SNOHOMISH COUNTY PUD NO. 1

2019 Update to the 2017 Integrated Resource Plan

2020 through 2039

Adopted

May 7, 2019

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Section 1: Executive Summary

The results of the 2019 Update to the 2017 Integrated Resource Plan indicate Snohomish PUD ("District" or "PUD") can adequately meet its customers' annual electricity demand – with its forecasted existing and committed resources and conservation acquisitions – for the 2020 through 2039 planning horizon.

On a seasonal basis, the 2019 Update shows the District has a relatively small near term winter capacity need in years 1-5. With forecast total cumulative new conservation acquisition to reach 70 aMW through 2029, the District's long term capacity need that would serve both winter and future summer needs is deferred until the late 2020's. These results are similar to the 2017 IRP findings, but are smaller in scale due to the effects of conservation acquisition and codes and standards that have accrued and moderated load growth expectations. The impact of more modest load growth is:

1. The PUD requires a smaller quantity of renewable energy and renewable energy credits as a percentage of its retail load to comply with the Energy Independence Act (EIA); and

2. The PUD is not expected to reach its contract high water mark or maximum amount of power it is eligible to purchase from the Bonneville Power Administration (BPA), at cost.

The PUD purchases over 80% of its power supply from BPA, which is comprised predominantly of hydroelectric generation. The single most significant portfolio risk the PUD faces in meeting its customer needs is the impact of low hydro conditions.

There are other uncertainties that create risks and rewards to the District's long-term plan for its power supply portfolio. These include carbon and clean energy policies, next steps on the

Columbia River Treaty negotiations between the U.S. and Canada, changes to the biological opinion governing operation of the Federal Columbia River Power System (FCRPS), introduction of spring spill regimes or dam breaching that create operational impacts on the FCRPS, from which the region – including the PUD – derives the majority of its carbon free energy supply. These uncertainties, in combination with the advancement of electrification of the transportation sector, emergence of regional energy markets, and increased volatility in the wholesale energy market during times of oversupply and system infrastructure constraints are just a few of the examples of why long range resource planning and the testing of a portfolio's resiliency is an integral part of how the PUD can address its changing customer and energy needs and how energy can be delivered sustainably in a safe and reliably manner to the communities we serve.

Section 2: Overview

BACKGROUND AND APPROACH

Snohomish PUD's 2017 Integrated Resource Plan ("IRP") was adopted by the Board of Commissioners in April 2018 and covered the 2018 through 2037 study period. It was filed with the Washington State Department of Commerce in August 2018, and forms the foundation for the 2019 Update to the 2017 IRP analysis.

The 2017 IRP's Long Term Resource Strategy included the acquisition of 93 aMW of new cumulative annual conservation by 2027, 114 aMW by 2037, and a 50 MW short term capacity contract to meet near term (2018 through 2022) winter capacity needs. Conservation's cumulative contribution to the PUD's existing resources and forecast winter needs deferred the need to acquire a 116 MW long-term capacity supply side resource until 2028. The strategy also included the addition of customer owned distributed energy resources and procurement of unbundled renewable energy credits (REC) to satisfy state renewables compliance requirements.

The 2019 Update was based on the same guiding principles and analytical framework as the 2017 IRP as follows:

1. Meet load growth first by pursuing all cost-effective conservation;
2. Understand the probabilistic range of available energy and capability from the PUD's existing and committed resources and range of impacts on the load resource balance across the 20-year study period;
3. For future load growth not met by the District's existing and committed resources and new conservation acquisitions, pursue clean, renewable resource technologies taking into consideration resource options that provide the optimum balance of environmental and economic elements;
4. Comply with all applicable state laws and regulations, Board policies, and established District planning standards; and
5. Preserve the PUD's flexibility to adapt to changing conditions.

During the summer of 2018, the District's IRP Technical Advisory team reviewed the planning environment and key planning assumptions, and defined the scope for the 2019 Update analysis. The team also incorporated several after action review and process improvement items from the 2017 IRP analysis. The result was adjustments to the schedule of the 2019 Update analysis for the purpose of better aligning portfolio results and the identified 10 year conservation potential to inform the District's setting of biennial conservation targets and provide key information ahead of the budget development timelines.

2019 IRP Update to the 2017 IRP

Analyses studied the 2020 through 2039 period across three different futures: the "expected" or Base Case, the Low Growth Case, and the High Growth Case. The analyses also tested sensitivities to the Base Case from the effects of higher Electric Vehicle (EV) adoption rates and growing penetration of customer owned rooftop solar.

REGULATORY REQUIREMENTS

Electric utilities in the state of Washington with 25,000 or more customers, that do not rely on the Bonneville Power Administration for meeting 100 percent of their customers' power needs are required to develop a comprehensive IRP every four years after 2008, with the option to provide an update or progress report to the plan every two years (Chapter 19.280.030, Revised Code of Washington). A mix of demand and supply side resources are to be considered.
These same utilities are also required to 1) pursue all available conservation that is cost-effective, reliable and feasible, and; 2) acquire a minimum amount of renewable resources, RECs - or a combination of both – to serve an increasing percentage of their retail loads (Chapter 19.285, RCW). These requirements apply to the Snohomish PUD.

The 2019 Update is consistent with the District's state regulatory requirements and:

- Reflects a progress report to the 2017 IRP analysis with least cost/least risk portfolios to meet future load growth across three different futures. The evaluated portfolios considered a mix of demand and supply-side resources, including renewable and nonrenewable resources;
- Incorporates the results of a new Conservation Potential Assessment (CPA) using an integrated portfolio approach for three different futures, using a societal cost of carbon. The Long Term Resource Strategy identified a 10-year conservation potential estimate of 70.4 aMW for the 2020 through 2029 study period;
- To satisfy its 15% renewables compliance requirements under the EIA (Initiative 937) effective January 1, 2020, the PUD will augment its existing renewables portfolio with the purchase of RECs from Northwest eligible renewables projects.

Utilities subject to the IRP statute are required not only to describe the mix of supply- and demand-side resources but, where applicable, how its resource plan addresses overgeneration events. The District's service area resides in and is served by the BPA Balancing Authority Area. As the Balancing Authority Area, BPA is responsible for moment-to-moment balancing of loads and resources within its footprint, including for the PUD. BPA mitigates overgeneration conditions or oversupply events on a regional basis through its Oversupply Management Protocol. An oversupply event is an event that historically occurs in the late spring, and is marked by moderate temperatures that reduce demand at the same time regional snow melt and spring rains resulting in high hydroelectric energy production that combine with high energy production from regional wind projects. The PUD has load, owned and contracted resources within the BPA Balancing Authority Area and as such is subject to BPA's Oversupply Management Protocol.[1]

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

PROGRESS ON 2017 IRP ACTION PLAN

Progress was made on every item in the District's adopted 2017 IRP Action Plan. The progress on the action items are shown below.

1. Pursue all cost effective conservation and further explore peak benefits, including the feasibility of demand response as a future utility-scale capacity resource for the PUD.
   The PUD is on track to acquire its two-year conservation target of 14.61 aMW for 2018 & 2019. During 2018, the PUD began piloting load-shifting programs with drainage district customers and is in the beginning phases of a comprehensive distributed energy resource planning effort to further assess demand response technologies and program options within our service area.

2. Explore low cost, low emissions alternatives in the Northwest for capacity resources to meet peak needs, including the ongoing evaluation of battery and pumped hydro storage, and discussions with BPA for peaking and capacity products.
   The PUD and PNNL have completed a technical evaluation of the MESA battery projects, and are in the final stages of completing the economic evaluation. PUD staff has continued due diligence efforts on potential development of viable local and regional pumped hydro storage sites as a carbon-free capacity and energy storage resource. In the coming year PUD staff expect to more formally engage with BPA and other regional partners to explore what products and resources may be available to help the PUD meet it future long-term capacity needs.

3. Ensure customer owned and distributed renewables programs are complementary to the PUD's overall power supply strategy.
   The PUD's New Energy Initiative's group has launched a distributed energy resource planning initiative in support of the PUD's long-term power supply and distribution system upgrade strategies through a cross-functional approach.

4. Develop a least-cost compliance strategy for meeting the state's renewables requirements under the Washington Energy Independence Act (EIA or Initiative 937).
   During 2018, PUD staff presented a least-cost compliance strategy and sought Board approval for a proposed banking strategy to augment its existing renewables and REC portfolio, including the authority to procure unbundled RECs. The 2019 IRP Update confirmed that procuring unbundled RECs to augment its existing portfolio is the least cost method to achieve the 15% annual renewables requirement.

5. Enhance short and long-term resource portfolio modeling capabilities, expand cost and risk tradeoff analyses.
   As part of the 2019 Update, IRP technical staff explored greater granularity in its portfolio optimization modeling, and evaluated the cost and risk tradeoff of acquiring a supply-side resource or relying on the market, within the PUD's specific risk tolerance, consistent with its planning standards. This cost/risk tradeoff mechanism was incorporated into the portfolio optimization model and reduced overall net portfolio costs while observing market reliance parameters.

6. Conduct an internal survey about the IRP to determine how the reference document is used; validate key findings and incorporate into District's next IRP process.
   Staff worked with Corporate Communications to develop a survey for release within the PUD to better understand how the IRP planning document is used or referred to by employees across the District ahead of the 2021 comprehensive IRP effort. Anticipate survey release to occur simultaneously with public hearings on the 2019 Update and publication of the draft document.

7. Re-assess the methodology used to determine the value associated with the deferral of PUD distribution and transmission investments; monitor the Northwest Power & Conservation Council's regional review.
   PUD Rates Department staff participated in regional work with Council staff to reassess the value of deferring transmission and distribution system investments.

This regional workgroup has developed a proposed methodology that will be considered as part of the Council's 8th Power Plan. PUD staff anticipate that regional agreement on this proposed methodology will occur during late 2019, early 2020, which can then be incorporated into the PUD's comprehensive 2021 IRP effort.

8. Continue to participate in regional forums and assess impacts associated with climate change, reduction in greenhouse gas emissions, renewable portfolio standards, and regional power and transmission planning efforts.

   District staff participate in numerous regional forums and efforts including the PNUCC System Planning Committee, the NWPCC's Resource Adequacy Forum and advisory committees associated with the Mid-Term Assessment of the Seventh Power Plan. District staff have also actively participated in fuel mix rulemaking dockets, Energy Imbalance Market stakeholder processes and BPA power and transmission planning initiatives.

Section 3: Changes Reflected in 2019 IRP Update

Several of the fundamental planning assumptions have changed since development of the District's 2017 IRP. Natural gas prices are forecast to be declining despite regional infrastructure challenges, and multiple carbon policies and voter initiatives have been proposed in Washington State over the past 18 months.

The following planning assumptions were refreshed in the 2019 Update:

- Load growth assumptions revised for each scenario
- Forecast wholesale natural gas and electricity prices were revised
- Cost/risk tradeoffs associated with the on-peak portfolio planning standards were evaluated
- Utility scale solar project costs were revised downward
- Repowered wind was added as a supply-side resource option
- A new Conservation Potential Assessment was performed
- Incremental portfolio emissions were evaluated for each scenario and sensitivity

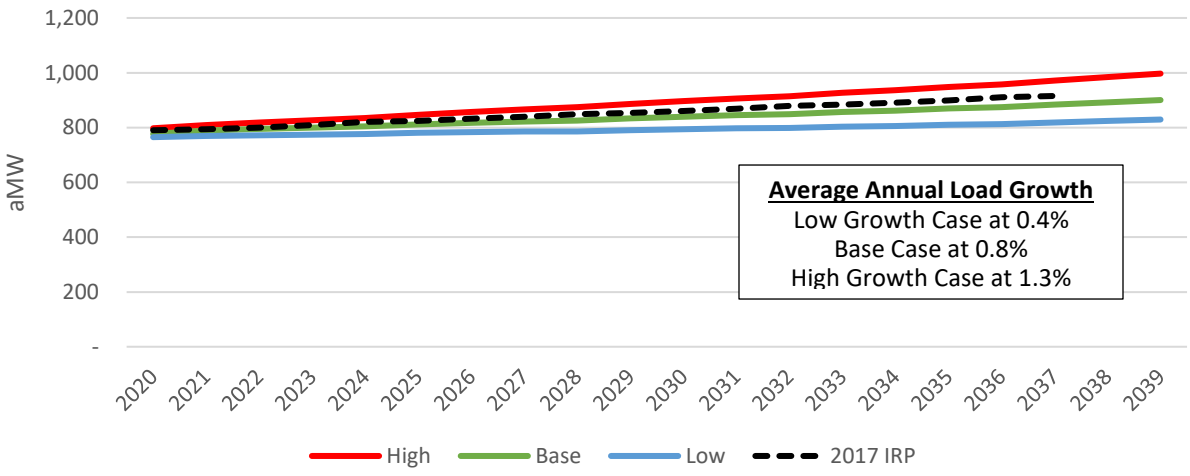
REVISED LOAD FORECAST

The PUD's 2019 Base Case load forecast is lower than the 2017 IRP forecast, and reflects the best available information regarding changes to the economic outlook for Snohomish County. Of note is the impact of Amazon's decision to grow a portion of its workforce outside of the Seattle Metro area, and a downward revision in the expected adoption rate of residential air conditioning. The annual average load growth under the 2019 Base Case is forecast to be approximately 3.5% lower than the 2017 IRP Base Case, and is a primary driver of reduced resource need in the 2019 Update.

The loads forecasts associated with the Low and High Growth cases represent economic and population deviations from this Base Case. The Base Case was revised, in part, from information provided by the 2018 Western Washington University's *Puget Sound Economic Forecaster*.

Each of the cases incorporates expected impacts of climate change on load; specifically projected changes for ambient temperature in Western Washington based on the University of Washington's Climate Impact Group's research, as informed by the 5th Assessment of the United Nation's Intergovernmental Panel on Climate Change.[2] Figure 3-1 shows the forecast load growth by scenario, before new conservation additions:

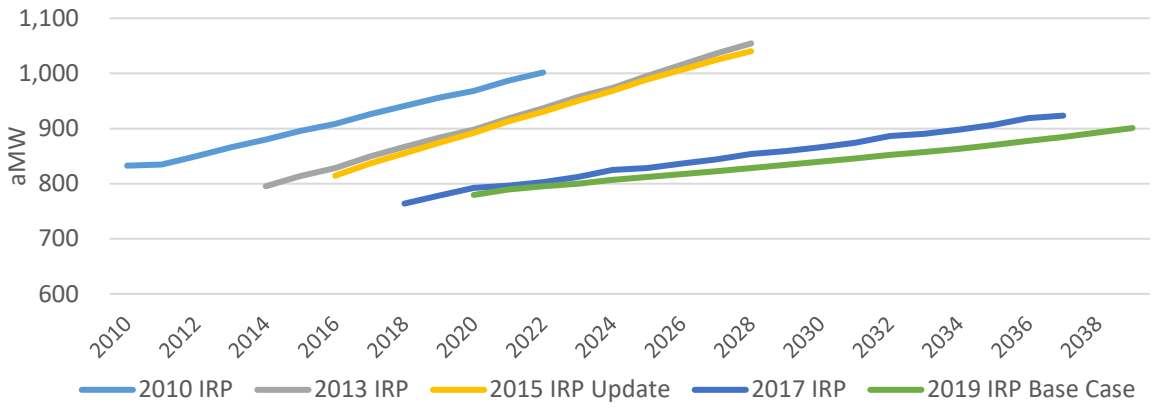
Figure 3-1
Forecast Retail Load Growth before New Conservation by Scenario
2020 through 2039



As Figure 3-2 illustrates, the District's historic IRP load forecasts – like other regional utilities' IRP load forecast – have been continually adjusted down for nearly a decade. A combination of conservation acquisition, improved energy codes and standards for buildings and products, fuel switching to natural gas, and consumer behavior and some loss of industrial load have all contributed to expectations of static to slightly declining future load growth. However, there are real load growth opportunities which have also been incorporated into the 2019 load forecasts. They include: increasing adoption levels of electric vehicles, siting of data servers and changes related to indoor cannabis cultivation.

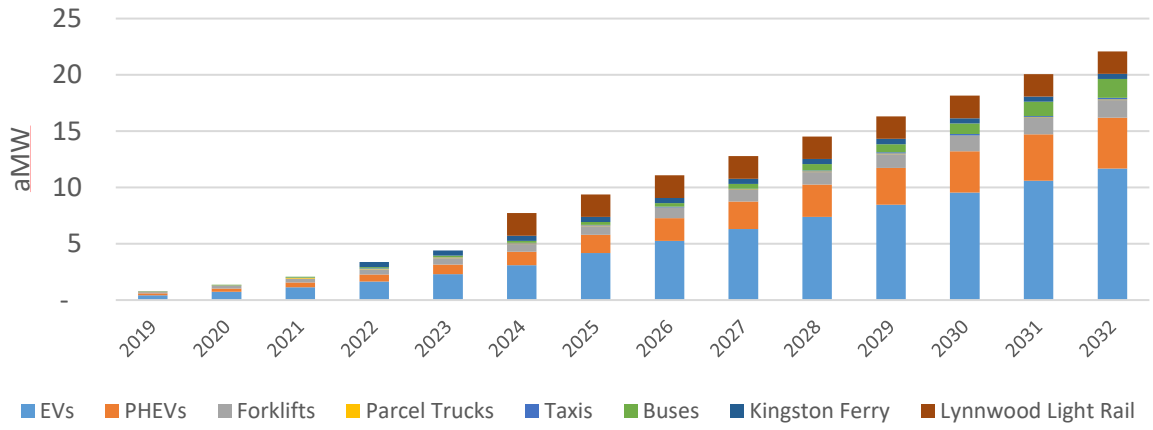
[2] Mauger,G.S.,J.H.Casola,H.A.Morgan,R.L.Strauch,B.Jones,B.Curry,T.M.BuschIsaksen,L. WhitelyBinder,M.B.Krosby,andA.K.Snover ,2015.State of Knowledge: Climate Change in Puget Sound.

