Tacoma Power

2022 Integrated Resource Plan

DRAFT

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CONTENTS

Tacoma Power 2022 Integrated Resource Plan (IRP) Update

Executive Summary

Tacoma Power is a national leader in providing renewable, reliable, and affordable energy. Virtually all the electricity we deliver to our retail customers comes from hydroelectric sources. A little more than half of comes from our long-term contract with the Bonneville Power Administration (BPA). We produce most of the rest ourselves at the four hydroelectric generation projects we own and operate. In most years, our resources provide more power than we need to serve our retail customers. When we have surplus electricity, we export that surplus to the rest of the region by selling it on wholesale power markets. The revenue from these sales helps us maintain electric rates among the lowest in Washington State and the nation.

Our Integrated Resource Plan (IRP) is a tool that helps us plan for an uncertain future so we can continue to provide reliable, low-cost power to our customers for decades. In each IRP, we look out over the next 20 years. We use sophisticated modeling tools and a great deal of analysis to help us understand how a potential decision about a power resource might affect us, and our customers, under a broad range of future conditions. We use our analysis to develop a resource strategy that ensures we enough power to meet customer needs into the future at the lowest possible cost and risk while meeting all clean energy regulatory requirements. We create a new IRP every two years because our projections of what the future might hold evolve. We conduct a full refresh of our IRP every four years and make smaller updates to the plan in the interim every two years. This IRP is an update to our 2020 plan.

BPA

- Renew BPA contract with the same Slice/Block product as we purchase today if product offerings remain similar to current products

Energy Conservation

- Acquire all economic achievable conservation identified in CPA

Other Resources

- Continue to develop capability to acquire DR, with goal of acquiring 10MW of DR

Western Grid Reliability

- Make final decision on joining Western Resource Adequacy Program (WRAP) and continue involvement in the meantime

Our 2022 IRP identifies a preferred resource strategy that is very similar to the one we identified in 2020. Like many of our other IRPs, our resource strategy includes renewing our BPA contract in 2028 and selecting the same Slice/Block product as we purchase today, acquiring all achievable economic conservation identified in our Conservation Potential Assessment (CPA). While our plan to acquire the conservation is firm, our preferred BPA contract renewal strategy is predicated upon the assumption that BPA's post-2028 contract and product offerings look similar to what they are today. We expect to have better information regarding potential future offerings in time for our next IRP and expect to analyze the question of BPA renewal again in both our 2024 and our 2026 IRPs. Our 2020 and 2022 IRPs also identify the addition of 10MW of demand response as our preferred strategy to shore up small adequacy risks that we might face if we find ourselves in a future where the Western grid becomes increasingly unreliable. In recent years, we have seen several indications that capacity may not always be plentiful in the market. We actively participate in efforts like the Western Resource Adequacy Program (WRAP) to ensure that the region builds sufficient capacity and maintains reliability. We plan to make a decision on whether or not to join by the end of 2022. Developing our capabilities to offer and manage demand response programs now also helps us prepare for a potential future in which we see accelerated load growth due to vehicle and building electrification.

2022 IRP Action Plan

	2-year action plan	4-year action plan	10-year action plan
Conservation	Acquire 53,114 MWh of energy conservation	Acquire all achievable economic conservation identified in CPA	Acquire all achievable economic conservation identified in CPA
BPA	Continue active participation in BPA post-2028 contract discussions	Near-final BPA decision	Renew or replace BPA contract with other low or no-carbon resource
Other Resources	Pursue additional opportunities for DR Update DR potential assessment Explore short-term contracts to shore up potential resource adequacy risks	Acquire 10MW of DR	Acquire additional DR if additional need is identified in IRP
Other Analyses	Final decision on joining WRAP Electrification Futures study Enhance climate change modeling		

1 INTRODUCTION

The Integrated Resource Plan (IRP) is a tool to help us plan for an uncertain future so that we can continue to meet our customers' needs for decades to come. Findings in the IRP represent our resource plan based on the best information available at the time of its creation. However, the plan may change as new information becomes available. Per Washington state law, we complete a full refresh of the IRP every four years and make small updates in the interim every two years. We completed our last full refresh of the IRP in 2020. Our 2022 IRP is an update to the 2020 IRP. Our 2022 IRP maintains the same basic modeling framework and scenarios as the 2020 IRP but relies on updated inputs for prices and loads and conducts a new sensitivity analysis around how our adequacy position might change if load grows at an accelerated pace as a result of vehicle and building electrification. We have also adjusted how we model certain resources in our system model and our assumptions regarding how much we can rely on purchasing from the wholesale power market to help meet our needs.

1.1 KEY QUESTIONS

We ask some of the same questions in 2022 as we did in 2020 but also consider some new questions.

1. **Updated BPA contract renewal analysis:** Our largest power purchase contract is with Bonneville Power Administration (BPA). Our current contract with BPA ends on September 30, 2028. Our 2020 IRP took a first look at the questions of whether to renew our contract with BPA in 2028, which BPA product might best meets our needs in the future and whether there might be value in diversifying our portfolio to be slightly less reliant on BPA in the future. We will continue to evaluate these questions over the next few IRPs as the 2028 date approaches.
2. **Updated analysis on the impacts of climate change:** Our 2020 IRP took a first attempt at including climate change projections directly into our system model. In our 2022 IRP, we repeat this analysis.
3. **New analysis on potential impacts of accelerated vehicle & building electrification:** As the market for electric vehicles continues to expand and local and state legislation encouraging vehicle and building electrification expand, the possibility of large load increases due to electrification is becoming increasingly likely. The 2022 IRP takes a first, simplified look at the potential resource adequacy impacts of accelerated of vehicle and building electrification. In our next IRP, we plan to take a more nuanced look at how much additional load we might see from electrification and how quickly it might roll out.

1.2 COMMUNITY INPUT PROCESS

As part of every IRP, we hold a community input process. The objectives of this process are to (1) educate stakeholders about Tacoma Power's long-term planning process and key industry developments that affect that process, (2) seek feedback on key IRP assumptions, approaches and products, and (3) seek input from stakeholders about what their priorities are so that we can consider them in our planning process.

IRP workshops are our primary outreach tool for the 2022 IRP. Our IRP workshops are open to the public, and anyone is welcome to participate. We advertise the workshops to all of our customers (e.g. on our website) but make a concerted effort to secure participation from individuals representing key interests in the community in order to ensure a diversity of perspectives (different customer classes, environmental and economic justice interests, external expertise, etc.). We held four workshops for the 2022 between December 2021 and July 2022. We post all workshop materials (slides, notes and meeting recording) on our IRP webpage.

1.3 REVIEW FROM OUR 2020 IRP

In our 2020 IRP, we found that our preferred resource strategy was to: (1) renew our Bonneville Power Administration (BPA) contract with the same Slice/Block product as we have today, (2) continue to acquire all economic achievable conservation identified in our 2020 Conservation Potential Assessment, (3) allow our Columbia Basin Hydro (CBH) to roll off (i.e. not to renew) as they begin to expire in 2022; and (4) acquire 10MW of demand response by 2024. While some of our assumptions and analyses have changed since 2020, we continue to identify a similar preferred strategy in this IRP. Table 1 provides a summary of key action items that we identified related to resource acquisition, resource retirement and further investigation into resources.

TABLE 1. ACTION ITEM PROGRESS

Action Item	Time Frame	Status
1 Do not renew CBH and notify parties of CBH renewal decision	2 years	Complete
2 Acquire 2-year CPA potential	2 years	Complete.
3 Acquire our 10-year CPA target	10 years	In progress. Acquired 2-year target. CPA has since been updated and 10-year potential has changed slightly.
4 Pilot cost-effective demand response options and acquire 10MW of demand response	10 years	In progress. Residential water heater demand response pilot is in the field, and we expect results in time for our 2024 IRP. Discussions with industrial customers regarding design and incentive structure for a program are progressing.
5 Actively participate in discussions with BPA about future product options	2 years	In progress. We have been and will continue to be actively engaged in these discussions.
6 Conduct demand response "potential assessment"	2 years	Complete. The DR Potential Assessment was used to inform assumptions about how much DR might be available and what it might cost to acquire. We plan to repeat the exercise for 2024.
7 Continue to evaluate BPA renewal options	10 years	In progress.
8 Continue to investigate the value of pumped storage	10 years	In progress. Our 2022 IRP considers a generic PSH resource in portfolios where a large capacity resource is needed and in plan to continue to consider it as a possible resource when appropriate in a portfolio in future IRPs.
9 Continue to follow the development of new technologies	10 years	In progress.

We also identified a number of different action items related to improving our modeling tools. We were able to achieve many but not all of these goals. While we will continue to work on improving the quality and capabilities of our models, our 2022 IRP takes a more focused approach to action items and identifies only actions directly related to our preferred resource strategy. Finally, we identified three action items related to equity. We discuss our progress related to these action items in Section 2.4.2.

