large Solar (Nameplate MW)**	**Wind (Nameplate MW)**	**DR/Rates (PW aMW)**
1st 10 Years	50	81	70	5	0	0	36.6
24-year Study Period	50	181	70	5	0	25	38

Figures 6-18 and 6-19 detail how portfolio resource additions in the LBPA Case address forecast monthly HLH and PW deficits. This case relies upon many of the same assumptions and forecasts as the base case but differs in one major input. This differing major input is in the form of a steeper reduction in existing BPA product allocations starting 2029.[62] New cumulative energy efficiency and conservation totaling 181 annual aMW are limited to bundles priced at less than $65 per MWh. Short-term market contracts of up to 50 MW are required to address winter deficits until 8-hour energy storage is available as early as 2024, with up to 70 MW available by 2029. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. The LBPA case also implements utility-scale renewables in the form of a 50 MW Montana wind contract in the final year of the study period, and a small local solar PV farm by 2029.

LBPA Case results are nearly identical to the Base Case, except that in order to compensate for the steeper reduction of BPA product allocation, the portfolio implements more demand-side resources and must utilize more expensive bundles to do so.

[62] LBPA Case assumes a further reduction in existing BPA product allocation starting 2029, amounting to an additional 40 annual aMW reduction by 2035.

Figure 6-18

LBPA Case P5 HLH - Resource Additions and Resource Need

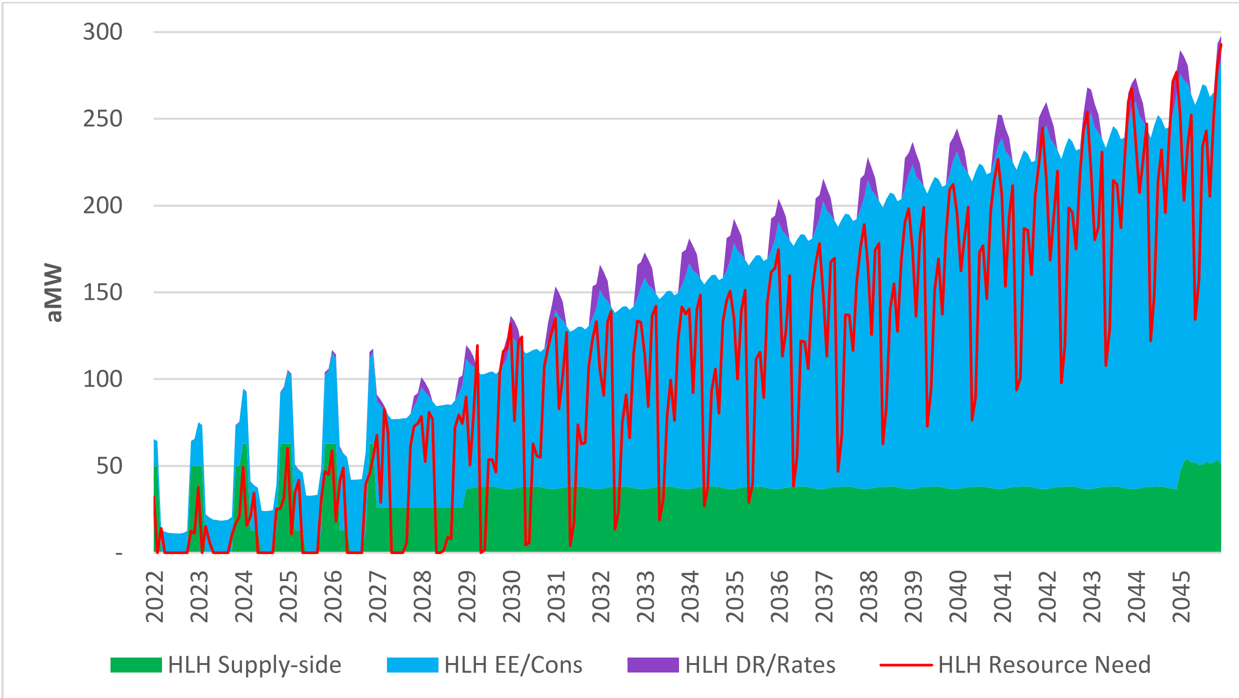
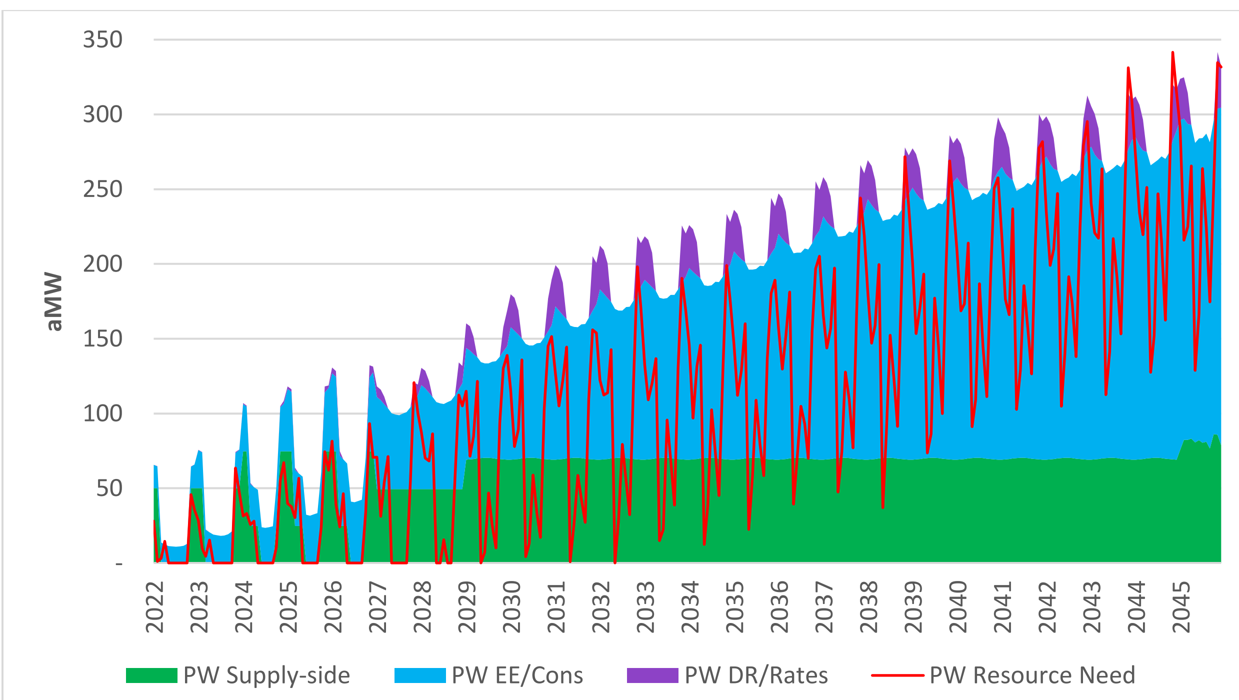


Figure 6-19

LBPA Case P5 PW - Resource Additions and Resource Need



High Policy (HPol) Case

Figure 6-20 summarizes the High Policy Case resource additions for the 10-year and 24-year time periods.

Figure 6-20

	Market (Nameplate MW)	EE/Cons (Annual aMW)	Energy Storage (Nameplate MW)	Local Solar (Nameplate MW)	Large Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (PW aMW)
1st 10 Years	75	81	70	5	0	0	30.9
24-year Study Period	75	181	170	5	0	0	26

Figures 6-21 and 6-22 detail how portfolio resource additions in the HPol Case address forecast monthly HLH and PW deficits. This case deviates from the Base Case market assumptions and forecasts.[63] New cumulative energy efficiency and conservation totaling 181 annual aMW are limited to bundles priced at less than $65 per MWh. Short-term market contracts of up to 75 MW are required to meet winter deficits until 8-hour energy storage is available as early as 2027, with up to 70 MW available by 2037. Additional high-capacity energy storage is needed in the form of 100 MW of 12-hour duration pumped hydro by 2041. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. The HPol case also implements utility-scale renewables in the form of a 25 MW Montana wind contract early in 2023, and a small local solar PV farm by 2029.

The HPol Case presents a unique market energy pricing environment mixed with an increased rate of electric vehicle penetration into said market. This environment requires significant investment in both demand and supply-side resources early in the study period. The incremental increase of customer-owned solar PV is outweighed by the incremental load increase from EVs, particularly during the winter season. Toward the end of the study period peak load increases due

[63] HPol case assumes increased rate of EV penetration, increased penetration rate of customer-owned solar PV, and substantially different and unique market energy price forecasts due to an assumption of a very low capacity of carbon emitting resources throughout the Western Interconnection.

to EVs is substantial, requiring additional investment in high capacity dispatchable resources such as pumped hydro storage.

Figure 6-21

HPol Case P5 HLH - Resource Additions and Resource Need

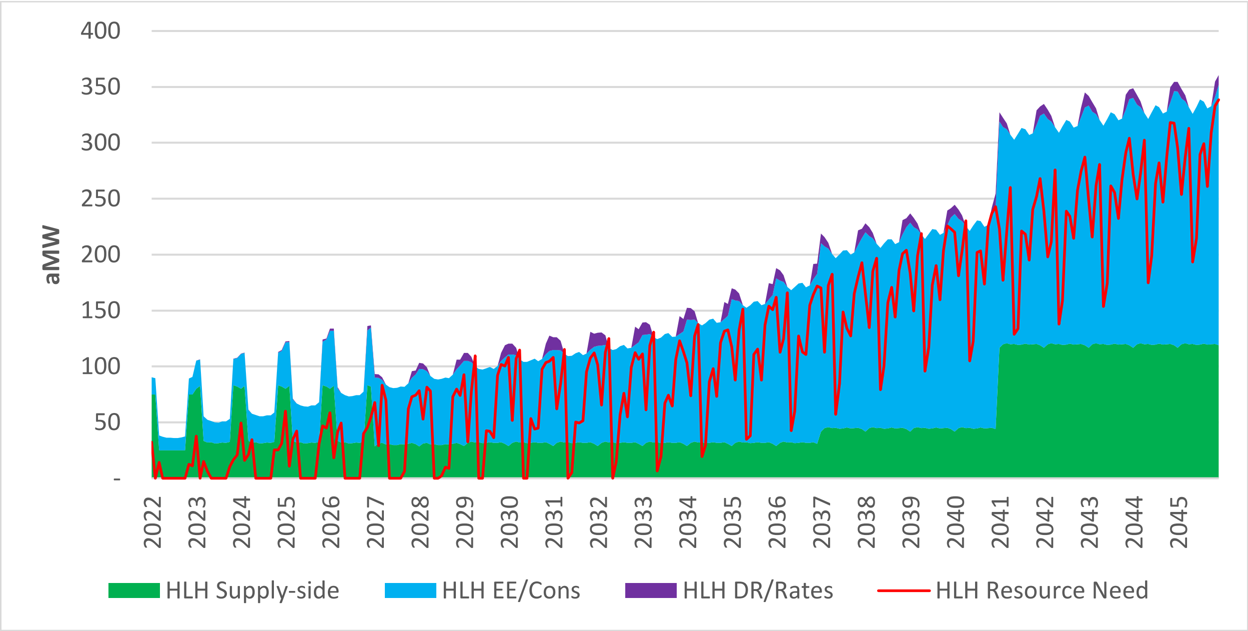
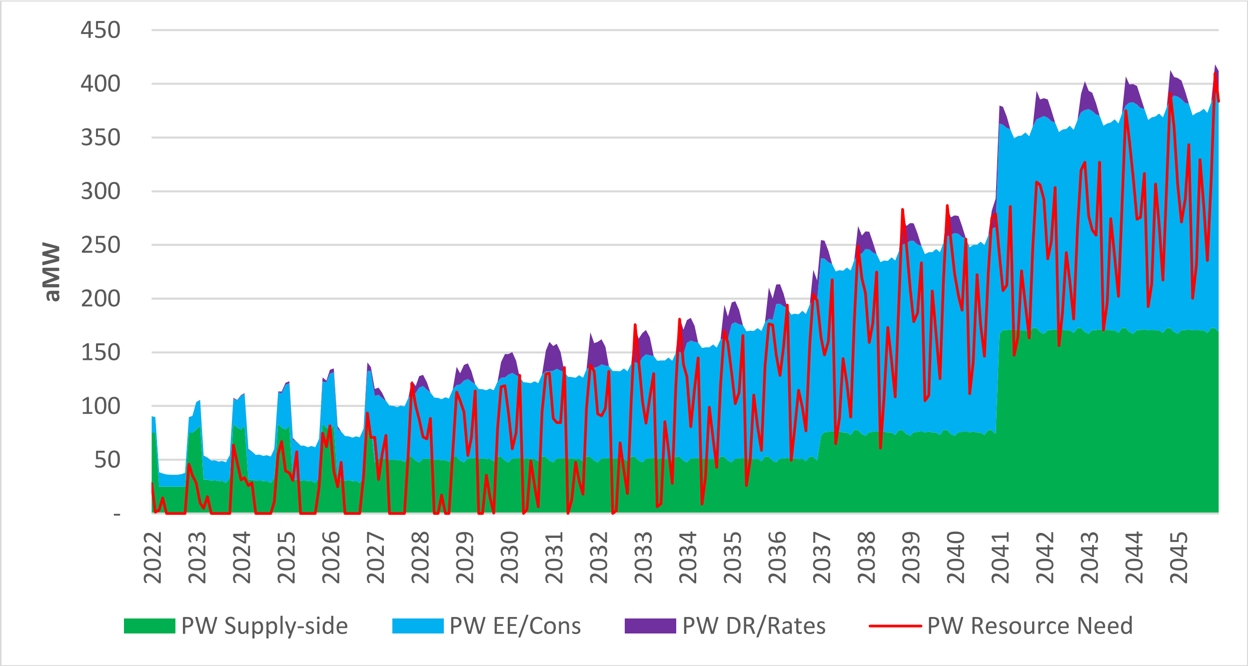


Figure 6-22

HPol Case P5 PW - Resource Additions and Resource Need



High Growth Case

Figure 6-23 summarizes the High Growth Case resource additions for the 10-year and 24-year time periods.

Figure 6-23

	Market (Nameplate MW)	EE/Cons (Annual aMW)	Energy Storage (Nameplate MW)	Local Solar (Nameplate MW)	Large Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (PW aMW)
1st 10 Years	50	78	35	0	50	25	38.1
24-year Study Period	50	173	145	5	100	25	40

Figures 6-24 and 6-25 detail how portfolio resource additions in the High Growth Case address forecast monthly HLH and PW deficits. This case forecasts high load growth and high market energy prices. New cumulative energy efficiency and conservation totaling 173 annual aMW are limited to annual bundles priced at less than $55 per MWh, and winter specific bundles priced at less than $65 per MWh. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. Short-term market contracts of up to 50 MW are required to address winter deficits until 8-hour energy storage is available as early as 2027. Due to forecast high peak load growth, additional energy storage is needed. This storage is multi-duration and high capacity including pumped hydro by 2037, totaling 165 MW by 2043. The High case also implements utility-scale renewables in the form of a 25 MW Montana wind contract by 2027, and a small local solar PV installation by 2041. The High case is also the only case to implement 50 MW of large utility-scale solar PV as early as 2029, scaling up to 100 MW with a higher inverter load ratio by 2045.[64]

The High Growth Case requires significant additional capacity from new resources to meet its higher load trend, relying less on the market due to high forecasted prices. This means acquiring

[64] See Section 5: Analytical Framework, for more discussion on how inverter load ratios were treated in the 2021 IRP.

more PUD-owned or PUD-contracted long-term resources, in addition to more expensive bundles of demand-side resources.

Figure 6-24

High Growth Case P5 HLH - Resource Additions and Resource Need

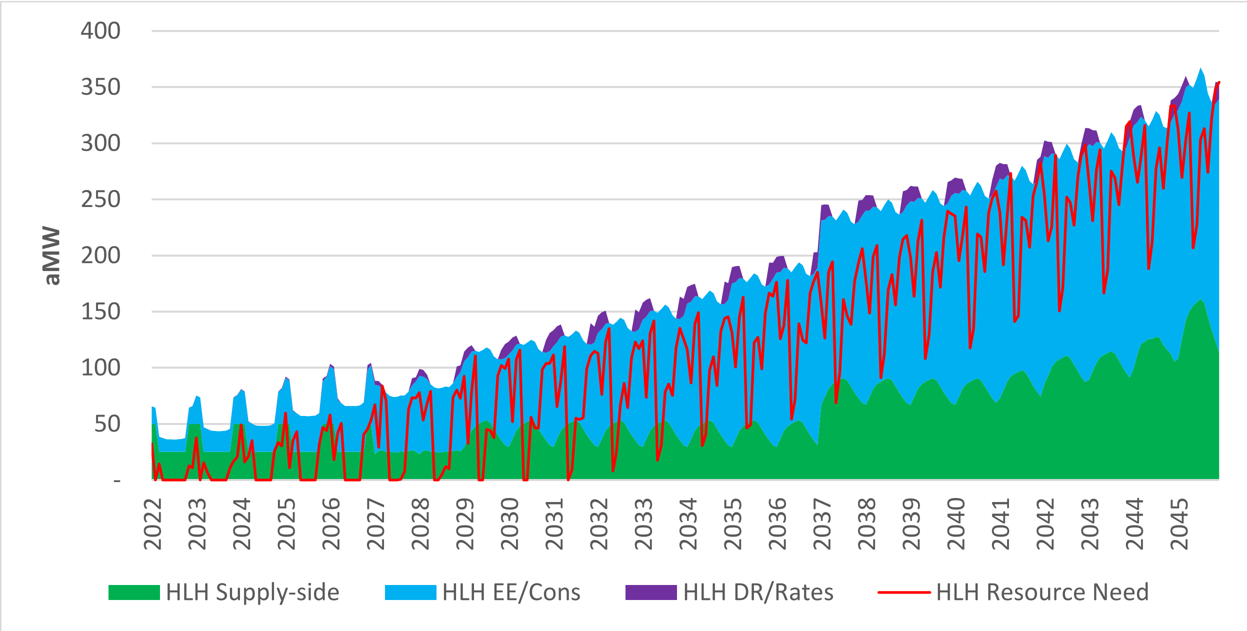
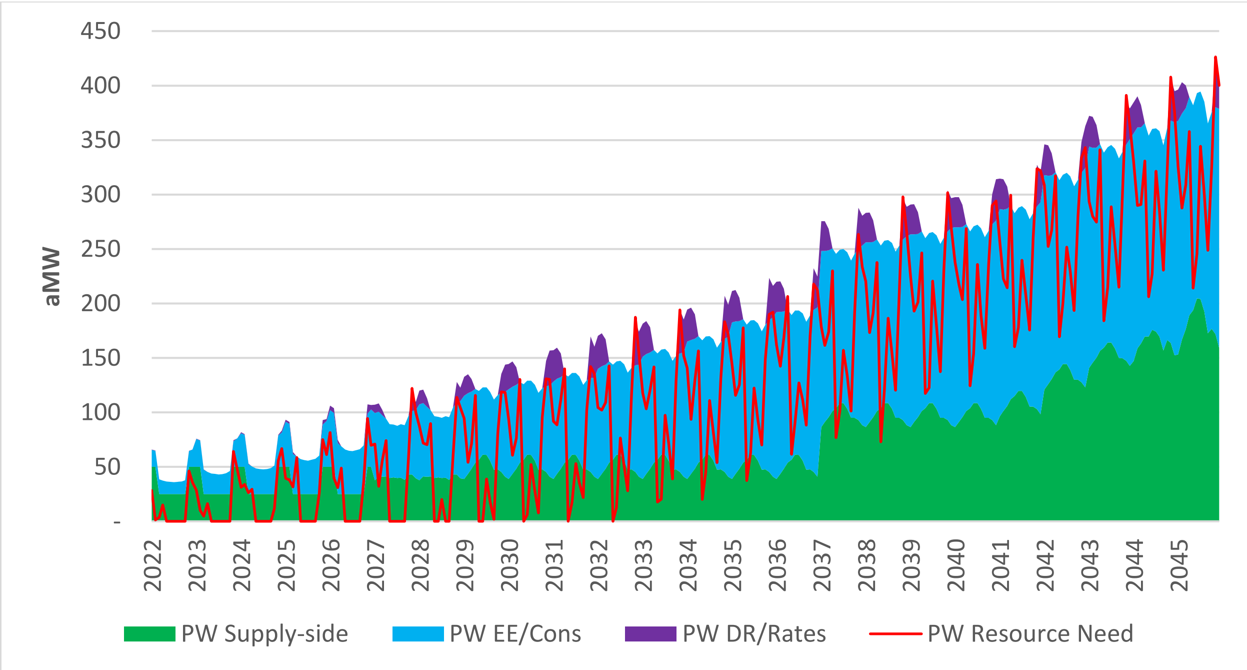


Figure 6-25

High Growth Case P5 PW - Resource Additions and Resource Need



High Electrification (Elec) Case

Figure 6-26 summarizes the High Electrification Case resource additions for the 10-year and 24-year time periods.

Figure 6-26

	Market (Nameplate MW)	**EE/Cons (Annual aMW)**	**Energy Storage (Nameplate MW)**	**Local Solar (Nameplate MW)**	**Large Solar (Nameplate MW)**	**Wind (Nameplate MW)**	**DR/Rates (PW aMW)**
1st 10 Years	50	77	45	5	0	75	26.2
24-year Study Period	50	171	230	5	0	75	21

Figures 6-27 and 6-28 detail how portfolio resource additions in the Elec Case address forecast monthly HLH and PW deficits. This case forecasts moderate market energy prices and a uniquely high rate of load growth beyond that of the High Case due to large scale electrification of the PUD's service territory. New cumulative energy efficiency and conservation totaling 171 annual aMW are limited to bundles priced at less than $55 per MWh. Demand response and rate programs help meet winter peak deficits starting in the 2027 to 2028 winter season. Short-term market contracts of up to 50 MW are required to address near-term winter deficits until 8-hour energy storage is available as early as 2024, scaling up to 70 MW by 2036. Due to high forecast peak load growth, more energy storage is implemented. This storage is multi-duration and high capacity, including 150 MW of pumped hydro by 2041 and totaling 230 MW by 2045. This case also implements utility-scale renewables in the form of a 75 MW Montana wind contract by 2027 and a small local solar PV farm by 2029.

The Elec Case implements the most supply-side resources out of any case due to electrification's effect on load growth. When compared to other cases, Demand-side resources, while effective overall, are relatively less effective in serving the Elec case load shape. This means in addition to moderately priced demand-side resources, more PUD-owned or PUD-contracted long-term resources are implemented, particularly those able to serve peak load such as storage.