Figure 3-2
Forecast Snohomish PUD Base Case Load Forecast by IRP



Electric vehicle (EV) adoption rate assumptions were included in each of the scenario load forecasts and reflect the PUD's expectation that EV's may become a significant component of future load growth.[3] Load associated with plug-in hybrid electric vehicles (PHEV) in the passenger vehicle market, and with new electric vehicles in the public transit system and in industry reflect broader expected electrification impacts within the County. Figure 3-3 illustrates this growth:

Figure 3-3
Snohomish PUD's Share of Forecast Regional Electric Vehicle Load



[3] The estimates for electric vehicle adoption (plug-in electric and battery electric technologies) in the PUD's service territory are 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, sponsored by Snohomish PUD, Chelan County PUD, Puget Sound Energy, Tacoma Power, Avista Utilities and Seattle City Light.
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CHANGES TO FORECAST MARKET PRICES

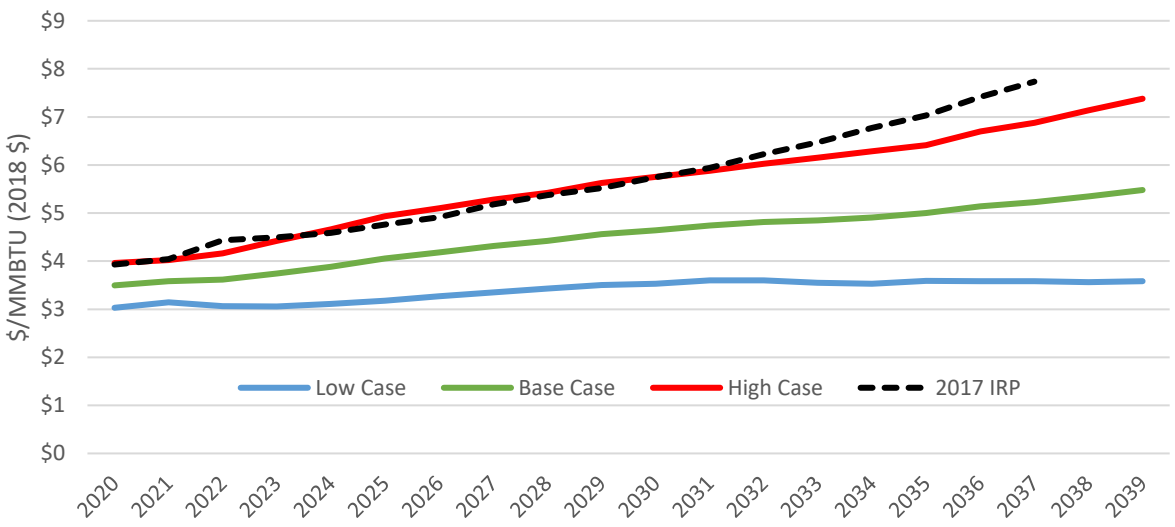
Staff modified inputs in the AURORA^{XMP} model to reflect natural gas assumptions for each scenario. A societal cost of carbon, discussed below, was applied to all generators in the WECC region. To guide resource build decisions in the future, staff also incorporated California, Washington and Oregon renewable portfolio standards (RPS) so there would be sufficient resources built to meet these states' increasing RPS targets. Planned future coal plant retirements were also included. These inputs were used to run a long-term capacity study WECC-wide. The result is a simulated market providing forecast price outputs.

Natural Gas Price Forecast

Figure 3-4 shows the decrease in gas prices compared to the 2017 IRP. The 2019 IRP Update used natural gas price forecasts from the February 2018 Energy Information Administration's Annual Energy Outlook, and from the Aurora^{XMP} 2018 Base Case.

Figure 3-4

Comparison of 2019 Forecast Natural Gas Price vs 2017 IRP Base Case



Societal Cost of Carbon

Staff used a societal cost for carbon ranging from $13.81 per ton of carbon dioxide equivalent in 2020 to $32.61 in 2039 (noted in nominal dollars per ton).[4] This level of carbon cost is consistent with the cost used in the 2017 IRP's Long Term Resource Strategy, and is informed from the EPA's Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis at the 5% average discount rate (revised August 2016 report is expressed in 2007 dollars per metric ton).[5]

Wholesale Electricity Price Forecast

Staff revised inputs in the AURORA^{XMP} model to reflect the natural gas and carbon cost assumptions by scenario. Carbon costs were applied to the fuel costs for supply-side resources fueled by natural gas, and increased the dispatch costs for certain supply side resources within the simulated WECC, impacting forecast wholesale electricity market prices relative to the level of the natural gas price forecast used in the scenario. Planned coal plant retirements were included (Colstrip 1&2 by 2022, Colstrip 3&4 by 2027); increasing renewable portfolio standards (RPS) were modeled for Washington, Oregon and California such that there would be sufficient energy and resource builds to satisfy the states' increasing RPS targets.[6]

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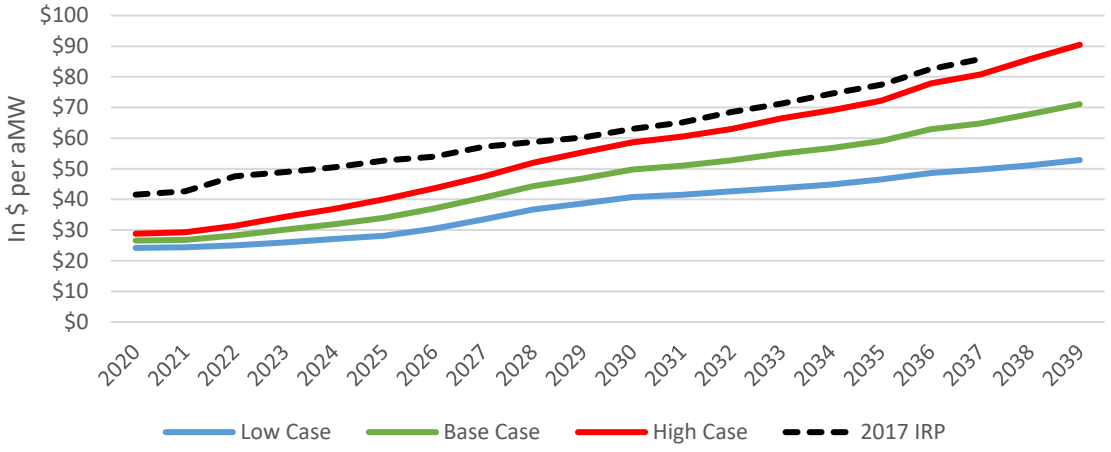
[4] By way of background, EPA's emissions limits are stated in the EPA regulations in "short tons," noted as 2000 lbs, while the societal cost is in metric tons. The 2017 IRP and 2019 Update documents reference carbon dioxide (CO2) emissions in "metric tons" or 2204.6 lbs. The conversion factor to convert one metric ton of CO2 to one short ton is 1.102, or 2204.6 lbs divided by 2000 lbs.

[5] EPA's Technical Update on the Societal Cost of Carbon revised August 2016 can be found at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

[6] California's new SB100 mandate for 100% clean and renewable energy by 2045 was not in place and therefore not reflected in the above 2019 Update wholesale electricity price forecast.

Figure 3-5

2019 Update Wholesale Electricity Price Forecast



EVALUATION OF PLANNING STANDARD COST/RISK TRADEOFFS

Planning standards are the "rules" that govern the development of candidate portfolios to ensure various needs and parameters are met. These standards typically vary from utility to utility depending on their existing resources and customer demand. Some utilities may institute a minimum loss of load probability plus a "planning margin" above their existing load resource balance as the metric or planning standard to demonstrate resource sufficiency.

One of the District's four planning standards tests whether the PUD's power supply portfolio can meet the **Annual Energy** needs of its customers across a calendar year, while the **Regulatory** planning standard ensures the PUD's portfolio can meet Board policy and strategies, as well as the state's EIA annual renewable and conservation requirements, as well as statutes governing integrated resource planning.

The other two District planning standards establish metrics to evaluate and ensure any future candidate portfolio are designed to meet the PUD's forecast monthly and peak week on-peak need 19 out of 20 times with the PUD's existing resources, under low hydro conditions. The **Monthly and Peak Week** (measured as highest demand Monday through Friday on peak within the month) are on-peak planning standards and have an established limit on the quantity of short term energy market purchases for the portfolio a planning basis, in order to avoid or to "cap"

market reliance during periods of scarcity. Forecast load resource balance deficits for the portfolio *above these limits* would be met by the addition of new resources, thereby limiting additional reliance on the wholesale energy market. Forecast load resource balance deficits for the portfolio *below these limits* would be managed by the District's Power Scheduling group within the short-term hedging horizon as more and better information becomes available to manage the portfolio.

The 2017 IRP's Action Plan Item #5 identified expanding long-term resource modeling capabilities, including analysis associated with cost and risk tradeoffs for the long term portfolios. In the 2019 Update scope, staff evaluated the cost risk tradeoffs for the Monthly On-Peak Planning Standard and the Peak Week On-Peak Planning Standards.

The **Monthly On-Peak Planning Standard** measures the ability of the PUD to meet monthly on-peak demand, 19 out of 20 times, with existing and committed resources, with no more than 100 aMW on-peak energy/capacity purchased from the wholesale energy market for a given month. The 100 aMW limit is therefore the volumetric limit or cap on purchases from the short-term market by the model. If a portfolio shows a month with a 101 aMW on peak deficit, then in accordance with the planning standard, a new resource would need to be added to the portfolio to address this single month deficit.

The **Peak Week Planning Standard** measures the ability of the PUD to reliably meet its highest on-peak demand during the most deficit week of a month, 19 out of 20 times, with existing and committed resources with no more than 200 aMW on peak energy/capacity purchased from the wholesale energy market. The 200 aMW limit caps the portfolio's forecast reliance on purchases from the short-term market by the model. If a portfolio shows a peak week deficit of 201 aMW on peak, then in accordance with this planning standard, the portfolio would need to add a new resource to the portfolio to address this deficit.

The cost and risk to acquire a new resource to serve a small need that exceeds the planning standard limit could accelerate acquisition of resource ahead of need for the sole purpose of satisfying the planning standard, creating other risks for the portfolio overall. For example, if a portfolio met the four planning standards, except during the July 2037 on peak period when there is a hypothetical 101 aMW deficit – or a deficit that exceeds the planning standard by 1 aMW at a P5 load resource balance – then prudency for the PUD would dictate that an analysis determine whether the need in that month should be met through a 1aMW wholesale market purchase or through the addition of a new resource to the portfolio.

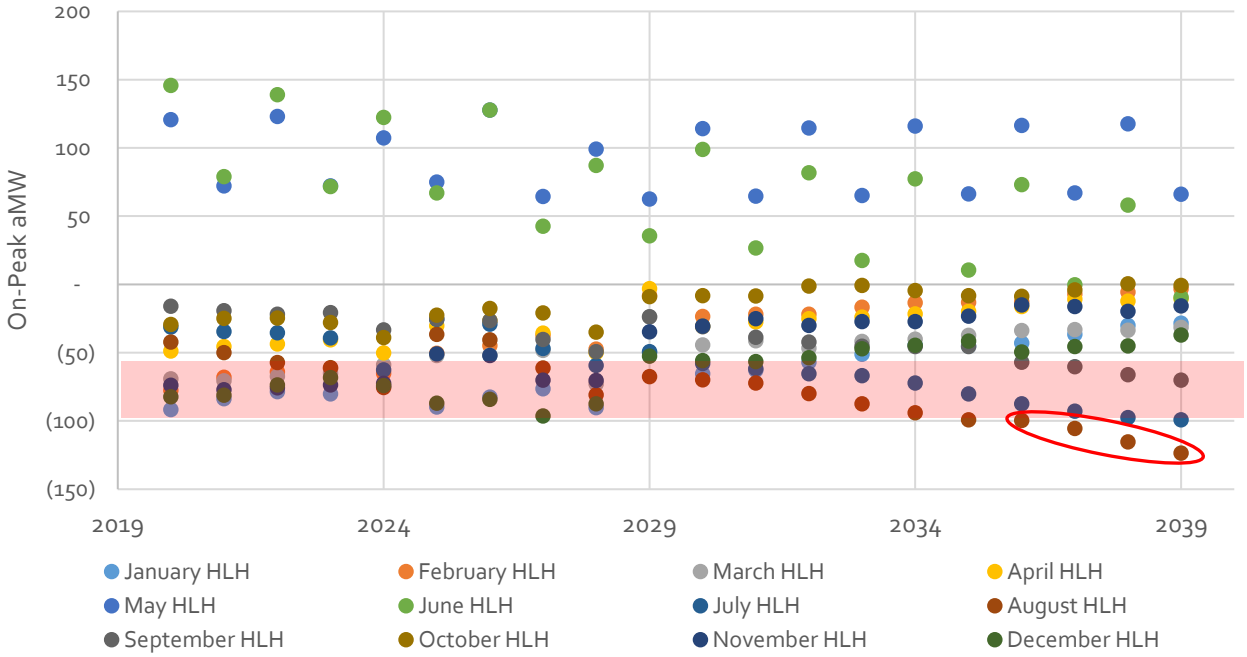
To balance the PUD's planning preference to stay within benchmark volumetric risk tolerances and limit reliance on short-term market purchases with the risk of early or over-acquiring resources for marginal needs that could result in larger portfolio acquisition costs for ratepayers, staff developed a cost-risk tradeoff logic to evaluate the prospective portfolios.
This logic incorporated the expected cost of the market purchase for the portfolio at P50, the expected cost of the market purchase at P5, including what would be an expected and more volatile or higher market price for market purchases made during periods of scarcity. This logic also tested a 0-10 aMW and a 10-25 aMW bandwidth limit exceedance of the volumetric limit for the planning standards. In this way, the Monthly On-Peak and Peak Week On-Peak Planning Standard limits were still generally enforced, but small variations were allowed in instances where the increased risk of market exposure, as modeled, proved preferable to adding a new resource to address the marginal deviations from the absolute volumetric limits.

The impact of this logic and planning standard refinement was that 2019 Update candidate portfolios made fewer incremental resource additions and produced portfolios with lower overall net present value costs because the portfolio optimization model was allowed to purchase small additional increments of energy from the market – limited by the logic's 0-10 aMW and 10-25 aMW bandwidth, rather than acquire a larger-scale resource.

In practice, candidate portfolios were generally within the planning standard volume limits. As shown in Figure 3-6, the Base Case portfolio deviates just four times from the Monthly On-Peak

standard across 240 monthly on-peak periods over the 20-year study period; the deviations occurred August on-peak at the end of the study period (2036 through 2039).

Figure 3-6



OTHER PLANNING ASSUMPTION UPDATES

Reduction in Utility Scale Solar Development Costs

In recent years utility scale solar costs have significantly declined. The 2019 Update incorporated lower costs for development of utility scale solar projects.

Addition of Repowered Wind to List of Supply Side Options

The region's wind developers with projects installed pre-2010 are beginning to assess the viability of "repowering" existing wind projects over the next 5-10 years as the wind turbines approach the end of their useful life. Repowering is the replacement of the wind turbine with a more efficient turbine, and taking advantage of the 20 years remaining on the balance of plant (towers, collection systems, substation). In this way, wind generation could be boosted at the same project location, with significantly less investment. The 2019 Update assumed repowered

wind resources would have to be price competitive with new green field wind and solar resources, and has included repowered wind in its list of supply-side resource options.

Other Updates

The two remaining updates included in the scope of the 2019 Update are addressed elsewhere in this document. The pertinent section reference has been included below for reader convenience.

- New Conservation Potential Assessment performed [Section 5, Resource Options]
- Consideration of incremental portfolio emissions by scenario [See Section 6, Portfolios]

Section 4: Resource Need

A significant effort in the long term resource planning process is for the utility to assess how long it can meet its customers' future needs with its existing energy and capacity resources under a variety of conditions, and under what circumstances new resource additions are needed. The timing of this future need depends in part on the future the PUD may face – slow, moderate or more robust load growth than in the past, the characteristics of the utility's existing and committed resource portfolio, and changes to regulatory requirements.

The utility must also consider other risks to its existing portfolio and ways to mitigate these risks. Examples include: evaluating the impact of below average hydro conditions on the portfolio, and assessing risk/rewards associated with the level of reliance on the short-term wholesale energy market while considering market price volatility. The 2019 IRP Update used the same analytical framework as the 2017 IRP analysis to evaluate the PUD's future resource need.[7]

The 2019 IRP Update forecasts a reduced resource need overall compared to the 2017 IRP analysis. This reduction is largely a reflection of a reduced load growth expectation in the 2019 Base Case. The following information on the PUD's forecast resource need and timing of same is based on a forecast of the PUD's load resource balance for the Base Case, at a P5 or likelihood that condition of deficiency would occur 1 out of 20 times - ***before any new conservation is acquired.***

SEASONAL NEED

The 2019 IRP Update analysis confirmed a small, near-term winter need in the 2020 through 2025 period, until the benefits of new conservation acquisitions can accumulate. By 2029, the PUD is forecast to have an emerging on peak summer need.

Figure 4-1 shows the reduction to winter need in the 2019 IRP Update compared to the 2017 IRP. The chart displays the Load Resource Balance (Load minus Resources) during the

[7] See Snohomish PUD's 2017 IRP, Section 5 – "*Analytical Framework*," page 79.

December On-Peak period where a balance less than 0 represents a deficit under P5 or low hydro conditions. Because the orange 2019 IRP line is above the blue 2017 IRP line, the deficit is less severe, reflective of a reduced need. An on peak winter market product beginning in Year 1 of the study period was the earliest portfolio need – until conservation acquisitions can begin to accumulative – in the 2019 Update and 2017 IRP. The scale of this need was reduced from 50aMW in the 2017 IRP to 25aMW in the 2019 IRP Update reflective of need reduction.