2 How we assess portfolio performance

We assess portfolios using several metrics. While the metrics we use evolve over time, they always include two fundamental criteria: (1) that portfolios leave us with enough resources to meet customer needs (resource adequacy) and (2) that costs are as low as possible given other constraints and priorities. For the 2020 and 2022 IRPs, we assess portfolios based on five metrics:

1. Compliance with Washington's Clean Energy Transformation Act (CETA)
2. Resource adequacy
3. Expected portfolio cost
4. Financial risk
5. Carbon emissions

We treat the first two criteria (resource adequacy and CETA compliance) as hard constraints, meaning that portfolios must meet these criteria to be a viable portfolio. Other criteria are considerations that help us select the best option.

2.1 CETA compliance

Any portfolio we acquire must meet the requirement that at least 80% of our load is served by renewable and nonemitting power. This IRP updates our method for calculating the 80% requirement in accordance with rulemaking released by the Department of Commerce in June of this year. The Department of Commerce's Phase IV CETA rulemaking order states, among other things, that:

> *Each utility required…to prepare an integrated resource plan must demonstrate compliance…by, at a minimum, showing through an hourly analysis that the expected renewable or nonemitting output of the resource portfolio could be generated and delivered to serve at least 80 percent of expected retail electric load.*

In each hour of each model run, we calculate how much renewable and non-emitting power we generate up to a maximum of our load in that hour, which we refer to as "CETA compliant generation". We add up the total MWh of CETA-compliant generation and compare it to the total MWh of load in a year for that model run to determine whether we are at or above the 80% required by 2030 under CETA. CETA will eventually require that 100% of load be served by carbon-free power by 2045, but that is still outside of the 2022 IRP study period.

It is important to note that our approach to estimating our CETA compliance is a planning-based approach consistent with Department of Commerce rulemaking. We expect the approach for demonstrating compliance for CETA over any given period will differ from the planning-based approach we use in the IRP.

2.2 Resource adequacy

A resource adequacy (RA) standard tests whether a utility has enough resources to meet loads based on some objective criterion. In our 2020 IRP, we updated our standard to reflect evolving best practices in resource planning and settled on a standard that addresses three dimensions of potential adequacy risk: magnitude, duration and frequency of potential shortfalls:

1) **Magnitude standard:** Annual expected capacity shortage of no more than 0.001% of load per year (NEUE of 0.001% per year).
2) **Duration standard:** No more than 2.4 hour of capacity shortage per year (LOLH of 2.4 hours per year).
3) **Frequency standard:** No more than 2 days with a capacity shortage of any magnitude or duration every ten years, or 0.2 days per year (LOLD of 0.2 per year).

If a portfolio meets all three standards, we consider it adequate. If it fails to meet one of the standards, we consider it inadequate. Because our 2022 IRP is an update, we use the same resource adequacy standard as our 2020 IRP. Our 2024 IRP will take a fresh look at our standard once again to ensure we continue to reflect customers' needs and align with industry best practices.

2.2.1 Western Resource Adequacy Program (WRAP) position

Widespread changes in demand for grid services, retirement of carbon emitting resources, and integration of variable energy resources represent a major transition for the power system. While individual utilities have standards to ensure adequacy in isolation, the patchwork of individual planning among interconnected entities may leave a region inadequate. Part of this risk may come from unrealistic regional capacity assumptions or over-reliance on shared market resources. Additionally, capacity resources can take time to build out and insufficient market and price signals may not result in the required supply. Planning in isolation may also fail to account for opportunities in meeting resource needs given geographically or temporally diverse demand and supply. The goal of WRAP is to ensure adequate resources exist among load serving entities in the WECC. The WRAP includes two major programs: a Forward Showing Program and an Operational Program. The Forward Showing Program involves the analysis of supply and demand to identify capacity requirements for each entity in future seasons. The Operational Program is a structure for pre-arranging access to capacity resources across participants during times of need. We plan to make a recommendation regarding whether or not to join the WRAP to our Public Utility Board before the end of 2022. We conduct a preliminary analysis to understand how future resource decisions might align with our WRAP forward-showing requirements if we were to join.

2.3 Cost and Financial Risk

A critical consideration in all resource planning is portfolio cost. Our 2022 IRP considers cost and financial risk through the following metrics: (1) expected costs of each future scenario individually and (2) average of the 25%, 10% and 5% highest-cost outcomes. We also consider qualitatively how flexible a resource leaves us to change course if the world unfolds differently than we expect.

2.4 Other Metrics

2.4.1 Carbon Emissions

For all of the portfolios we consider, the only mechanism through our portfolio would have any carbon emissions associated with it is through purchases we make on the wholesale market or through similar purchases made by BPA that are passed through to Tacoma Power. Because short-term markets do not tag which generator is used to produce the power one is buying, it is not straightforward to estimate how carbon-intensive those purchases are. For simplicity, we assume that the carbon intensity of market purchases is equal to the average of the marginal emissions rate at the Mid-Columbia trading hub modeled in each year for each scenario in our AURORA model (see Section 3.3.3). For emissions associated with the BPA contract, a fixed mix of resources is assumed based on BPA's most recent official fuel mix report[1]. While this assumption is unlikely to be accurate, modeling the potential changes in the share of BPA's portfolio that will come from market purchases under different future scenarios and water conditions is unnecessarily complex given the small amount of emissions associated with the BPA contract. We examine carbon emissions for our preferred resource strategy and some leading alternatives primarily as a formal check that we expect to continue to maintain low emissions into the future.

[1] See "Hydropower Fuel Mix" at https://www.bpa.gov/energy-and-services/power/hydropower-impact

It is important to note that, while helpful, our IRP estimates of wholesale market purchases are incomplete. Our current IRP modeling tools are only able to say how much power we would buy or sell in an hourly real-time market. They do not consider what our purchases would look like in the context of operations like pre-selling power days or even months ahead of time when we have ample water supply or in the context of new sub-hourly markets like the Western Energy Imbalance Market (EIM) that we recently joined.

2.4.2 How does equity factor into our resource metrics?

We identified three action items related to incorporating equity in our 2020 IRP. Two involved developing and, over a longer period, fully incorporating equity metrics to account for equity in resource acquisition decisions. We have made some progress in this area but still have more work to do. In our Clean Energy Implementation Plan[2] we identify three metrics to track energy benefits[3], reduction of burdens[4] and resiliency[5]. Currently the IRP's contribution to ensuring equity is less direct. The IRP's recommendations can serve to create an environment that makes it easier to achieve equitable outcomes, but it is not appropriate tool for ensuring that those recommendations are operationalized in an equitable way.

For example, the IRP aims to ensure that our resource supply is adequate. Having enough resources to meet customer needs is necessary but not sufficient to maintain reliability and resiliency. Similarly, the IRP aims to ensure that we keep portfolio costs as low and as low-risk as possible. This is necessary but not sufficient to ensure that customers are not burdened by their energy bills. Other operational efforts at the utility like bill assistance programs are also necessary to reduce energy burden.

One area where the IRP may be able to consider equity more directly is in the area of energy benefits. Currently our CEIP measures the share of eligible homes that have received a high touch conservation measure (weatherization or HVAC). In the future, this may expand to include participation in other distributed energy programs like rooftop solar or demand-side programs like demand response. The IRP is not the appropriate tool to plan conservation programs in an equitable consider whether or not a particular resource option creates an opportunity to enhance equity in energy benefits. For example, if a distributed or demand-side option is of similar cost and risk to a utility-scale supply-side resource option, we may consider whether the distributed or demand-side options has the opportunity to enhance (or worsen) the equitable distribution of energy benefits.

3 Updates to Models and Assumptions

3.1 Overview of Our Modeling Framework

Our IRP modeling process has four key steps:

1. Model resource build in the Western Electric Coordinating Council (WECC) region for each of the future scenarios considered in the IRP using the capacity expansion functionality in the commercially available AURORA modeling software tool;

[2] The CEIP is a new planning document that is required as part of CETA. It aims to make sure utilities are prepared to meet CETA's clean energy requirements. Our first-ever CEIP was due on January 1 at four-year intervals (in 2022, in 2026, etc.) Our 2022 CEIP is available on our IRP webpage.
[3] To track energy benefits, we measure the share of electrically heated homes built before 1989 that have received a high-touch conservation measure (weatherization or HVAC).
[4] To track reduction of burdens, we measure the share of households who are energy burdened, defined by CETA as the share of annual household income used to pay annual home energy bills.
[5] To track resiliency, we measure the average number of service interruptions and the average number of minutes of service interruption per year.

2. Model WECC-wide prices and other outcomes given a particular capacity expansion using AURORA;
3. Simulate dispatch of the Tacoma Power system given a particular set of prices, loads and water conditions using a home-built model called SAM;
4. Post-process outputs from SAM to calculate resource adequacy metrics, portfolio costs, financial risk and emissions using a variety of tools (Excel, R, Stata, Python, etc.).