Figure 6-27

Elec Case P5 HLH - Resource Additions and Resource Need

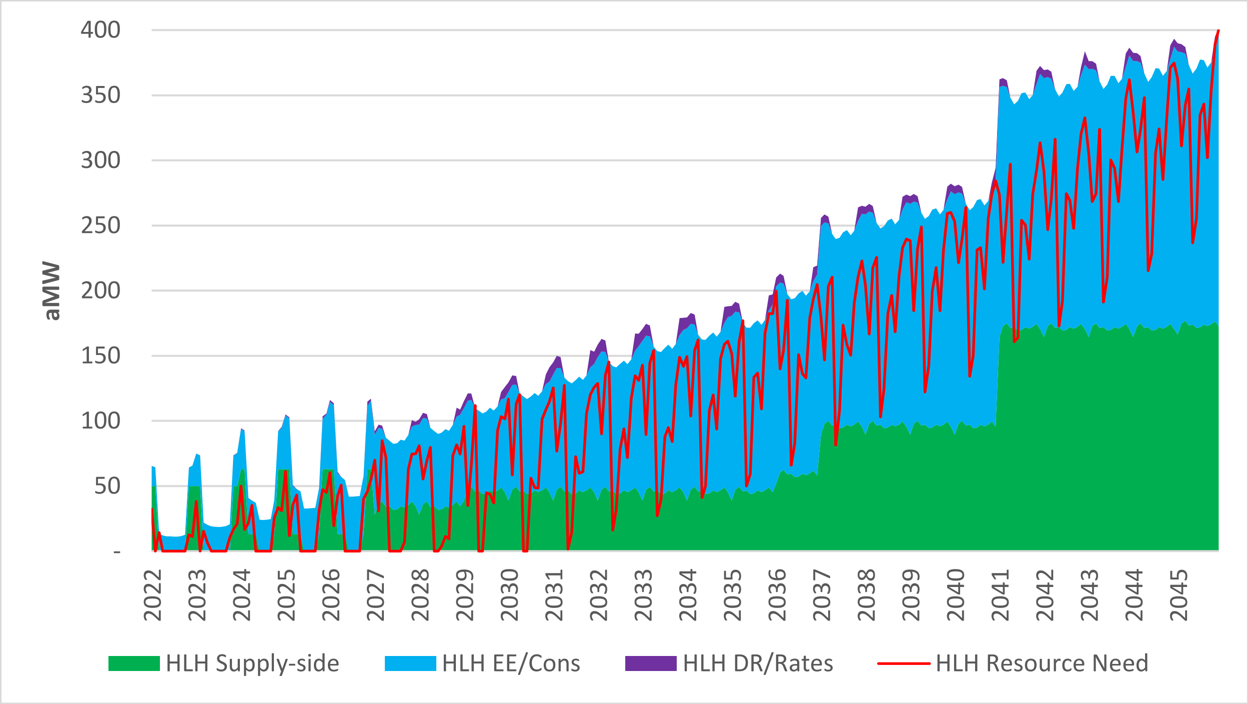
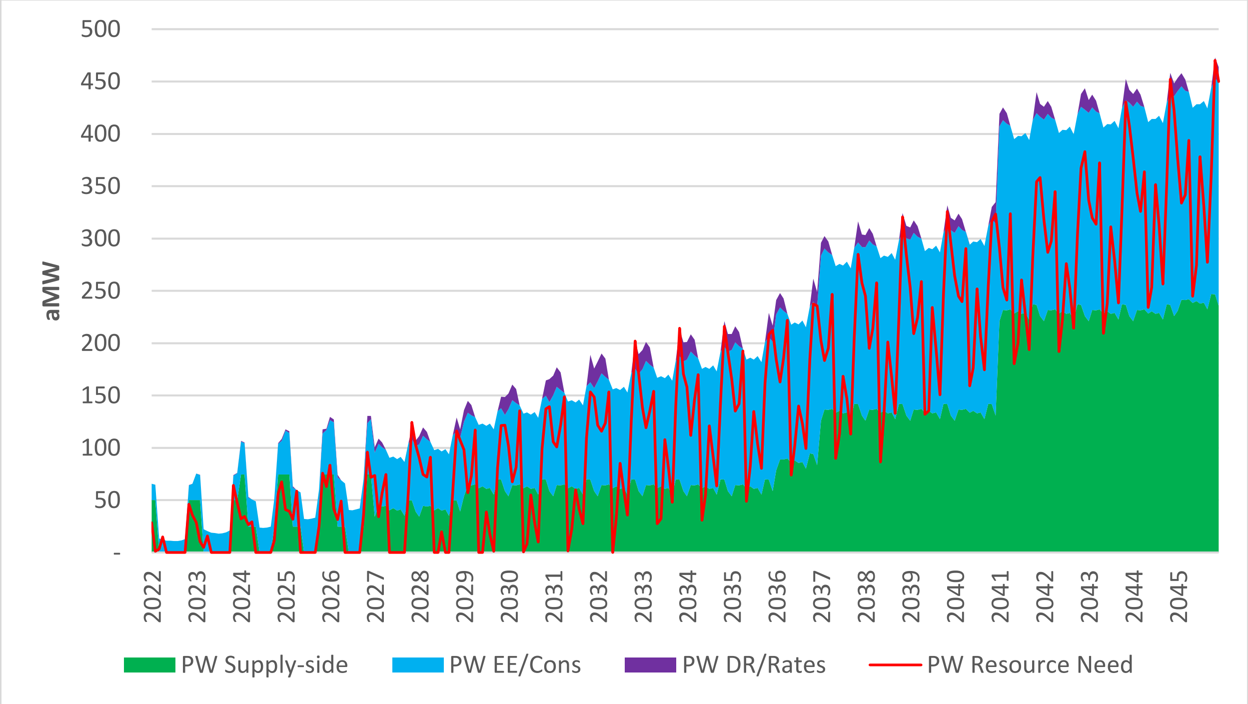


Figure 6-28

Elec Case P5 PW - Resource Additions and Resource Need



Determination of the Long-Term Resource Strategy

The PUD's approach to determining a long-term resource strategy is to utilize the totality of information learned across scenarios studied to choose a specific scenario upon which to base the long-term resource strategy. This selection is based on how well the selected scenario balances both needs and portfolio additions when compared to other scenarios. In many cases, the Base Case (or Expected Case) satisfies this condition, as many of its dimensions reflect the mid-point of several other scenarios.

This approach has not always been utilized in historic IRPs. In the 2017 IRP, which was the first PUD IRP to model climate change impacts upon load and hydrology, the Climate Change scenario was used as the basis of the long-term resource strategy as it better reflected the long-term needs of the PUD relative to the Base Case, which did not contain climate change impacts.

The 2021 IRP proposes to use the Base Case scenario as the basis for the Long-Term Resource strategy. This recommendation is based on the uncertainty surrounding forecasts at this particular time in the Northwest, and the similarity of observed results across portfolios. These two dimensions are explored further below:

- **Forecast uncertainty.** While every IRP contains a degree of forecast uncertainty, the 2021 IRP was produced during a pandemic, and the speed, strength, and shape of economic recovery in Snohomish County will be particularly difficult to predict. Rather than apply a specific weighted guess in one direction (such as the High Case or Low Case), the Base Case takes a neutral position on what could happen next.

- **Scenario Result Similarity.** Despite uncertainty across scenarios, there is not a significant deviation of resource additions across scenarios, particularly in the first 10 years. This similarity in outcomes across scenarios suggests that the Base Case scenario portfolio additions will also serve other scenario environments well. The causality of this similarity is the nature of the BPA contract.

The BPA contractual allocation decreases under lower loads and increases under higher loads, until the contract reaches its maximum contractual allocation. Resources added in the first 10 years such as conservation generally help lower loads and extend the BPA contractual limit over a prolonged period of time. These resources also help meet regulatory requirements or help mitigate existing capacity needs. These planned investments over the next 10 years are beneficial to the PUD under any scenario.

The Base Case forecast also contains many variables identified by stakeholders in the 2021 IRP visioning process and reflects a reasonably holistic measurement of the operating environment. These elements include (but are not limited to):

- Forecasted climate change impacts on load and hydrology;
- Consideration of changes in the local economic environment;
- The impact of state policies on the wholesale market;
- Forecast electric vehicle adoption, and;
- Forecast customer-owned solar adoption

There are no variables identified or not included in the Base Case that would warrant rejection of the Base Case as the basis for the Long-Term Resource Strategy.

Proposed Long-Term Resource Strategy

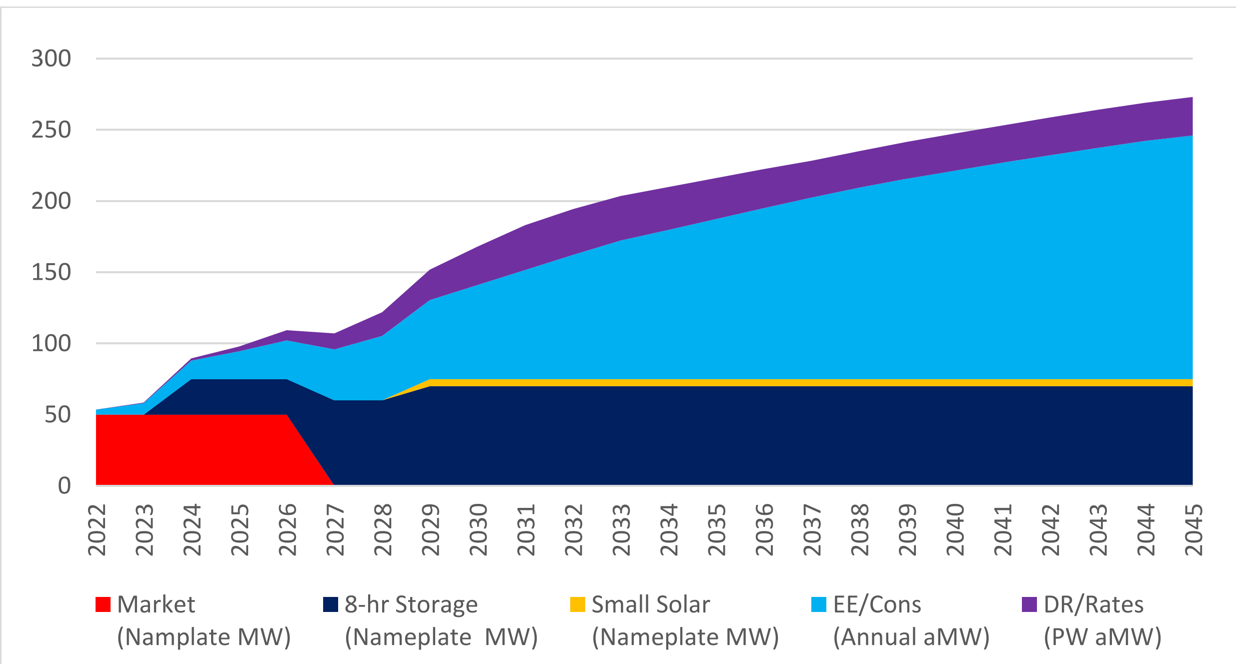
The proposed Long-Term Resource Strategy for the 2021 IRP is based on the Base Case scenario and contains the resources identified through economic optimization to be most cost-effective while satisfying all relevant planning standards, including regulatory requirements. The 2021 IRP uses a 24-year study period, and the Long-Term Resource Strategy provides a vision for the resources that would be added across that time period. The 2021 Long-Term Resource Strategy will set the biennial conservation target for 2022 & 2023, provide the applicable targets for 2022-2025 for the 2021 Clean Energy Implementation Plan, and the 2022-2031 forecast for the 2021 Clean Energy Action Plan.

While the Long-Term Resource strategy anticipates future resource development, it is not a binding proposal through time as state law requires the PUD to update and publish IRP's every two years. These updates will evolve and amend the PUDs vision for the future and may suggest more efficient or cost-effective methods or actions based on the forecast environment at that time.

Figure 6-29 depicts the Long-Term Resource Strategy resource additions across the 24-year study-period. As illustrated, the strategy utilizes a short-term market capacity contract to add 50MW of winter capacity over the first five years of the study period. In addition, the strategy “grows” conservation and demand response cumulatively to 171 annual aMW and 27 Winter Peak Week aMW respectively. The strategy also calls for the PUD to add 25MW nameplate of 8-hour duration storage in the first five years of the study period and grow that total to 70MW nameplate by 2029. Finally, the strategy finds that 5MW nameplate of local utility-scale solar added in 2029 would help the PUD meet future needs.

Figure 6-29

Base Case Portfolio Additions



The PUD's Long-Term Resource Strategy is summarized below at the time periods the PUD will report for the biennial conservation target (2022-2023, cumulatively), CEIP (2022-2025), and CEAP (2022-2031).

Figure 6-30

Long-Term Resource Strategy Targets

	2023 (2-year)	2025 (4-year)	2031 (10-year)
Conservation (Cumulative Annual aMW)	7.96	19.35	76.59
Demand Response (Cumulative Peak Week aMW)	0.6	3.6	31.6
Market Capacity Product (Nameplate MW)	50	50	0
Long-Duration Energy Storage (Nameplate MW)	0	25	70
Small Local Solar (Nameplate MW)	0	0	5
Renewable Energy Certificates (Cumulative MWh)	0	0	969,873

Risk Analysis of the Long-Term Resource Strategy

With regard to the Long-Term Resource Strategy, the 2021 IRP considers a cross-section of pertinent risks to ensure the strategy is appropriately positioned to address additional risks not captured explicitly in the portfolio economic optimization model. The 2021 IRP finds that the Long-Term Resource strategy is reasonably able to address these future risks and as a result remains the recommended course of action for the PUD.

Revenue Support Risk

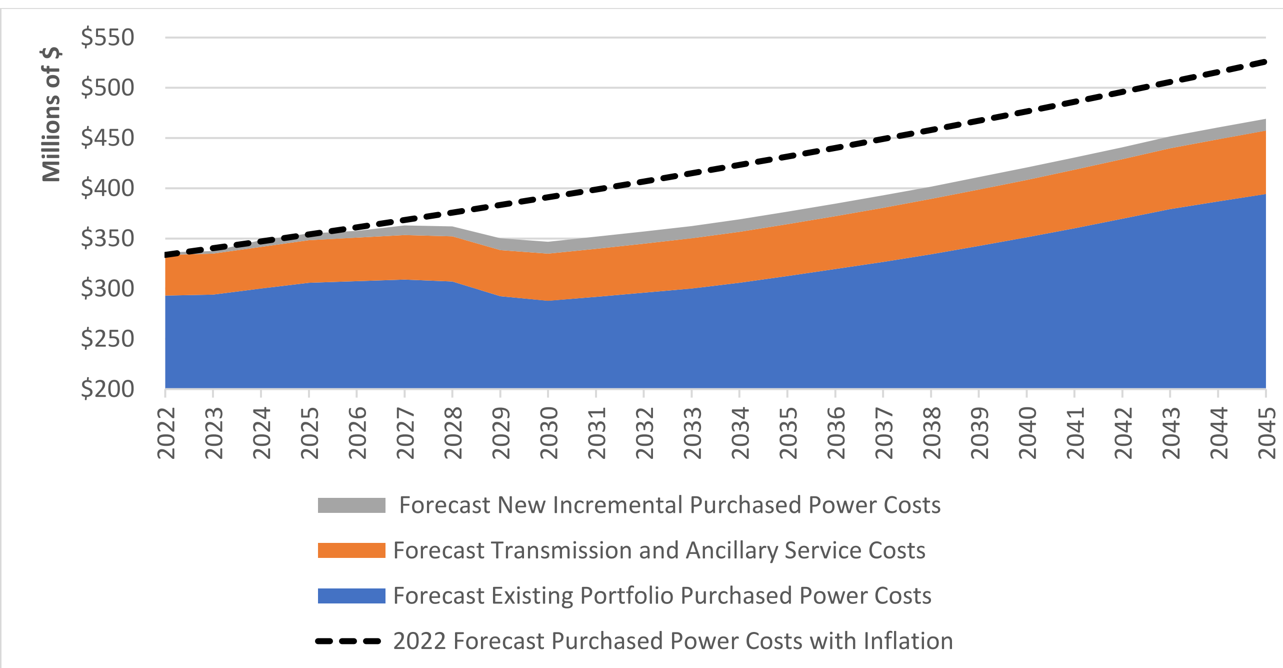
A fundamental question for any plan is its affordability. To address this question, identified resources from the Long-Term Resource Strategy are imported into a forecast of the PUD's Purchased Power forecast for the existing portfolio. One fundamental change to PUD's forecasted Purchased Power is that the PUD's current wind contracts are set to expire beginning in 2024 and ending in 2029. As a result, although there is some inflationary pressure on that forecast, there are also structural decreases that can be expected.

Figure 6-31 shows the resulting forecast Purchased Power forecast for the PUD with existing resources and those supply-side resources identified in the 2021 IRP. Near-term costs are expected to be within the rate of inflation, but as wind contracts retire and a new market environment and BPA contract evolve, long-term Purchased Power costs are forecasted to stay relatively flat and under the rate of inflation.

This forecast capital outlay assumes that new fixed asset costs can be amortized over their useful life and would have a higher concentration of near-term costs under different financial assumptions. This forecast does not account for demand-side resource acquisition such as conservation and demand-response. Utility conservation costs may be a net-savings relative to the present due to forecast acquisition volumes, though the PUD may also seek to keep conservation funding at similar levels to serve harder-to-reach customers. Many Demand Response costs may be considered sunk costs of AMI and are difficult to forecast at this point in the AMI planning effort. In summary, forecast changes to PUD Purchased Power Costs appear to be within reason, and suggest the Long-Term Resource Strategy is affordable to implement.

Figure 6-31

Long-Term Resource Strategy Targets



Post-2028 BPA Contract Risk

The PUD's long-term power contract with BPA is set to expire in 2028, and the PUD's Long-Term Resource strategy must help the PUD meet its customer's needs amidst that uncertainty. This uncertainty is addressed through assumptions of reduced Federal System Size and associated BPA allocations across scenarios.

To test the robustness of the Long-Term Resource strategy, the Base Case was also considered with an assumption that the Federal System Size and PUD allocation of BPA resources will be held constant. The results were similar to the standard Base Case scenario. Figure 6-32 compares the 10-year results of both versions of the Base Case scenario.

Figure 6-32

Portfolio Additions in Years 1-10 Across Scenarios

	Market Contract (Nameplate MW)	EE/Cons (Cumulative Annual aMW in Year 10)	8-hr Storage (Nameplate MW)	Local Small Solar (Nameplate MW)	Large Utility-scale Solar (Nameplate MW)	Wind (Nameplate MW)	DR/Rates (Cumulative Peak Week[65] aMW in Year 10)
Base Case	50	77	70	5	0	0	31.6
Base Case [NO BPA CHANGES]	50	73	70	0	0	0	30.1

As part of this risk evaluation, the PUD consulted with BPA to establish whether and how planned resource additions from the Long-Term Resource Strategy would impact billing determinants if the PUD were to utilize different BPA power products. This high-level analysis is reflective of the limited information about Post-2028 products available at the time of the study period. Rather than evaluate which product is the best fit, this study evaluates whether planned investments would still "work" or provide cost-savings under other BPA product options. It is envisioned that the 2023 IRP will include more analysis on Post-2028 BPA product switching as more information becomes available.

[65] Peak Week is a planning period further explained in Section 5

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This would add value in all scenarios by reducing load and extending the PUD's BPA allocation as modeled under any BPA product.

- **Demand Response.** Under the Load Following or Block product, demand response programs that shift from the on-peak hours to off-peak hours would add value. Hourly load shifts between hours in the On-Peak period would not add significant value due to the billing structure of these products. This may mean a demand response program would need to be restructured should the PUD change BPA products Post-2028.

- **Long-Duration Storage.** This resource likely to add significant value under all products. An in-service-territory resource may be treated as a net load increase which would increase the BPA allocation for the PUD. The ability to shift significant load from On-Peak to Off-Peak periods could add unique value under other product types. An indicative estimate that considers a programmatic use of a 50MW long-duration storage resource to reduce peak load and shift on-peak (HLH) load to off-peak (LLH) hours, could result in around $1.5 million in annual savings under a BPA Load-Following Product (at BP-22 prices) relative to no action. An indicative estimate that considers programmatic use of a 50MW long-duration storage resource to reduce peak load and shift on-peak load to off-peak hours could result in approximately $1.5 million in annual savings under a BPA Load-Following Product (at BP-22 prices) relative to no action. This cost-savings figure may vary should elements of the Post-2028 contract structure change.

- **Small, Local Solar (5MW).** Due to the nature of the product and contract, small local solar may not add significant value under a Load Following Product but would add value under a Block or Slice product contract.

Policy Risk

In a rapidly transforming electricity industry, it is important for a Long-Term Resource Strategy to both comply with the laws of today and to consider the potential for future policies impact upon the PUD's portfolio and regulatory costs. To provide a risk analysis around this topic, the 2021 IRP assesses how resource choices may be impacted by clean energy and carbon policy changes over time.

Clean Energy Policy

CETA, a guiding energy policy in Washington State, is currently establishing the rules by which it will regulate utilities. Several key policy questions remain unanswered in that rulemaking. The 2021 IRP was designed to ensure the PUD was compliant with CETA based upon the statutory language and established rules.

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This resource will reduce load and CETA compliance targets for clean energy, making them easier to attain.

- **Demand Response.** This resource helps the PUD stretch its portfolio of renewable resources, helping the PUD achieve clean energy targets.

- **Long-Duration Storage.** This resource can store the PUD's renewable resource generation in periods it is surplus to demand and redeploy that generation in periods the PUD has higher demand, helping the PUD achieve clean energy targets.

- **Small, Local Solar (5MW).** This renewable resource would directly contribute to clean energy targets.

Carbon Policy

Passed in 2021, Washington's Climate Commitment Act (CCA) provides the foundation for carbon policy in Washington state through a Cap-and-Invest program, but the time of this writing the CCA has not yet begun its rulemaking process in earnest. At a high level, because the legislature considers CETA to be the guiding statute regarding carbon emissions for utilities, the CCA allows electrical utilities an emissions allowance based on historical emissions and seeks to add no new costs to utilities unless they significantly exceed the allowance compared to their historical emissions.