Figure 4-1
Comparison of Change in Winter On-Peak Need
2019 Update Net Load Resource Balance vs 2017 IRP

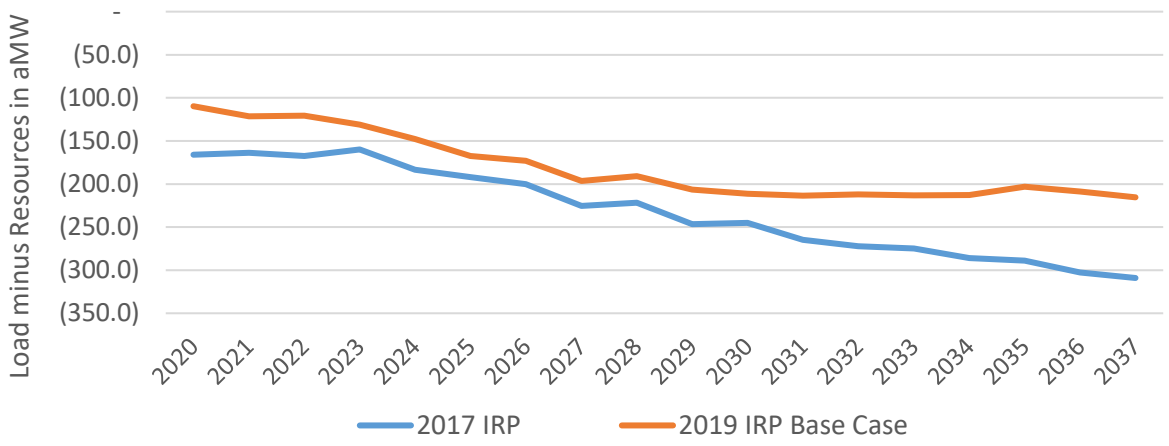
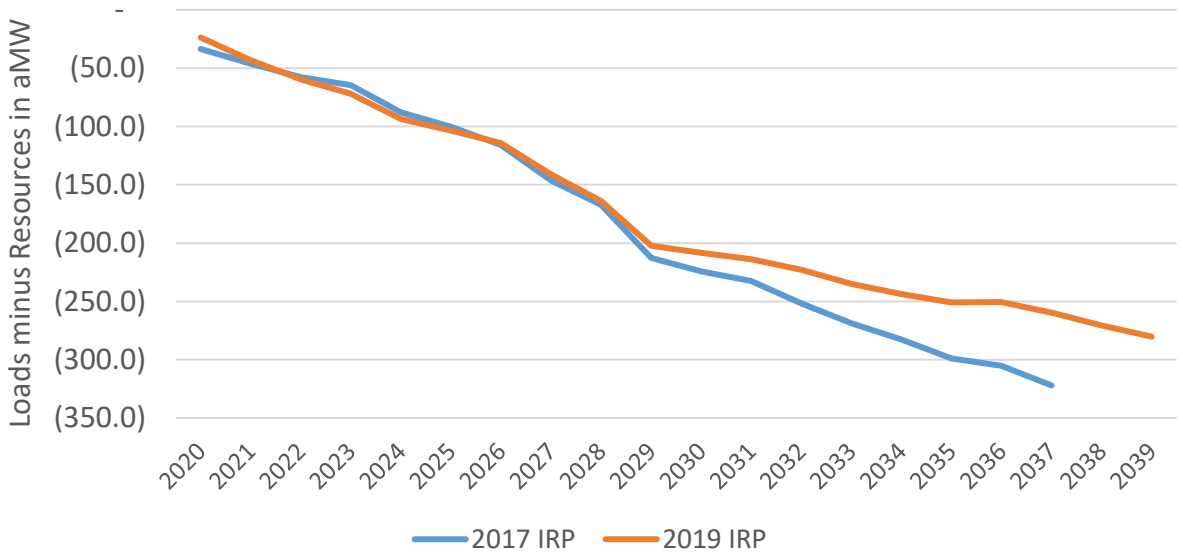


Figure 4-2 shows the change in summer need in the 2019 IRP Update compared to the 2017 IRP for the 2020 through 2039 time period. The chart displays the Load Resource Balance (Load minus Resources) during the August On-Peak Energy period where a balance less than 0 represents a portfolio deficiency under P5 conditions. Similar to the 2017 IRP, the summer need persists and grows through the end of the study period.

Figure 4-2
Comparison of Change in Summer On-Peak Need
2019 Update Net Load Resource Balance vs 2017 IRP



While the scale of need has changed, the seasonality of the PUD's forecast resource need has not. The PUD still has near-term winter-needs in the 2020 through 2025 period, until the benefits of new conservation acquisition can accumulate and by 2029 has emerging summer needs.

As shown by month in Figure 4-3 below, the winter Load Resource Balance (LRB) on peak deficits occur across the study period: Year 1 (2020), Year 10 (2029), and Year 20 (2039). The largest deficits occur Year 1 (2020) during the winter months of January, February, November, and December. By Year 10 of the study period (2029), forecast summer deficits in July and August are roughly equivalent to size of the forecast winter deficits in the months of November through February.

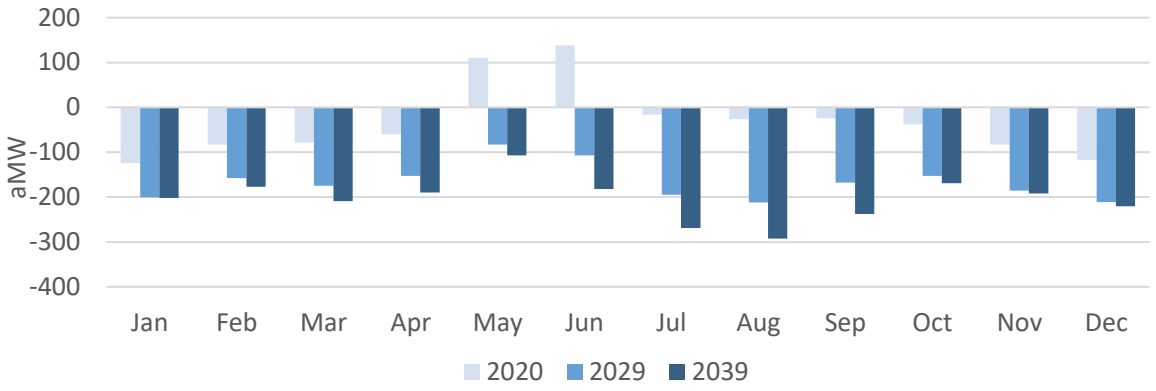
The Climate Change Analysis in the 2017 IRP informed the PUD's long-term hydropower supply forecast and underlie the assumptions on worst case summer hydropower generation.[8] The PUD's climate change analysis was based on representative concentration pathway (RCP)

[8] The PUD's Climate Change Analysis in the 2017 IRP was based on representative concentration pathway (RCP) 4.5 from the *5th Assessment Report*, published by the United Nations Intergovernmental Panel on Climate Change. The PUD's analysis used a composite of Global Climate Models, downscaled for the Pacific Northwest region, informed by data from the University of Washington's Climate Impacts Group. The PUD's 2017 IRP, *Appendix D: Climate Change Analysis*, details the data and modeling sources used in the analysis, including modeling assumptions and approach, located at https://www.snopud.com/Site/Content/Documents/custpubs/2017-IRP_AppD.pdf .

4.5 from the *5th Assessment Report* published by the United Nations Intergovernmental Panel on Climate Change. The PUD used a composite of Global Climate Models, downscaled for the Pacific Northwest region, informed by data from the University of Washington's Climate Impacts Group.

The expectation based on this analysis is for reductions in snowpack and shifts in seasonal snow melt over time, reducing available stream flows to fuel hydroelectric generators during the summer period. Therefore, forecast winter deficits are most often caused by cold weather volatility and the associated increases in customer demand for heating, while summer deficits are a result of lower hydro availability in combination with increased air conditioning demand.

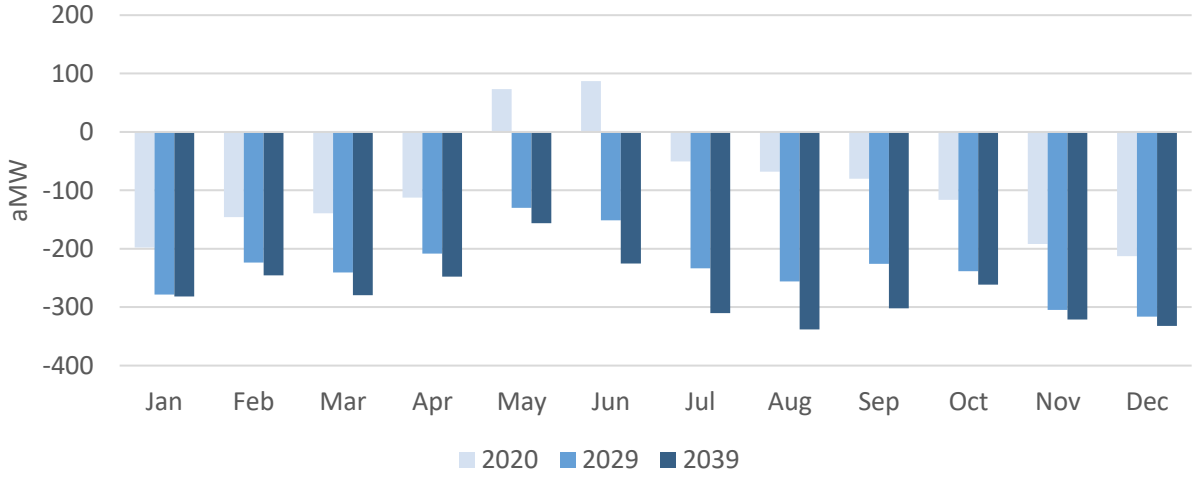
Figure 4-3
Forecast Monthly On-Peak Position Deficit at P5 Load Resource Balance



PEAK WEEK NEED

For the highest consumption each month on peak, Monday through Friday (80 hours total), or the peak week period, the forecast load resource balance deficits are shown in Figure 4-4 for Year 1 (2020), Year 10 (2029), and Year 20 (2039) of the study period by month. The same seasonal and chronological patterns of need while similar to Figure 4-3 showing monthly need at P5, are larger in magnitude in Figure 4-4. The metric shown is the highest within month need and occurs during the winter and the summer months.

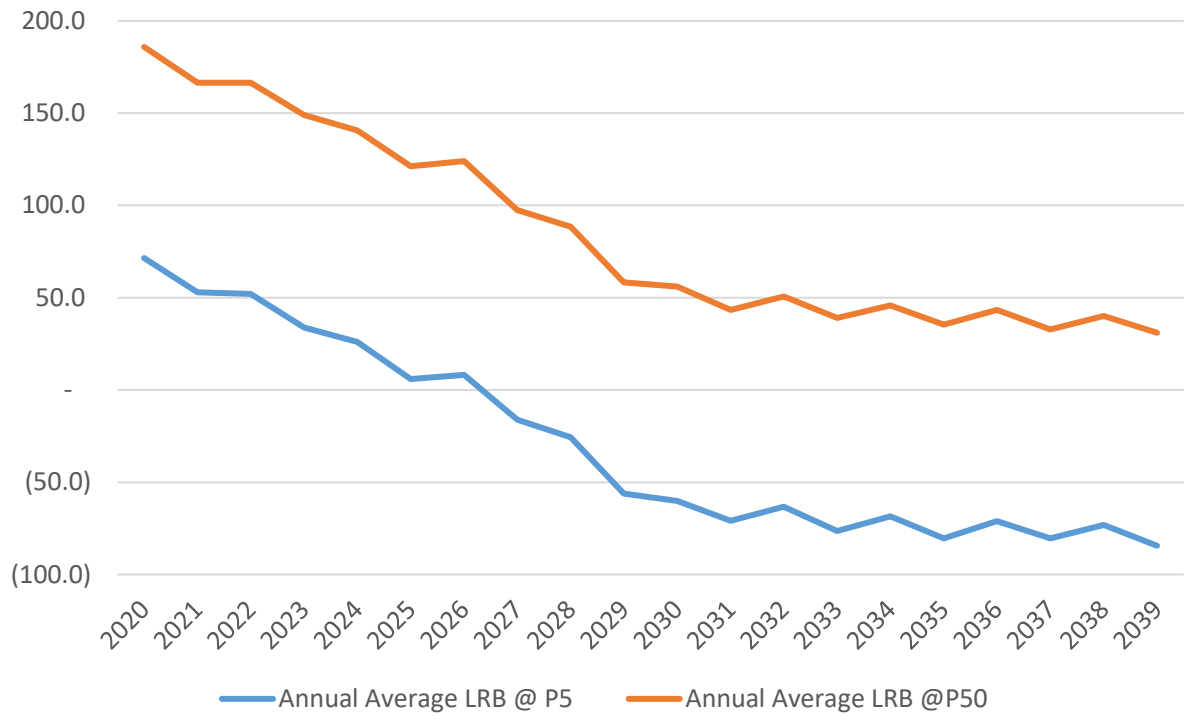
Figure 4-4
Forecast Peak Week On-Peak Position Deficit at P5 Load Resource Balance



ANNUAL ENERGY NEED

Based on the 2019 IRP Update planning assumptions that the PUD would contract for a similar product and quantity of power from BPA in the post-2028 contract period, the PUD has no annual energy need at either P50 (expected) or P5 (conditions 1 in 20) as shown in Figure 4-5. On an average annual energy basis, the PUD is expected to be surplus before any new resources are added across the 2020 through 2039 study period. The PUD has a 1-in-20 chance (P5) of being deficit on an annual average basis beginning in 2027 prior to any new resource additions.

Figure 4-5
Forecast Annual Average PUD Net Portfolio Position
(Existing and Committed Load Resource Balance at P50 and P5)

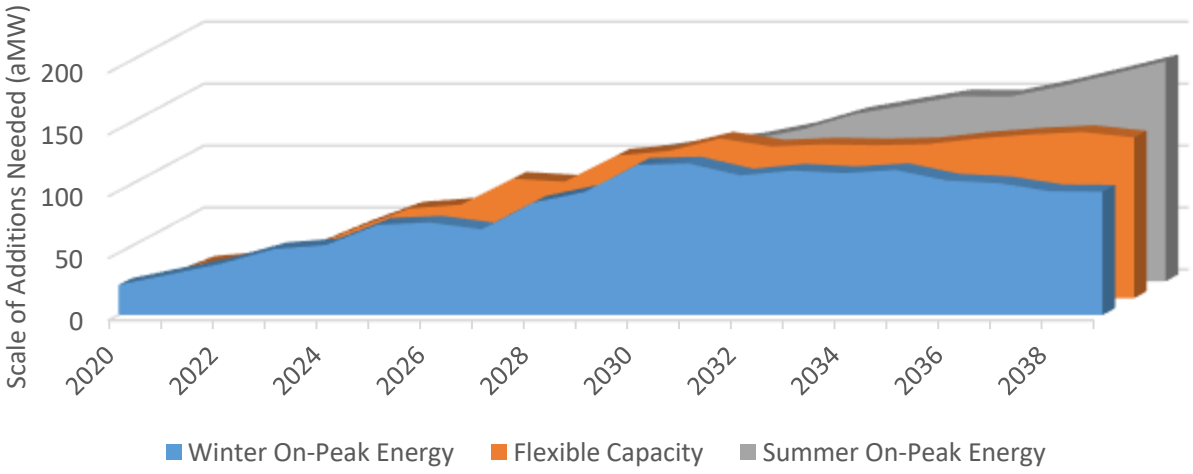


IDENTIFIED RESOURCE NEED

The 2019 Update analysis of the PUD's existing load resource balance identifies three generalized portfolio needs: a near-term winter need (Years 1-5), and a long-term winter and summer need (Years 6-20). Figure 4-6 shows these generalized needs for the Base Case.

The PUD's near-term need is for winter on-peak energy as measured in the December On-Peak Energy period at P5 (blue shape), and winter on peak capacity where the orange bar exceeds the blue bar (during 2026-2028 for example) to help with peak load needs within a month where the on-peak energy alone could not serve the need. The winter capacity need shown in the orange shape is measured at December Peak Week at P5. Late in the study period (2032-2039) summer on-peak energy is expected to be the biggest portfolio need – even after accounting for expected rooftop solar that customers may add. Summer energy need is measured during the August On-Peak Energy period at P5. As a result, identified lowest reasonable cost portfolios added resources that served one or more of these generic needs at the lowest cost.

Figure 4-6
Base Case: Winter Energy, Capacity and Summer Energy Need (before New Conservation)



Section 5: Resource Options

The 2019 IRP Update evaluated the relative costs and benefits of different types, sizes and delivery timing of commercially available resources using the same methodology as the 2017 IRP. Supply side and demand side resources were evaluated using the same measurements: their potential contributions to capacity, energy, and satisfying annual renewable compliance requirements. In this way, the PUD was able to use an integrated portfolio approach for each scenario, creating candidate portfolios that combined the best mix of demand and supply side resources to meet future need, based on least cost criterion. The methodology used to evaluate resource options did not change from the 2017 IRP; several new resources were added for consideration and costs of certain renewable resources were reduced (e.g., utility scale solar) to reflect the resource development marketplace.