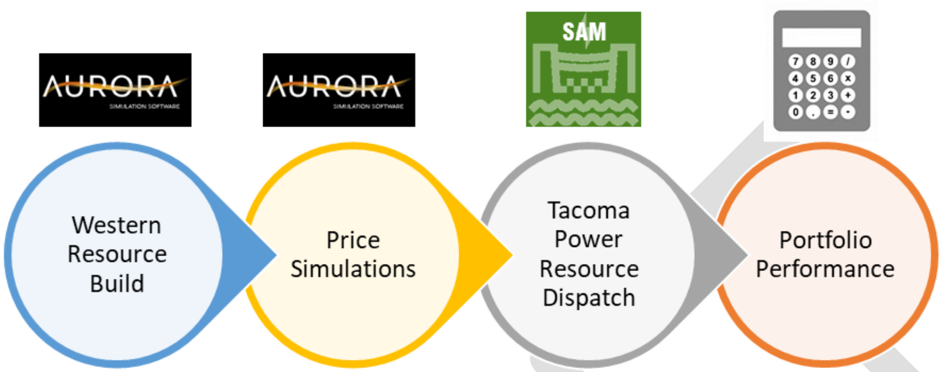

FIGURE 1. OVERVIEW OF TACOMA POWER IRP MODELING PROCESS

3.1.1 About our System Model (SAM)

SAM is an in-house software tool built to model our hourly generation similar to how we operate our system. The inputs into SAM are inflows, loads, future scenarios, and energy prices. SAM is a deterministic model, meaning it provides outputs based on a single set of loads, prices and water conditions. However, we run many different simulations of loads, prices and water conditions within SAM to create a set of probabilistic outputs.

Within SAM, resources dispatch independently of one other. Currently, we model existing Tacoma Power-owned resources such that each resource has its own set of constraints that must be met in every hour. Examples of constraints include target water elevations levels, maximum discharge, and amount of operating reserves to carry. Other resources, such as wind and solar, are represented by hourly energy profiles.

3.1.2 Accounting for Uncertainty

Like many IRPs, our IRP looks 20 years into the future. It is difficult to predict what conditions we might face even five years from now, let alone in twenty years. The IRP addresses the uncertainties we face in the future in two key ways. The first approach deals with the normal year-to-year variability we might expect to see expect to see through **stochastic analysis**. It takes into account variability in streamflow conditions, temperatures (which affect load), and natural gas prices (which are a major determinant of power prices). The second approach, **scenario analysis**, envisions alternative futures where we change our key assumptions about the future trajectory over time of inputs like load growth, renewables costs or natural gas prices. Our 2020 IRP considered four scenarios, and our 2022 IRP will consider the same four scenarios:

1. **Cruise Control**, in which environmental policies continue as they exist today with no additional changes.
2. **Carbon Policy Accelerates**, in which renewable energy policies are extremely strong and spread to almost every state in the WECC.

3. **Technology Solves Everything**, in which renewable energy policies are also strong, but costs of clean energy technologies are very low and the WECC is able to cost effectively integrate large amounts of renewable resources.
4. **Reliability Reigns**, in which poor planning and challenges with integrating renewables lead to grid instability and eventually a roll back of clean energy policies in 2030 in an effort to restore grid reliability. A more fitting name for this scenario may be Reliability ***Wanes then*** Reigns, as the unreliable nature of the grid in the early period features heavily in our findings regarding resource adequacy.

For each scenario considered in the IRP, we run 58 weather years (which includes both inflow conditions and temperatures seen in a historical calendar year) in combination with 5 different gas risk runs (which yield different wholesale market prices). All together, we run 1,160 simulations across our four core scenarios. In addition to these four scenarios, we run additional simulations for separate sensitivity analyses (e.g. impacts of climate change, load increases due to vehicle and building electrification, etc.).

3.2 Updates to AURORA inputs

In each IRP, we use the most updated AURORA inputs possible. Changes to the Aurora database and inputs include updates to natural gas prices, loads, resources, and WECC model topology.

3.2.1 Natural gas price assumptions

In summer of 2021, we saw a steep increase in forward prices for natural gas. Although the Aurora database's default natural gas price is a blend of forward prices and long-term gas price forecasts, that blended forecast was developed in 2020 and did not reflect the reality of high summer natural gas prices that have become a regular occurrence. In order to capture a wider range of possibilities, we develop four natural gas price scenarios for each of the four IRP scenarios – two with elevated near-term prices based on forward prices published in the summer of 2021 and two with lower near term prices Figure 2. It is worth noting that these price scenarios were developed prior to the war in Ukraine and are significantly lower than the $8+ /MMBtu forward prices we are currently seeing in 2022. That said, these four forecasts represent an average price for the respective scenarios. Within Aurora, we still run five gas risk runs, which draw random gas prices from a distribution defined by the underlying averages in Figure 2. Those random draws do in fact reach prices as high as $10/MMBtu (real 2021$).

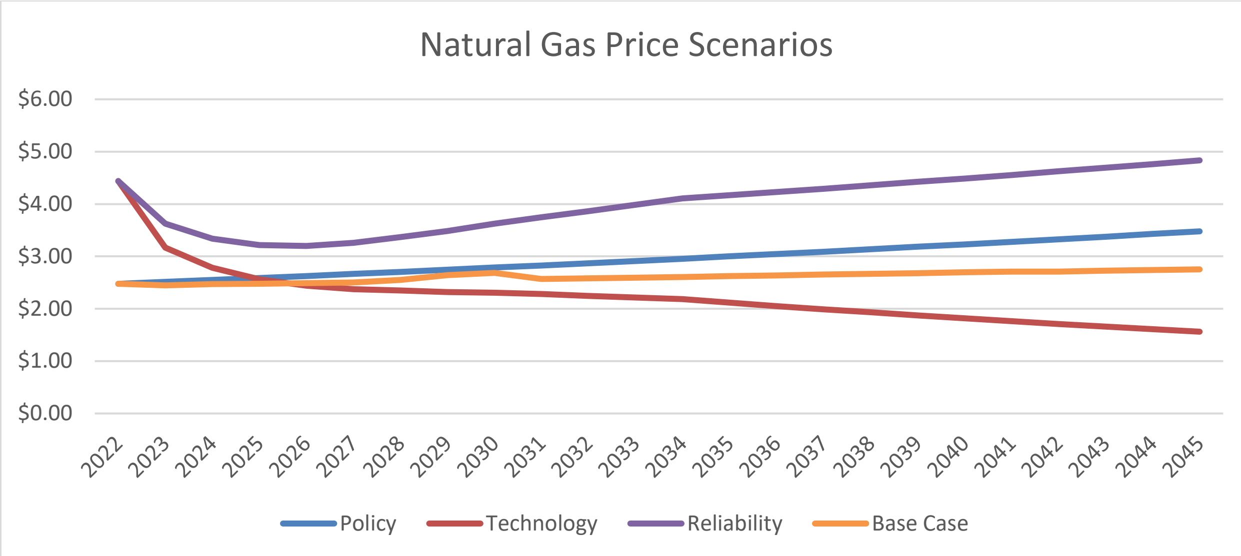

FIGURE 2. NATURAL GAS PRICES BY SCENARIO

3.2.2 Loads

WECC load forecasts project a small change in annual energy and peaks. The 2022 WECC energy forecast shows a slight increase in the early years relative to the 2020 forecast and slight decrease in the later years (Figure 3). WECC peak load forecasts are slightly lower overall (Figure 4). Annual WECC-wide energy and peak forecasts by are presented by scenario in Figure 5 and Figure 6, respectively. Loads for the four IRP Scenarios are based on the growth rates in Table 2 and are similar to those used in our 2020 IRP.