Current expectations are that the impact of CETA on the emissions content of the wholesale market is likely to minimize risk that the PUD would exceed its allowance, though this is subject to the designed implementation of the program through rulemaking. The PUD's principal risks of carbon emissions exposure are from PUD market purchases and market purchases made by BPA and embedded in a BPA contract, though this may be addressed in the Post-2028 BPA contract.

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This resource will reduce load and need for market energy purchases.
- **Demand Response.** This resource helps the PUD stretch its portfolio of renewable resources, helping the PUD avoid market purchases.
- **Long-Duration Storage.** This resource can store the PUD's renewable resource generation in periods they are surplus to demand and redeploy them in periods the PUD has higher demand, helping the PUD avoid market purchases.
- **Small, Local Solar (5MW).** This renewable resource would generate clean energy and help the PUD avoid market purchases.

Future Market Risk

Regional organizations, utilities, and regulatory entities have increased discussion of developing organized markets in the Pacific Northwest, and across the Western United States. These markets may include additional options for serving load, marketing energy, and economically dispatching resources across the broader grid. There is a potential risk that the relative values of different resource types would vary under a future organized market as compared to the current bilateral market. This could occur because some resource types are challenging or less economic to dispatch within a future market structure, or because market rules may not fully recognize the value of all resource attributes. Because of uncertainty around whether future markets may develop and what form they may take, the IRP considers these risks at a high level:

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This resource would act as a load modifier, and not a market resource. It would be unaffected by a future market.

- **Demand Response.** There are a variety of forms of demand response programs, some of which may not be eligible for direct participation in organized markets, potentially limiting this resource’s market value in that context. However, most or all demand response programs would likely retain their value through local deployment as a modifier to load. In addition, many demand response programs can be phased in or phased out, allowing the PUD to phase out programs that are no longer economic.

- **Long-Duration Storage.** This resource would likely to be eligible to participate in a wide variety of potential future markets. There is potential that this resource could particularly benefit from an organized day-ahead market where it is more common for resources to bid into specific hours of value in a day-ahead schedule. Storage could have more value in a future market compared to the current regional market.

- **Small, Local Solar (5MW).** This resource is a must-run resource without an ability to react or respond to price signals in a future market. The generation profile of this resource is not likely to generate energy in particularly valuable hours. However, summer energy prices are typically elevated relative to spring and fall, and organized markets also have the potential to provide more economic balancing services for variable resources such as solar. Overall, the market structure may not have a substantial impact on this resource's overall value. The small scale of this resource limits its total nominal risk.

Transmission Risk

The PUD's transmission portfolio, which is held via contract from BPA has defined limits and significant resource additions outside of the service territory will come with additional transmission expense and scheduling. The financial costs of new transmission for resources outside of the service territory is added to the full cost of resource ownership as a consideration in the economic optimization model.

Physical transmission risk also considers the availability of the transmission line to bring energy into the PUD's service territory. While full power flow models can be run to quantify this risk, no resource additions outside the PUD's service territory were found to be economic.

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This resource reduces load reduction inside the service territory, reducing pressure on the existing transmission portfolio to bring resource generation to the PUD to serve load.

- **Demand Response.** This resource shifts load inside the service territory from peak hours to lower load hours, reducing pressure on the existing transmission portfolio to bring resource generation to the PUD to serve load during high-demand periods.

- **Long-Duration Storage.** This resource utilizes the existing transmission portfolio to bring in resource generation in low-load hours, and redeploy it in higher load hours, reducing pressure on the existing transmission portfolio to bring resource generation to the PUD to serve load.

- **Small, Local Solar (5MW).** This resource would be sited within the service territory and considers utilization of the PUD distribution system, rather than the transmission portfolio.

Resource Adequacy Risk

As the Western Resource Adequacy Program (WRAP) continues to be developed, a preliminary design offers insights, but not conclusions, about how future resource will be treated for resource adequacy (RA) purposes[66]. In general, resources that contribute to how the PUD's portfolio would be evaluated in the WRAP may help the PUD reduce costs associated with compliance with program rules and provide opportunities for the PUD to market some program specific resource adequacy sharing products.

The following narrative description represents considerations for the Long-Term Resource Strategy resource additions.

- **Conservation.** This resource reduces load, and helps the PUD reduce its RA requirement

- **Demand Response.** This resource can act either as a load modifier, or, if dispatchable over a significant number of hours, a resource in the WRAP. The contribution of demand response programs is highly dependent upon the design of the developed programs. It is not expected that Demand Response would reduce RA requirements on a 1:1 basis of expected peak hour reductions.

[66] More information about the WRAP can be found at: https://www.nwpp.org/

- **Long-Duration Storage.** This resource is subject to Qualified Capacity Contribution program designs. 8-hour duration dispatchable storage resources get credit for 100% of nameplate for the summer period and 96% of nameplate for the winter period in the preliminary design materials (with additional consideration for forced outage rates). This resource would be a significant resource in the WRAP.

- **Small, Local Solar (5MW).** This resource would be subject to Effective Load Carrying Capability analysis in the WRAP. For solar resources, it is anticipated that these values will be determined by geographic zone, and ultimately speak to the confidence level that the resource would generate during regional capacity critical hours (those hours the region may be most likely to experience a loss-of-load event). It is not anticipated this resource would make a meaningful contribution to winter period resource adequacy periods, but the resource may make a contribution to summer period resource adequacy requirements. This resource is not considered a significant resource adequacy resource.

Risk Analysis Conclusion

While the pandemic provides a planning background with unprecedented uncertainty, the framework of the IRP, and the supplemental risk analysis provided in this section provides additional assurance that the Long-Term Resource Strategy is appropriate as a basis for the PUD to plan for resource additions.

7 - Key Insights and Action Plan

A central finding of the 2021 integrated resource plan is a significant portfolio need under adverse conditions that warrants significant actions be taken by the PUD over the next ten years. Substantial forecast on-peak energy and peak week capacity deficits under adverse weather conditions for all eight case portfolios in this IRP are indicative that relying only on market resources to augment the existing portfolio and meet these measured needs may place the PUD at a heightened financial risk should that market prove expensive.

The 2021 IRP analysis identified the following causalities of these seasonal energy and capacity needs:

1. Limitations inherent in the existing portfolio; several owned and contracted resources are limited in their ability to be dispatched up and down, hour to hour, and within an hour.

2. The PUD forecasts growing loads under the Base Case, with significant potential for additional load due to potential changes in electric vehicle adoption and building electrification; and

3. The PUD's portfolio is expected to shrink over time, due to significant wind contract retirements, and historical trends of reduced effective generation capacity of the federal system contracted for through BPA.

While this is the central insight from the 2021 IRP, the totality of the analysis also provides insights into new opportunities, how the PUD can meet future challenges, and how risks presented themselves across scenarios. The following sub-section collects these "key insights" from the 2021 IRP.

Key Insights from the 2021 IRP

1) **The PUD is well-positioned for CETA compliance. No PUD-owned or operated carbon emitting resources are needed now or in any of the potential futures analyzed.**
   While the PUD's current and forecast capacity deficits could be solved with thermal resources such as a natural gas facility, analysis finds it more economical to meet these capacity shortfalls with non-emitting resources including conservation, demand response, and energy storage. An analysis of using thermal resources to meet capacity needs in the Base Case instead of energy storage forecast an increase the net present value cost of the portfolio by approximately twenty million dollars; an approximate 9% increase. This analysis did not include the significant risk of future policies increasing the cost of operating thermal resources.

2) **Short-term market contracts and purchases should serve primarily as a bridge to meet forecast resource-load gaps until demand and supply-side resources come online to fill those gaps.**
   Long-term resources and demand-side programs take time to construct, develop, and implement. Procuring firm market products in advance of need, and in advance of a seasonal wholesale trading horizon can help the PUD mitigate portfolio needs and serve as a bridge until additional conservation and demand-response can be developed, and a long-duration storage resource can be built or acquired.

3) **Cost effective conservation continues to provide the PUD with significant value.**
   Conservation has been a consistently sound investment for the PUD for several decades. The analysis from this IRP cycle confirms this value and plans for significant additional investment over the 24-year study period. On an annual basis, conservation absorbs forecast load growth until the 2040's in most scenarios, stretching the capability of the existing resource portfolio to meet load, and keeping the PUD within its BPA contractual allocation for BPA until the 2030's.

4) **Develop of demand response and smart rate programs will help the PUD keep customer costs low and serve load.**

   The 2021 IRP was the first PUD IRP to find demand response programs cost-effective. This was made possible by planned AMI investments bringing down the costs of acquiring demand response and smart rate programs, and by changes in State energy policies increasingly hourly price volatility and the value of demand response programs. This resource type appears to have particularly exceptional value in helping contribute to winter load events.

   In the summer of 2021, the PUD launched pilot programs that may help the PUD gain additional insights into customer needs, program effectiveness, and perspectives on how to bring programs to scale. While the promise of demand response programs is high, the Demand Response Potential Assessment also found the scale of potential portfolio contributions to be limited. As such, demand response programs provide one component of a multi-component strategy to help meet future needs.

5) **Long-duration utility-scale energy storage resource will significantly reduce the PUDs portfolio deficits under adverse conditions, provide the PUD with a flexible resource to complement its existing portfolio, and prepare the PUD for the future.**

   In every scenario, an 8-hour duration, utility-scale storage resource is selected. This resource is a fossil-fuel alternative for capacity and would provide the PUD with a dispatchable resource that can help balance the portfolio, prepare for future markets, meet future resource adequacy obligations, and creatively utilize its renewable energy portfolio to meet customers' needs.

6) **Under high load trajectories, investments in larger-scale renewable resources such as wind power are likely the best candidate to meet those additional needs.**

   Case portfolios with higher load forecast need additional resources to serve that additional load. In every one of those cases, wind power is a selected resource from the optimization process. In particular, wind from Montana is selected due mainly to its better winter seasonal generation profile and higher net capacity factor when compared to wind from Columbia Gorge, where the PUD currently contracts 217 megawatts nameplate of wind power.

Clean Energy Action Plan

Clean Energy Action Plans (CEAPs) are a new component of utility resource planning introduced by the Clean Energy Transformation Act. The purpose of the CEAP is to identify the likely action over the next 10 years to meet the goals of CETA. The 2021 IRP contains the Clean Energy Action plan in its 10-year vision of the Long-Term Resource Plan, and it presents the Long-Term Resource Action Plan's contributions to long-term clean energy goals.

As stated in the 2021 IRP, the PUD's existing portfolio produces more clean energy than retail load and is expected to continue to do so over the course of the 24-year study period spanning 2022-2045, after new conservation. As such, given the current status of rulemaking, the PUD considers the portfolio to be 100% clean and the PUD to have a clear pathway to continue to be 100% clean by 2045.

In order to preserve the clean energy attributes of the portfolio, although additional resources are needed to serve customer load, no emitting resources are planned to be added to the portfolio.

Clean Energy Action Plan Summary

The 10-year Clean Energy Action Plan has identified the following resources to be added by 2031 as shown in Figure 7-1.

Figure 7-1

Long-Term Resource Strategy Targets and Clean Energy Action Plan Targets

	2031 (10-year)
Conservation (Cumulative annual aMW)	76.59
Demand Response (Cumulative Peak Week aMW)	31.6
Long-Duration energy Storage (Nameplate MW)	70
Small Local Solar (Nameplate MW)	5

Resource Adequacy

The PUD's resource adequacy standards are defined in Section 5: Planning Standards and include P5 planning metrics for seasonal energy and seasonal capacity using stochastic methodology that includes the impact of weather on loads and variable resource generation, including the effects of climate change.

2021 Action Plan

The 2021 Integrated Resource Plan has identified several near-term actions to ensure the PUD can meet the needs of its customers in a rapidly changing environment, well into the future:

1. **Pursue all cost-effective conservation** and further explore programmatic conservation portfolio optimization, to include consideration of capacity-value, distribution-system value, and BPA reimbursement.

   Conservation is the single largest portfolio addition for every scenario evaluated in the 2021 IRP. It remains the PUD's resource of choice for meeting future load growth as it has in previous IRP cycles. The acquisition of conservation savings reduces the demand for electricity, delaying the need to acquire or develop and more expensive and/or less effective new resources, which can reduce the overall cost of energy and capacity, including deferral for additional transmission and distribution capacity upgrades.

   The PUD has been a regional leader in its acquisition of conservation for over 40 years. It has successfully developed and operated numerous cost-effective programs that help customers of all types conserve or use energy more efficiently. The 2021 IRP identifies a need to acquire 171 aMW of new cumulative annual energy savings and 222 aMW of new winter on-peak energy savings over the 2022 through 2045 period. The 10-year conservation potential for the Long-Term Resource Strategy (Base Case) was identified at 77 aMW.

   To attain this level of conservation achievement, the PUD must continue to develop strategies and programs that reach all sectors, with special focus on implementation strategies for conservation that brings capacity contributions.

2. **Pursue acquisition of significant long-duration utility-scale energy storage**.

   The 2021 IRP clearly identifies long-duration storage as the supply-side resource of choice, finding it cost-effective across all eight scenarios. The Long-Term Resource strategy specifically defines the need for utility-scale 8-hour dispatch duration energy storage scaling to 70 MW nameplate capacity by 2029.

This Action Item will require PUD staff to perform additional due diligence on the storage technologies available at the highest value and lowest reasonable cost to customers, with a goal of acquiring or building a significant resource around 2024.

3. **Develop a roadmap to significant, lowest-cost Demand Response programs** leveraging AMI, to include dispatchable demand response programs and smart rate constructs. The PUD has been developing pilot programs that explore various deliveries and designs of demand response programs, and as would be expected, these programs are at a pilot scale. In order to meet the programmatic scale goals for demand response, the PUD needs to develop the roadmap for the organization to bring the highest-value programs to scale. This must necessarily plan for how to best leverage the roll out of AMI technology, which is expected to yield the lowest cost programs. Further, the PUD should explore programmatic demand response portfolio optimization, to include consideration of capacity-value, and distribution-system value.

4. **Further develop geospatial modelling capabilities of demand-side resource potential** with the intention of refining the ability to capture avoided Transmission & Distribution system costs from demand-side investments, and to better understand the geographic distribution of planned investments. Further develop analytical methodology for applying geospatial analysis to inform future Clean Energy Implementation Plans.

5. **Continue to enhance and leverage short and long-term resource portfolio modeling capabilities**; expand cost and risk tradeoff analyses.

   PUD staff's development of in-house modeling tools leveraging the KNIME Analytics Platform and other programming resources have played crucial roles in allowing staff to create advanced models regarding load resource balance, new resource output, energy pricing simulations throughout various defined environments, and portfolio optimization. As the electricity markets, industry, and policies continue to evolve, staff must keep pace with these changes and develop the modeling tools that provide visibility into potential risks and opportunities for the PUD.

6. **Continue to participate in regional forums and assess impacts associated with climate change**, reduction in greenhouse gas emissions, clean energy policy compliance, and regional power and transmission planning efforts. Given the renewable content of the PUD's portfolio, and the close relationship of renewable resources with local and regional weather, it is important for PUD staff to continue to monitor climate science to inform future outlooks, and policies related to carbon reduction in order to identify and optimize the PUD's clean energy portfolio for the benefit of its customers.

7. **Continue to participate in the development of a regional resource adequacy program**, in order to further limit reliability risks to customers. As regional capacity resources retire, it will be important for the PUD to stay involved in regional efforts to improve resource adequacy. The PUD has been a participant in the Northwest Power Pool's Western Resource Adequacy Program (WRAP), contributing ideas to its design and governance structure. This effort holds promise for low-cost resource adequacy mitigation to augment the PUD's resource portfolio with an efficiently designed resource sharing program. PUD staff should continue to be involved in the program development, and upon its maturity towards a binding, final program design, critically evaluate the PUD's participation to assess if joining will bring net benefits for PUD customers.

8. **Continue to participate in regional forums discussing the formation of organized markets** in the Pacific Northwest in order to ensure hydropower is appropriately valued, that the economic opportunities and risks of planned dispatchable resources are accounted for, and that forecast cost of service is appropriate. Various regional discussions on RTO's, Day-Ahead Markets, and other market structures can present new risks and opportunities for the PUD. In order to adequately plan for the future, and influence market formation and design considerations, PUD staff should continue to participate in relevant discussions, evaluations, and exploratory efforts in order to develop new opportunities for the PUD on behalf of its customers and mitigate risks.

9. **Continue to participate in the Post-2028 contract negotiation process with the Bonneville Power Administration** in pursuit of a low-cost, high environmental quality, and reliable post-2028 contract. PUD staff should continue to play an active and collaborative role developing a sustainable, affordable, and practical BPA contract to take effect in 2029. This contract should seek to help the PUD comply with all relevant state and federal policy requirements for clean energy and carbon, appropriately position the PUD for the potential of future markets, mitigate or address capacity needs, and continue to incentivize conservation investment. As the contract negotiation process matures, PUD staff must also critically evaluate all the BPA power products available to the PUD in order to find the products that would result in the lowest reasonable cost to PUD customers. This analysis is expected to be included in the 2023 IRP update.

Clean Energy Implementation Plan

The Clean Energy Implementation Plan is to be informed by the IRP but include a separate public process and assess specific questions contained in the law not included in the IRP. The resulting Clean Energy Implementation Plan will be a separate document informed by the 2021 IRP and adopted separately by the Commission.

The following Clean Energy actions will be considered by the CEIP public process and included in the CEIP document.

Figure 7-2

New Planned Resources

	2025 (4-year)
Conservation (Cumulative annual aMW)	19.35
Demand Response (Cumulative Peak Week aMW)	3.6
Market Capacity Product (Nameplate MW)	50
Long-Duration energy Storage (Nameplate MW)	25
Small Local Solar (Nameplate MW)	0

Appendix A. Progress on 2019 IRP Action Items

1. Pursue all cost-effective conservation and continue efforts to capture near-term winter capacity benefits of conservation to mitigate market reliance during adverse load events.	The PUD is on track to acquire the 12.24 aMW of conservation identified in the 2019 IRP and Biennial Conservation Target by the end of the year in 2021.
2. Conduct a utility-specific study to better understand the opportunities of existing and emerging summer conservation technologies and technical achievable potential, including participation in NWPCC planning efforts associated with the Eighth Power Plan.	PUD staff participated on the Conservation Resources Advisory Committee that contributed to the NWPCC's new Power Plan (now called the 2021 Power Plan), and contracted for a new, comprehensive Conservation Potential Assessment (CPA) that reflected the latest measures from that plan.
3. Continue to explore low cost, low emissions alternatives in the Northwest for capacity resources to meet peak needs across seasons, including evaluation of batteries, pumped hydro storage and potential to partner with BPA for future peaking or capacity products.	The PUD pursued technical economic analysis of several regional pumped storage hydro projects in British Columbia, Washington State, and Montana.
4. Align and integrate PUD -wide Distributed Energy Planning efforts to help manage future technology and customer preference changes and leverage new opportunities to provide better service at a lower cost to customers.	PUD staff serve on the DER Planning Team, and have lead development of geospatial analysis of the CPA and DRPA supply curves to further the efforts of the DER team

5.	Enhance short and long-term resource portfolio modeling capabilities to provide more precise and time granular analyses of portfolio challenges and potential solutions.	The 2021 IRP utilizes a completely redesigned load-resource balance model, utilizing an hourly stochastic portfolio modeling approach.
6.	Monitor and actively participate in regional forums, legislative policy discussions and rulemaking initiatives, and BPA power and transmission planning initiatives in support of Board policies and the PUD's Mission and Strategies Priorities.	PUD staff are actively involved in multiple regional forums and were active in the Clean Energy Transformation Act rulemaking process, BPA BP-22 Rate Case proceedings, and several other high impact regional convenings.
7.	Evaluate available load-shifting technologies and resources as a potential emission-free resource to mitigate future capacity needs and long-term summer on-peak energy needs.	The 2021 IRP includes a new, comprehensive Demand Response Potential Assessment (DRPA)

Appendix B. EIA Compliance Crosswalk

The Energy Independence Act creates two fundamental obligations for utilities with at least 25,000 retail customers: 1) an obligation to pursue all conservation that is cost-effective, reliable and feasible, and 2) meeting Washington State's Renewable Portfolio Standard (RPS) using either the Target Methodology, Cost Cap methodology, or No Load Growth methodology. This Appendix provides additional details on how these obligations are reflected in the 2021 IRP. The following tables show applicable law, how we complied, and where you can find references in this document.

Conservation

Conservation acquisition is addressed in both the Conservation Potential Assessment and the IRP. The CPA highlights areas that are accomplished through the CPA modeling process, and this appendix provides more detail on how remaining conservation planning elements are included in the IRP.

WAC 194-37-080 Section	Requirement	Implementation
(5)(c)	**Economic achievable potential**. Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	The PUD uses its IRP optimization model to determine what measures are cost effective by comparing the costs and benefits of conservation measures against other resources. See Section 6: Portfolio Development for more details.
(5)(d)(i)	Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits;	The costs considered in the levelized cost include measure capital costs, O&M costs, periodic replacement costs, and any non-energy costs. Benefits included avoided T&D capacity costs, non-energy benefits, O&M savings, periodic replacement costs. Avoided energy costs, generation capacity value, and any risk premium are factored into the PUD's IRP modelling through the Portfolio Optimization process described in Section 6: Portfolio Development. Measure costs and benefits can also be found in the individual measure files as well as the "ProCost Measure Results" file in the CPA.

WAC 194-37-080 Section	Requirement	Implementation
(5)(d)(v)	Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	The PUD incorporates regional market price forecasts as part of its IRP modelling. See Section 4: Market Price Forecast for further details.
(5)(d)(vii)	Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion deferral benefits are modelled through the District's IRP analysis. Hourly savings data developed as a part of this CPA enabled the PUD's IRP to evaluate the capacity contribution of each measure bundle with respect to the PUD's peak demands. See Section 6: Portfolio Development for further details.
(5)(d)(viii)	Include the social cost of carbon emissions from avoided non-conservation resources	The PUD's IRP modelling factors in carbon costs per the requirements of Washington's EIA and CETA. See the Section 4: Market Price Forecast for further details.
(5)(d)(ix)	Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources	The PUD's IRP addresses risk through probabilistic modelling. See the Section 6: Portfolio Development for further details.