DEMAND-SIDE RESOURCES

Conservation

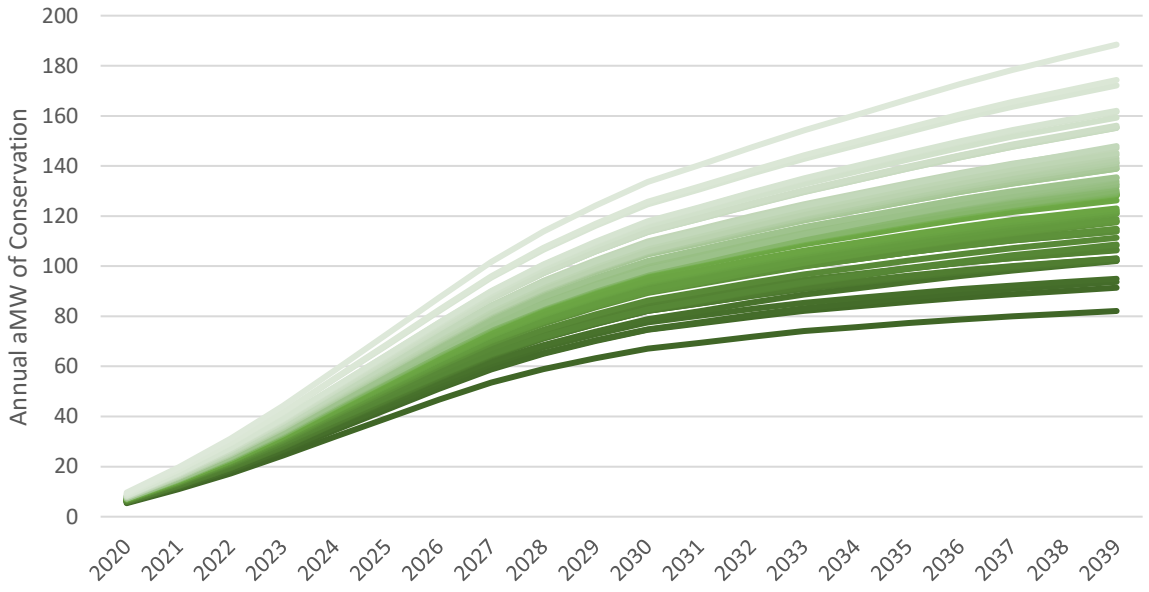
The PUD contracted with EES Consulting for an updated utility-specific conservation analysis, the 2019 Conservation Potential Assessment (CPA) study, consistent with the requirements set forth by Washington's Energy Independence Act (Chapter 19.285, Revised Code of Washington). The CPA identified all technically achievable conservation within the PUD's service territory over the 20 year study period from 2020-2039 informed by: the PUD's past conservation achievements; the regional 2016 Residential Building Stock Assessment (RBSA); an oversample of the PUD's service territory for certain RBSA conservation measures; and measures identified in the Seventh Power Plan. The CPA informs the amount, type, and availability of conservation measures, their associated savings, and costs.

The CPA assessed each technically achievable conservation measure, and grouped measures into two seasonal groupings – winter and annual- and then into eight different bundles based on each measure's 20 year levelized cost. Measures in the winter seasonal grouping provided conservation almost exclusively during the winter period, while measures in the annual grouping

reflected measures expected to deliver energy savings across most of the months of the year. Different combinations of the two seasonal groupings and eight cost bundles results in 64 possible conservation supply curves, each with a different annual and seasonal technically achievable potential, and different cost points. The 64 possible bundles are shown on an annual average basis in Figure 5-1. These are the conservation supply curves used to determine the amount of conservation considered to be cost-effective and economic, alongside supply side resource options, using an integrated portfolio approach for each scenario.

Figure 5-1

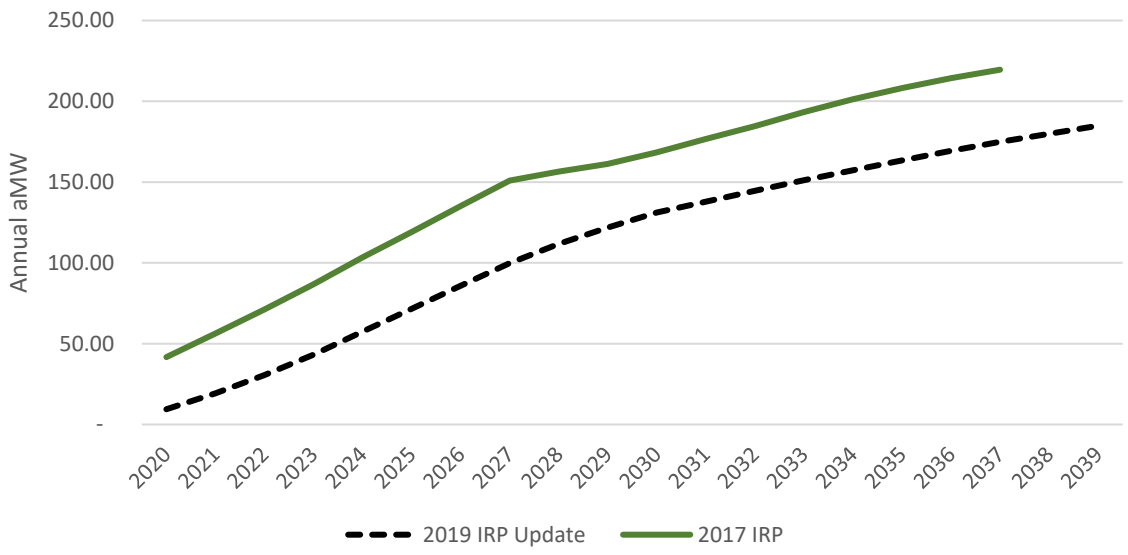
64 Conservation Supply Curves evaluated in 2019 IRP Update



The total cumulative annual average technical potential for new conservation was lower than the technical potential identified in the 2017 Conservation Potential Assessment study. This is due to a number of factors: 1) reductions as a result of actual conservation achievements in 2017 & 2018, and 2) changes due to incorporation of federal lighting standards, reducing the amount of available conservation savings previously attributable to lighting measures. The following Figure 5-2 shows the comparison of technical achievable conservation potential between the 2019 and 2017 CPA studies.

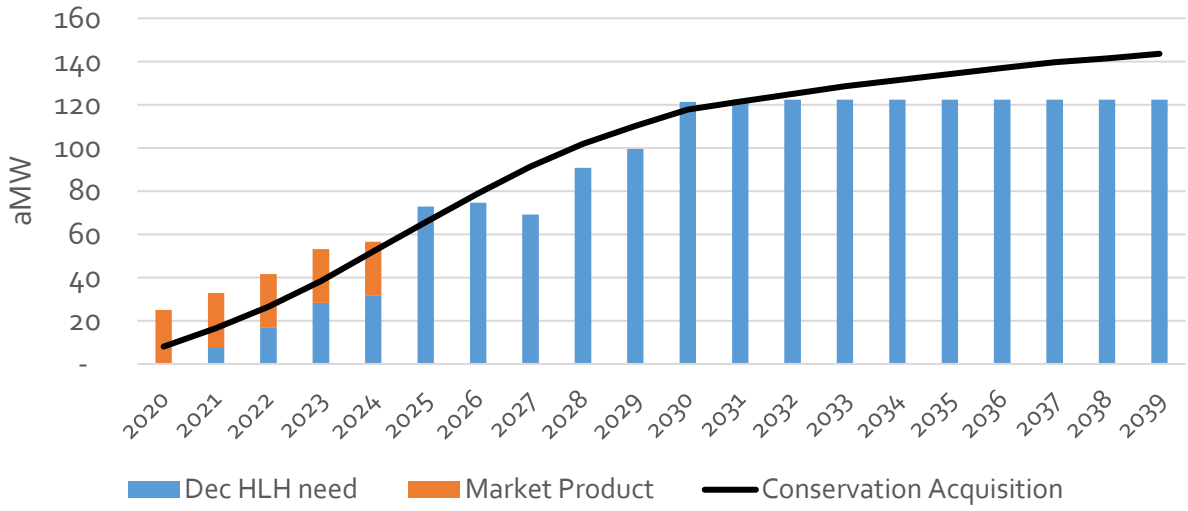
Figure 5-2

Comparison of 2019 vs 2017 CPA Technical Achievable Potential at PUD busbar



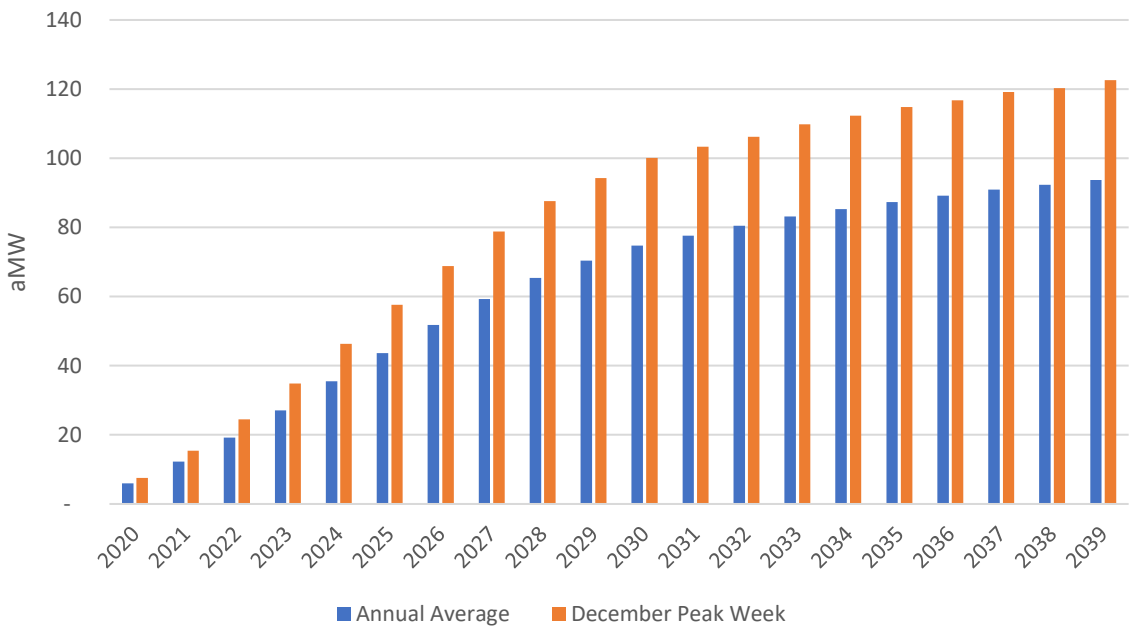
Conservation bundles were then evaluated based on their monthly, seasonal, and annual contributions to a potential portfolio, in the same way that demand response and supply-side resources were evaluated. Consistent with EIA requirements, staff also tested acceleration of conservation and identified the economic benefit of an 11 year accelerated ramp for retrofit measures, which met nearly all of the PUD's forecast winter needs by the 2030 timeframe.

Figure 5-3



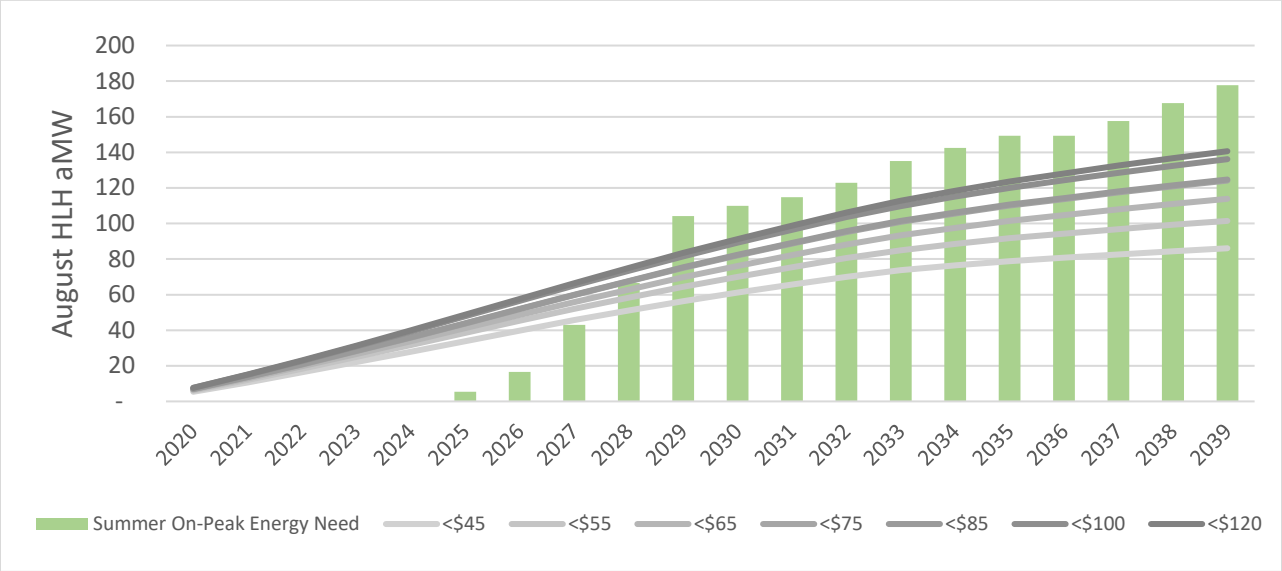
The total cumulative conservation identified as cost effective under the Base Case is in line with previous studies. The Base Case 10-year conservation potential estimate of 70.4 aMW at the BPA busbar was found to be cost effective, and contributed 94 aMW in savings against the forecast winter peak week need by year 10 of the study.

Figure 5-4
Base Case Conservation at BPA busbar



While the 2019 CPA identified significant annual and winter measures, there was not sufficient technical achievable potential available to offset forecast summer needs late in the study period at any price. Figure 5-5 shows the gap between the conservation supply curve and the summer need forecast late in the study period under the Base Case. Future CPAs will reassess this potential within the PUD's service territory as additional measures become available and building stocks shift over time.

Figure 5-5
Summer Energy Need and Technical Achievable Conservation Potential in the Summer



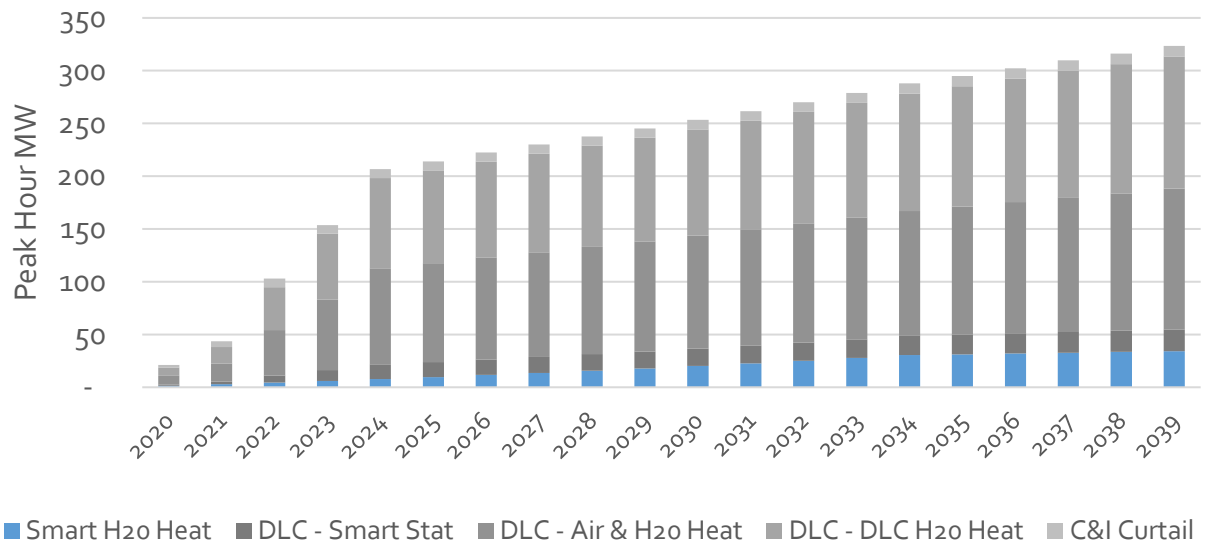
Demand Response

The 2019 IRP Update utilized the same 2017 Demand Response Potential Assessment (DRPA) as the 2017 IRP to determine how and whether demand response was cost competitive and could serve a portion of the PUD's future long-term needs. The DRPA was limited to five programs available to offset winter peak loads. These programs are summarized as:

1. Three direct load control programs were assessed, modeled as voluntary marginal load displacement from equipment groupings of: water heaters, thermostats, and water heaters and thermostats at the same property.
2. A commercial and industrial curtailment program was assessed and modeled as voluntary, callable, load shifting.
3. A smart water heater program was also modeled as a grid-enabled water heater able to shift a portion of on-peak load to off-peak load by pre-heating water in off-peak periods.

The benefit of the demand response programs as modeled was that they were found to provide a large amount of capacity to reduce load during a limited number of peak hours when certain resource options were excluded (see Figure 5-6 for technical potential of peak hour reductions).

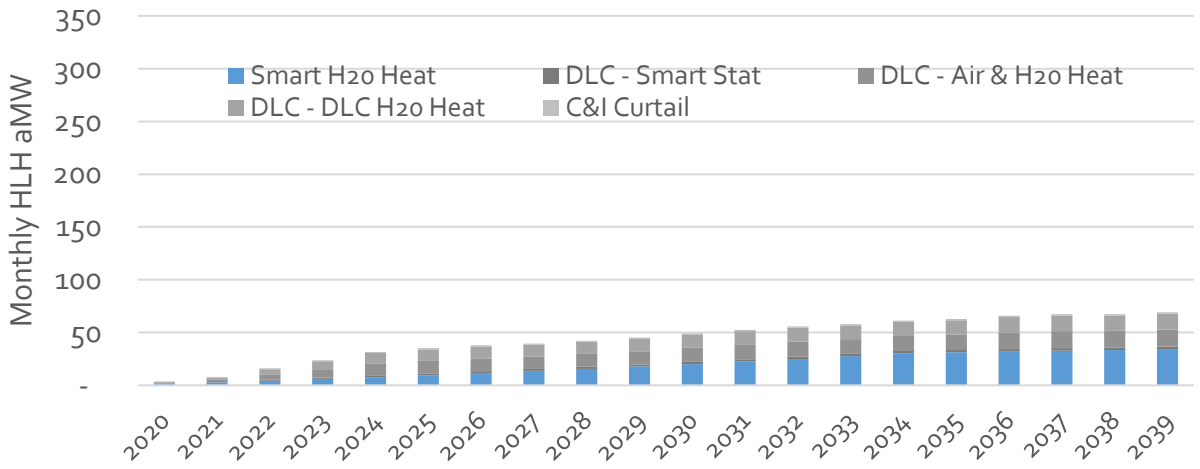
Figure 5-6
Peak Hour Contributions Over Time of Five Evaluated Demand Response Programs



One limitation of note is that some of the five programs have limited availability – or are "call-limited" – such that they lack flexibility or are limited in their availability to help meet the PUD's peak needs more than a handful of times in a given season. Smart water heaters were the exception, and were a technology that showed promise in its ability to shift significant load across seasons and years with higher availability than the other programs assessed.