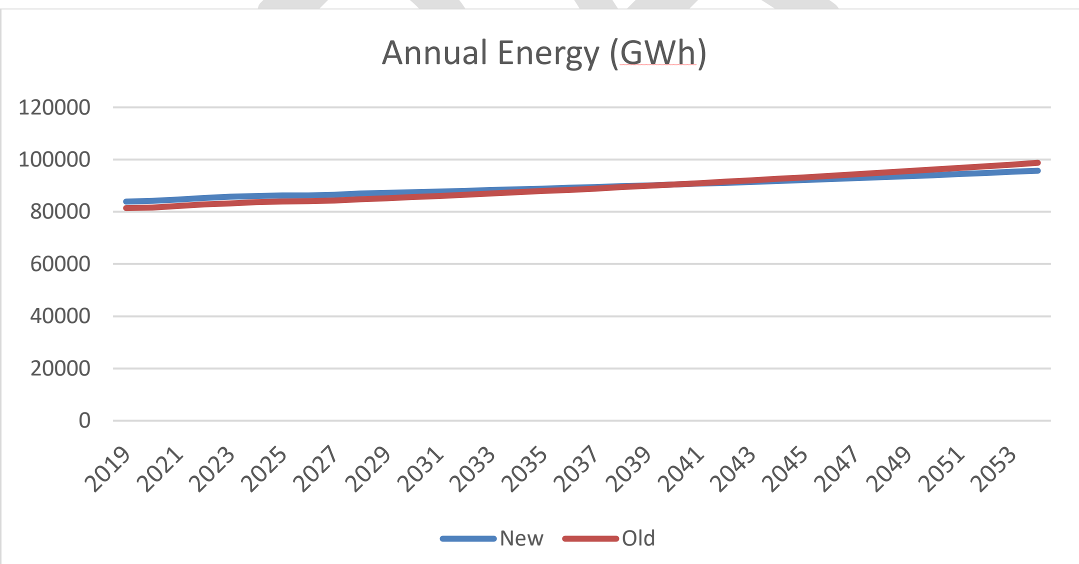

FIGURE 3. NEW (2022) AND OLD (2020) WECC ANNUAL ENERGY FORECASTS

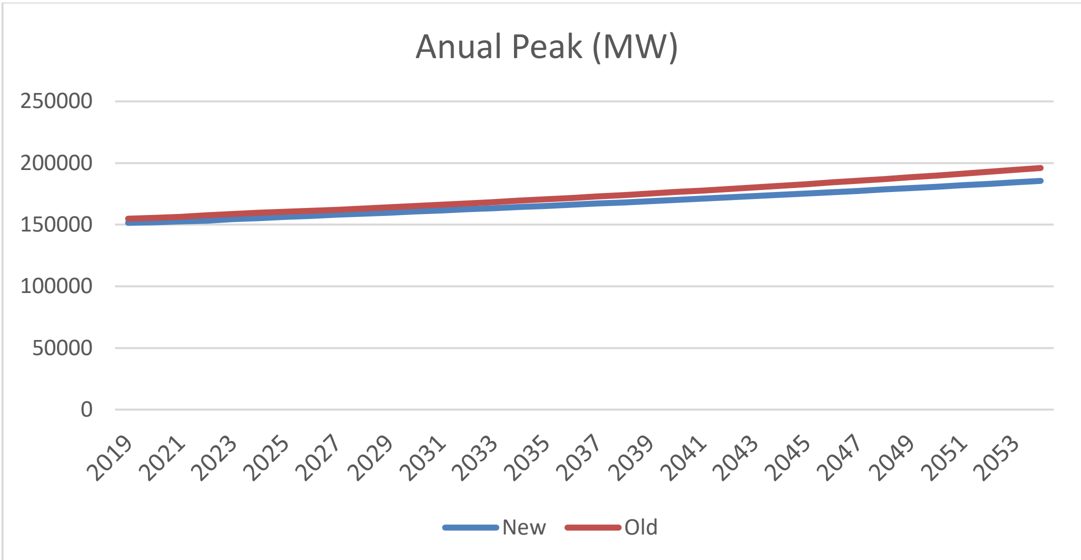

FIGURE 4. NEW (2022) AND OLD (2020) WECC ANNUAL PEAK FORECASTS

TABLE 2. ANNUAL GROWTH RATES FOR WECC ENERGY AND PEAK FORECASTS BY SCENARIO

	Carbon Policy Accelerates	Technology Solves Everything	Cruise Control	Reliability Reigns
Energy growth rate	1.74%	-0.79%	0.79%	1.11%
Peak growth rate	2.13%	0.00%	0.85%	1.28%

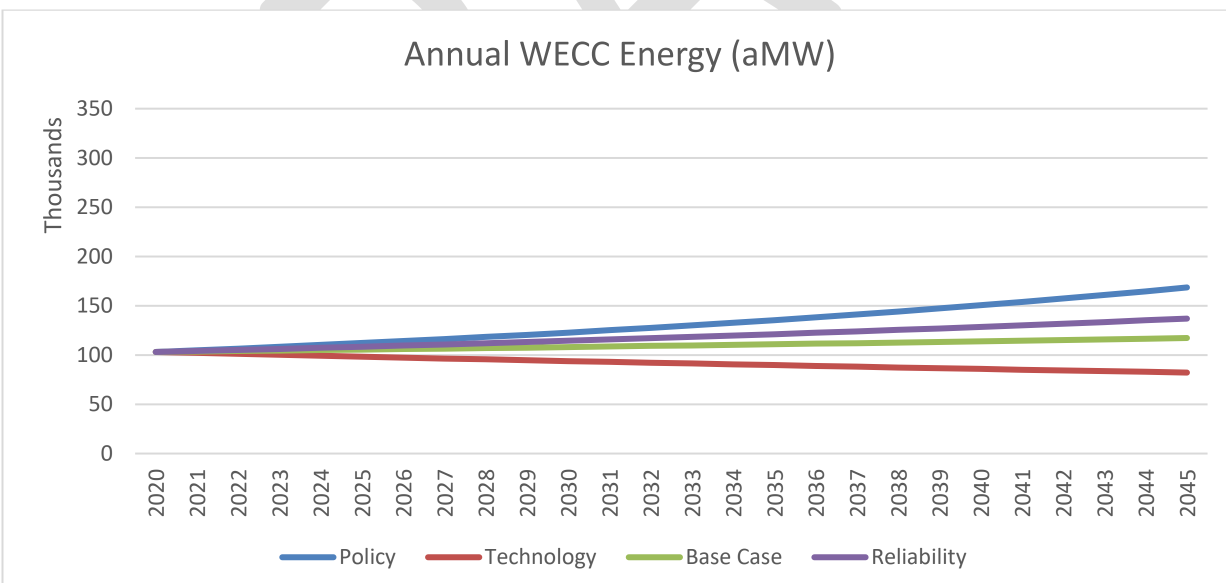

FIGURE 5. COMPARISON OF WECC ENERGY FORECAST BY SCENARIO

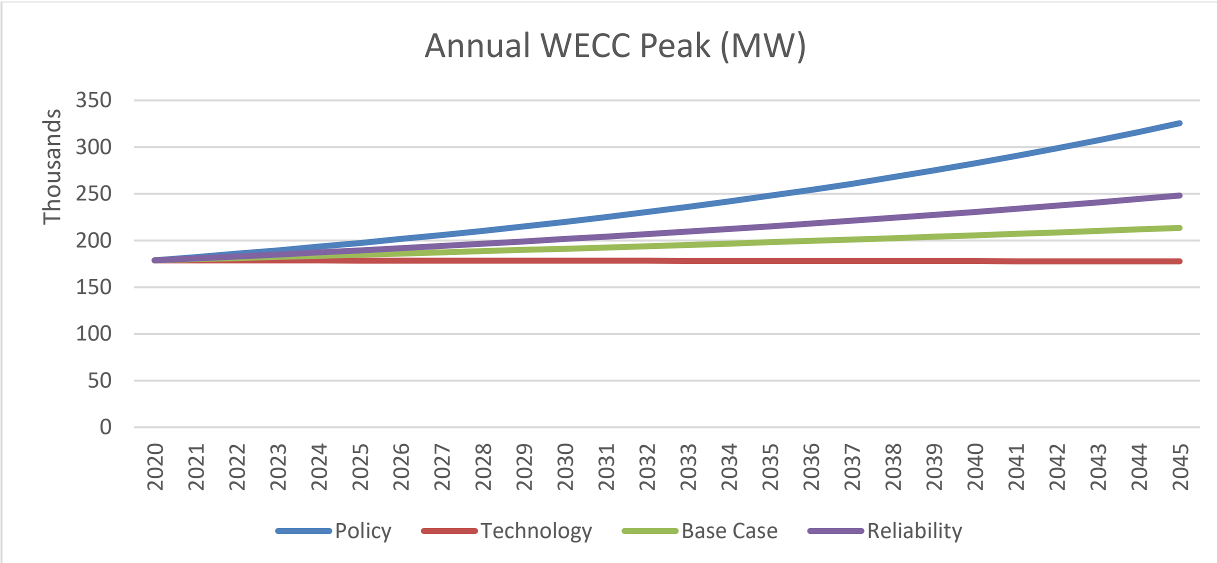

FIGURE 6. COMPARISON OF WECC PEAK FORECAST BY SCENARIO

3.2.3 Resources

The key changes to our AURORA resource assumptions between 2022 and 2020 are regarding the treatment of battery storage and updates to assumptions regarding coal retirements and new natural gas builds. The updated AURORA database now allows us to include battery energy storage as an option in our capacity expansion model. Due to computational constraints, battery storage was not included in the 2020 IRP. Our 2022 assumptions for announced early coal retirements are 35% higher than in our 2020 IRP (see Figure 8 versus Figure 7). This increase is in part due to new announcements and in part due to some corrections to input errors in our 2020 model. Finally, AURORA's updated default database assume that eliminates new natural gas resources post-2030 to reflect growing policy constraints and uncertainty around natural gas investments. We keep this "no new gas" default in our capacity expansion model.