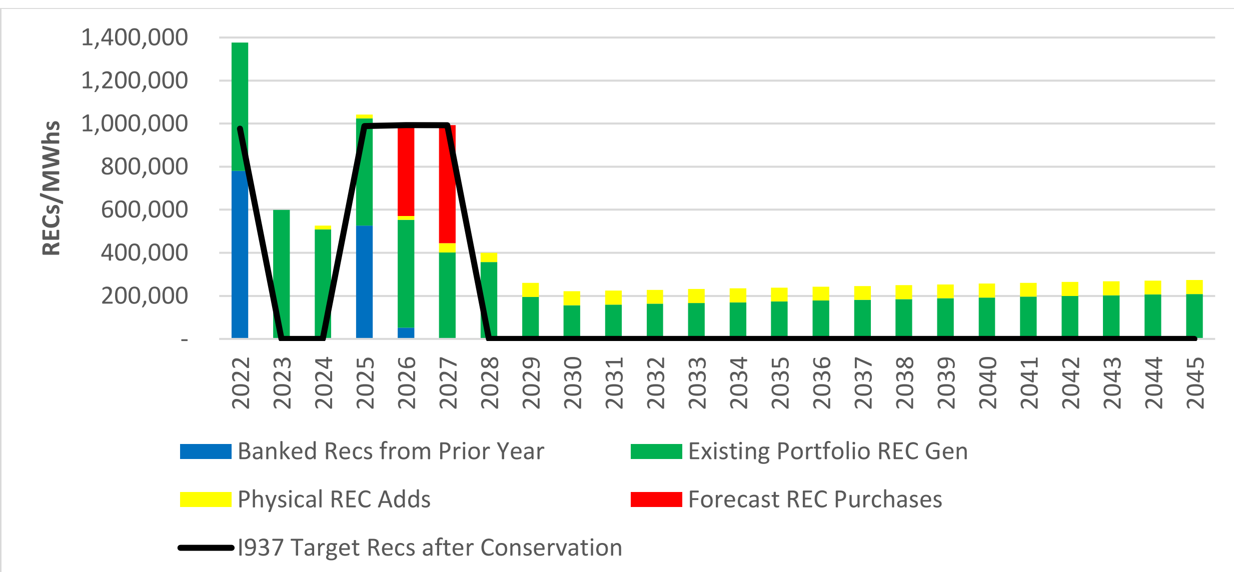
Renewable Energy

The Energy Independence Act also established a renewable portfolio standard (RPS) with renewable energy targets for utilities, in addition to other compliance mechanisms, which the Department of Commerce is tasked with overseeing on an operational basis. In order to determine the most cost-effective route to RPS compliance, the 2021 IRP considers the target methodology for compliance, the No-Load-Growth compliance mechanism, and the effects on EIA requirements of CETA legislation toward 100% clean utilities. The Long-Term Resource Strategy finds a mix of these compliance methodologies across the study period to be the most cost-effective way to meet regulatory obligations and customer needs, but this is expected to be revisited in future IRP updates.

Figure B-1 shows how the Target for Renewable Energy Credits (RECs) changes across the study period given planned conservation and the impact of the binding period for CETA. While it is currently forecast that the Target Compliance Methodology creates a significant REC target in 2022, it is envisioned that the effect of conservation on load may shift the compliance methodology in 2023 & 2024 to the No Load Growth strategy, which could significantly decrease EIA compliance costs, and therefore increase the value of conservation acquisition in those years. It is envisioned that the Target Methodology may be used for the majority of pre-2030 years thereafter. Because EIA rules allow RECs generated in a given year to be rolled forward (or banked) on a limited basis, it is envisioned that the PUD's existing portfolio of renewable energy resources may be able to serve most regulatory compliance needs in most years. It is forecast that additional RECs may need to be purchased from the open market in 2026 & 2027 to augment the REC portfolio in those years. These forecasts will be the subject of continuous monitoring and updating by the PUD to ensure that regulatory needs are met. Last, in 2030, the PUD anticipates being able to demonstrate the utility is served by 100% clean energy and exempt from EIA requirements per RCW.

Figure B-1

Generated, Banked, and Forecast REC Purchases



Appendix C. CETA Compliance Crosswalk

At the time of this IRP's development, many key provisions of the Clean Energy Transformation Act were still in the rulemaking process. As a result, the PUD analyzed the language of Senate Bill 5116 to ensure the 2021 IRP met reasonable expectations for how the law's rules could be shaped. Some portions of the law have completed rulemaking processes, but many more sections are interdependent upon sections that have not been completed. For this reason, the 2023 IRP Update is expected to have additional detail and may vary in some respects to the interpretations provided as the basis for the 2021 IRP.

Table C-1 provides a summary of highlighted portions of the Clean Energy Transformation Act, how they were interpreted, how they relate to the PUD and the 2021 IRP, and where in the 2021 IRP more discussion can be found.

Figure C-1

Clean Energy Transformation Act Considerations in the 2021 IRP

Citation	Statutory Requirement	2021 IRP Treatment and References
Sec. 3 (1)(a)	Utilities must eliminate coal-fired resources from electric rates by 2026	The PUD has no coal-fired resources, is not considering contracting for coal-fired generation, and is not considering building a coal plant. This is discussed in **Section 2: Overview of the PUD's Portfolio**, and **Section 5: Resource Options**
Sec 4 (1-5)	Utilities should be carbon neutral by 2030 and can use up to 20% alternative compliance mechanisms (including unbundled RECs) in order to achieve this goal.	The PUD's Portfolio Optimization tool required eligible resource generation of no less than 80% of retail load in 2030, linearly increasing to 100% by 2045. The PUD's existing portfolio contains eligible resources forecast to significantly exceed current retail load, and the PUD does not intend to add fossil fueled resources. Therefore, the PUD expects to significantly exceed the statutory threshold in all years of the 2030-2045 compliance period. It should be noted that eligible resource REC retirement in the compliance is expected to require contractual changes to the PUD's BPA contract to create the RECs associated with the PUD's BPA allocation. More information on these elements of CETA are provided in **Section 2: Existing Supply-Side Resources, Section 3:**

		Energy Policy & Regulatory Requirements, and **Section 6: Portfolio Development.**
Sec 4 (6)	Utilities must pursue all cost-effective, feasible, and reliable conservation and demand response	The 2021 IRP uses the integrated portfolio approach and the portfolio development and optimization approach described in **Section 6: Portfolio Development** to arrive at the combination of available resources that results in the lowest net costs to customers while meeting reliability and regulatory standards. Feasibility is addressed in Technical Potential analysis in the Conservation Potential Assessment and Demand Response Potential Assessment that provide the supply-curve inputs into the 2021 IRP.
Sec 4 (8)	Utilities must ensure all customers benefit from the transition to clean energy.	The 2021 IRP uses a lowest reasonable cost approach to determine the most affordable way to meet customer's needs and reliability and regulatory standards. In this way, and through the ratemaking process, the PUD ensures its resource plan provides lowest cost clean energy to customers. In addition, the Clean Energy Implementation Plan process addresses equitable distribution of benefits and provides additional context to the PUD's plans. Last, analysis found that the CETA provision allowing the PUD to mitigate EIA RPS costs by being 100% clean could provide cost-savings to all customers (See Appendix B – Renewable Energy).
Sec 5	All retail sales of electricity must be from renewable and non-emitting resources by 2045.	The PUD forecasts it is on track to meet this standard by virtue of having eligible resources in existing portfolio in excess of its expected retail load, and by planning to add only eligible supply-side resources in its Long-Term Resource Plan. This is discussed further in **Section 6: Portfolios and Long-Term Resource Strategy**, and **Section 2: Overview of the PUD's Portfolio.**
Sec 6 (2)	Consumer-owned utilities must develop a four-year Clean Energy Implementation Plan that is informed by the utility's IRP and Clean energy Action Plan	The PUD will file a Clean Energy Implementation Plan separate from the 2021 IRP, using the 2021 IRP to inform it, and using the 4-year targets identified in **Section 7: Clean Energy Implementation Plan.** The PUD considers its Long-Term Resource Plan to also be the Clean Energy Action Plan, and the details of the 10-year actions are provided in **Section 7: Clean energy Action Plan.**

Sec 14 (f)	IRP's must contain a 10-year forecast of regional generation and transmission capacity on which the utility may rely upon to deliver energy to its customers	The PUD conducts a WECC-wide resource simulation to determine a plausible mix of resources in the Western United States and Canada that would meet regional reliability standards, as discussed in **Section 4: Market Price Forecast.** In addition, the PUD sets Planning Standards for market reliance at levels expected to be below market depth and within the operating parameters of the PUD's Transmission Portfolio. Planning Standards are discussed in **Section 5: Planning Standards**. The Transmission Portfolio is discussed in **Section 2: Existing Supply-Side Resources.**
Sec 14 (g)	Utility IRP's must determine resource adequacy metrics for the resource plan consistent with the forecasts	The PUD provides its Resource Adequacy metrics as its Planning Standards as described in **Section 5: Planning Standards, Resource Adequacy, and Resource Adequacy Metrics.**
Sec 14 (h)	Utility IRP's must forecast distributed energy resources installed by customers and their impact on load and operations	**Section 4: Key Variables for Scenarios** describes how the 2021 IRP forecasts Rooftop Solar Generation and electric Vehicle Impacts on load, and **Section 5: Identifying Resource Need** explains how these load forecasts are incorporated in analysis of PUD resource need.
Sec 14 (i)	Utility IRP's must identify resource adequacy metrics for use in other portions of CETA statute	The PUD provides its Resource Adequacy metrics as its Planning Standards as described in **Section 5: Planning Standards, Resource Adequacy, and Resource Adequacy Metrics.** The PUD uses an integrated portfolio approach to integrate all resource planning functions for the PUD, including the CEIP, CEAP, IRP and identification of economic conservation and demand response.
Sec 14 (k)	Utility's must conduct a cumulative impact analysis of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities	This analysis is expected to be presented in the Clean Energy Implementation Plan, which identifies vulnerable populations that may be impacted by proposed actions of the CEIP, CEAP and Long-Term Resource Plan.
Sec 14 (1)A	Utility's must develop a 10-year Clean Energy Action Plan	The PUD considers its Long-Term Resource Plan to also be the Clean Energy Action Plan, and the details of the 10-year actions are provided in **Section 7: Clean Energy Action Plan.**

Sec 14 (3)	Utility's must use the Societal Cost of Carbon specified by the statute in the development of Clean Energy Action Plans	The PUD's Clean Energy Action Plan is the Long-Term Resource Strategy in the 2021 IRP, as discussed in Section 7. The 2021 IRP uses the prescribed Societal Cost of Carbon, as discussed in **Section 4: Market Price Forecast.** Because the PUD uses an integrated portfolio approach, the SCC is used to develop the IRP, the CEAP, and identify cost-effective conservation.

Appendix D. 2021 IRP Visioning Process

Introduction – What is an IRP?

The Public Utility District #1 of Snohomish County (the PUD) engages in planning for its future needs in a process called the Integrated Resource Plan, or IRP. The PUD utilizes this planning process to ask one of the most fundamental questions for a consumer-owned utility: How should the PUD serve our customer-owners? Or said another way, where does the utility want to go, and how do we get there?

To answer this question, the PUD engages in a planning process whose scope covers the next 25 years. This is not one-time process – the PUD engages in a new planning process every four years, with a two-year update that continues the engagement with the PUD's customer-owners, and allows for dynamic adaptation to an always changing utility landscape.

Utilities face many important operational questions, such as:

- What will our future loads be, and how do we plan to meet them?
- Does our existing portfolio meet our needs, and for how long?
- If we need to add resources to our portfolio, what resources are the best fit? And when should those resources be added?

An IRP attempts to answer all of these questions and aims to find the answer that best meets our customers' needs. The PUD utilizes an "Integrated Portfolio Approach" to resource planning, which allows the utility to compare several different possible portfolios to find the best mix of resources for meeting the PUD and our customers' future needs. The overall IRP development process is split into five phases spread over 18 months:

This timeline is structured such that the PUD can produce its IRP on a schedule that aligns with other important existing PUD initiatives, such as establishing biennial conservation targets and internal PUD budgeting, as well as new regulatory needs, such as the Clean Energy Implementation Plan.

As noted in the timeline above, before the PUD can start assembling portfolios and assessing resource mixes, we must first determine what those future needs might be. This is the first phase of the PUD's IRP process – Visioning.

Phase 1: The Visioning Process – What is it?

As the PUD engages in planning for the future, the first question that must be asked is "What possible futures could the PUD face between now and 2045?" When planning, the PUD cannot simply make its best guess of what a single future would look like - there must be an evaluation of a range of potential futures to make sure that we are well positioned for whatever possible events may occur. The PUD must also understand the long-term needs and priorities of our customers to properly plan and meet those needs.

The scope of visioning is intended to be broad, examining a range of possible changes across subject matter areas, including (but not limited to) the economy, technology, social and cultural considerations, and the environment. The scope of topics also spans all geographic boundaries, from cities, to counties, to states, to nations.

<u>When thinking about the future, the possibilities and combinations of variables are endless; Visioning helps the PUD to narrow down that infinite scope into something manageable and to</u>

identify key points and variables that are important both to the PUD, and to our customer-owners.

Based on the feedback received during the visioning process, it is the IRP staff's goal to establish two things:

- A set of **Scenarios** relevant to our customer's long-term needs; these are the potential "futures" to analyze. Scenarios are sets of variables organized to forecast how a potential future could play out locally, regionally, and nationally; and

- **Sensitivities,** which are variations upon a single meaningful variable within a given scenario. An example could be how variations in the single variable of "Climate Change" might alter the needs and optimal portfolio within any given scenario.

Phase 1: The Visioning Process – Setting the Scope with Our Customers / Who Participated?

If the goal of the Visioning process is to establish a set of futures that incorporate important events and topics, the PUD must identify exactly what those important events or topics might be. Historically, the PUD has organized a cross-functional internal team of subject-matter experts to participate in a multi-day visioning process that worked to identify those important possible topics. The broad participation of experts from disparate departments across the utility helped to provide important and unique perspectives to the IRP planning staff and ensured that the resulting scenarios were robust.

In this 2021 IRP process, the PUD has expanded and improved its Visioning process to include input from some of the most important voices: those of our customers. When establishing the 2021 Visioning team, IRP staff reached out to a number of customer groups and organizations across the PUD's service territory with the intention of soliciting a representative cross-section of our customer base. The PUD's goal was to try to get as many diverse points of view as possible to contribute to the planning process, and to identify topics and issues that were important to them as customers. This cross-section of customers included representatives from:

The United States Navy, Naval Station Everett
Boeing
The Port of Everett
Marysville-Tulalip Chamber of Commerce
Economic Alliance of Snohomish County
Washington State University, Everett
SoundTransit
Snohomish County Government
Student body of Western Washington University and Washington State University, Everett

Our customer participants were joined by a cross-functional group of PUD subject matter experts drawn from several different internal groups. Customers and PUD staff worked side by side during the visioning process, which helped facilitate understanding and education for both groups.

The PUD was represented by participants from the following workgroups:

Rates, Risk, and Economics
Power Supply
Energy Services
Generation
Distribution Planning
Government Relations
Corporate Communications
Business Readiness
Customer Analytics

In addition to those participating in the visioning team, the PUD wanted to ensure that feedback was received from our residential and small business classes of customers, which is difficult to gather in a workshop setting. The PUD instead reached out to these groups of customers using surveys. A sample of over 1,500 residential customers and over 400 small businesses were engaged on a survey to capture priorities and considerations from those groups that could be considered in long-term planning efforts. Highlighted results from these surveys can be found in Attachment C of this report.

Phase 1: The Visioning Process – How was the process structured?

As PUD staff began planning the visioning process, a few key principles were established:

1. The overall group should be no greater than approximately 30, or the size of a classroom. PUD staff wanted to ensure that all voices had a chance to be heard, and that conversations and discussions would not be impacted by an unmanageable number of participants.

2. Work sessions should be no longer than three hours. The intention was to be mindful of our participants time and other responsibilities.

3. The meeting cadence should be approximately one per month. Again, being mindful of the participants other obligations, the PUD wanted to give participants time to think and consider the topics and questions involved.

4. PUD staff wanted to make sure to reflect gratitude to the participants for their time – breakfast was provided!

Based on these principles, the following meeting structure was devised:

Meeting 1 (January) – Orientation and Education

Meeting 2 (February) – Work Session #1: Identifying Important Study Topics

Meeting 3 (March) – Work Session #2: Assessing Identified Topics for Impact and Likelihood

Meeting 4 (April) – An opportunity to Provide Follow-up: How the PUD would use the Input Provided

Phase 1: The Visioning Process – What happened at each meeting?

<u>Meeting 1 – January 9, 2020</u>

The intent of the first meeting was to provide each participant with some background information on the PUD, the IRP, and what the goal of the visioning process would be.

The meeting kicked off with a welcome from the PUD's Assistant General Manager of Customer Service Pam Baley, who thanked the participants for their time and stressed the importance of the PUD's IRP process, both for staff and for customers. Following Pam's welcome, the participants had a chance to introduce themselves and their representative organization - it was a valuable use of time to engage the group and let everyone know who their fellow participants were.

The first substantive half of the meeting was devoted to describing exactly what an IRP is, why the IRP is important to the PUD, and what role the visioning team plays in its construction. The objective of this discussion was to emphasize the vital role of the planning work being performed in the IRP, and why the feedback of the visioning team was integral to the overall process.

The second substantive half of the meeting was aimed at creating a common baseline of information about the PUD and its loads and resources. IRP staff collaborated with Corporate Communications to take advantage of new interactive presentation tools through Poll Everywhere, allowing active audience participation during the presentation process. Staff would ask questions pertinent to the upcoming presentation, and meeting participants could use their phones or smart devices to answer a tailor-made poll question, with (anonymous) results displaying to the group in real time. This provided an opportunity for participants to engage in the conversation, while allowing staff facilitators to gauge relative knowledge levels of the group with respect to PUD resources and operations.

Example questions included "What do you think is the largest source of the PUD's forecasted load growth?" and "From what resource type does the PUD receive the majority of its annual energy?" After each set of questions, a PUD subject matter expert would give a short "TED talk" style presentation, answering the question and providing further education and context around the subject area.

The two primary subject areas discussed were Loads and Load Forecasting, led by Senior Manager of Rates, Economics, and Risk Brian Booth, and the PUD's energy sources and resource portfolio, led by Senior Manager of Power Supply Anna Berg. Meeting participants were fully engaged in these presentations and had many questions of their own. Discussion on these two topics filled the remainder of the morning.

The meeting closed with PUD staff gave a brief preview of the work that would be done at the next meeting and prompted participants to think in the interim about what issues and futures might be important to them and their organizations.

Meeting 2 – February 5th, 2020

This meeting was the first work session, where participants were expected to actively contribute their ideas and viewpoints. The introduction of the meeting reviewed the IRP and visioning process at a high level and reiterated why they are important to the PUD. It also briefly described some of the new regulatory requirements mandated by Washington State's Clean Energy Transition Act (CETA).

Following the introduction, PUD Customer Analytics staff represented by Laura Lemke discussed the results of recent survey work performed by the PUD. Survey subjects ranged from likelihood to purchase electric vehicles to likelihood of installing solar panels in the next 10 years. PUD staff utilizes customer surveys and polls to help gather data for consideration – it is one more tool in the PUD's toolbox for understanding our customer's needs and helping make sure that the PUD is positioning itself to be responsive.

After the short discussion of the survey results, the substantive work of the workshop began with hands-on brainstorming about potential futures. The room was divided into small focus groups by table – 5 to 6 people per group. PUD staff ensured via seating charts that there was a mix of PUD participants and external participants in each group. The goal of the small groups was to brainstorm topics that could be important to consider in future planning – this could be from the perspective of the individual participating, or that individual's larger organization's perspective. Participants were instructed not to consider the likelihood of a particular event occurring, nor the magnitude of its impact this stage; this was to ensure that any and all ideas were heard and considered without limitation.

IRP Visioning: Customer and PUD staff small group brainstorming – February 5, 2020

To help organize and categorize the wide range of possible topics and thoughts, the PUD team requested that each idea be sorted into one of following five "buckets":

- Policy – What policies at the local, state, federal level and beyond could have an impact on the future?

- Technology – What technological developments could have an impact on the future?

- The Economy – What economic or monetary changes could have an impact on the future?

- Society – What societal and social changes could occur that would impact the future?

- The Environment – What kind of environmental changes could impact the future?

For each category, past examples were provided to help kick off the process, such as: “What would a ‘Great Recession’ for the Economy look like?”, or “What would be the effects of an Income Tax in WA state, should one ever be passed by the legislature?” The goal of this exercise was for participants to think about what would be important to each of them when considering the future, and to identify those issues for the PUD.

Each small group tackled one of the five subject categories for a period of time, then the categories rotated and each group focused their brainstorming on a new category until each group had created a list of issues for each category. At the end of the work session, 84 topics had been put forward across the small groups.

In closing, participants were asked to think about the issues they identified ahead of the next meeting and to consider both the likelihood of those issues occurring, as well as the possible impacts. These metrics would be the focus of work during the next meeting.

Staff work between Meetings 2 and 3

In Meeting 2, the input from participants in the visioning process generated 84 topics of interest in potential futures for consideration at Meeting 3. However, 84 topics would be difficult to properly rank and evaluate in a large group setting.

Staff worked between Meetings 2 and 3 to identify themes among the topics and help distill some of the similar thoughts and perspectives into a more easily workable form. Once completed, the list of 84 topics had been condensed down into a “short list” of approximately 40 topics, evenly distributed across the five category areas.