Figure 5-7 shows all five demand response programs on a monthly on-peak basis across the study period. In comparison with Figure 5-6, the smart water heater technology (highlighted in the blue bars in both graphs) is the only technology without a significant drop in portfolio contributions from peak hour to average monthly on-peak period contributions as expressed in aMW.

Figure 5-7
Monthly On-Peak Contribution from DR Programs



Additional research is needed to more clearly assess market availability, timing, and cost to implement many of these promising emerging technologies, and their ability to shift peak loads to off-peak times each day. Further exploration of peak-shifting and demand response technologies has been included in the 2019 IRP Update Action Plan.

SUPPLY-SIDE RESOURCES

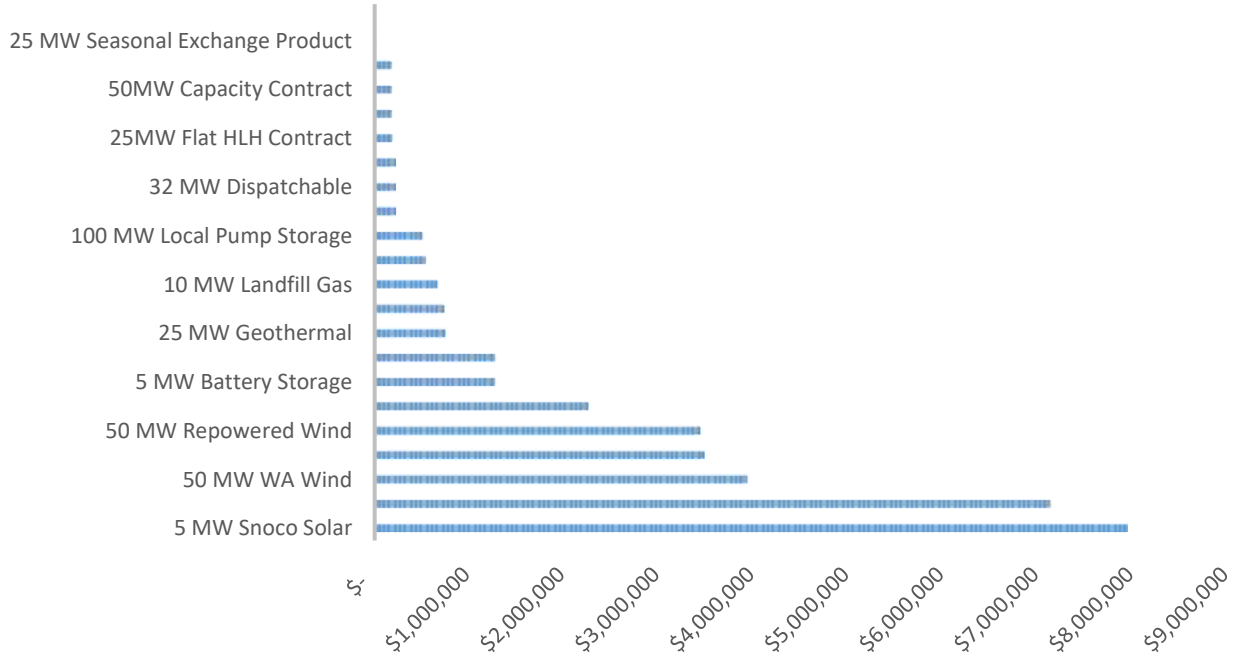
Supply side resource costs were refreshed where applicable in the 2019 IRP Update. Of note was the reduction in utility scale solar costs, the incorporation of several different short term market products to serve as an energy and capacity bridge in the portfolio and address winter need until new conservation acquisitions could cumulate, and the addition of repowered wind. Just like the 2017 IRP, the 2019 IRP Update considered the unique operating characteristics of each supply side resource in the development of candidate portfolios.[9]

[9] Annual capacity factor information for each supply side resource considered in the 2019 IRP analysis can be found in the Technical Appendix located at https://www.snopud.com/Site/Content/Documents/custpubs/AppA_2019%20Update.pdf

Many regional wind developers with wind projects installed in the pre-2010 period are evaluating the viability of "repowering" existing wind projects in the next 5-10 years. Repowering an existing wind project is the act of replacing the wind turbine in years 15-20 of the project life with a more efficient turbine, and to take advantage of the 20 years remaining on the useful asset life of the balance of plant (towers, collection systems, substation). In this way, output could be boosted at the same project location, with significantly less investment. Because a repowered wind approach is emerging, the 2019 Update assumed repowered wind would have to be at least price competitive with new green field wind and solar resources, and added repowered wind to the list of supply-side resource options.

The basis of the PUD's supply side costs came from a survey of other Pacific Northwest utilities' IRPs, the Council's Seventh Power Plan, research papers and other sources to gather cost and operations data on renewable and nonrenewable generating resources.[10]

Figure 5-8
Levelized Cost of Winter On-Peak Capacity by Resource Type
(in 2020 dollars)



[10] For a list of the levelized costs of energy and annual capacity factor by resource option, please see the Technical Appendix located at https://www.snopud.com/Site/Content/Documents/custpubs/AppA_2019%20Update.pdf .

Section 6: Portfolio Development and Analysis

After the resource need has been identified and the resource options have been defined, the last process of integrated resource planning is identifying what combination of future resources – in concert with the utility's existing resource portfolio – results in the lowest reasonable cost portfolios under different scenarios. The goal of the analysis, consistent with the requirements in RCW 19.280.030 – *Developing a Resource Plan*, is to integrate into a long-range assessment the best mix of supply and demand side resources that, using least cost criterion, meet current and future needs.

Methodology

An in-house portfolio optimization model was developed to solve for the lowest reasonable cost portfolio that satisfied all planning standards and constraints in the 2017 IRP. The same model methodology was used to construct the portfolios for each scenario in the 2019 IRP Update. The portfolios were evaluated under expected conditions and adverse conditions, or conditions that deviated from expected. The scenarios helped identify impacts and test the resilience of each portfolio.

SUMMARY OF CANDIDATE PORTFOLIOS AND SENSITIVITIES

Figure 6-1 describes the planning assumptions for each of the scenarios analyzed in the 2019 Update to the 2017 IRP analysis:

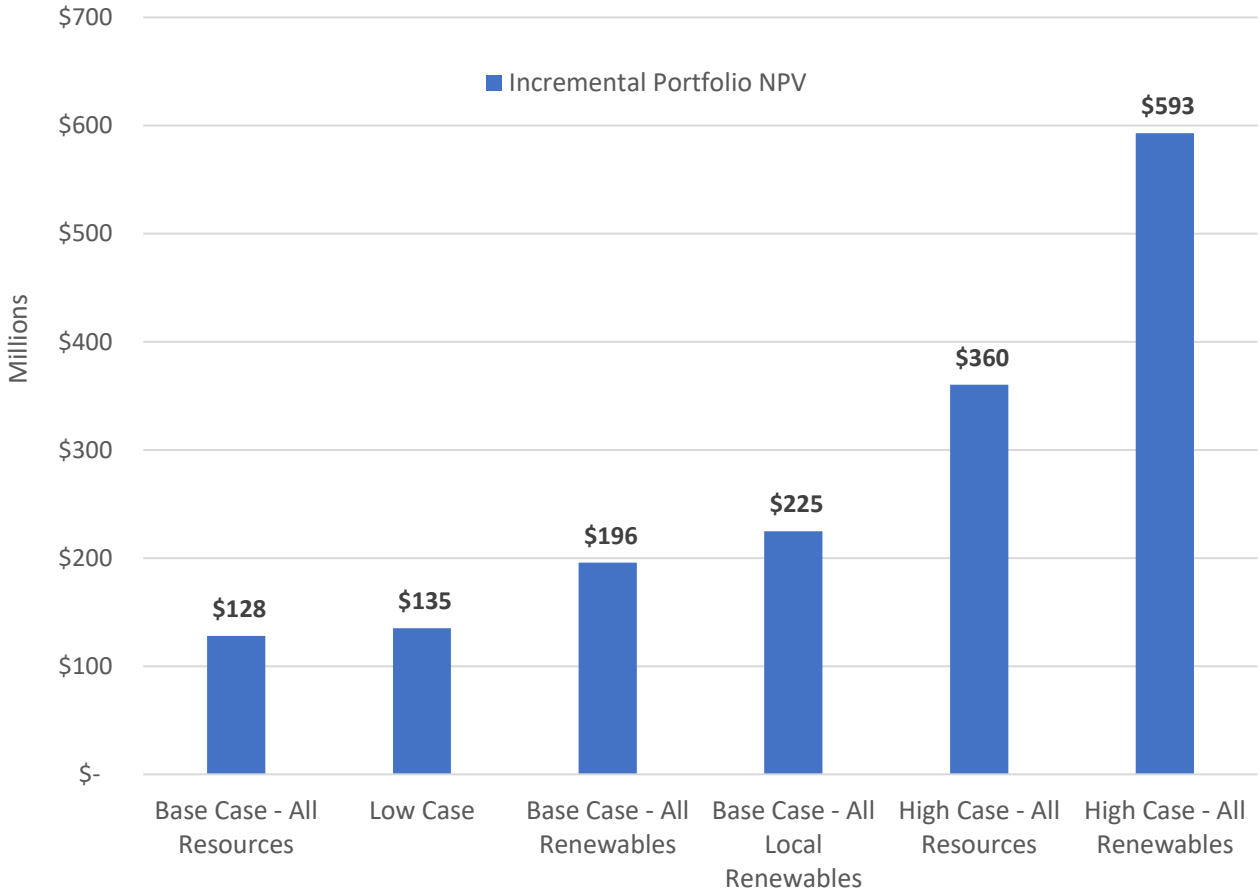
Figure 6-1
Comparison of Scenario Variables

Scenario	Annual Average Load Growth	Societal Cost of Carbon[11]	Natural Gas ($/mmBTU)	Forecast Wholesale Electricity Prices
Low Case	0.4%	$14-33	$3.03-$3.58	$24.18 - $52.86
Base Case	0.8%	$14-33	$3.50-$5.38	$26.57- $71.08
High Case	1.3%	$14-33	$3.96-$7.38	$28.81-$90.47

[11] Staff used a societal cost for carbon ranging from $13.81 per ton of carbon dioxide equivalent in 2020 to $32.61 in 2039 (noted in nominal dollars per ton). This level of carbon cost is consistent with the cost used in the 2017 IRP's Long Term Resource Strategy, and is informed from the EPA's Technical Update of August 2016 for the Social Cost of Carbon for Regulatory Impact Analysis at the 5% average discount rate measured in dollars per metric ton of carbon dioxide equivalent. See page 13, footnotes 4 and 5 for carbon conversion factors.

Figure 6-2 illustrates the total net portfolio cost in net present value (NPVs) for each primary candidate portfolio and sensitivities. The net portfolio cost NPV includes the forecast modeled incremental costs of the portfolio offset by the forecast modeled incremental revenues, created from portfolio surpluses over the study period, valued at the forecast market price applicable for that scenario.

Figure 6-2
Comparison of 2019 Candidate Net Portfolio Cost NPVs by Scenario



Key Findings

Several general trends and insights emerged in the development of the 2019 Update portfolios. Figure 6-3 below summarizes the resource and REC additions for the five main scenarios and sensitivities:

1. Conservation remains the PUD's resource of choice as a cost-effective resource to meet some or all of the PUD's winter energy need, depending on the scenario. For the Base Case - All Resources portfolio, conservation defers the need for long-term capacity additions until the late 2020's.
2. A 5 year short-term market product is needed for the 2020-2024 period to bridge the gap during winter on-peak periods under adverse conditions, until the acquisition of conservation accumulates and can meet the forecast need post-2024.
3. In the All Renewables scenarios, utility scale solar was found to be a viable resource addition to help meet forecast summer needs late in the study period.
4. Several of the All Renewables scenarios identified that demand response programs that shift load may be a cost effective demand-side management resource and can contribute to serving future capacity and summer on-peak energy needs.[12]
5. Unbundled RECs continue to be the PUD's least cost compliance path to meet EIA annual renewables compliance requirements.

[12] While the Smart Water Heater Program from the 2017 Demand Response Potential Assessment was the specific resource identified in candidate portfolios that limited supply side resource to All Renewables only, more research is needed to further define the technologies that may be able to provide portfolio benefit, actual availability and scale, and cost.

Figure 6-3
Summary of New Resource Additions by Scenario[13]

Scenario/Sensitivity	Total Cumulative Conservation (aMW)	Short Term Capacity Contract (Dec HLH aMW)	Long Term Capacity Resource (Nameplate MW)	Renewables (Nameplate MW)	Demand Response (20 Yr Peak Hr)	RECs (aMW)
Low Case – (All Renewables)	94	25	-	-	34	103
Base Case – Any Resource	94	25	66	5	-	103
Base Case – All Renewables	94	25	-	55	34	91
Base Case – All Local Renewables	94	25	-	15	34	103
High Case – All Resources	102	25	132	-	-	114
High Case – All Renewables	141	25	-	100	34	80

[13] For reader ease, Table 6-3 simplified how new resource additions are shown (by nameplate in MW or by annual average energy in aMW). However, both the 2017 IRP and 2019 IRP Update has fully considered the unique operating characteristics that each supply side resource offers or contributes in the development of the IRP's candidate portfolios. To view the annual capacity factor and levelized cost of energy for each supply side resource considered in the 2019 IRP analysis, please reference the Technical Appendix located at https://www.snopud.com/Site/Content/Documents/custpubs/AppA_2019%20Update.pdf .

Base Case Portfolios

The Base Case represents the PUD's current expectations for future load growth and future market conditions. The annual average load growth before new conservation is 0.8% and that growth includes current expectations for future electric vehicle adoption. That load growth is mitigated by forecast rooftop solar installations that contribute nearly 5 aMW on an annual average basis by 2039. Within the Base Case, three lowest cost portfolios were considered that different types of resources to build portfolios that met PUD planning standards. The three scenarios included:

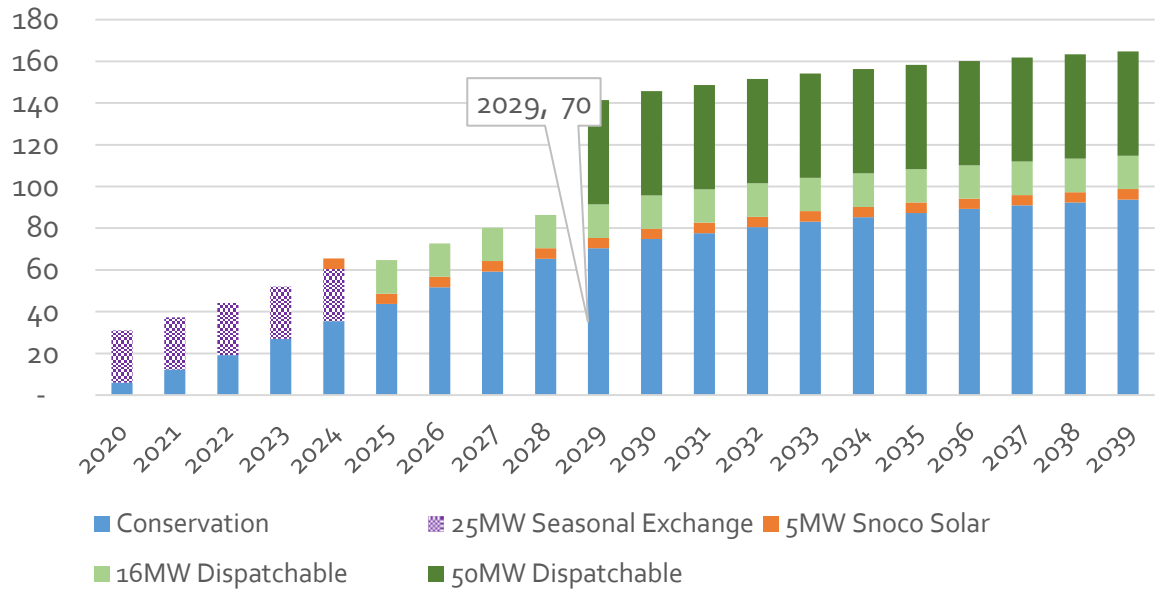
1. **An "All Resources" scenario** where any resource from the demand-side and supply-side menu could be selected;
2. **An "All Renewables" case** where only demand-side resources defined supply-side renewables could be selected. A defined supply-side renewable does not include dispatchable capacity resources, which could be renewable-based, but which gets its price point from a natural gas plant price proxy. An example of a defined renewable resource would be utility scale solar, which refers to a specific technology type.
3. **An "All Local Renewables" case** where only demand-side resources defined supply-side renewables that could be sited within the PUD's service territory could be selected.