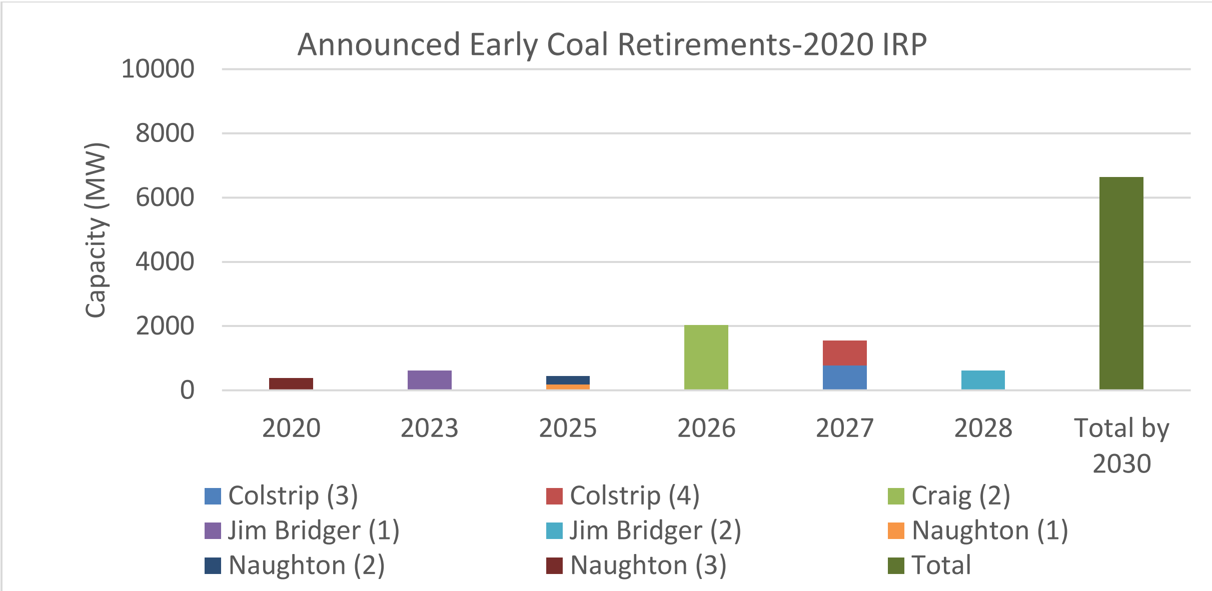

FIGURE 7. ANNOUNCED COAL RETIREMENTS INCLUDED IN THE 2020 IRP

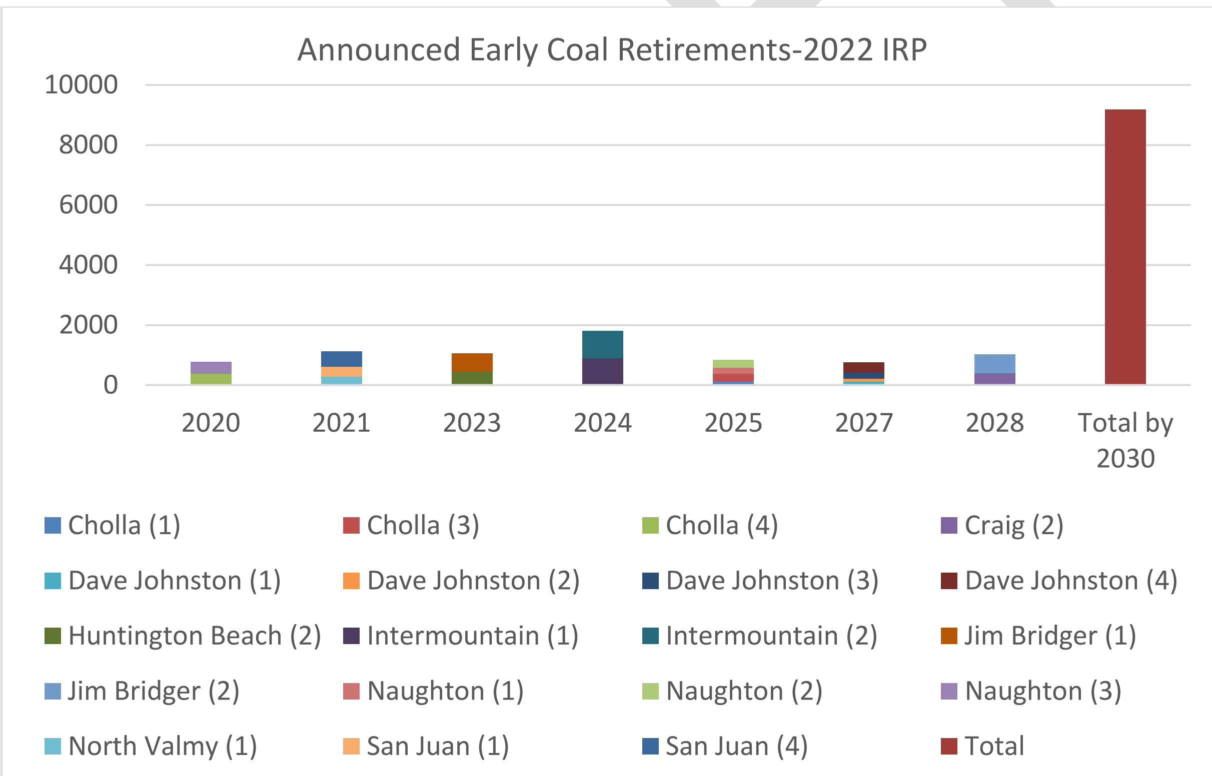

FIGURE 8. ANNOUNCED COAL RETIREMENTS INCLUDED IN THE 2022 IRP

3.2.4 Topology

In 2021, Energy Exemplar released an updated Aurora database that changed the structure and makeup of the zonal topology in its model. Under the new topology, each zone is a balancing authority rather than a state or part of a state. Because of this change, we update the RPS constraints we use in the model. Instead of each state having its own RPS constraint, we create a single WECC-wide RPS equivalent. This change means that renewables from any part of the WECC can serve to meet the blended RPS requirement in any part of the WECC. Figure 9 compares the single WECC-wide RPS (dotted line) to the state-level RPS requirements. Our 2022 WECC-wide RPS requirement is 11% higher than in the 2020 IRP (Figure 10) due to increases in RPS levels in Nevada, Oregon and Colorado since 2019 as well as the inclusion of Idaho utility's renewable goals (not officially an RPS).