Meeting 3 – March 4, 2020

The third meeting had two main objectives:

- Give participants an opportunity to share organizational goals or objectives that may not have been addressed thus far in the process
- Rank and assess the 40 topics generated by the last meeting

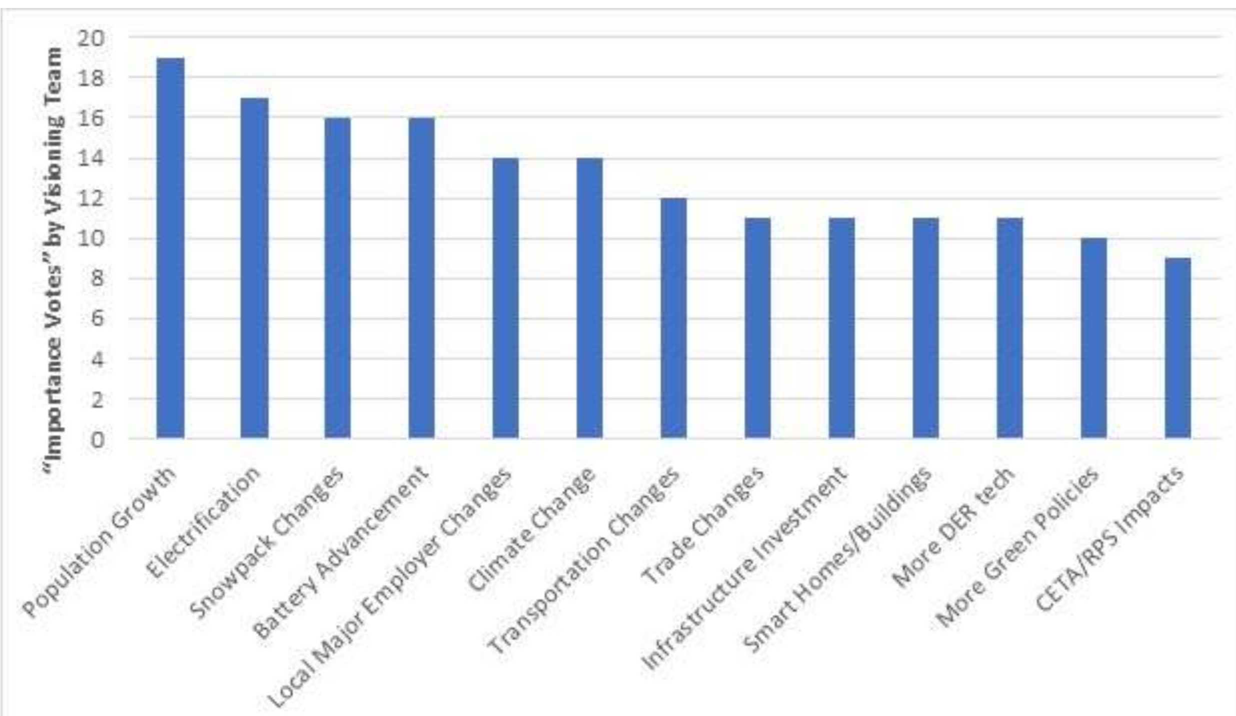
To open the meeting, PUD General Manager John Haarlow greeted the participants, thanked them for their involvement in the IRP process, and provided some thoughts on PUD initiatives and priorities looking to the future. Following his greeting, Laura Lemke provided information from household survey work performed by the PUD. Participants actively engaged in the discussion, asking questions about some of the implications of the data, focusing on data related to electric vehicles and demand response.

Following these discussions, customers were given an opportunity to express any thoughts or perspectives that they had not yet had an opportunity to express. Due to the tight time constraints around the working sessions, some perspectives may have not yet had an opportunity to be expressed – the PUD wanted to provide ample time to hear those thoughts and ideas.

The discussion was facilitated by questions regarding goals and priorities, specifically around carbon targets or renewable energy policies internal to the participants organization. Staff also solicited information regarding future organizational plans of which the PUD should be aware. Conversation filled the allotted time and the PUD received valuable feedback from several participants in the room.

Following that discussion, participants were given fifteen “dot” stickers. Around the room, staff had prepared hanging sheets that listed each of the 40 topics by category area. Participants were given instructions to “vote” using the dot stickers for topics that they felt were important, and that the PUD should consider in its IRP process. Each participant had to use at least 2 dots per category (10 dots total) but then could allocate their remaining five dots at their discretion, allowing for multiple votes to be assigned to a single topic if it was felt that topic was particularly important.

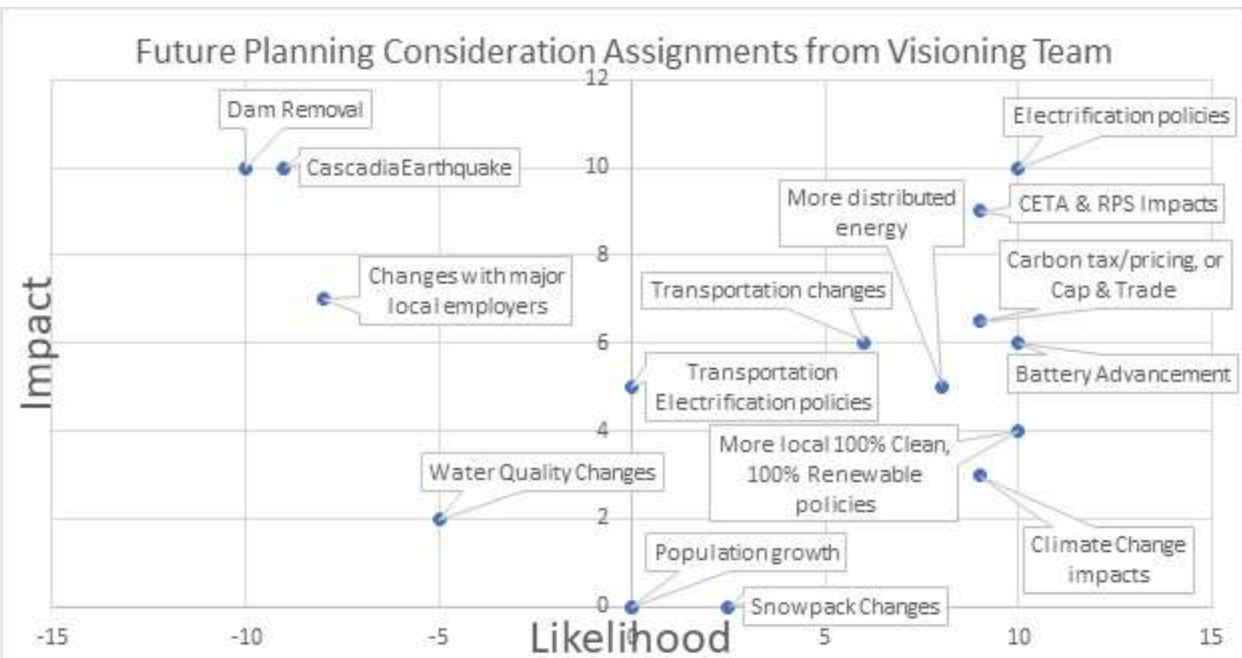
This process allowed participants to get up from their tables, move around the room, and engage with other participants about how they wanted to vote. Facilitators were also posted at each category to help answer questions or clarify the higher level “themes” into which some ideas had been sorted. Once complete, staff quickly tabulated the votes and highlighted the top vote receiving topics for further conversation.



Visioning topics with the most study interest – March 5, 2020 Visioning Process Meeting

Once the topics had been ranked by votes, participants engaged in a large group discussion to determine two parameters for each individual topic: its likelihood of occurrence, and the magnitude of its impact if it were to occur. A more detailed examination of the topics, votes received, and rankings, can be found in Attachment A of this report.

These two parameters were displayed as an X and Y axis on the meeting room's whiteboard – the larger group was asked to discuss where on each axis the topic should be placed. Using examples from the list above, electrification policies were discussed to be both "high impact" and "high likelihood." Conversely, something like a major earthquake in the Pacific Northwest (titled the Cascadia quake) may be very "high impact" but was considered to be "low likelihood." Staff attempted to balance discussion around the highest voted issues, and also to capture topics from each of the categories so as to create a reasonable cross-section of issues for consideration and inclusion into Scenarios.



<u>Meeting 4 – April 1, 2020</u>

While the intention was to hold each of these meetings in person, the COVID-19 outbreak required that the PUD hold the final meeting via teleconference. The goal of the final meeting was to provide follow-up to the group regarding the information gathered and close the loop on how their input would be utilized.

The call consisted of PUD staff providing a recap of the meeting process to date, a detailed description of the work performed in each work session, and then a presentation describing the work performed by the IRP team subsequent to Meeting 3 organizing the topics and data into Scenarios and Sensitivities.

Ultimately, the topics identified and evaluated resulted in seven Scenarios to be studied in the IRP process. Three sensitivities were also identified. These Scenarios and Sensitivities would provide the basis for the work performed in Phase 2 of the IRP process, where these potential futures would be analyzed, and where the needs of the PUD would be measured and assessed. A high-level summary of the proposed Scenarios and Sensitivities is provided in Attachment B, and a cross-reference of those Scenarios and Sensitivities to the priorities and topics identified by the Visioning Team is provided in Attachment A just below.

Attachment A: Identified Topics and Descriptive Data

The following table shows the topics identified and evaluated by the team, how they were evaluated for importance, impact and likelihood, and how they are reflected in the Scenarios and Sensitivities proposed, which are provided in a table on the following page. Scenarios and Sensitivities will be described in greater detail in the main body of the IRP document.

Topic	Importance "Votes"	Likelihood Score	Impact Score	Incorporation into IRP
Population Growth/Migration Changes	19	0	0	Low, Base, and High Case Scenarios
Electrification policies (affecting homes, businesses, electric vehicles)	17	10	10	Electrified Future Scenario
Snowpack (water storage, hydro fuel) changes	16	2.5	0	Climate Change Sensitivity (RCP 4.5 and RCP 8.5)
Battery advancement (efficiency, cost, deployment scales)	16	10	6	High Technology Scenario
Boeing and other major local employer's future	14	-8	7	Low, Base, and High Case Scenarios
Climate Change	14	9	3	Climate Change Sensitivity (RCP 4.5 and RCP 8.5)
Transportation changes	12	6	6	Low, Base, and High Case Scenarios reflect different EV forecasts, as does High Technology forecast
International/Domestic Trade changes	11	2	5	Low, Base, and High Case Scenarios

Smart homes and facilities (customer interaction with utility)	11	Not Ranked	Not Ranked	High Technology Scenario
Green economy/Clean Tech/Divestment from fossil fuels/Green New Deal	10	Not Ranked	Not Ranked	Green New Deal Scenario
CETA/RPS Standards	9	9	9	All Cases
Carbon tax/pricing/cap&trade	6	9	6.5	Green New Deal Scenario
Hydropower dam policies (removal, regulation)	6	"-10,0"	"10,0"	Shrinking BPA Scenario
Cascadia Earthquake	5	-9	10	Not reflected in Plan
100% Clean, 100% Renewable Policies	5	10	4	Green New Deal Scenario
Water quality, quantity, and rights concerns	4	-5	2	Climate Change Sensitivity (RCP 4.5 and RCP 8.5)

Attachment B: Proposed IRP Scenarios and Sensitivities

Case	**Description**
Base Case	Climate change, forecast load growth, projected EV, projected rooftop solar, CETA compliance, BPA is at expected, Rate structure is at expected
High Electrification	High EV variance, Most new connections all-electric, propane and natural gas fuel-switching at equipment replacement
High Technology	High battery wholesale market presence, Rate structure evolution w/AMI, DER emphasis, high EV load shaping
High Policy	100% Clean by 2035 WECC-wide, Carbon-price WECC wide, High EV penetration by 2035
Less BPA	BPA contract allocation yields less output at same cost trajectory
Locals Only	Meet all need with local resources, including customer-sited resources
Risk Diversification	Limited market reliance exposure, deliberate location, and resource diversity of portfolio
Sensitivities	
Low Growth	Load trajectory takes low-end economic growth trajectory (trade policies, pandemic, business cycle, employer changes)
High Growth	Load trajectory takes high-end economic growth-trajectory (local employer growth, enhanced trade, immigration)
High Climate Change	Impact of higher GHG trajectory on temps, snowpack, hydrology, and A/C penetration under the IPCC's RCP 8.5 scenario standards

Attachment C: Customer Survey Data and Results

Residential Customer Survey

This survey was conducted in the February 2020, to a sample of over 1,500 customers. There were 359 overall customer responses. The following represent highlights of those customer survey results:

Figure 1: How likely are you to buy an electric car in the next 10 years?

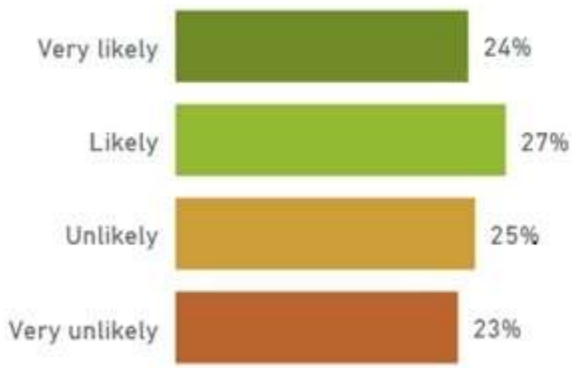


Figure 2: If you are "Likely" or "Very Likely" to purchase an electric vehicle in the next 10 years, how important will the cost of gasoline relative to the cost of electricity be to your decision?

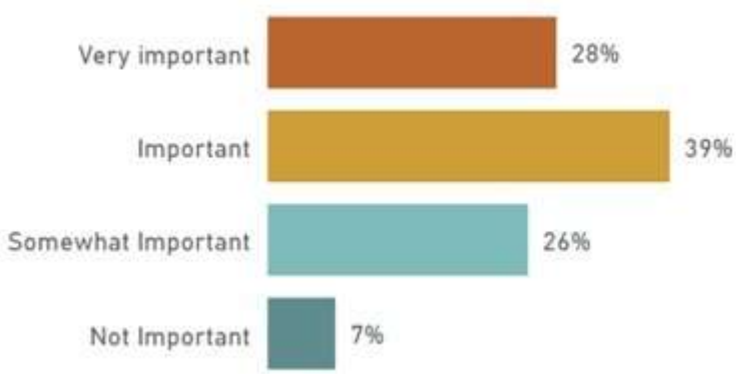


Figure 3: Under what conditions would you consider replacing your gas water heater with an electric water heater?

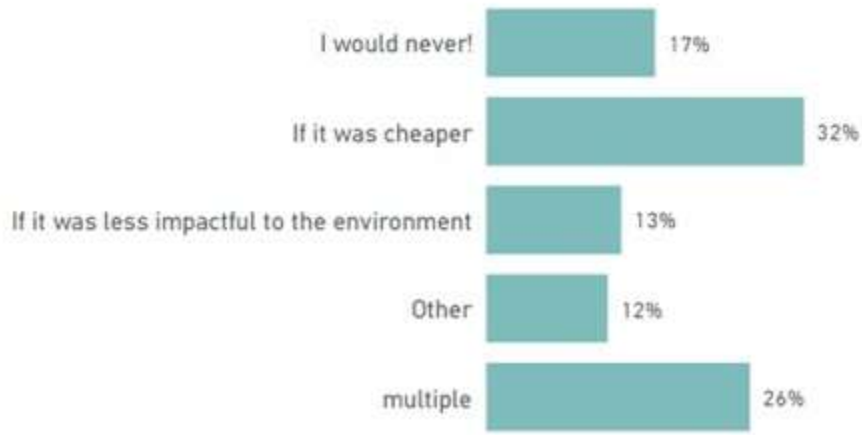


Figure 4: Under what conditions would you consider replacing your gas oven or range with an electric model?

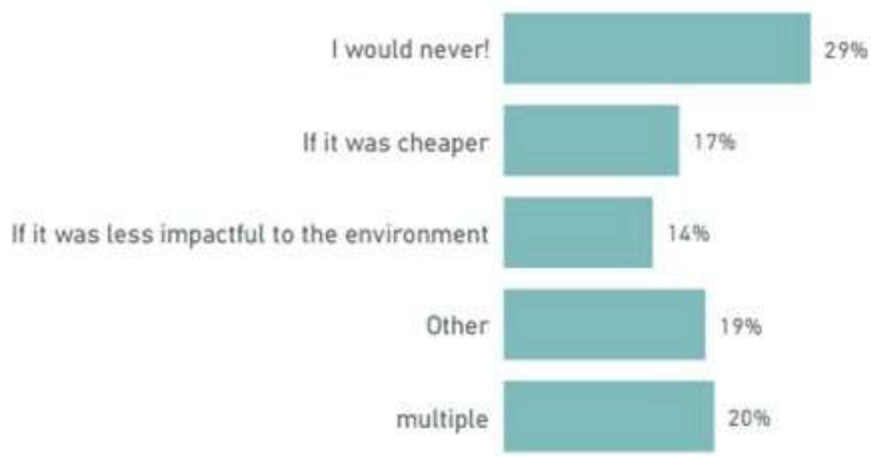


Figure 5: Would you be willing to reduce your energy use for a period of 3 hours in exchange for a small on your bill?

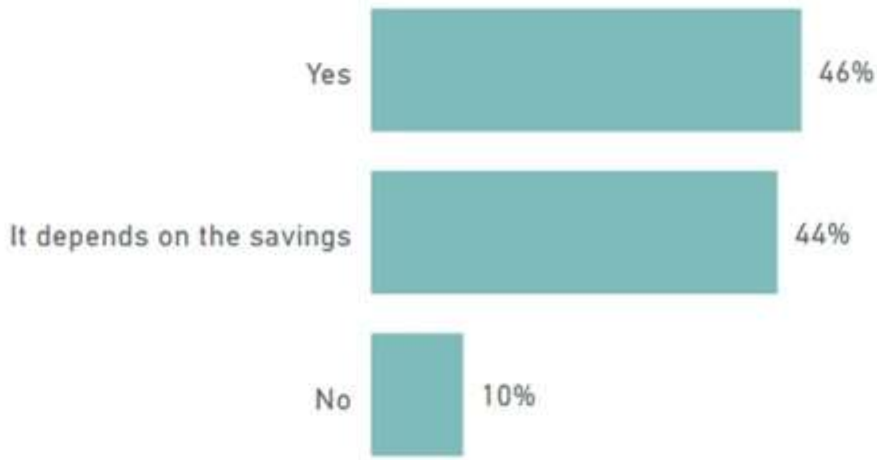
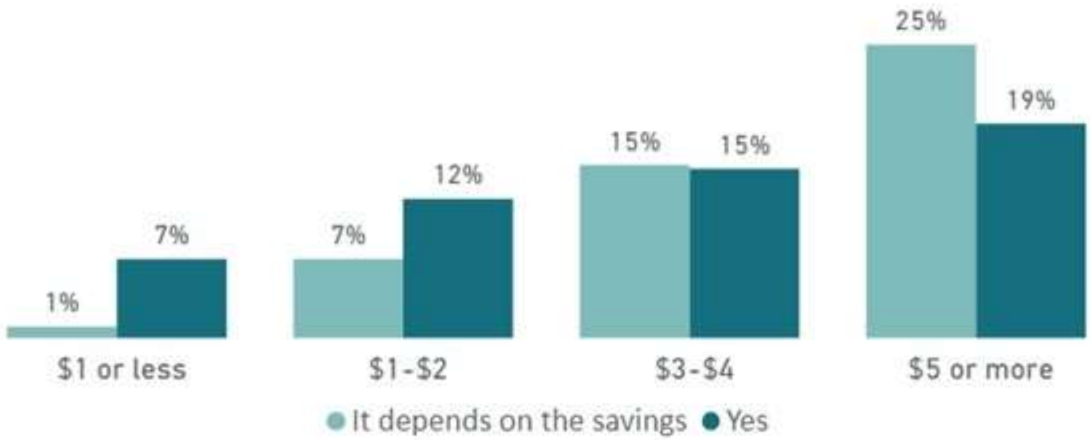
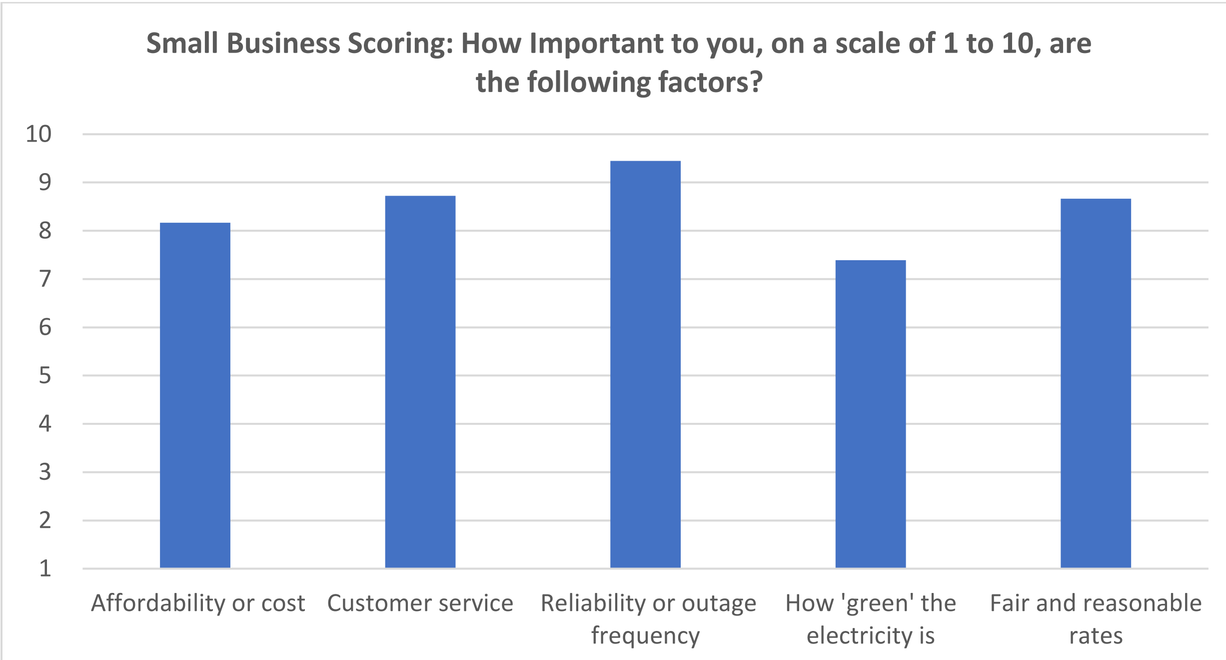


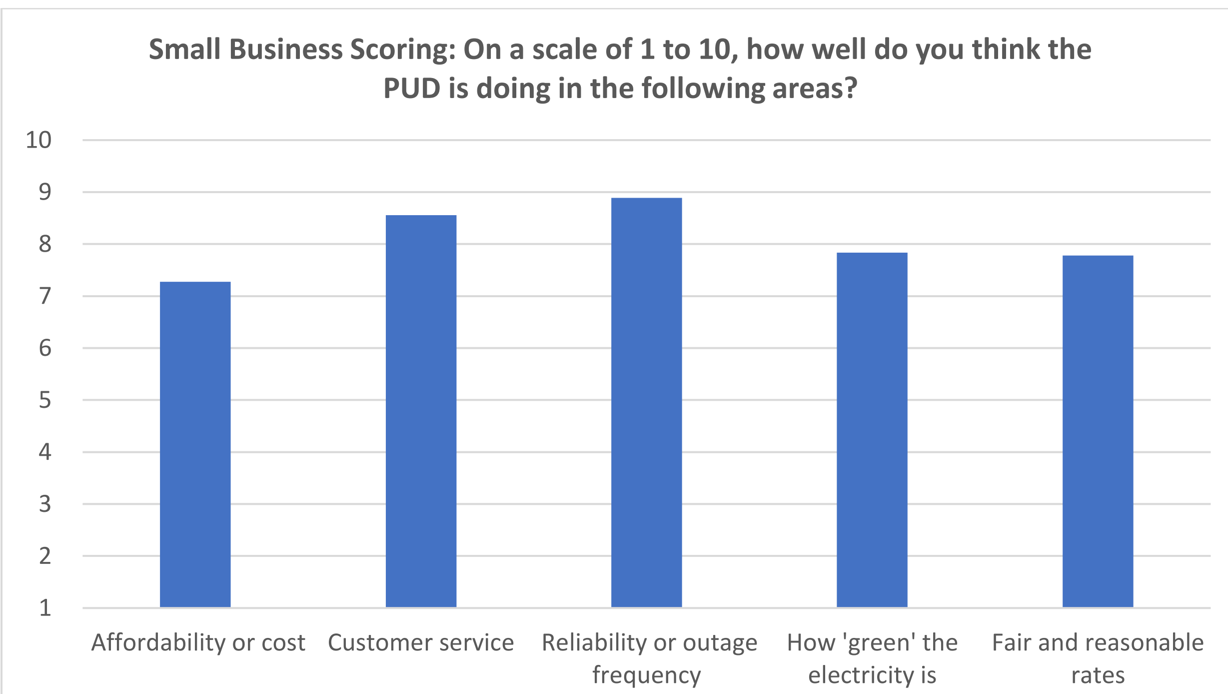
Figure 6: If you answered "Yes" or "It Depends on the Savings" to the previous question about reducing energy use for 3 hours to receive a monthly bill credit, how big would that bill credit need to be in order for you to participate?