Base Case - All Resources

The incremental NPV of the All Resources portfolio was $128 million. The All Resources scenario selected 94aMW of conservation on a 20-year basis, and 70.4 aMW by Year 10 in 2029. A 25MW market product was added in the first five years to serve December-January winter needs. A 16MW nameplate dispatchable capacity resource was added in 2025 (Year 6) to meet winter capacity needs and contribute to summer energy needs, and a 50MW dispatchable capacity resource was added in 2029 to augment those needs. Lastly, a 5MW utility scale solar project sited in Snohomish County was added to contribute to summer energy needs and contribute to I-937 Renewable Portfolio Standard compliance. The balance of Renewable Portfolio Standard compliance needs, after renewable attributes of the existing portfolio, and the addition of the local solar, were met by the purchase of unbundled Renewable Energy

Certificates from eligible northwest renewable projects. **Total emissions of the portfolio were 5.1 million metric tons of CO2 over 20 years, most of which came from the PUD's share of BPA's market purchases.**

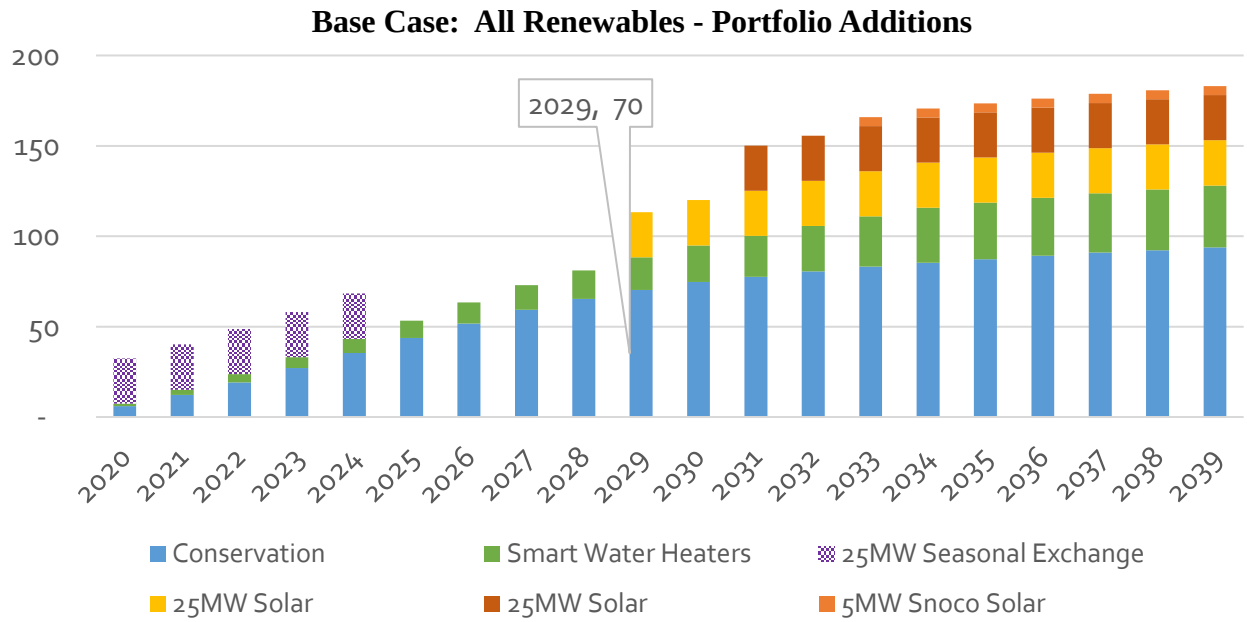
Base Case: All Resources – Portfolio Additions



Base Case - All Renewables

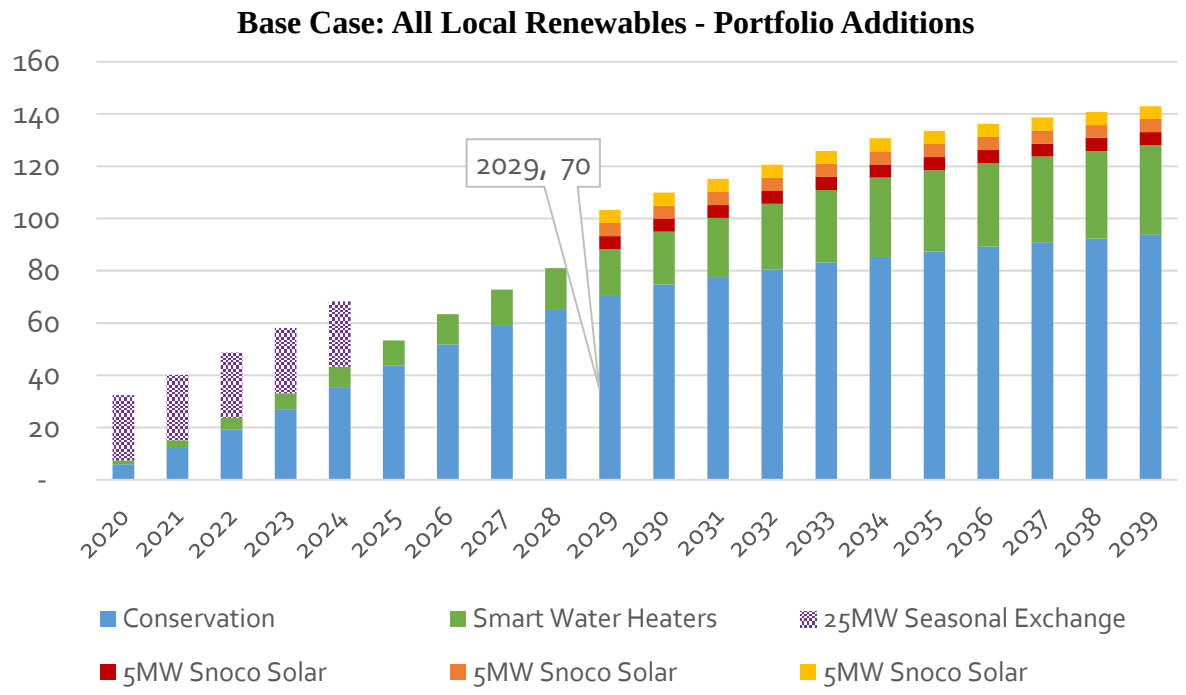
The incremental NPV of the All Renewables portfolio was $195 million, roughly 52% higher than the All Resources portfolio. The All Renewables scenario also selected 94aMW of conservation on a 20-year basis, and 70.4 aMW by Year 10 in 2029 – the same conservation level as the All Resources scenario. A 25MW market product was added in the first five years to serve December-January winter needs. A Smart Water Heater demand response program that shifts on-peak load to off-peak periods year-round was selected, growing into a total on-peak to off-peak shift of 34aMW after 20 years of program maturity. Two 25MW nameplate Eastern Washington utility scale solar projects were added to serve summer need, with the first added in 2029 (Year 10) and the second added in 2031 (Year 12). Lastly, a 5MW utility scale solar project sited in Snohomish County was added in 2033 to serve summer energy needs and contribute to the annual EIA renewables compliance. Unbundled RECs from eligible northwest renewable

projects were also added to meet compliance targets. **Total emissions of the portfolio were 4.9 million MT of CO2, roughly 6% lower than the Base Case All Resources portfolio.**



Base Case - All Local Renewables

The incremental NPV of the All Local Renewables portfolio was $225 million, roughly 76% higher than the All Resources portfolio, and 15% higher than the All Renewables portfolio. The All Local Renewables scenario also selected 94aMW of conservation on a 20-year basis, and 70.4 aMW by Year 10 in 2029 – the same conservation level as the All Resources and All Renewables scenarios. A 25 aMW market product was added in 2020 for five years to serve December-January winter needs. A Smart Water Heater demand response program that shifts on-peak load to off-peak periods year-round was selected, growing into a total on-peak to off-peak shift of 34aMW after 20 years of program maturity. Three 5MW utility scale solar project sited in Snohomish County were added beginning in 2029 to serve summer energy needs and contribute to the annual EIA renewables compliance. Unbundled RECs from eligible northwest renewable projects were also added to meet compliance targets. **Total emissions of the portfolio were 4.9 million MT of CO2, roughly 6% lower than the Base Case All Resources portfolio.**



Base Case Technology Sensitivities

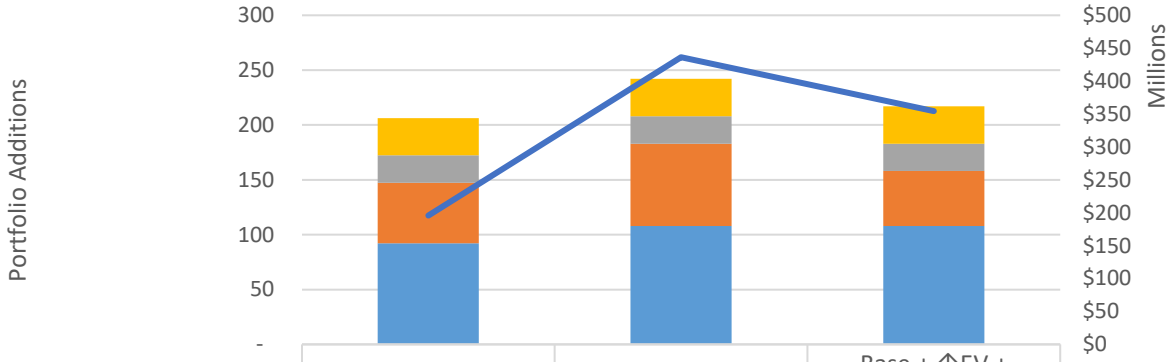
In addition to looking at expected case, the 2019 IRP Update included consideration of possible variances in specific technology forecasts that affect net load forecasts. The purpose of the sensitivity analysis is to see how different a portfolio strategy might look if technology forecasts were significantly different than expected. The EV Variance sensitivity looks at a total number of EV load in 2039 roughly 2.4 times greater than the expected EV load. A higher EV adoption rate translates to increased portfolio need. The EV Variance + Rooftop Solar Variance assesses the impact to the Base Case load forecast if EV loads were 2.4 times larger than expected and rooftop solar nameplate installation rates were twice the expected rate. Scenarios were looked at from both an All Renewables and an All Resources perspective.

The findings of the sensitivity analysis were that the portfolio solutions with the All Renewables and All Resources scenarios were remarkably similar, regardless of the technology variances. Rather than affecting the type of resource needed, the technology sensitivities generally changed the quantity and timing of the resources needed. For instance, higher EV load generally caused a

greater need for conservation acquisition across scenarios. Higher rooftop solar penetration generally mitigated some of the new resource builds created by the higher EV loads, and resulted in lower overall resource acquisition and incremental portfolio NPV costs than the High EV sensitivity. In all technology sensitivities, the All Renewables resource option was more expensive than the All Resource approach from an incremental portfolio NPV perspective.[14] Figure 6-7 comparisons the Base Case Technology sensitivities across three technology sensitivities, using an All Renewables scenario to find the most cost-effective portfolio.

Figure 6-7

Base Case: All Renewables
Portfolio Build differences due to Technology Variance



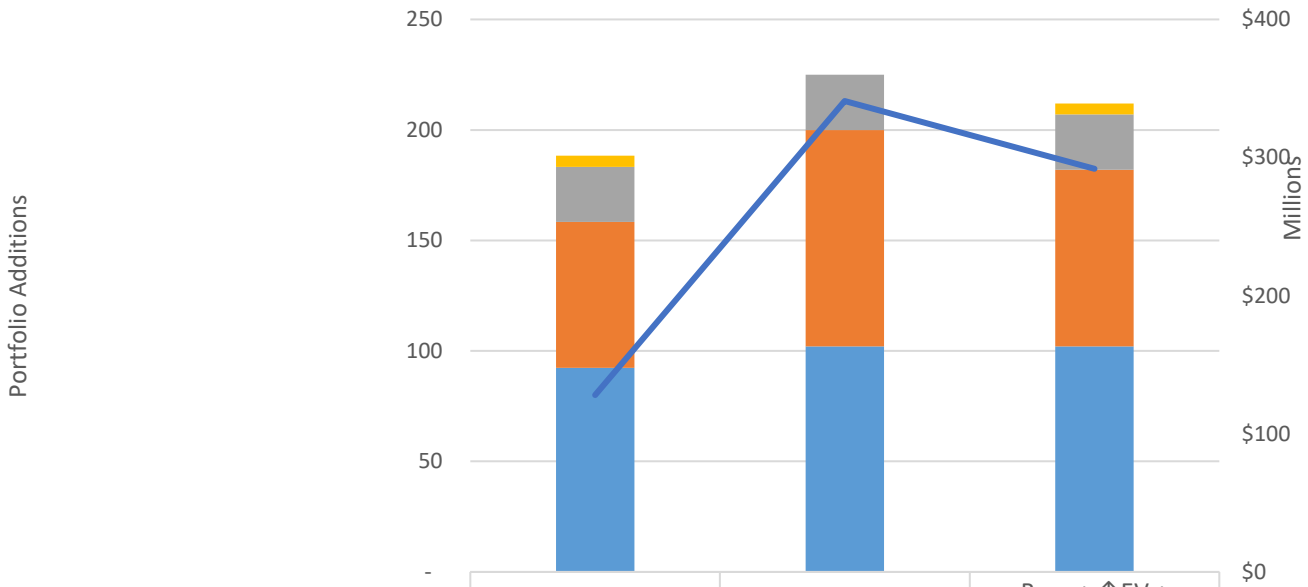
	Base	Base + ↑EV	Base + ↑EV + ↑Rooftop Solar
Demand Response (20-Year Peak Hour)	34	34	34
Short-Term Market (Dec HLH aMW)	25	25	25
Solar (Nameplate MW)	55	75	50
Conservation (20 Year aMW)	92	108	108
NPV	$195,771,041	$436,296,459	$354,354,440

[14] The technology sensitivity analysis only looked at the incremental NPV costs of balancing the PUD's portfolio to load increases, and is not a rates analysis or average cost analysis. Results of a net impact study on rates impacts could reach different conclusions on the net cost or benefit to the PUD, or average retail rates.

Figure 6-8 shows the portfolio comparisons of Base Case portfolios with three technology sensitivities, using an All Resources scenario to find the least cost portfolio.

Figure 6-8

Base Case: All Resources
Portfolio Build Differences due to Technology Variance

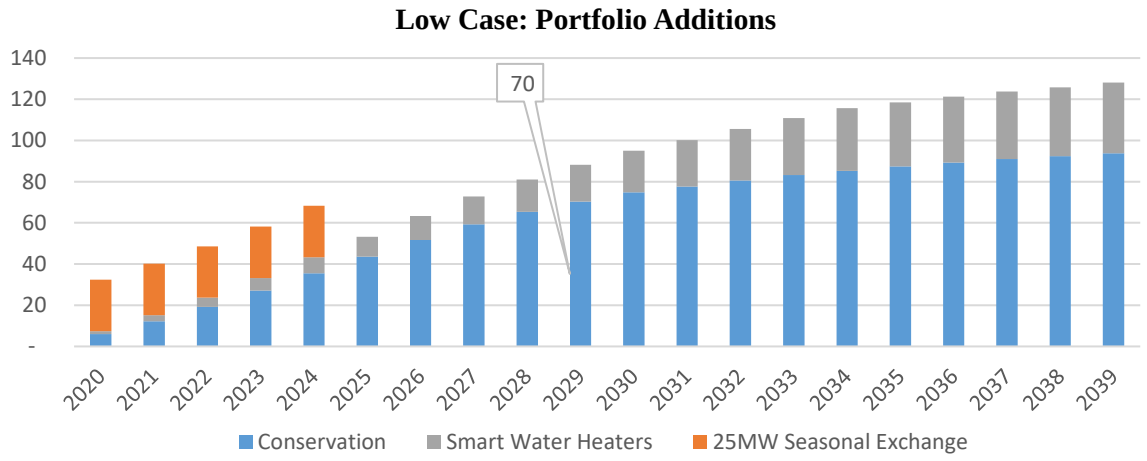


	Base	Base + ↑EV	Base + ↑EV + ↑Rooftop Solar
Solar (Nameplate MW)	5	0	5
Short-Term Market (Dec HLH aMW)	25	25	25
Dispatchable Capacity (Nameplate MW)	66	98	80
Conservation (20 Year aMW)	92	102	102
NPV	$128,077,377	$340,953,586	$291,781,201

Low Case Portfolio

The Low Case represents load growth lower than current expectations for future load growth and future market prices that are less expensive than current PUD expectations. The annual average load growth before New Conservation is 0.4% and that growth includes lower expectations for future electric vehicle adoption and assumes forecast rooftop solar installation will contribute approximately 3 aMW on an annual average basis by 2039. The incremental NPV of the Low Case portfolio was $135 million, roughly 5% higher than the Base Case All Resources portfolio, due to reduced portfolio surpluses to monetize at wholesale market prices to offset portfolio costs. The Low Case scenario is the only scenario where the lowest cost portfolio returned is already an All Renewables portfolio.

The Low Case scenario selected 94aMW of conservation on a 20-year basis, and 70.4 aMW by Year 10 in 2029 – the same conservation level as every Base Case scenario. A 25MW market product was added beginning in 2020 to serve the first five December-January winter needs. A Smart Water Heater demand response program that shifts on-peak load to off-peak periods year-round was selected, growing into a total on-peak to off-peak shift of 34aMW after 20 years of program maturity. Annual EIA renewables requirements needs were met with the purchase of unbundled RECs from eligible northwest renewable projects. **Total emissions of the portfolio were 4.5 million MT of CO2, roughly 12% lower than the Base Case All Resources portfolio.**



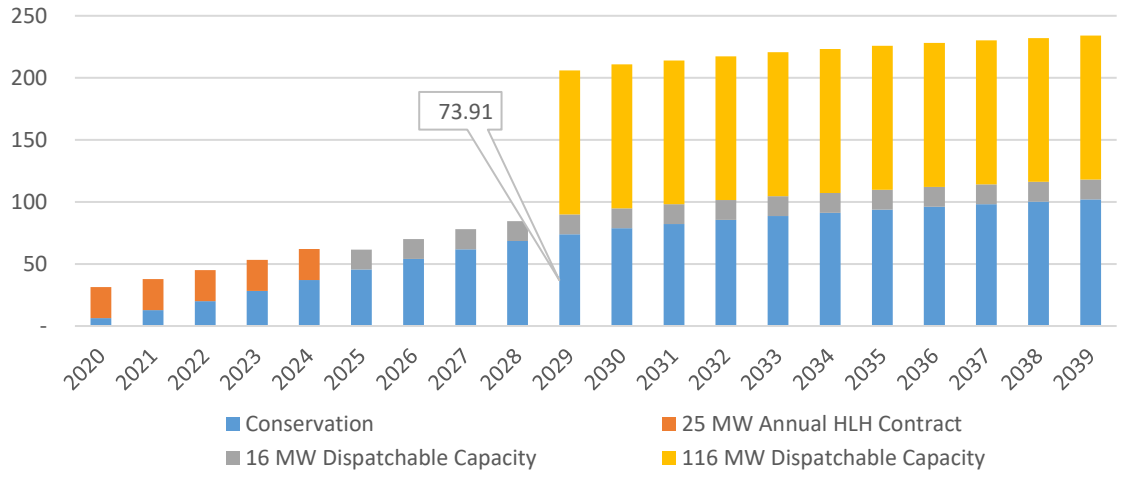
High Case Portfolio

The High Case represents load growth higher than current expectations for future load growth and future market prices that are more expensive than current PUD expectations. The annual average load growth before New Conservation is 1.3% and that growth includes raised expectations for future electric vehicle adoption. That load growth is mitigated by a forecast rooftop solar installation that contributes about 12.5 aMW on an annual average basis by Year 20 (2039). Importantly, the High Case is the only case where the PUD has an annual average energy need, and as a result, different resource types are added to meet that need.