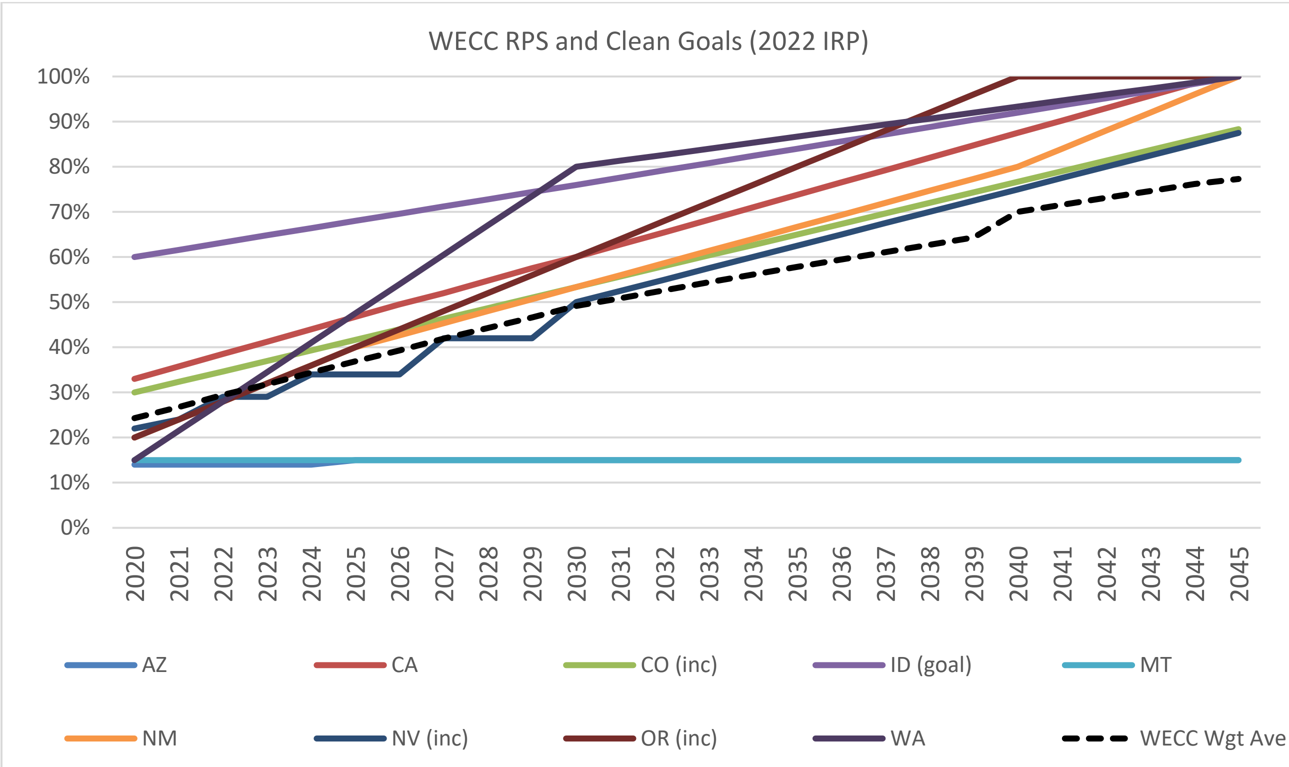

FIGURE 9. COMPARISON OF STATE-BY-STATE RPS AND WECC-WIDE EQUIVALENT RPS VALUES

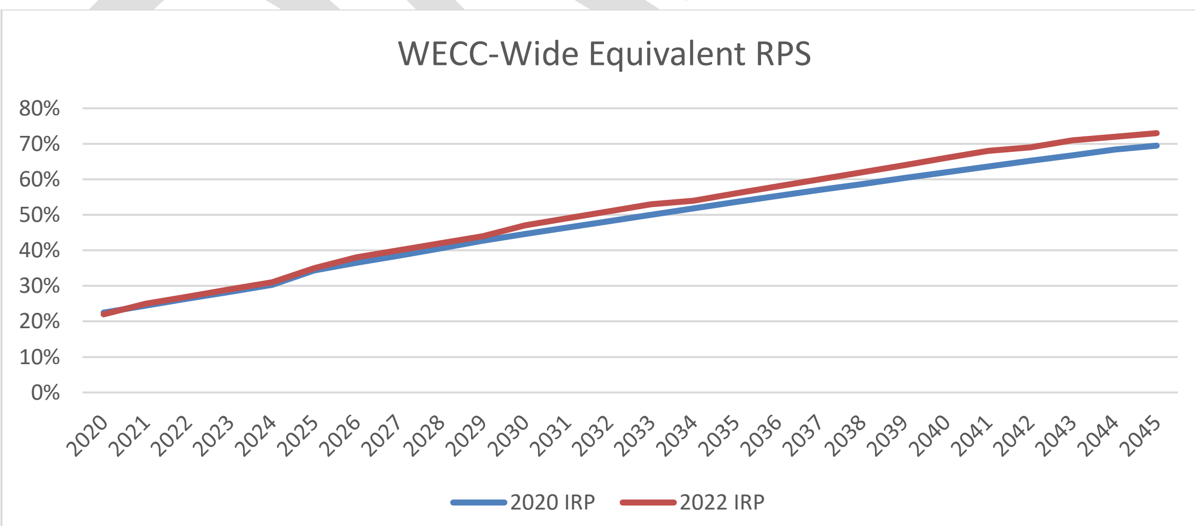

FIGURE 10. COMPARISON OF WECC-WIDE EQUIVALENT RPS LEVEL BETWEEN 2020 AND 2022 IRP

3.3 Updated AURORA outputs: capacity expansion and price simulation

3.3.1 Capacity expansion

Figure 11 shows the WECC buildout and economic retirements for each of our four future scenarios. The economic retirements represent new or accelerated retirements ahead of their scheduled end date in the AURORA database. The Carbon Policy Accelerates scenario (referred to simply as *Policy* in these graphs) has both higher loads and an increased RPS and results in the largest buildout of resources, including battery storage. The opposite is true for the Technology Solved Everything scenario (referred to as *Technology* in these graphs), which has the smallest buildout of resources. The Cruise Control (referred to as *Base Case*) and Reliability Reigns (referred to as *Reliability*) scenarios have a similar magnitude of buildout, but the Reliability Reigns case results in more new gas generation after 2030. This is due in part to the fact that it is the only scenario in which we allow the model to select new gas resources.[6] The Reliability Reigns scenario also results in significantly less economic retirement of coal post-2030.

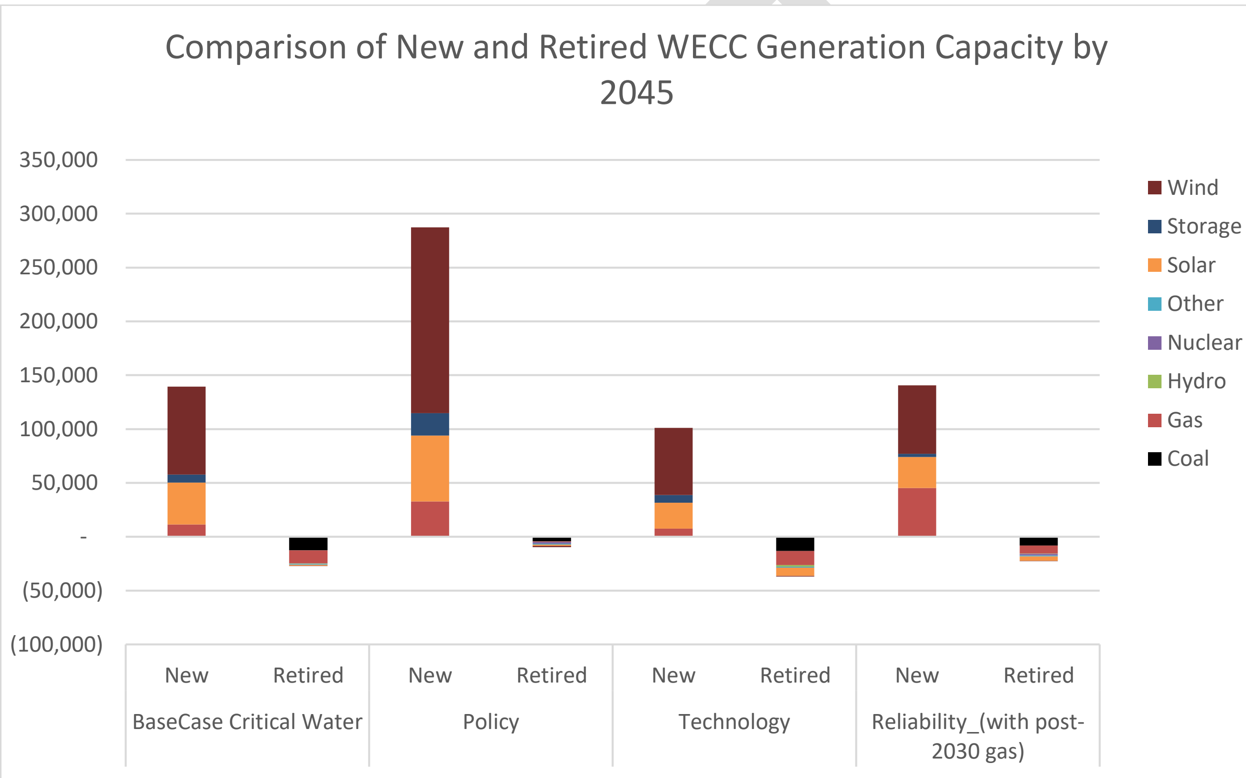

FIGURE 11. AURORA CAPACITY EXPANSION RESULTS BY SCENARIO (NEW BUILDS AND ECONOMIC RETIREMENTS)

3.3.2 Price forecast

Figure 12 shows the resulting price forecast across each of the historic weather years modeled for each of the four scenarios. Base case (Cruise Control scenario) prices stay flat, rise in 2028, and then remain mostly flat throughout the forecast horizon. The increase in 2027 (in all scenarios, not just the Base Case) is due to an assumed carbon tax taking effect more broadly across the WECC in states where an existing carbon tax or cap does not yet exist. The Carbon Policy Accelerates scenario shows steadily increasing prices through the forecast horizon while the Technology Solves Everything scenario shows a steadily declining price forecast. The Reliability Reigns scenario was

[6] New gas resources are allowed to be built in the post-2030 period only, when we see a "backsliding" of carbon policies in the interest of maintaining reliability.

designed to be restrictive until 2030, after which reliability becomes more important than policy. As a result, prices stay high and then drop post-2030 as more reliable gas resources come online. Figure 13 compares the annual average price and standard deviation in prices for each scenario. With the exception of Technology Solves Everything, all of the scenarios exhibit high volatility in the later years of the forecast when renewables are more widespread and low-cost energy storage options are somewhat limited. Still, the Carbon Policy Accelerates and Reliability Reigns scenarios have the highest volatility in prices.