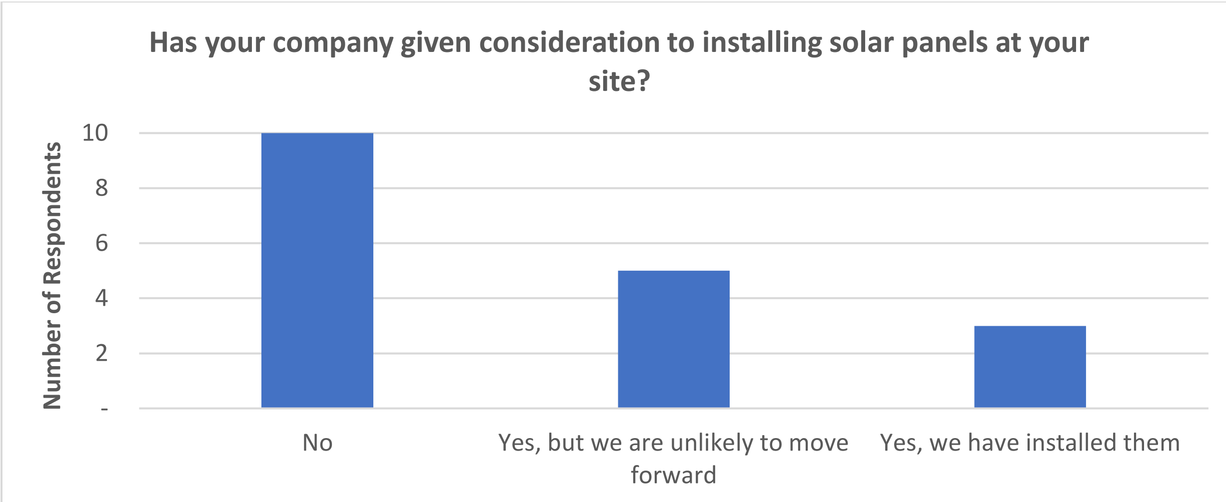


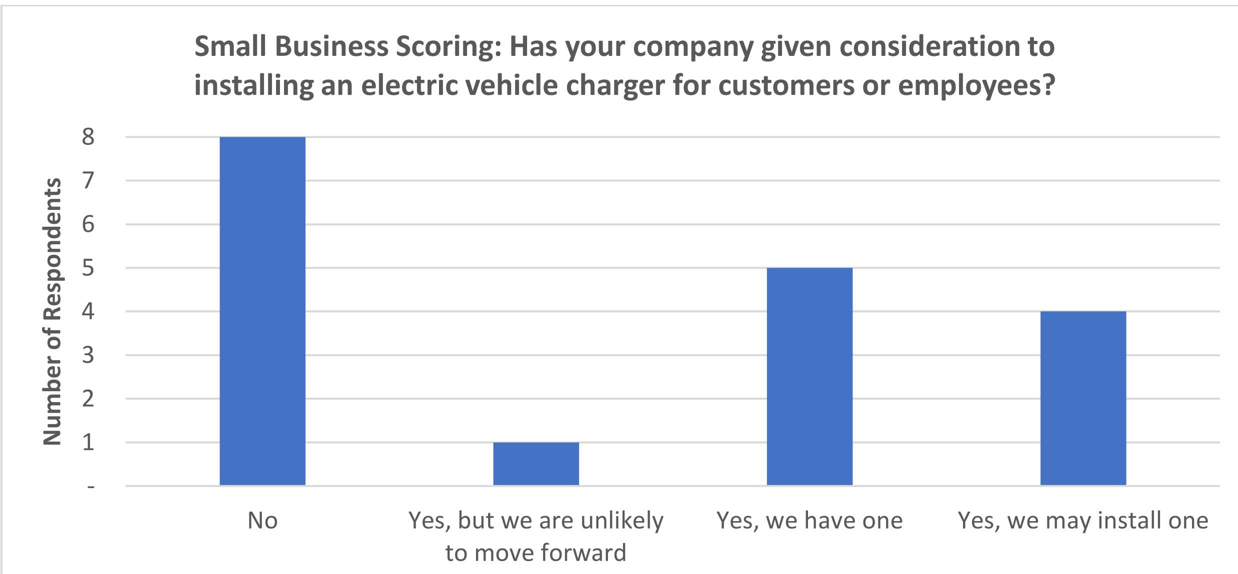
<u>Small Business Survey</u>

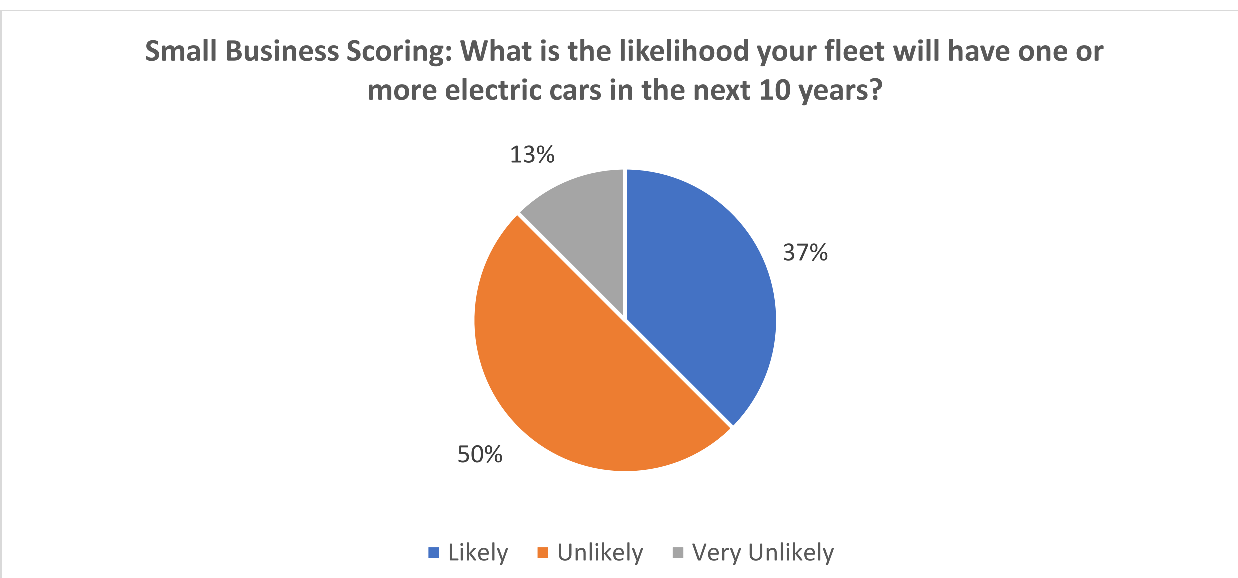
The Small Business Panel survey was sent out in February 2020 to a sample size of 400 local business. The survey received a response of 18 small, local businesses. The respondents reflected a reported 11,798 employees across 77 different locations or facilities within Snohomish County. Below is a sampling of the survey results.






Has your company given consideration to installing solar panels at your site?
Number of Respondents
10
8
6
4
2
-
No
Yes, but we are unlikely to move forward
Yes, we have installed them


Small Business Scoring: Has your company given consideration to installing an electric vehicle charger for customers or employees?
Number of Respondents
8
7
6
5
4
3
2
1
-
No
Yes, but we are unlikely to move forward
Yes, we have one
Yes, we may install one


Small Business Scoring: What is the likelihood your fleet will have one or more electric cars in the next 10 years?
13%
37%
50%
Likely
Unlikely
Very Unlikely

Appendix E. Emerging Technologies

Overview

The purpose of this appendix is to examine and describe various supply-side generation and energy storage technologies that did not make it into the body of the PUD's 2021 IRP. These technologies are generally newer technologies that need more time to mature and become commercially available in and around our greater geographic region at a price point that is reasonably competitive with existing alternatives that could or do meet similar needs. Each technology listed is categorized into one of three groups based on its generation attributes. These three categories are Baseload, Renewable, and Energy Storage.

Emerging Baseload Technologies

Enhanced Geothermal Systems (EGS)

EGS allow for generation of geothermal electricity without having a naturally occurring trifecta of heat, water, and permeable rock traditionally required for existing geothermal electricity generation facilities in the world today. EGS effectively uses technology such as advanced drilling and injection methods to enhance or artificially create one or more of the aforementioned trifecta to generate electricity.

One of two main benefits of EGS versus traditional geothermal systems is they can be implemented virtually anywhere, as opposed to traditional geothermal being limited by very limited by geographic location. The other main benefit is that the vast majority of feasibly accessible geothermal energy sits in hot dry impermeable rock deeper than 3 kilometers under the surface, which is very technologically and economically difficult to extract. However, that same geothermal energy underneath just the mainland United States is enough to serve the entire world's current energy needs for over a thousand years. As the technology and processes mature in the years and decades to come, the cost benefit analysis could put EGS at the forefront of baseload electricity generation. Figures E-1, E 2, and E 3 below show geothermal temperature distributions at 3.5, 6.5, and 10 kilometers respectively underneath the surface of the mainland United States.

Figure E-1 – Geothermal potential at 3.5 km depth

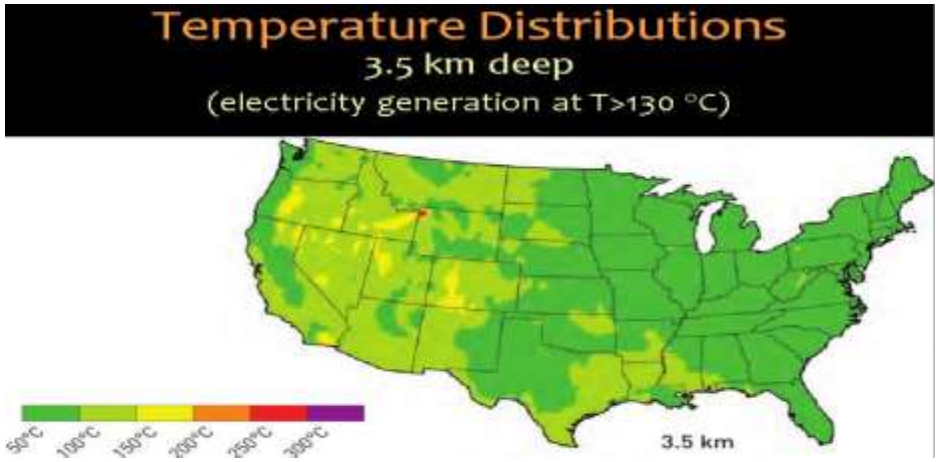


Figure E-2 – Geothermal potential at 6.5 km depth

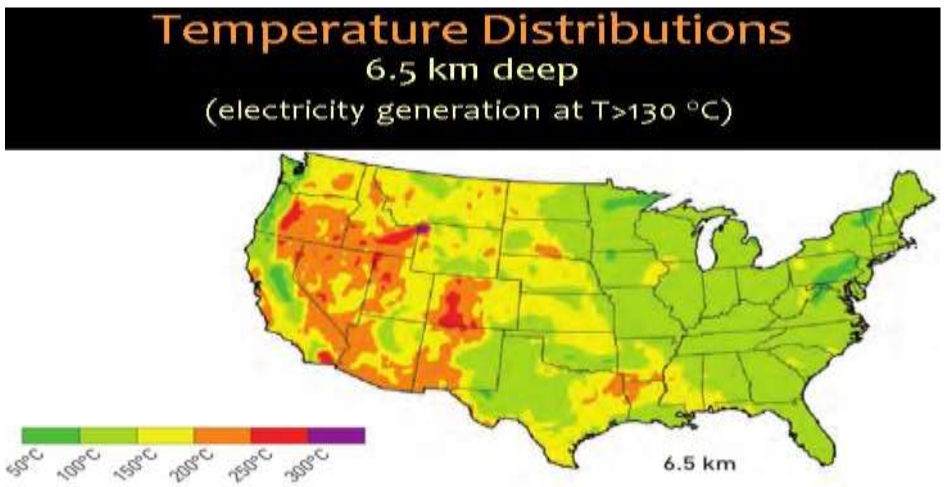
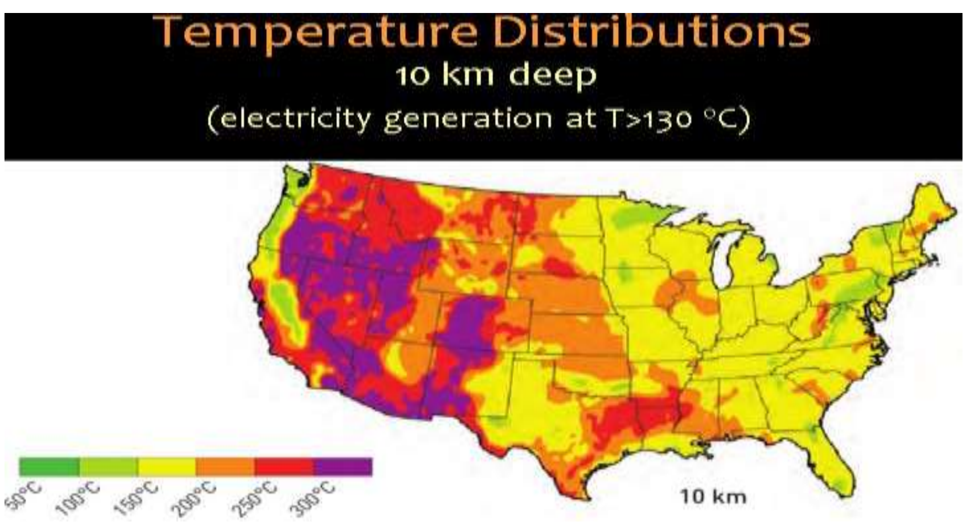


Figure E-3 – Geothermal potential at 10 km depth



Small Modular Reactors (SMR)

SMR are nuclear fission reactors that are significantly smaller than traditional nuclear fission reactors and modularized such that they are manufactured at an industrial facility and then transported and assembled onsite, with the end-goal being a cheaper, safer, and more reliable version of nuclear power. Much like conventional nuclear fission reactors, SMR come in many different technoloical configurations. These configurations include molten salt, gas-cooled, lead-cooled, boiling water, and pressurized water reactors as the most common designs.

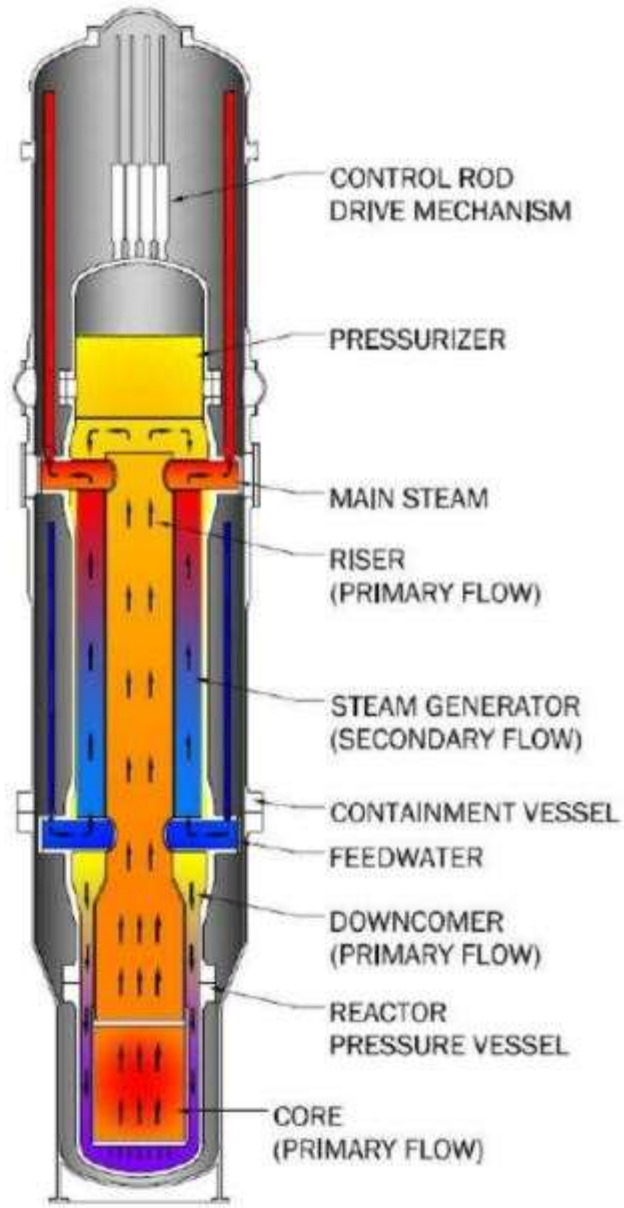


Figure E-4 – Pressurized Water SMR design

Currently, the only part of the world that has operational SMR units is Russia, but there are a two unique SMR projects that have passed the design stage and are now in the licensing stage here in the United States. These projects are headed by General Electric Hitachi and NuScale companies, with the latter anticipating the completion of its first commercially operational facility before the end of this decade.

A future with SMR playing an important part of baseload power capacity is promising. As the technology comes to fruition here in the United States in the years to come, the PUD will be monitoring SMR progress in potential, safety, generation attributes, and cost.

Emerging Renewable Technologies

Offshore Wind Turbines

Offshore wind turbines have been operational since at least the early 1990's, with the first commercially operational site being off the coast of Denmark. Offshore wind offers a large potential when compared against traditional wind turbines on land. This is because, generally speaking, wind speeds are faster and more reliable offshore than onshore. Additionally, because they are built or deployed at sea, they don't have the same restrictions in size due to land or transportation requirements. Functionally, they work the same as land-based turbines, but require unique infrastructure in order to properly install them and transmit power from the sea to the land. This required infrastructure is what plays a large part in making the cost of offshore wind relatively uncompetitive with other comperable resources, at least here in the United States. It should be noted that in Europe, offshore wind is competitve in cost, and has about two-thirds of the world's total offshore wind capacity. World wide, offshore wind makes up less than 1% of total power generation.

Figure E-5 – Diagram of a conceptual offshore wind installation

Offshore wind installations come in two different types of technology. First is the fixed bottom offshore wind turbine. This technology makes up nearly all offshore wind turbine installations in the world. It employs, as the name suggests, a fixed foundation that is embedded deep into the seabed, with the tower, blades, and turbine itself sitting well above the water line. Figure E-6 on the right displays various types of fixed bottom foundations. Fixed bottom turbines sit in shallow waters, typically at no more than 50 meters depth. The limitation of deployment to shallow waters means that this type is often close to the shore, thus limiting feasible deployment areas.

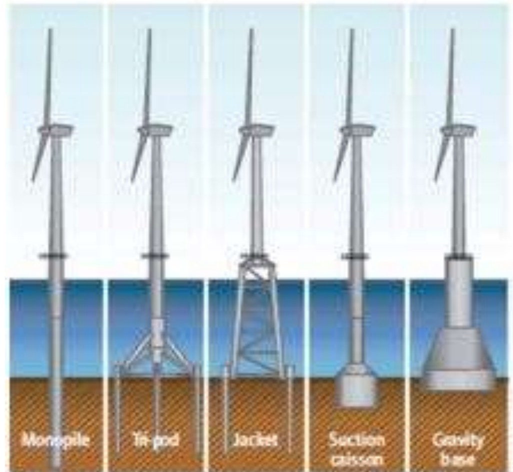


Figure E-6 – Various Fixed Bottom Foundations

The second type of offshore wind is a relatively new technology called the floating bottom, with a first ever deployment in 2007 over 13 miles from shore. Just as it sounds, the foundation is instead a floating structure that is anchored to the ground by tethering systems. Figure E-7 on the right displays various types of floating bottom foundations. The benefit of using floating bottoms is that they can be deployed significantly farther off from shore at depths in excess of 150 meters, where wind speeds are generally higher than in shallower waters. This extra depth allowance mitigates some of the major limitations of offshore wind, but it can add cost by requiring more mileage of submarine cables and related transmission infrastructure.