High Case - All Resources

The incremental NPV of the High Case portfolio was $360 million, roughly 2.8 times higher than the Base Case All Resources portfolio. The High Case scenario also selected 102 aMW of conservation on a 20-year basis, and 74 aMW by Year 10 in 2029 – just over the conservation level selected in each Base Case scenario. A 25MW market product was added in the first five years to serve on-peak energy needs in each month. Two increments of dispatchable capacity were added; 16MW in 2025 and 116MW in 2029. Unbundled RECs from eligible northwest renewable projects were also added to meet compliance requirements. **Total emissions of the portfolio were 6.3 million MT of CO2, roughly 24% higher than the Base Case All Resources portfolio.**

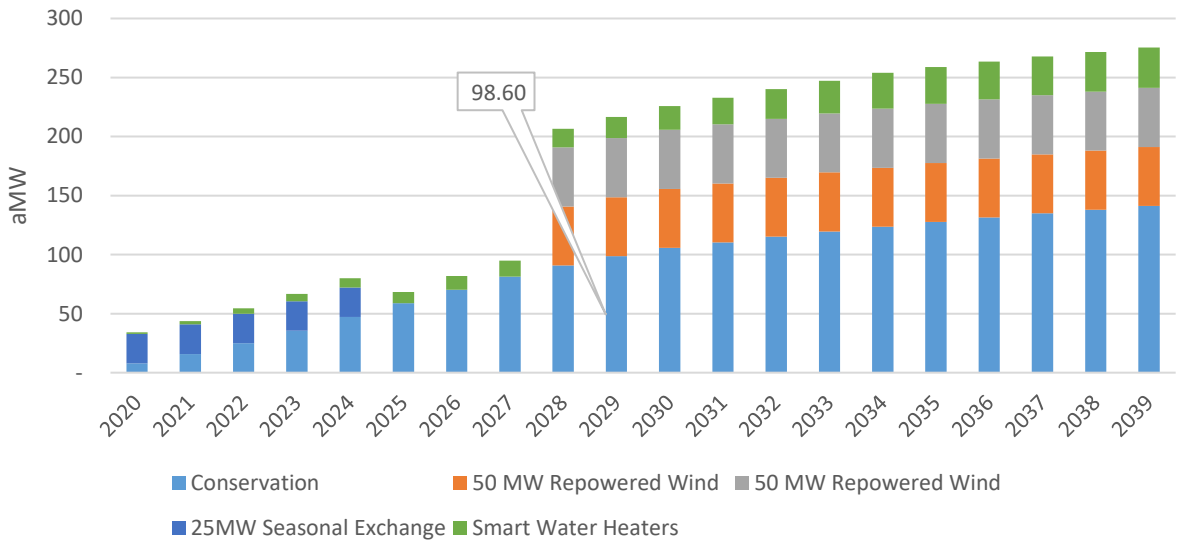
High Case: All Resources - Portfolio Additions



High Case - All Renewables

The incremental NPV of the Low Case portfolio was $593 million, roughly 4.6 times higher than the Base Case All Resources portfolio, with the higher incremental NPV reflective of a larger total resource acquisition and higher resource acquisition costs. The High Case scenario selected 141aMW of conservation on a 20-year basis, and 98.6 aMW by Year 10 in 2029. A 25MW market product was added in the first five years to serve winter on-peak energy needs. A Smart Water Heater demand response program that shifts on-peak load to off-peak periods year-round was selected, growing into a total on-peak to off-peak shift of 34aMW after 20 years of program maturity. A 100MW nameplate repowered wind resource was added in 2028 to provide annual energy and contribute to summer and winter on-peak energy needs. Unbundled RECs from eligible northwest renewable projects were also added to meet compliance requirements. **Total emissions of the portfolio were 5.1 million MT of CO2, roughly the same as the Base Case All Resources portfolio.**

High Case: All Renewables - Portfolio Additions



Portfolio Comparison

Looking across all scenarios, there were a number of features of cost-effective portfolios that were similar:

- Significant volumes of new conservation, between 94-141aMW over 20 years on an annual average basis, were added to each new portfolio. The conservation was not added to meet annual energy needs, but rather, primarily because it cost-effectively managed winter portfolio exposure
- A near-term market product was added in every scenario to help bridge near-term winter portfolio needs until new conservation could accumulate and meet needs
- There were no significant supply-side resource additions in the first five years of the study period, and for many portfolios, the first ten years.
- Portfolios with dispatchable capacity resources generally resulted in lower cost portfolios because they allowed for the most tailored alignment between resource need and resource addition, and they were able to dispatch generation to limit market exposure under adverse conditions, while dispatching on a limited basis in surplus conditions.

Notable differences between scenarios include:

- An annual energy need found only in the High Case before new conservation, resulting in the addition of annual energy resources in addition to resources that more directly served the PUD's winter and summer needs.
- Portfolios testing the All Renewables sensitivity generally augmented conservation acquisition with load-shifting demand response (Smart Water heaters) to serve on-peak energy needs and capacity needs, along with utility-scale solar to serve long-term summer needs.
- The Low Case was the only scenario where an All Renewables scenario was the lowest cost portfolio option. This occurred because the lower load forecast created a reduced need, and the need was cost effectively managed by conservation and load-shifting demand response.

Section 7: Long-Term Resource Strategy

A Long Term Resource Strategy must reflect and balance the potential for risk and uncertainty, while identifying the best portfolio using least cost criterion. An effective Long-Term Resource Strategy must also be able to meet expected needs and effectively pivot if future technology, legislative or regulatory changes create new challenges and opportunities for the PUD.

Three principal factors frame the types of risk and uncertainty the PUD must seek to address through a Long Term Resource Strategy:

1. The impact of climate change on the PUD's existing resource portfolio and forecast future seasonal needs;
2. The progress and development of emerging technologies and their potential impact on PUD load growth and customer need across time; and
3. A Long-Term strategy that is compliant with the policies of today, and can adapt to the changing needs of our customers and other regulatory policy changes of tomorrow.

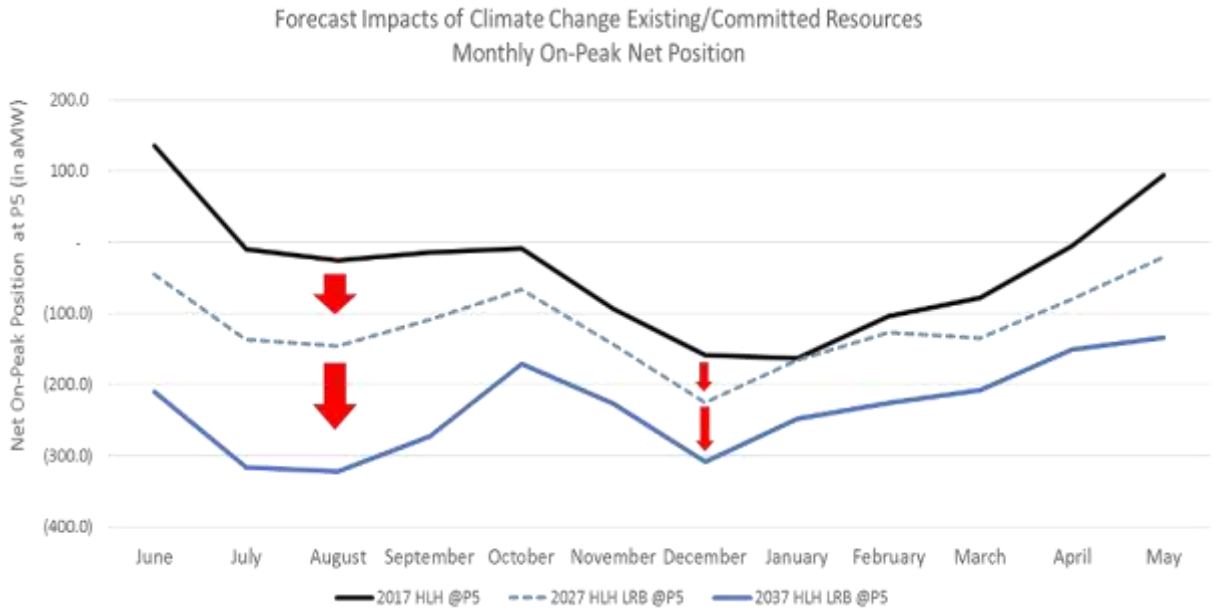
PORTFOLIO RESILIENCY

Addressing Changing Seasonal Needs

Climate change effects the PUD's portfolio over the study period by shifting the timing and scale of energy delivery of the PUD's existing owned and contracted hydropower resources, and changing the timing and scale of customer need and use patterns. Generally, the climate change impact on hydropower shifts more of the potential energy into the winter period from summer due to warmer weather that reduces snowpack at increasingly higher elevations and suggests that more precipitation will fall as rain instead of snow. This helps the PUD better meet winter customer demand needs, but does so at the expense of reduced summer hydropower production largely due to less snowpack and runoff. Customer demand is expected to gradually decline in winter due to milder temperatures, and increase in summer due to warmer temperatures that will increase cooling load (air conditioning).

Figure 7-1 shows the transition of forecast deficits by month shifting from a winter emphasis, to both a winter and summer emphasis by year 10 of the study period (2029). As a result of anticipated changes in customer load drivers like air conditioning and reduced heating load, and shifts in potential snowpack runoff and hydropower generation shapes it is no longer sufficient to plan only for near-term winter needs. The PUD needs to also actively explore long-term summer on-peak energy options or resource options that can effectively manage near-term winter needs and longer term summer needs.

Figure 7-1
Comparison of Changes in Monthly On-Peak Load Resource Balance Forecast Deficits in Years 1, 10, and 20 of Study Period



Technology Advancements

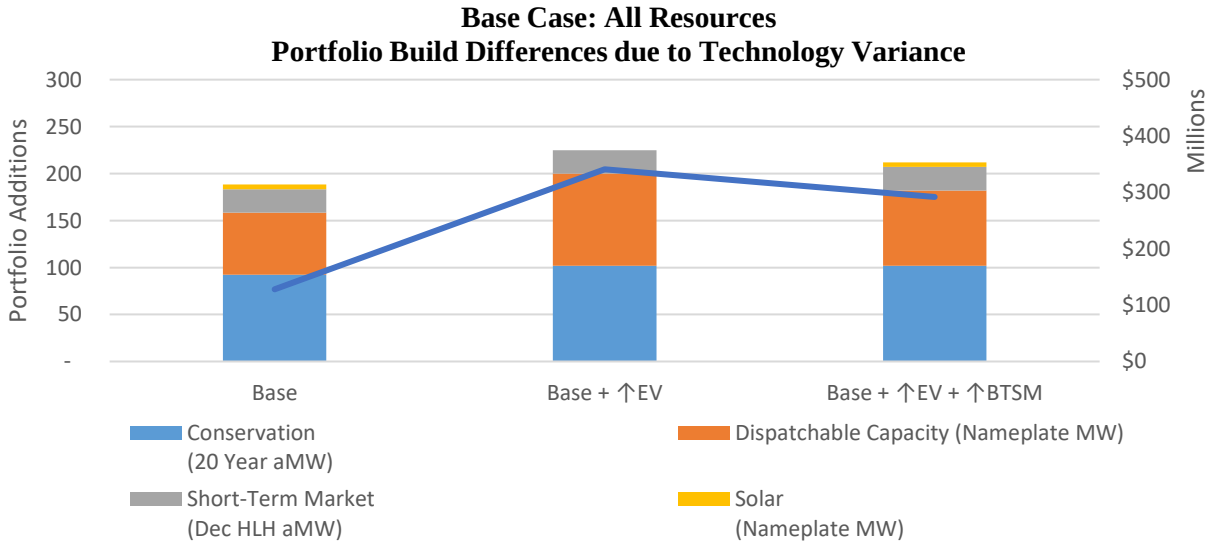
Forecasts of future load are more difficult the farther into the future the forecast extends. While the PUD has a solid understanding of the impact of weather on its customers load now, it has an imperfect view of future customer behavior and future technologies that customers will adopt in the future. At the time of this writing, there is some public dialogue about whether public policy could or should "electrify" a significant share of the Northwest economy based upon the idea that due to the low carbon content of the Northwest electricity sector, displacing other fuels with electricity could reduce carbon emissions. If "electrification" of the economy does come to

fruition, it could create a different outlook for customer demand for electric home-heating, electric vehicles, rooftop solar and other technologies.

All future load forecasts included in the 2019 IRP Update included forecasts based on the best available information of future electric vehicle load and future rooftop solar, but additional analysis was also conducted to see how different portfolios would respond to more aggressive adoption rates of these technologies. The conclusion, for the assumptions studied, was that a long-term strategy could adapt to these technologies by scaling up the quantity of otherwise cost-effective resource acquisition.

Figure 7-2 shows that in a Base Case - All-Resource environment, the scale of conservation acquisition and the scale of acquisition of dispatchable capacity resources would increase if a 2.4 times higher adoption of rate of electric vehicles than expected were to occur, but that need would be mitigated if it came coincident with a 2 times higher penetration of solar. In this way the Base Case - All Resources portfolio additions can be viewed as resilient to technology variance, as different quantities of the same resources are the lowest reasonable cost response to differing technology adoption, rather than different resource types, which would suggest a portfolio may need to course correct if a technology forecast were significantly different than forecast.

Figure 7-2



Regulatory Uncertainties

Changes in State and Federal policy regarding the environment and energy have oscillated significantly in recent years. While the 2017 IRP contemplated the potential implementation of the Clean Power Plan outlined by the Obama administration, subsequent court challenges and a federal administrative change have changed the near-term outlook for federal energy policy. At the same time, there have been several efforts to introduce new carbon and energy policy changes within Washington State and West Coast States, all of which can or will have significant implications on the cost and availability of regional power. Future policy is difficult to predict, but the implications of future policy on large-scale investments to the PUD are a significant risk. As a result, the PUD's Long-Term Resource Strategy needs to be reflective not just of the lowest reasonable cost portfolio of today, but of the potential policies of the future.

Legislative risks for future resources include the potential for fossil-fuel based resources to be limited or assessed a carbon tax. This has the potential of making some resources, like natural gas plants, vulnerable to potential legislative risks. This risk is addressed in the 2019 IRP Update by assigning a carbon cost to the dispatch of the long term capacity resource, as well as using natural gas plants as a market-setting price point for the cost of dispatchable capacity, but not committing to that technology type.

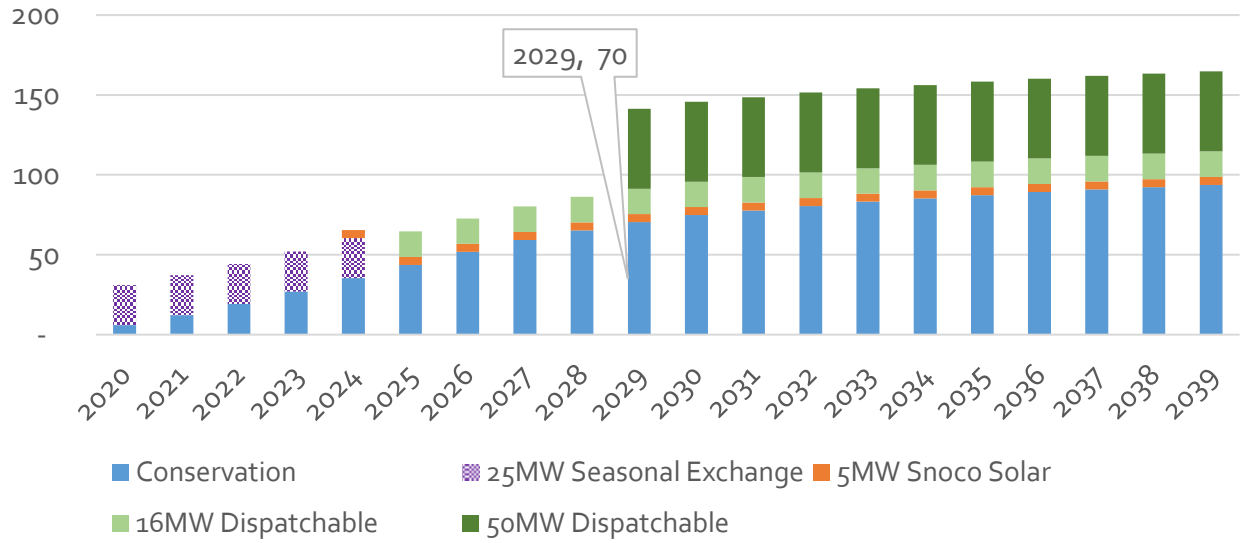
Legislative risks for future resources also include legislated targets for Renewable Portfolio Standards or clean energy. In Oregon and California these types of policies have layered on top of carbon pricing efforts and have an additive effect on future resource option economics. These types of policies can also significantly impact the market for Northwest energy, increasing the supply of average energy and pushing down average energy prices, but creating more price volatility in specific hourly markets. This could change the type of market exposure the PUD faces, as well as its cost – and in turn affect the PUD's preferences for physical resources or meeting more needs from the market. Increases in renewable supply coinciding with Northwest peak hydropower generation periods can result in renewables curtailment, undercutting some of the long-term economics of some renewable resources. At the same time, increases in RPS requirements or similar Clean Energy Policies could change the economics for supply-side

resources and conservation in the future. While the 2019 IRP Update only assessed current RPS policies for the state of Washington, it is expected that other clean energy policies will be evaluated as they are proposed, with deeper treatment of portfolio resiliency part of the next comprehensive IRP.