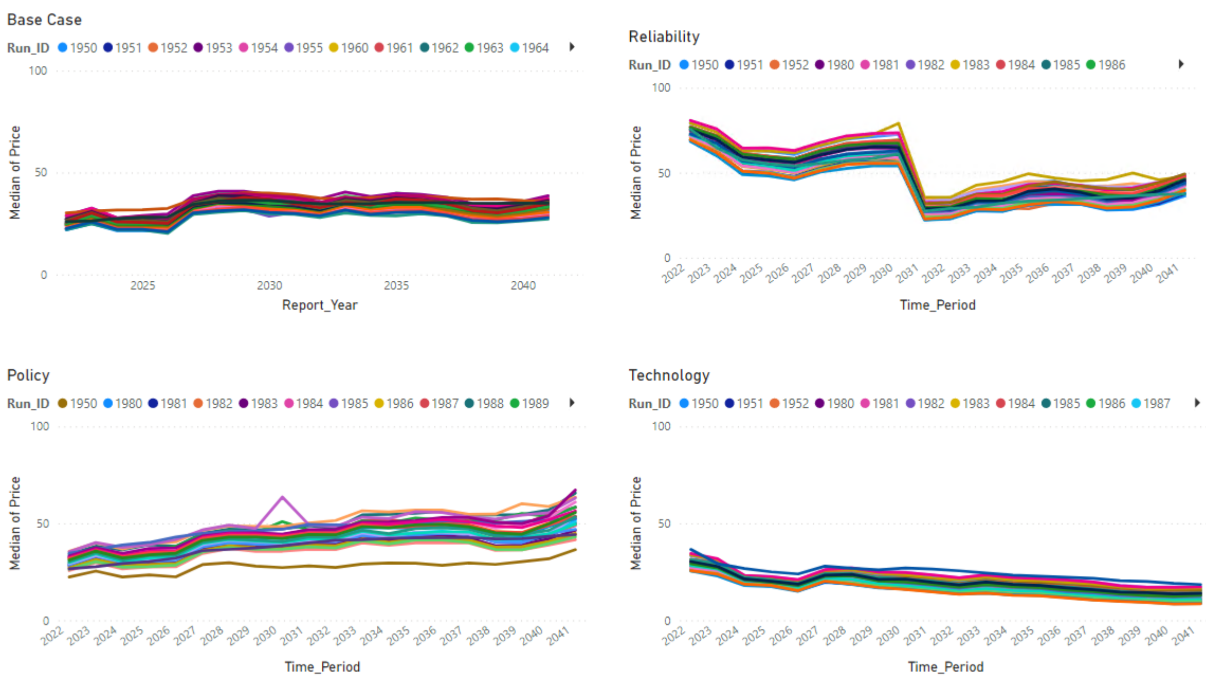

FIGURE 12. MEDIAN PRICE FORECAST BY WEATHER YEAR, BY SCENARIO

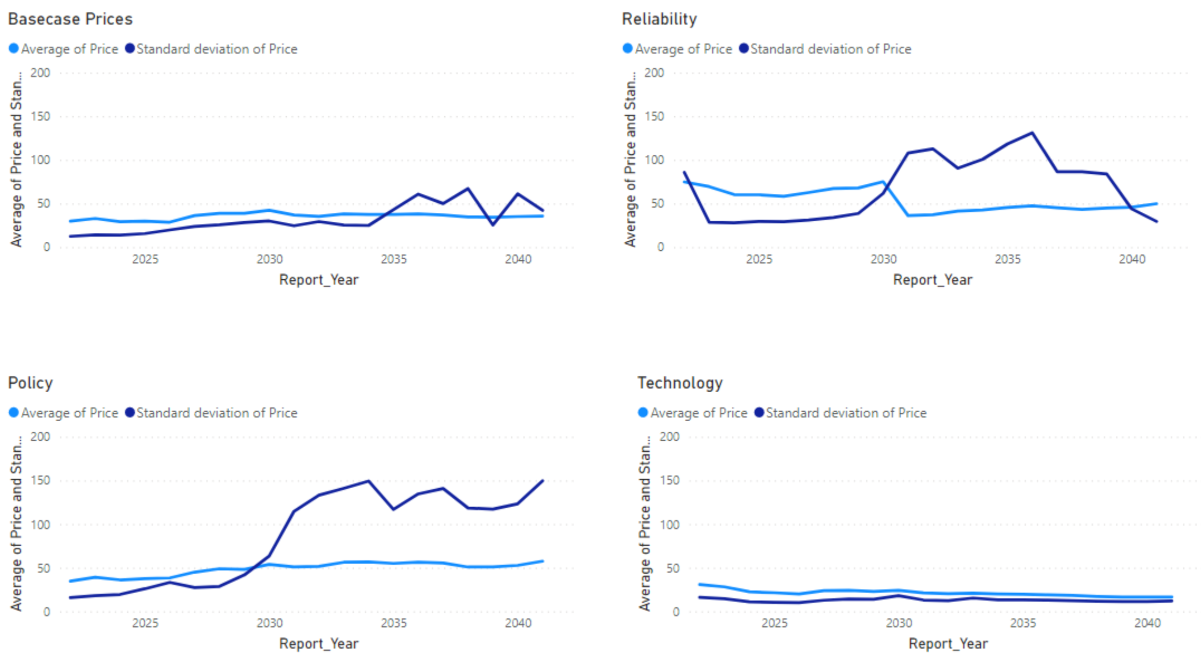

FIGURE 13. COMPARISON OF ANNUAL AVERAGE AND STANDARD DEVIATION OF PRICE BY SCENARIO

3.3.3 WECC-WIDE EMISSIONS

Figure 14 compares annual emissions in metric tons for each of the four scenarios. All but the Reliability Reigns scenario show declining absolute emissions over time. The Reliability Reigns scenario shows a much lower initial CO2 emission level that declines slightly, levels off and then increases steadily. This is because the Reliability Reigns scenario has the most aggressive early coal retirement assumptions initially but, unlike the other three scenarios, allows gas to be built post-2030 for reliability purposes. The Technology Solves Everything scenario has the lowest and most rapidly declining emissions due to low load and inexpensive renewables and storage.

Figure 15 compares the annual average of the marginal emissions factors (in units of MT/MWh) for each of the scenarios. These values are calculated by first taking the hourly marginal emission factor and then averaging those values over the year. The general patterns in the average of the marginal emissions rate is similar to what we see for total emissions.

Figure 16 compares the annual average emission factor (in units of MT/MWh) for each of the scenarios. These values are determined by dividing the annual emissions by annual demand. Because this value includes all generation serving load, not just generation on the margin (which is often natural gas), this emission factor is significantly lower than the annual average marginal emission factor in Figure 15. Again, in all but the Reliability Reigns scenario, emission factors decline consistently over time.

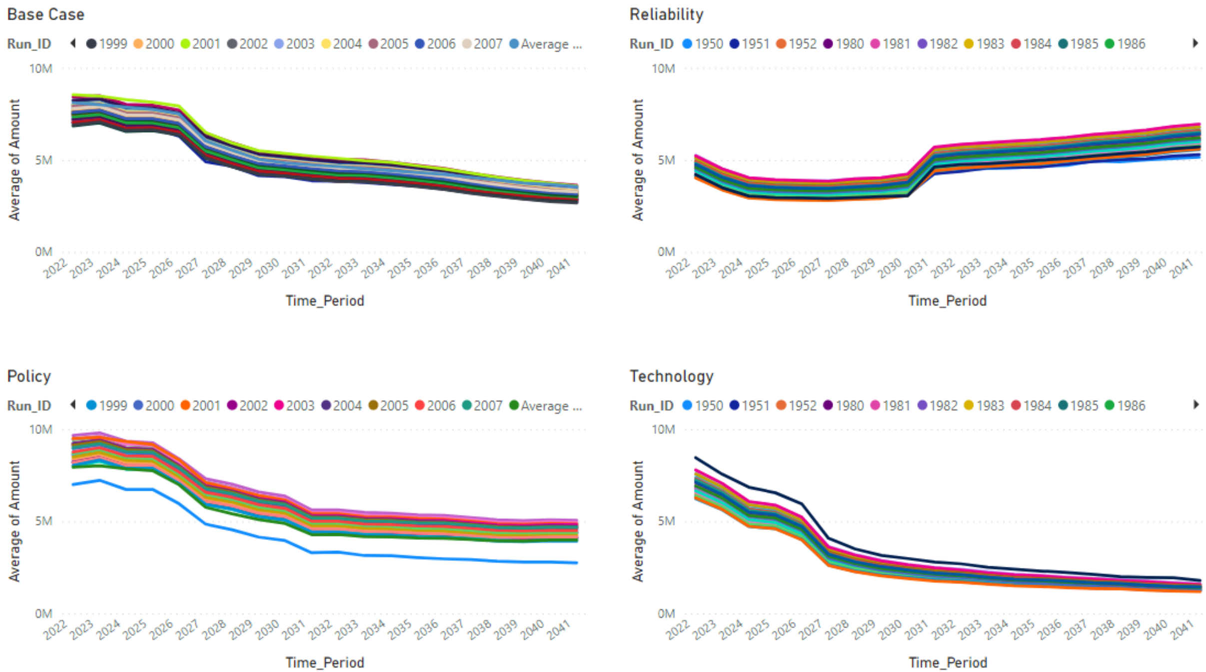

FIGURE 14. WECC-US CO2 EMISSIONS BY SCENARIO (METRIC TONNES)

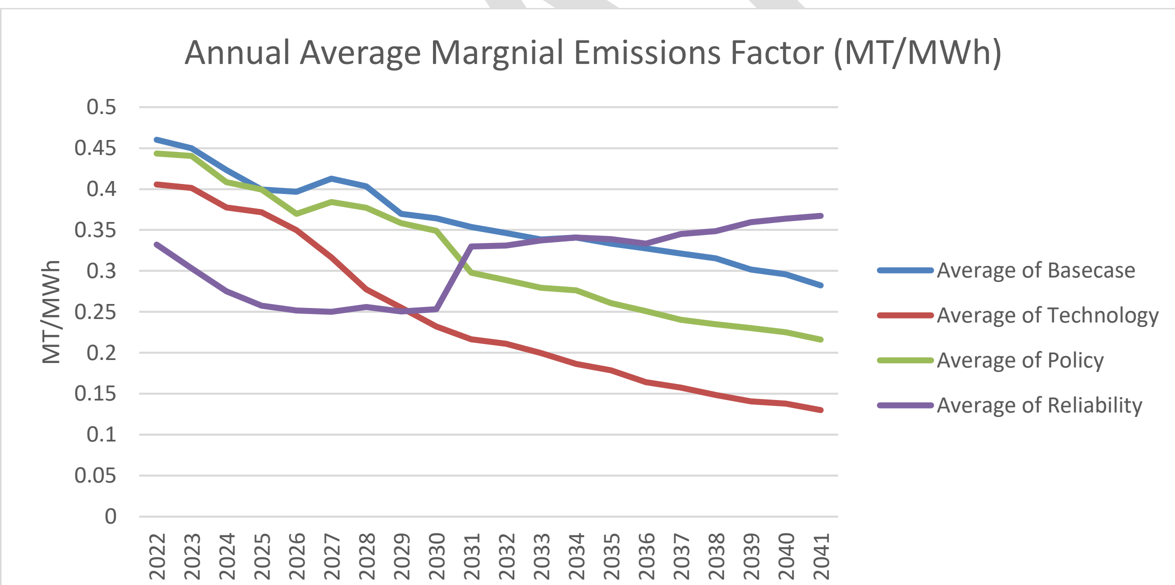

FIGURE 15. ANNUAL AVERAGE MARGINAL EMISSION FACTORS BY SCENARIO (MT/MWH)