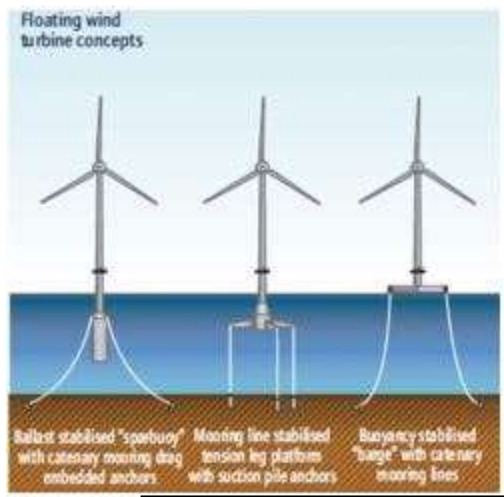


Figure E-7 – Various Floating Bottom Foundations

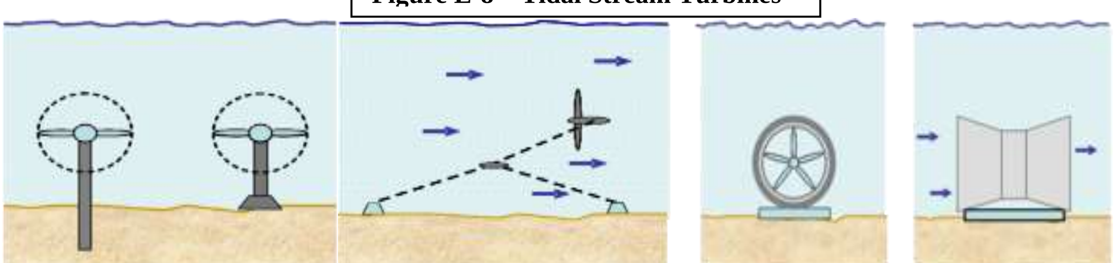
In the Pacific Northwest, the shallow water requirements and necessary wind speed distributions make the fixed bottom technology a bad fit overall. However, the floating bottom technology has much potential, particularly in Oregon. Within three nautical miles of of Oregon's coast, NREL finds over 60 GW of technically harvestable capacity. This capacity would need to be harvested using floating platforms due to the increased depth. As the floating technology matures and drops in price, as it has been and is projected to continue to do so, it may prove a valuable resource for the future capacity and energy needs of our customer-owners.

Tidal Power

Tidal energy comes from naturally occuring tidal forces in the oceans. These forces are the result of gravitational attraction exerted by celestial bodies, particulary the moon and to a lesser extent the Sun, in conjunction with the Earth's natural rotation and spin. Currently, the largest tidal-based power generation facility is 254 MW, located in South Korea. Tidal power generation comes in two primary types, with a few other types still early in the research and development stage.

The first primary type is called tidal stream generation. It harnesses the kinetic energy of the tides using a tidal stream generator, commonly called a tidal turbine. Functionally, these generators work similarly to a wind turbine, except harvesting water movement instead of wind movement. Because water is roughly 800 times as dense as air, these turbines are more expensive due to the additional structural engineering requirements necessary to operate. However, they can capture significantly more energy than a regular wind turbine of the same size due to the huge increase of flow density. These generators simply harvest energy from the tide as it comes and goes, and have minimal environmental impact. Figure E-8 below shows various types of tidal generators.

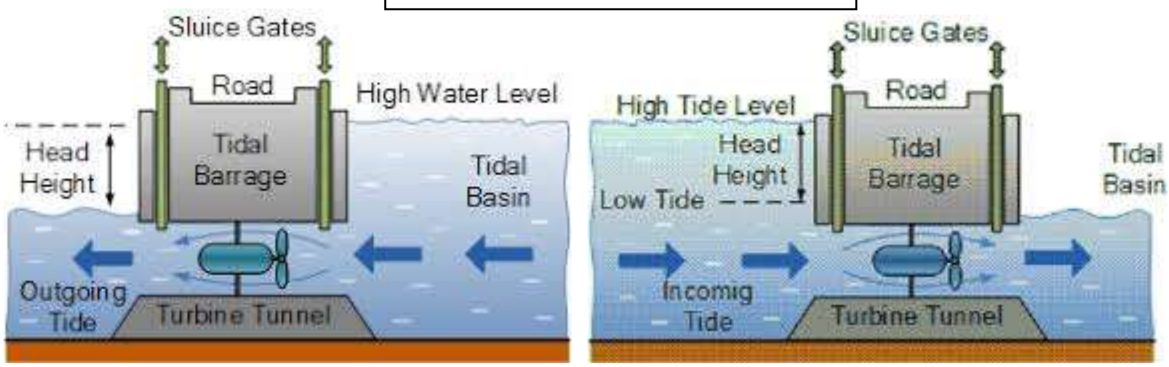
Figure E-8 – Tidal Stream Turbines



Mounted Axial *Cable Tethered* *Shrouded*

The other primary type of tidal power generation is called tidal barrage. It captures the potential energy of the tides as they come in and out of a bay, basin, or river using a barrage, which is similar to a dam. Turbines installed on the barrage wall can generate power as the water flows into and out of the barrage construct during high and low tides. The aforementioned 254 MW facility in South Korea utilizes the tidal barrage method, as does another facility in France at 240 MW. In fact, nearly all installed tidal generation capacity worldwide utilizes the tidal barrage method. Unfortunately, this method also has a large environmental impact and very expensive upfront cost due to the barrage structure. It is likely that this method of tidal power would require a barrage to be built for other reasons besides generation due to the high environmental impact.

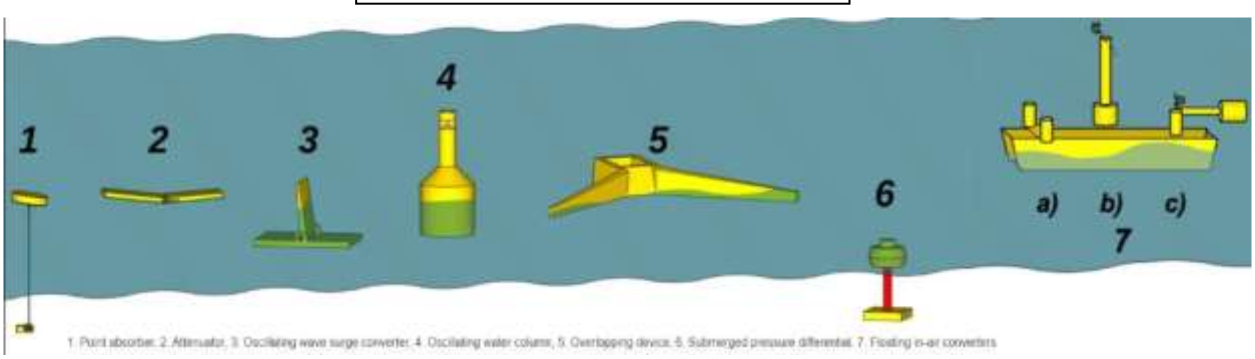
Figure E-9 – Tidal Barrage Concept



Wave Power

Wave power, like tidal power, is generated from moving water in the oceans. However, unlike tidal energy, wave energy is extracted at or near the surface level of the water from wind-generated waves. This energy can be converted to electricity using wave energy converters (WEC). Figure E-10 below displays various types of WEC.

Figure E-10 – Wave Energy Converters



Several different technological types of WEC have been deployed, or are planned to be deployed in various locations all over the world. However, the local environmental impacts of these devices is not entirely known, but can be considerable over time. To date, only about 10 MW of wave power capacity has been installed worldwide, with coastal worldwide potential to be greater than 2 TW.

For the Pacific Northwest area, the coastal areas off of Oregon and Southern Washington have been identified as highly ranked by NREL for future wave power development. As the technology is matures and is implemented further, it is expected that cost would drop, making wave power a potential resource for the Pacific Northwest of the future.

Emerging Energy Storage Technologies

Hydrogen Fuel Cell Energy Storage

Hydrogen fuel cell technology is hardly new, as the first known invention was in the late 1830s. Unlike a typical electro-chemical battery, a fuel cell is designed to replenish so long as hydrogen and, most often, oxygen are flowing. A big benefit of fuel cells is their reliability in that they lack moving parts and don't require any sort of combustion. Additionally, hydrogen cells suffer from very little from storage degradation, which creates potential for using hydrogen fuel cells as a very long dispatch duration energy storage resource.

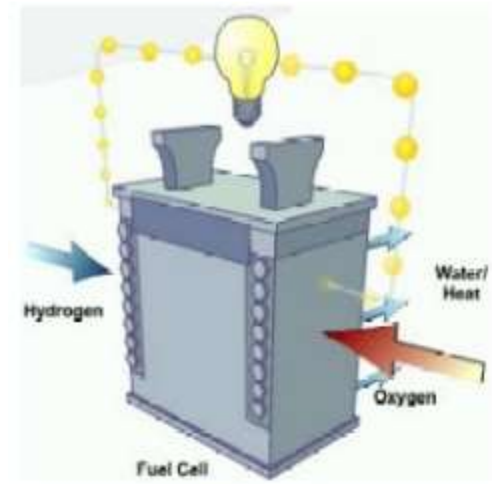


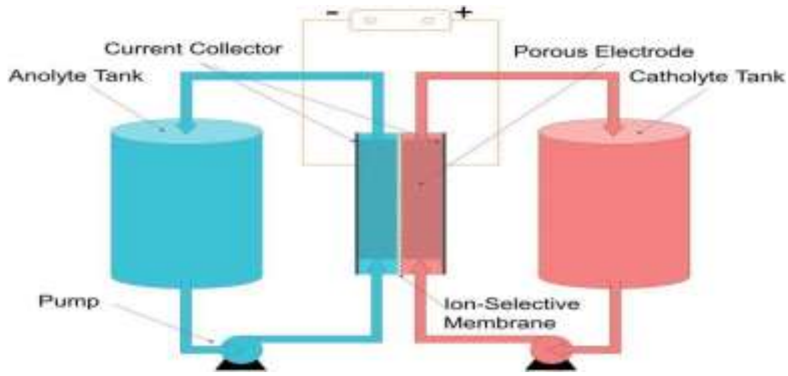
Figure E-11 – Hydrogen Fuel Cell

The general concept and useful function of a hydrogen fuel cell for utility-scale energy storage is that offpeak electricity can be used to create hydrogen via electrolysis. The hydrogen is then phyiscally stored and then later re-electrified during peak hours. This process unfortunately suffers from a rather low roundtrip efficiency, especially when compared to other existing energy storage options, between 30 and and 50 percent. However, the long life cycle, low degradation, non-specific siting requirements, and very long dispatch durations make hydrogen fuel cells an attractive future option as the technology matures and becomes more widely commercially available at utility scale and at a competitive price point.

Flow Batteries

Flow batteries, sometimes called redox batteries, are electro-chemical cells where two chemical components are dissolved in liquids and pumped through two different sides of a membrane. This process allows an electric current to flow through the membrane while these liquids circulate. Figure E-12 below shows a diagram of a typical flow battery.

Figure E-12 – Flow Battery



The most common type of flow battery is a rechargeable type based on the chemical element vanadium. Currently, these batteries suffer from lower roundtrip efficiency when compared to alternatives such as lithium-ion batteries, and cost similar amounts for a short duration storage operation. They also suffer from relatively low energy density and low rates of charge and discharge. It should be noted that newer generations of vanadium batteries are in development with the goals of meeting or exceeding current lithium-ion roundtrip efficiencies and increasing energy density. As it stands today, longer duration storage is a much more attractive option for the flow batteries, because it is not necessary to double the batteries, only the size of the storage tanks. Furthermore, flow batteries do not suffer the same levels of severe degradation than that of traditional lithium-ion batteries during their lifetime and use. Lifespans can approach or exceed 30 years before degradation starts having a relevant impact on the system operations.

Additional types of flow batteries exist and are in production and further development, utilizing different chemical compounds such as zinc-bromide. Sandia National Laboratories has found that this type of flow battery has slightly cheaper capacity and energy storage capital costs, but found issues with scalability as well as lower roundtrip efficiency.

Overall, flow batteries offer a potential solution to mid and long duration storage needs, but the technology is not quite yet mature enough to reach roundtrip efficiencies and energy density to be competitive on a utility-scale with other options. However, as the newer generations of flow battery technology come to fruition, and in particular the newer generations of vanadium flow batteries, it is very possible that this resource could be considered at the right relative price point and storage attributes.

Flywheel Energy Storage

Flywheel energy storage (FES) works by accelerating a heavy mass (a flywheel) at a very high rotational velocity in order to store energy in the form of rotational kinetic energy. This energy is discharged as the rotational velocity of the flywheel lessens, and can be harnessed to create electricity. Figure E-13 to the right displays a typical flywheel and its important components. FES systems store and discharge electricity in the form of direct current, and thus could pair well with solar photovoltaic generation facilities. In fact, there are a few of such planned facilities at utility-scale in Australia and Asia in the next few years.

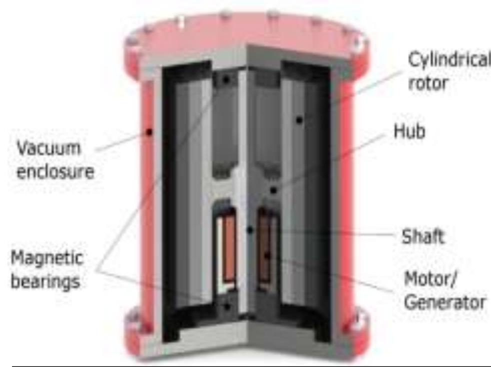


Figure E-13 – Flywheel Energy Storage

Some major benefits of FES are long lifecycles at over 30 years, very minimal operational degradation, and good end of life qualities depending on the material used such as steel or titanium. Some drawbacks include siting constraints, and a low amount of publicly available operational and test data as the technology is still new, particularly at utility-scale. As other parts of the world begin implementing FES, particularly when paired onsite with solar generation, SnoPUD looks forward to gathering and analyzing future operational and cost data for potential future modeling.

Appendix F. Supply Side Resource Generation Modeling

Biomass and Geothermal Generation Attributes

Biomass and geothermal are considered as traditional baseload resources and their generation attributes are based off nearly identical assumptions. They are assumed to be generating a static amount of energy on an hour-to-hour basis throughout any given year of operation. The difference between the two is only in annual capacity factor (CF) assumptions. Biomass is assumed at 60% and geothermal is assumed at 80%.

Solar PV Generation Attributes

To determine an 8760 solar PV generation profile, geographic sites must be chosen and specific data relevant to solar PV generation must be gathered such as Global Horizontal Irradiance (GHI) and Plane of Array Irradiance (POA), and the system power output (MW_{AC}). Then, mathematical relationships between these data series are established to produce probabilistic generation profiles. The two chosen sites for solar PV installations are Yakima County, WA and Snohomish County, WA for the larger and smaller scale sites, respectively. For the larger scale Yakima site, a higher ILR at 1.4 is chosen alongside a more traditional choice of a 1.2 ILR.

First, 22 years of historic 8760 GHI data are gathered from NREL's National Solar Radiance Database (NSRDB) and then averaged. Then, the 8760 POA and power output data is gathered from NREL's PVWatts website. However, PVWatts offers POA and power output data for a single theoretical average year. So, a mathematical relationship between GHI and POA is established with an R^2 value of 0.978 using machine regression learning. This allows the creation of a full 8760 generation distribution profile for all 22 historic years. This distribution is then aggregated and forecast for each year of the study period on a P50 and P5 basis. This process is repeated for each solar PV site location and ILR as needed.

Wind Generation Attributes

Wind generation profiles vary by time and site location. The two sites chosen are Columbia Gorge and Central Montana. The methodologies to determine probabilistic forecast generation profiles varies for each site.

For Columbia Gorge wind, historic 8760 wind and generation data are gathered from existing onsite PUD-contracted wind generation and analyzed. A larger net CF scalar is mathematically applied to better match the larger modern and future wind turbine area sweeping sizes and power coefficients. This net CF scalar approximation is determined from both NREL's 2020 Annual Technology Baseline report as well as the Northwest Power and Conservation Council's 2021 Power Plan. This process allows the creation of a full 8760 future generation profile on a P50 and P5 basis.

For Montana wind, a combination of historic 8760 wind data from the Northwest Power and Conservation Council and from NREL's Wind Prospector is gathered and analyzed. Analysis determined that the Council's data better matches a P5 probabilistic generation profile, while data from the Wind Prospector is a better fit for a P50 profile. A larger net CF scalar is applied here as well, befitting for a potential future Montana location.

Run-of-the-River Hydroelectric Generation Attributes

All historic data gathered for Run-of-the-River Hydroelectric (RotR) attributes comes entirely from existing PUD-owned and operating RotR projects. This historic data is used to construct P5 and P50 generation profiles for future years relevant to this IRP.

Renewable + Storage Generation and Storage Attributes

For these baseload resources, the storage is assumed to be AC-coupled 4-hour lithium-ion batteries and is modeled at half the nameplate capacity of the renewable generation component. The above renewable 8760 probabilistic generation profiles of Columbia Gorge Wind, Yakima Solar PV, and RotR Hydro are each slightly modified. Four hours' worth of off-peak generation, rather than being routed onto the grid, are instead routed into the paired onsite battery storage (which includes roundtrip efficiency losses) and distributed later to serve peak evening load in addition to the amount already being served by the renewables. Effectively, this makes for significantly better P5 HLH and PW generation profiles, but at the costs of roundtrip efficiency losses combined with the total resource costs of the storage component, which are considerably high.

Storage Dispatch Attributes

All standalone storage resources are run through an hourly dispatch model, based on hourly dispatch duration and variable cost of the resource, to determine the hours of the year the storage resource would be used for either market arbitrage or capacity need. This dispatch model is comprised of historic hourly generation data from all PUD-owned and contracted resources from 2012 through 2019, historic load data matching each of those hours, and historic market energy price data from Mid-C matching each of those hours. These time-matching historic hourly data sets combined with market price forecasts (relative to each portfolio scenario) are used to create 8760 probabilistic dispatch attributes, which include roundtrip efficiency losses relevant to the storage technology type.

Appendix G. Wholesale Market Energy Prices

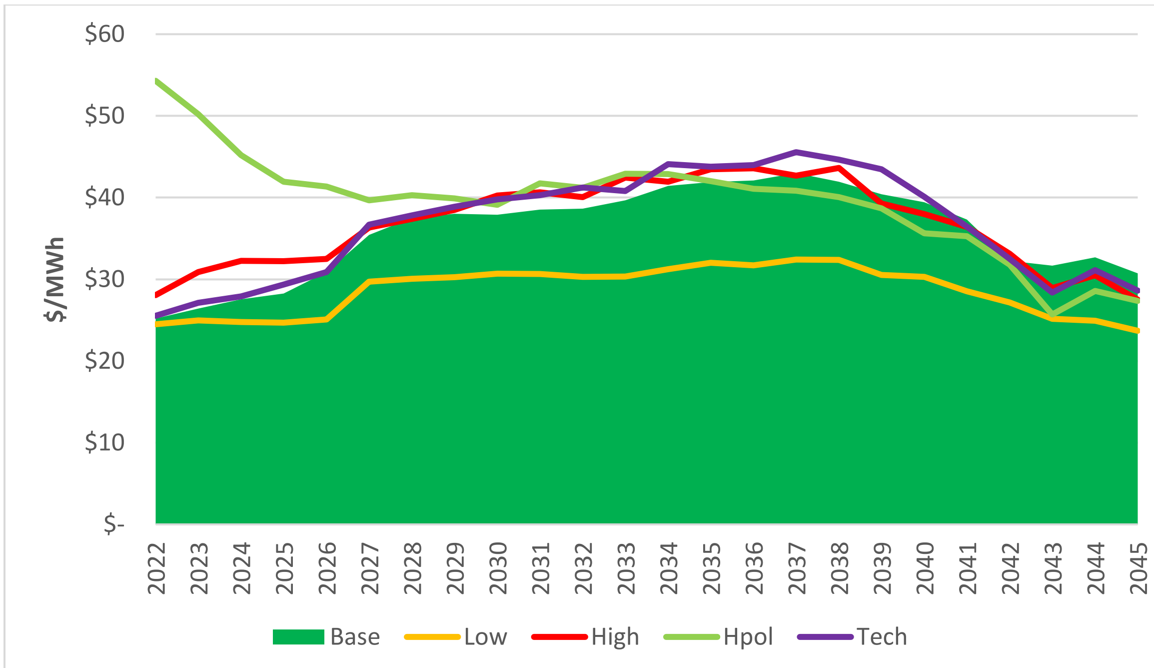
Five unique models to forecast wholesale market energy prices throughout the study period were developed for the eight scenarios in this IRP. Each price forecast model assumes unique inputs as discussed in Section 4 of this IRP. All market price forecasts include the societal cost of carbon at a 2.5% annual discount rate. The table below shows the market price forecasts and their respective applicable scenarios.

Market Price Forecast Model	Scenario(s)
Base Forecast	Base Case, Less BPA, High Electrification
Low Forecast	Low Growth
High Forecast	High Growth
High Policy Forecast	High Policy
High Technology Forecast	High Technology

The matrices and graphs below display the modeled price forecasts for the annual average, monthly average, monthly average on-peak, and monthly average peek week respectively.