LONG-2019 TERM RESOURCE STRATEGY

The Base Case - All Resources portfolio provides the lowest reasonable cost portfolio while managing future portfolio risks, and adds one 25 MW short term market product for Years 1-5, accumulates 70 aMW of new conservation by 2029[15], and defers the need for a significant long term capacity resource investment until 2029. **With an incremental portfolio cost NPV of $128 million, this portfolio was found to be 35% less than the next closest portfolio option in the Base Case**. Figure 7-3 shows the portfolio additions of the Base Case - All Resources portfolio, while subsequent sections describe what needs the resources meet, and how they account for future risks and uncertainty.

Figure 7-3
2019 Long Term Resource Strategy
Base Case: All Resources - $128 NPV

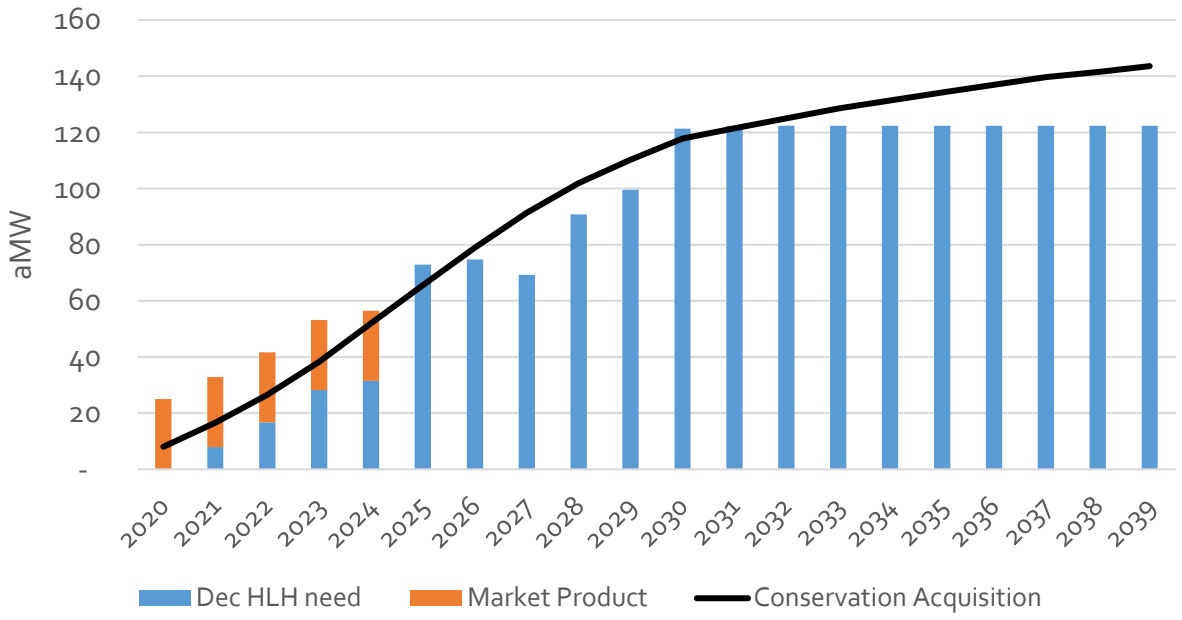


[15] The 10 year conservation potential identified as cost effective in the Long Term Resource Strategy for the 2020 through 2029 period, consistent with statute, is 70 aMW.

Near-Term to Long-Term Winter Needs

Base Case expectations are that the PUD near-term needs are winter on-peak energy and capacity. These needs can be met cost-effectively with a 25 MW near-term market product that serves December-January Winter On-Peak energy needs, and new conservation acquisitions. By accelerating discretionary conservation from a 20-year implementation to an 11-year conservation, nearly all of the PUD's winter needs – near-term, mid-term, and long-term – can be met on a P5 basis. Figure 7-4 shows the effectiveness of the 25 MW market product and new conservation in meeting the PUD's forecast winter on-peak energy needs. The addition of conservation defers the PUD's need for a large, one-time investment in the near-term as conservation savings accumulate, and provides the most cost-effective resource to serve the PUD's forecast long-term winter needs. If the actual effects of future technology on customer load are different than expected, the PUD has the ability to reassess its conservation technical potential every two years and make adjustments.

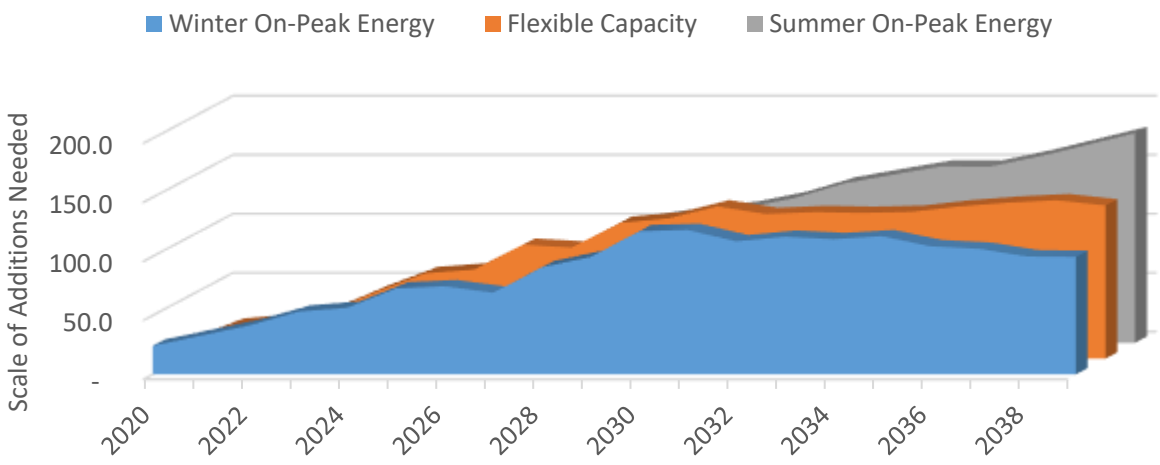
Figure 7-4
Base Case: New Conservation and Market Product meet Winter On-Peak Needs



Mid-Term to Long-Term Capacity and Summer Needs

The PUD's long-term summer need and incremental capacity need is measurable but not significant through the mid-2020's. The need becomes larger at the end of the 2020's. Figure 7-5 shows the forecast summer need as the largest portfolio need by 2032 before new conservation, while capacity needs begin around Year 6 (2025) and gradually increase over time.

Figure 7-5
Base Case Portfolio Needs Over Time Before New Conservation



Summer needs are driven by assumptions of changing hydrology affecting generation of the existing portfolio due to climate change and increased customer loads in those months. These assumptions of future hydrology and customer behavior affecting load, while backed by data, are difficult to forecast over this long a time horizon. It is possible that as better data becomes available that forecasts for summer need could increase or decrease.

A dispatchable capacity resource allows the PUD to meet mid-term capacity needs and long-term summer needs in a flexible, modular way. Because the PUD is surplus on an annual basis, as well as the spring and fall after conservation for most of the study period, a more flexible resource allows the PUD to meet its seasonal needs without adding to surplus. This flexibility

gives the PUD the option to dispatch the resource or rely on the market, which could be important if regional surplus renewable energy pushes energy prices down. In addition, it could provide the PUD with an opportunity if market dynamics create premiums for specific hourly markets.

A dispatchable capacity resource could be a natural gas plant, a biofuel plant, or any other type of resource that is not fuel-limited and is thus able to run whenever needed. What makes the resource cost effective is its ability to limit the PUDs market exposure in adverse conditions through generation, while only dispatching surplus energy when market conditions are economic.

Because the PUD does not need a dispatchable resource product at scale for many years, there is ample time to do due diligence on the right resource, and ensure that it fits with the market and regulatory environment. As the PUD approaches its 2028 contract expiration of its existing contract with BPA, it is also possible that some or all of this need could be met by a different configuration of BPA product.

The Long Term Resource Strategy does not commit the PUD to any long term resource decisions that could prove uneconomic if carbon policy changes significantly; instead, the strategy invests in a conservation level that meets expected winter needs, invests in a discreet, short-term capacity contract to provide for near-term capacity needs, and anticipates investments in unbundled RECs as part of a strategy to cost-effectively comply with EIA standards. The time before a long-term resource decision needs to be made also means the Long Term Resource Strategy can be revaluated in the next IRP, when more may be known about a defined carbon policy.

EIA (I-937) Annual Compliance

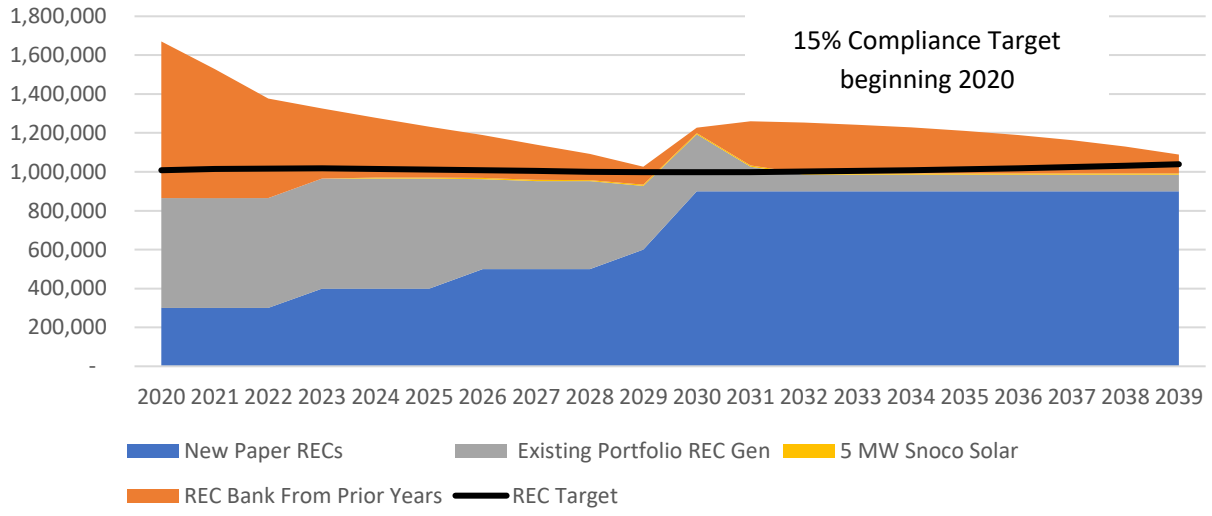
Every scenario tested in the 2019 IRP Update found that meeting Renewable Portfolio Standard needs was cost-effectively done with a substantial volume of unbundled RECs. This is because, except for the High Case, the PUD does not have an annual energy need, and near-term seasonal needs in the winter are most cost-effectively addressed through acquisition of conservation and a market product, rather than a supply-side resource that may have renewable attributes.

The Long-Term Resource Strategy from the Base Case finds that the majority of majority of REC needs would be met through the purchase of unbundles RECs to augment the renewables in the PUD's existing portfolio. The strategy also finds, that some small investment in local, Snohomish County solar may also help contribute to RPS compliance and long-term summer needs.

Figure 7-6 below shows how the PUD's compliance would be met under the Long-Term Resource Strategy, with a REC bank from the PUD's existing resource portfolio that can be carried over into future years and the procurement of unbundled REC purchases.

Figure 7-6

EIA Renewables Compliance



2019 Action Plan

The 2019 IRP Update identified a number of activities to be implemented and identified several areas where further investigation and exploration by the utility could enhance future decision-making. The near term actions the PUD can take to meet the needs of its customers in a rapidly changing environment, well into the future, include:

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.

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.

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.

4. Align and integrate District-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.

5. Enhance short and long-term resource portfolio modeling capabilities to provide more precise and time granular analyses of portfolio challenges and potential solutions.

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.

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.

Supply-side resource costs were refreshed where applicable in the 2019 IRP Update. The basis of the PUD's supply side costs came from a survey of other Pacific Northwest utilities' IRPs, the Council's Seventh Power Plan, research papers and other sources to gather cost and operations data on renewable and nonrenewable generating resources.

Supply-side resource cost assumptions were developed for each resource for delivery in each year of the study period they were determined to be commercially available to the PUD. Costs included development, transmission, integration costs (if applicable), operations and maintenance expenses, and fuel costs (if applicable and including the social cost of carbon of any emitting fuel combustion).

1. Average Annual Levelized Cost of Energy

The table below shows each supply side resource option considered in the 2019 Update, the annual capacity factor for the resource, and its levelized cost of energy for delivery in the year 2020.

Resource	Annual Capacity Factor	Average Annual Levelized Cost of Energy ($/MWh)
25MW Flat HLH Contract (on peak hours, 12 months)	56%	$38.64
50 MW Repowered Wind	35%	$67.38
50 MW Montana Wind	42%	$69.46
10 MW Landfill Gas	85%	$ 75.58
50 MW WA Wind (NW or Col. River Gorge wind)	35%	$77.00
25 MW Utility Scale Solar (Eastern WA solar)	24%	$84.94
25 MW Geothermal	90%	$85.03
15 MW Biomass	85%	$89.15
30 MW Low Impact Hydro	46%	$105.50
5 MW Snoco Solar (Snohomish County solar)	13%	$134.64
232 MW Dispatchable Capacity	10%*	$154.22
116 MW Dispatchable Capacity	10%*	$198.51
25MW Capacity Contract (5 yr term, up to 876 hours, Nov-Feb)	10%*	$205.00
5 MW Battery Storage	15%*	$241.38
25 MW Battery Storage	15%*	$241.38
50 MW Dispatchable Capacity	9%*	$255.50
16 MW Dispatchable Capacity	9%*	$255.50

32 MW Dispatchable Capacity	9%*	$255.50
100 MW Local Pump Storage	18%*	$309.94
100 MW Low Cost Regional Pump Storage	18%*	$333.29
25 MW Capacity Contract (Extension to Years 6-7)	10%*	N/A
25 MW Seasonal Exch 1 (Annual off peak to Nov-Feb on peak swap)	N/A	N/A
25 MW Seasonal Exch 2 (Summer on peak to Nov-Feb on peak swap)	N/A	N/A

*The annual capacity factor for a resource that can provide dispatchable capacity, or can be turned on or off, would typically be notably higher than is shown here. The low annual capacity factor reflects the portfolio modeling assumption that a resource of this type, given the PUD's surplus energy position, would only be dispatch to meet periods of peak customer demand, limited to 10% or 876 hours in the year. Similarly batteries are modeled as dispatching 15% on an annual basis due to charge cycle constraints, and pumped storage hydro is modeled as dispatching 18%.

2. Levelized Cost of Winter Capacity

Resource costs presented in the table below are delivered in the year 2020. The capacity value is specific to the capacity value of one megawatt (1 MW) delivered during the on peak hours, Monday through Friday, for a total of 80 hours for the on peak, or "Peak Week" in December. The Peak Week is intended to reflect the highest demand week within the month of December, at 95% confidence.

Resource	**Levelized Cost of Capacity ($/MW)**
25 MW Seasonal Exch 1 (Annual off peak to Nov-Feb on peak swap)	$ 9,155
25 MW Seasonal Exch 2 (Summer on peak to Nov-Feb on peak swap)	$ 10,182
232 MW Dispatchable Capacity	$ 139,276
116 MW Dispatchable Capacity	$ 179,271
50MW Capacity Contract (5 year term, up to 876 hours, Nov-Feb)	$ 179,584
25MW Capacity Contract (5 year term, up to 876 hours, Nov-Feb)	$ 189,808
16 MW Dispatchable Capacity	$ 223,814
32 MW Dispatchable Capacity	$ 223,814
50 MW Dispatchable Capacity	$ 223,814
100 MW Local Pump Storage	$ 503,091
100 MW Low Cost Regional Pump Storage	$ 541,783
10 MW Landfill Gas	$ 662,061

15 MW Biomass	$ 737,538
25 MW Geothermal	$ 744,888
25 MW Battery Storage	$ 1,268,673
5 MW Battery Storage	$ 1,268,673
50 MW Montana Wind	$ 2,255,943
50 MW Repowered Wind	$ 3,436,834
30 MW Low Impact Hydro	$ 3,481,160
50 MW WA Wind (NW or Col. River Gorge wind)	$ 3,927,954
25 MW Utility Scale Solar (Eastern WA solar)	$ 7,125,727
5 MW Snoco Solar (Snohomish County solar)	$ 7,943,809
25 MW Capacity Contract (Extension to Years 6-7)	N/A

3. Levelized Cost of Summer Capacity

The levelized cost of summer capacity for supply-side resources is assumed to be delivered in the year 2029, when the PUD sees an emerging summer on peak energy need. The capacity value is specific to the capacity value of one megawatt (1 MW) delivered during the on peak hours during the month of August, at 95% confidence.

Resource	**Levelized Cost of Capacity ($/MW)**
232 MW Dispatchable Capacity	$ 173,667
116 MW Dispatchable Capacity	$ 223,610
50 MW Dispatchable Capacity	$ 279,258
16 MW Dispatchable Capacity	$ 279,258
32 MW Dispatchable Capacity	$ 279,258
100 MW Local Pump Storage	$ 422,367
100 MW Low Cost Pump Storage	$ 453,541
25 MW Utility Scale Solar (Eastern WA solar)	$ 513,876
5 MW Snoco Solar (Snohomish County solar)	$ 555,887
25 MW Geothermal	$ 599,656
50 MW WA Wind (NW or Col. River Gorge wind)	$ 812,866
10 MW Landfill Gas	$ 826,824
15 MW Biomass	$ 975,266
25 MW Battery Storage	$ 1,068,580
5 MW Battery Storage	$ 1,068,580
50 MW Montana Wind	$ 1,635,737
50 MW Repowered Wind	$ 2,070,277
30 MW Low Impact Hydro	$ 2,802,432
25 MW Seasonal Exch 1 (Annual off peak to Nov-Feb on peak swap)	N/A
25 MW Seasonal Exch 2 (Summer on peak to Nov-Feb on peak swap)	N/A
50 MW Capacity Contract (5 year term, up to 876 hours, Nov-Feb)	N/A
25 MW Capacity Contract (5 year term, up to 876 hours, Nov-Feb)	N/A
25 MW Flat HLH Contract (on peak hours, 12 months)	N/A
25 MW Capacity Contract (Extension to Years 6-7)	N/A