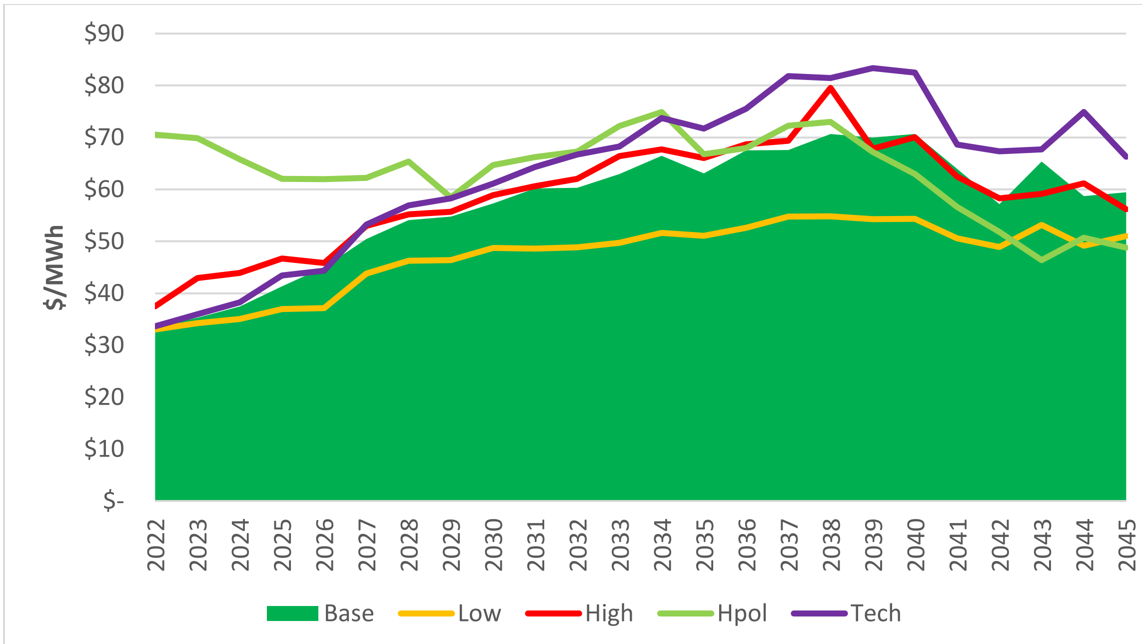
Annual Average Market Price Energy Forecasts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	$25.21	$26.41	$27.54	$28.26	$30.89	$35.44	$37.50	$38.02	$37.89	$38.53	$38.65	$ 39.67	$ 41.42	$41.90	$ 42.10	$ 43.00	$ 41.95	$ 40.41	$ 39.42	$37.33	$32.28	$ 31.68	$ 32.70	$30.72
Low	$24.49	$24.99	$24.76	$24.68	$25.10	$29.69	$30.06	$30.25	$30.68	$30.66	$30.30	$ 30.34	$ 31.22	$32.03	$ 31.70	$ 32.42	$ 32.39	$ 30.53	$ 30.29	$28.55	$27.14	$ 25.18	$ 24.92	$23.70
High	$28.05	$30.87	$32.25	$32.20	$32.50	$36.34	$37.40	$38.49	$40.27	$40.64	$40.07	$ 42.44	$ 41.94	$43.46	$ 43.60	$ 42.70	$ 43.63	$ 39.27	$ 37.98	$36.42	$33.11	$ 28.93	$ 30.49	$27.50
Hpol	$54.30	$50.20	$45.19	$41.94	$41.35	$39.67	$40.27	$39.89	$39.12	$41.75	$41.21	$ 42.93	$ 42.90	$42.00	$ 41.06	$ 40.86	$ 40.07	$ 38.68	$ 35.61	$35.29	$31.77	$ 25.69	$ 28.57	$27.37
Tech	$25.53	$27.13	$27.91	$29.36	$30.88	$36.68	$37.83	$38.90	$39.78	$40.31	$41.22	$ 40.79	$ 44.11	$43.77	$ 43.98	$ 45.56	$ 44.64	$ 43.48	$ 40.11	$36.45	$32.48	$ 28.40	$ 31.11	$28.63



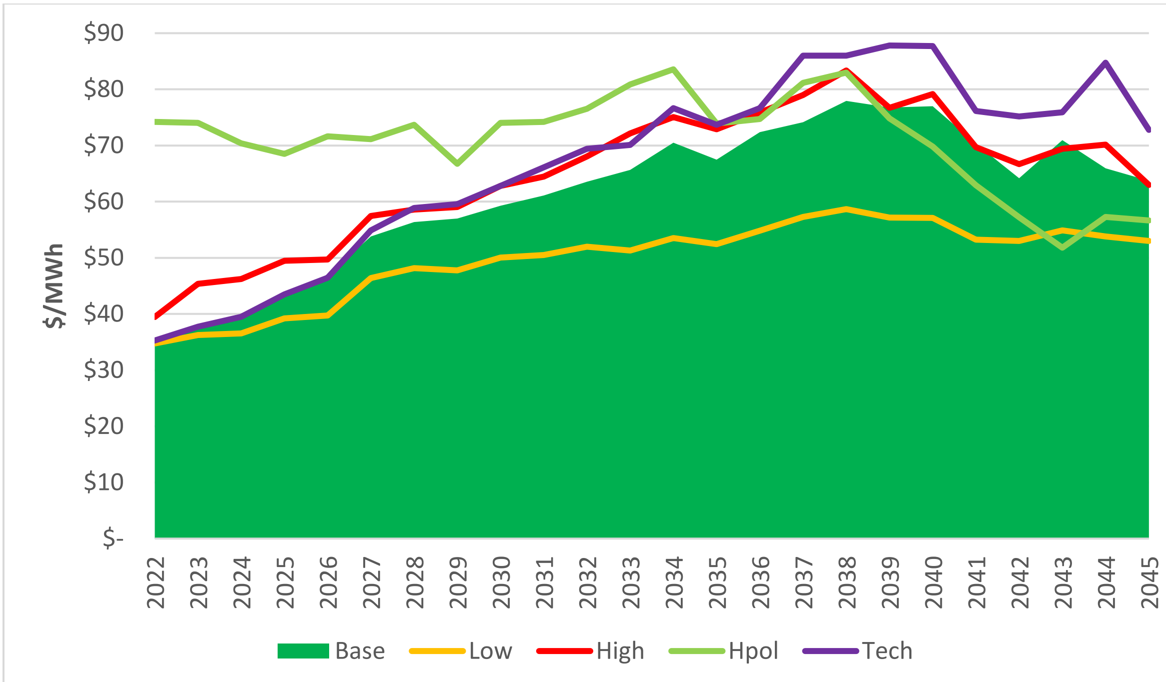
Winter Seasonal Average Monthly Market Price Energy Forecasts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	$33.42	$35.29	$37.48	$41.36	$45.02	$50.46	$54.08	$54.74	$57.29	$60.21	$60.33	$ 62.96	$ 66.50	$63.08	$ 67.53	$ 67.57	$ 70.66	$ 70.00	$ 70.68	$63.95	$57.18	$ 65.34	$ 58.73	$59.46
Low	$33.03	$34.25	$35.03	$36.96	$37.17	$43.79	$46.28	$46.39	$48.71	$48.60	$48.87	$ 49.68	$ 51.61	$51.04	$ 52.61	$ 54.74	$ 54.82	$ 54.27	$ 54.35	$50.60	$48.93	$ 53.19	$ 49.15	$51.01
High	$37.49	$42.91	$43.93	$46.72	$45.85	$52.96	$55.21	$55.67	$58.90	$60.61	$62.04	$ 66.40	$ 67.69	$66.02	$ 68.67	$ 69.39	$ 79.54	$ 67.81	$ 70.07	$62.44	$58.25	$ 59.16	$ 61.18	$56.16
Hpol	$70.55	$69.88	$65.80	$62.02	$61.96	$62.19	$65.36	$58.49	$64.71	$66.25	$67.28	$ 72.20	$ 74.90	$66.76	$ 67.92	$ 72.28	$ 72.98	$ 67.18	$ 62.93	$56.60	$51.78	$ 46.38	$ 50.68	$48.76
Tech	$33.65	$35.98	$38.25	$43.45	$44.33	$53.22	$56.92	$58.27	$61.11	$64.29	$66.72	$ 68.26	$ 73.75	$71.72	$ 75.55	$ 81.80	$ 81.42	$ 83.35	$ 82.49	$68.63	$67.36	$ 67.72	$ 74.88	$66.27



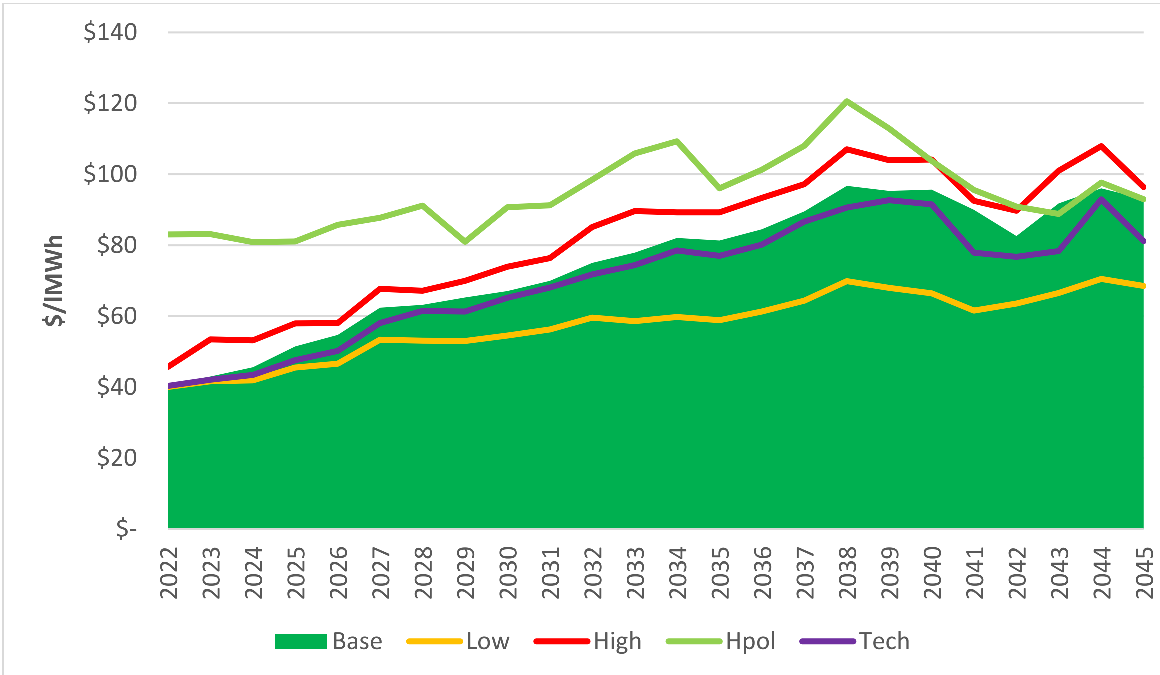
Winter Seasonal Average Monthly On-Peak (HLH) Market Energy Price Forecasts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	$35.29	$37.30	$39.50	$43.92	$46.84	$53.81	$56.36	$57.00	$59.26	$61.09	$63.53	$ 65.66	$ 70.47	$67.48	$ 72.39	$ 74.16	$ 77.94	$ 76.74	$ 76.99	$70.33	$64.14	$ 70.93	$ 65.92	$63.71
Low	$34.74	$36.23	$36.51	$39.20	$39.75	$46.38	$48.18	$47.76	$50.05	$50.47	$51.98	$ 51.29	$ 53.54	$52.46	$ 54.83	$ 57.30	$ 58.67	$ 57.15	$ 57.13	$53.21	$52.99	$ 54.91	$ 53.81	$53.00
High	$39.46	$45.38	$46.20	$49.45	$49.70	$57.44	$58.58	$59.05	$62.83	$64.47	$68.07	$ 72.14	$ 75.03	$72.87	$ 75.88	$ 79.00	$ 83.35	$ 76.69	$ 79.15	$69.68	$66.68	$ 69.42	$ 70.17	$62.97
Hpol	$74.21	$74.05	$70.36	$68.48	$71.65	$71.14	$73.71	$66.72	$74.02	$74.21	$76.53	$ 80.88	$ 83.56	$73.89	$ 74.71	$ 81.18	$ 82.98	$ 74.83	$ 69.84	$62.90	$57.22	$ 51.80	$ 57.29	$56.64
Tech	$35.27	$37.72	$39.49	$43.51	$46.42	$54.89	$58.85	$59.58	$62.79	$66.09	$69.41	$ 70.12	$ 76.63	$73.67	$ 76.63	$ 85.99	$ 86.01	$ 87.80	$ 87.72	$76.11	$75.16	$ 75.93	$ 84.76	$72.80



Winter Seasonal Average Monthly Peak Week (PW) Market Energy Price Forecasts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	$40.61	$42.99	$45.60	$51.42	$54.69	$62.38	$63.22	$65.25	$67.07	$69.98	$75.05	$ 77.92	$ 82.09	$81.29	$ 84.52	$ 89.51	$ 96.74	$ 95.34	$ 95.66	$89.96	$82.58	$ 91.75	$ 96.02	$93.06
Low	$40.04	$41.61	$41.91	$45.50	$46.62	$53.39	$53.07	$53.01	$54.51	$56.21	$59.56	$ 58.59	$ 59.76	$58.82	$ 61.30	$ 64.39	$ 69.88	$ 67.92	$ 66.42	$61.53	$63.50	$ 66.49	$ 70.49	$68.47
High	$45.71	$53.41	$53.21	$57.98	$58.01	$67.67	$67.18	$69.95	$73.88	$76.32	$85.14	$ 89.63	$ 89.23	$89.26	$ 93.36	$ 97.21	$107.00	$103.97	$104.11	$92.47	$89.68	$101.01	$107.94	$96.42
Hpol	$83.06	$83.13	$80.87	$81.02	$85.78	$87.75	$91.14	$80.97	$90.67	$91.27	$98.46	$105.90	$109.32	$96.06	$101.25	$108.02	$120.58	$112.90	$103.77	$95.57	$90.87	$ 88.82	$ 97.66	$92.95
Tech	$40.33	$42.03	$43.40	$47.54	$50.22	$58.01	$61.48	$61.30	$65.14	$68.09	$71.75	$ 74.39	$ 78.49	$77.02	$ 80.11	$ 86.66	$ 90.64	$ 92.73	$ 91.54	$77.87	$76.75	$ 78.38	$ 92.94	$81.18



Appendix H. Emissions

Forecast emissions present in any scenario in this IRP come entirely from assumptions of long-term and short-term wholesale market energy purchases. Three different evolving emissions factors, based on a defined WECC wide deployment scaled down to WA State, were used to calculate the forecast emissions in each scenario. The table below shows the emissions factor model and their respective applicable scenarios.

Emissions Factor Model	Scenario(s)
Base Factor	Base Case, Low Growth, High Growth, Less BPA, High Climate Change, High Electrification
High Policy Factor	High Policy
High Technology Factor	High Technology

Attachments J-1 and J-2 below show the emissions factors, which are in units of metric tons of carbon dioxide equivalent per megawatt-hour (mtCO2e / MWh).

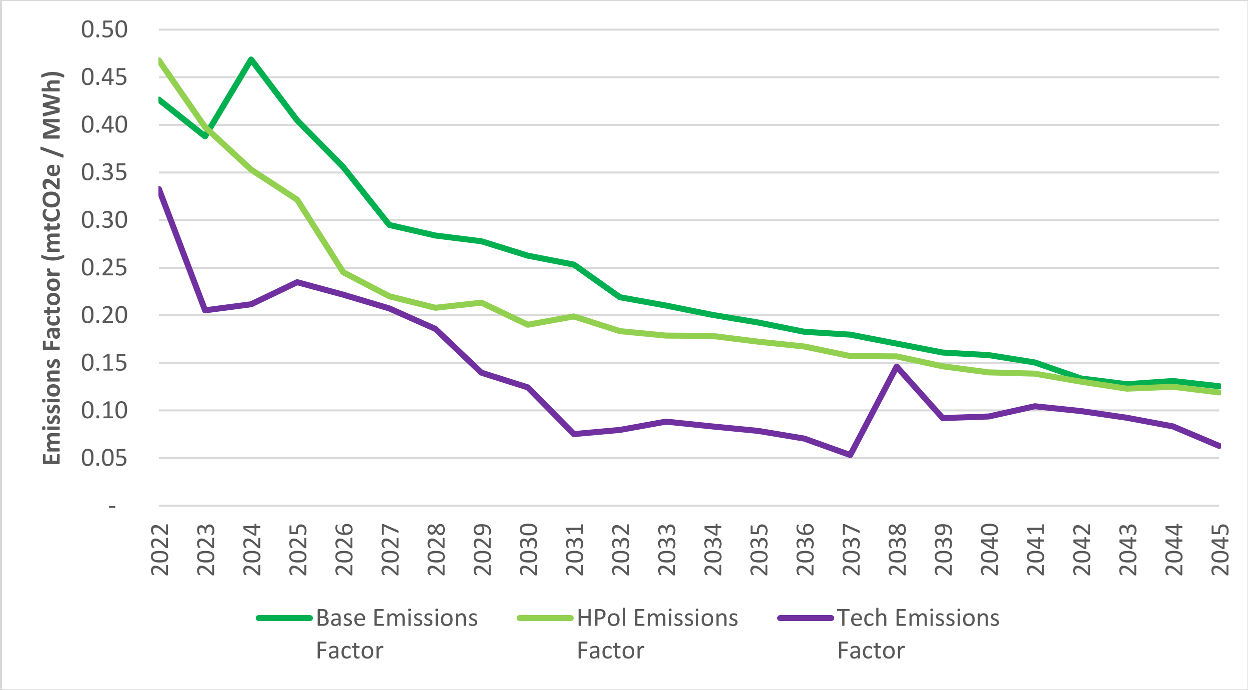
Attachment J-1

Emissions Factors Table

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Base	0.426	0.388	0.469	0.405	0.356	0.295	0.284	0.278	0.263	0.253	0.219	0.210	0.201	0.193	0.183	0.180	0.170	0.161	0.158	0.150	0.134	0.128	0.131	0.126
HPol	0.468	0.398	0.353	0.321	0.245	0.220	0.208	0.213	0.190	0.199	0.183	0.179	0.178	0.172	0.167	0.157	0.157	0.146	0.140	0.139	0.130	0.123	0.125	0.119
Tech	0.333	0.205	0.212	0.235	0.222	0.207	0.186	0.140	0.124	0.075	0.079	0.088	0.083	0.079	0.070	0.053	0.146	0.092	0.094	0.104	0.099	0.092	0.083	0.063

Attachment J-2

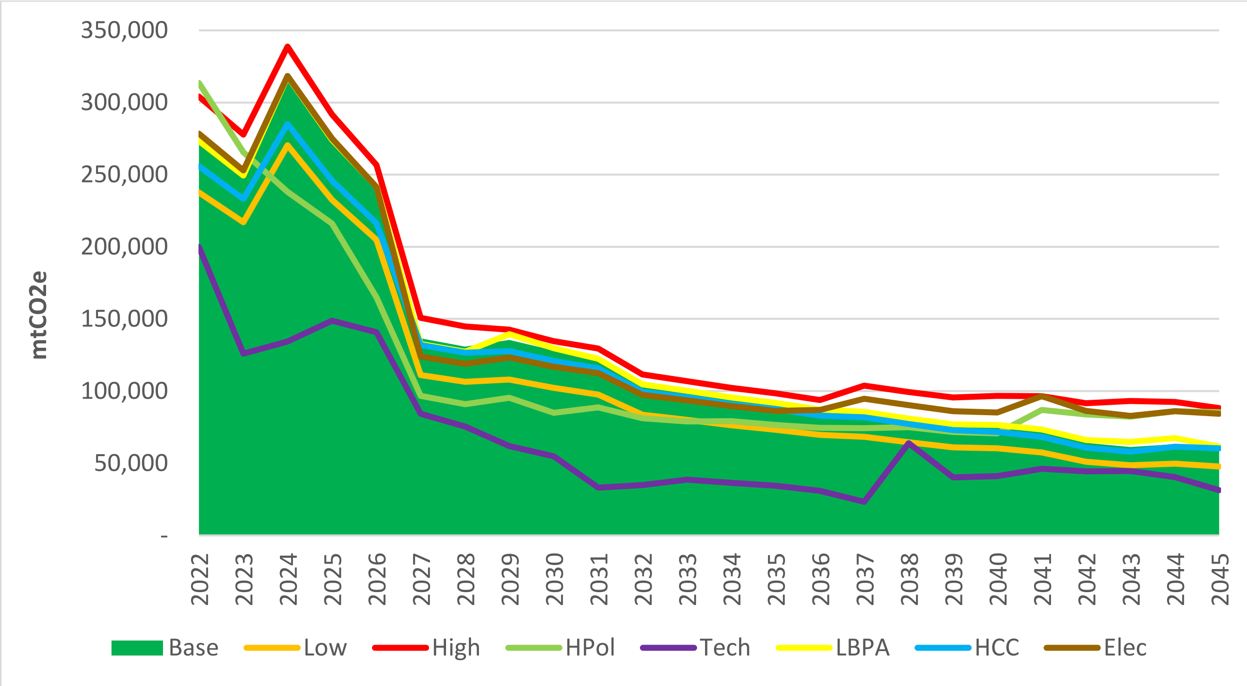
Emissions Factors by Type over Full Study Period



Each scenario requires different amounts of market energy purchases to be made over different years of the study period in order to satisfy portfolio needs. Attachments J-3 through J-5 below show the yearly emissions forecast, average yearly, and total cumulative by scenario over the study period.

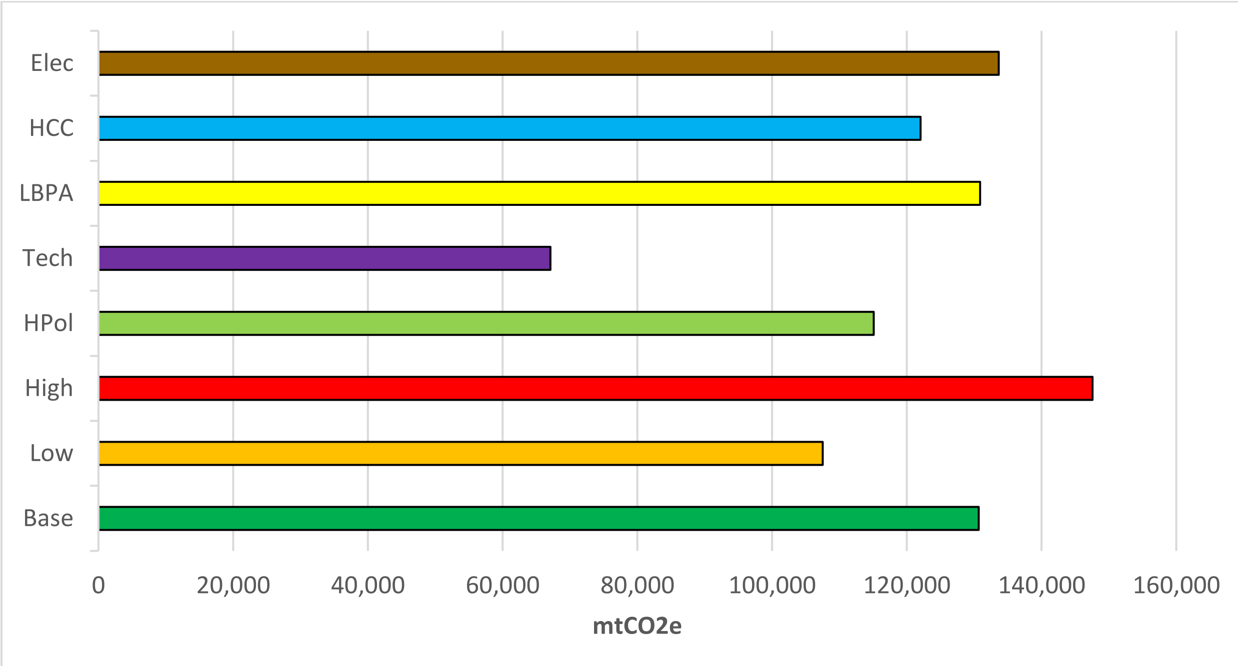
Attachment J-3

Yearly Emissions by Scenario over Full Study Period



Attachment J-4

Yearly Average Emissions by Scenario



Attachment J-5

Total Cumulative Emissions by Scenario over Full Study Period