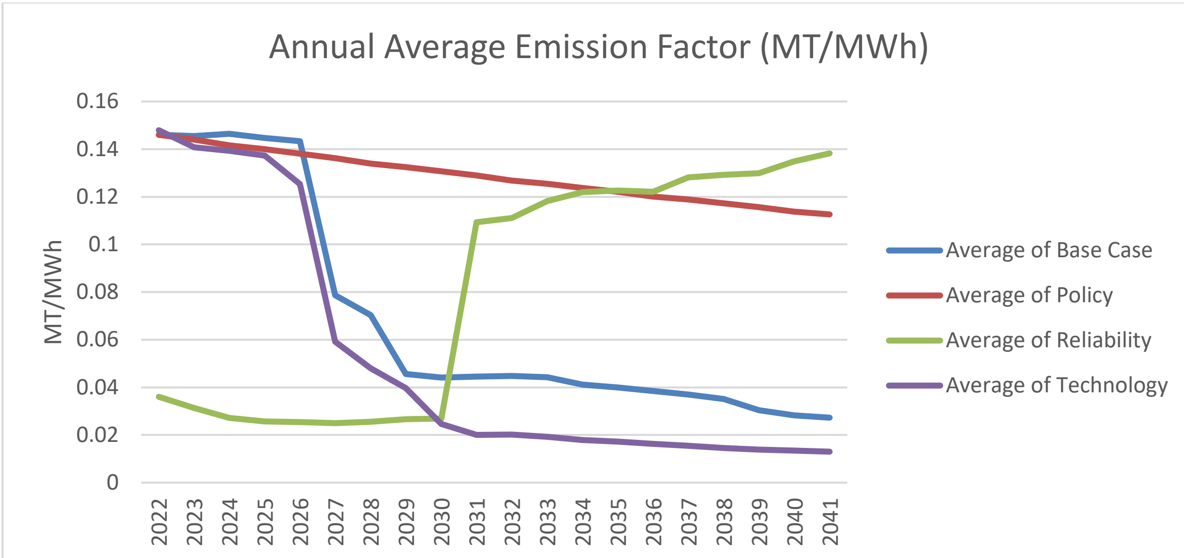

FIGURE 16. ANNUAL AVERAGE EMISSION FACTOR BY SCENARIO (MT/MWH)

3.4 Updates to System Model Inputs & Assumptions

3.4.1 Load

Similar to the method used in our 2020 IRP, we use historical daily high and low temperatures to establish a relationship between weather and hourly loads and create weather-adjusted hourly loads. We do this for each of the 58 weather years we model and then adjust the set of load profiles to follow the average annual forecast trajectories associated with each scenario of the future. Figure 17 presents the annual trajectory of Tacoma Power's load for each scenario we model, and Figure 18 presents the distribution of hourly loads across scenarios and months. We find that our model can sometimes over-predict demand during extreme cold temperatures, so we set a ceiling for possible peak load to be no more than 10% higher than recent historical loads.

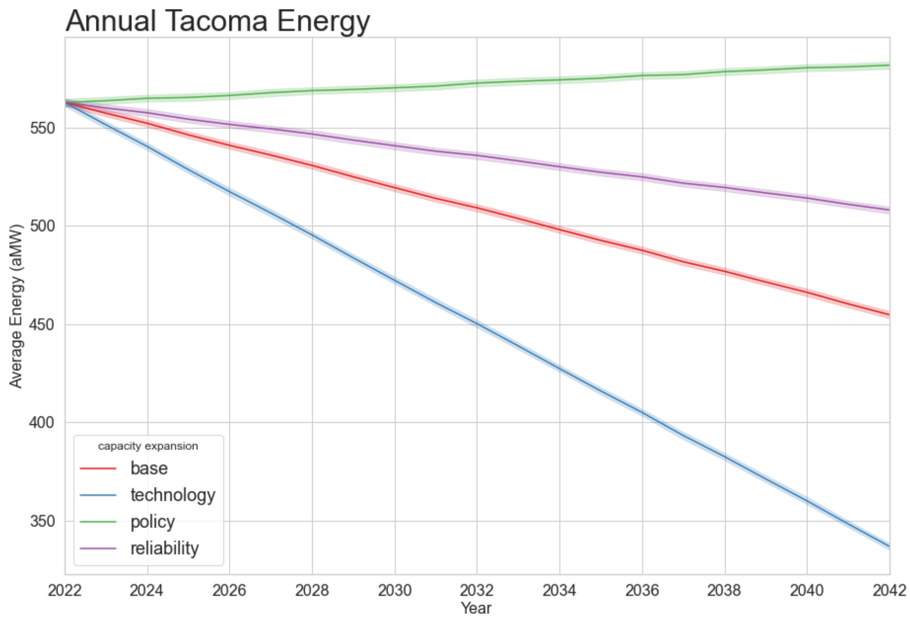

FIGURE 17. TACOMA POWER LOAD TRAJECTORIES ACROSS SCENARIOS IN SAM

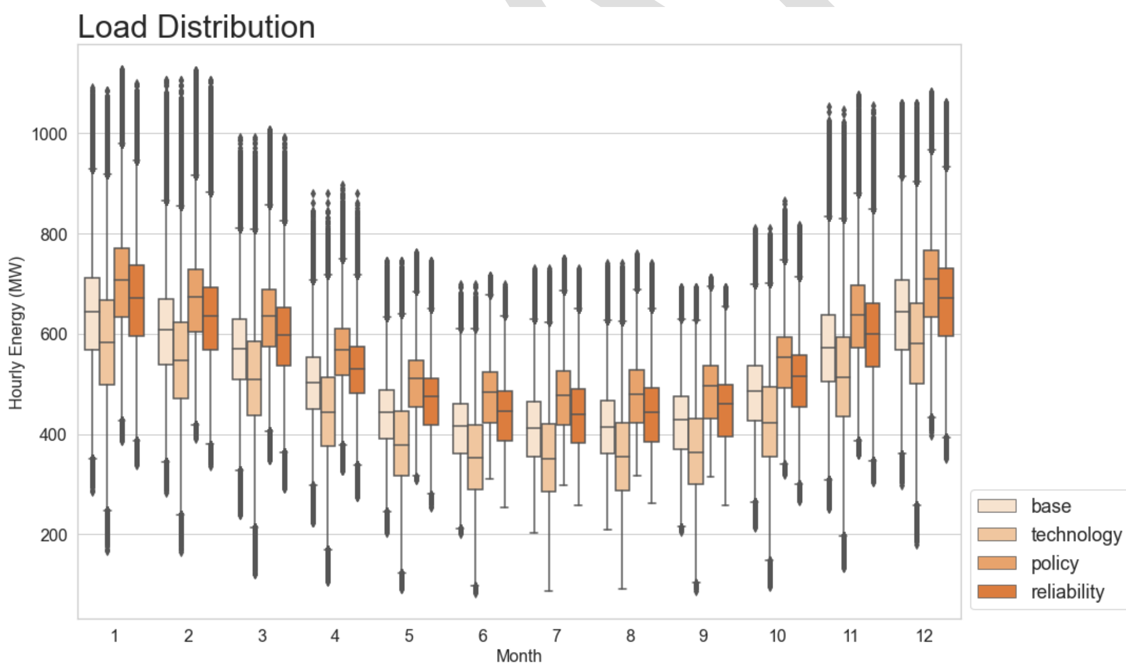

FIGURE 18. DISTRIBUTION OF MONTHLY TACOMA POWER LOAD ACROSS SCENARIOS IN SAM

3.4.2 UPDATE TO MARKET RELIANCE ASSUMPTION

A critical assumption built into resource adequacy assessments is the extent to which a utility can rely on the wholesale market to buffer potential inadequacy events. In the 2020 IRP, we assumed that up to 50MW of power could be purchased from the wholesale market at any time (the same assumption that was used in the 2015 IRP and in the 2017 IRP update). In this IRP, we take a more nuanced assumption that ties our assumption regarding reliance on the wholesale market to the market implied heat rate[7]. We consider the heat rate in each hour in each particular simulation and use that to determine the extent to which we would be able to rely on the market. When heat rates are low, we do not place any limit on our ability to rely on the market for capacity. This will mean that we never find ourselves at risk of shortfalls in hours with low heat rates. When heat rates are very high, we do not allow any reliance on the market. When heat rates are somewhat high, we allow some limited reliance on the market (either 50MW or 25MW, depending on what the heat rate is). Table 3 presents the market reliance assumption we use for different heat rate ranges. We ground our heat rate cutoffs in the distribution of heat rates from our AURORA runs for our Cruise Control (base case) scenario in the year 2022. The cutoffs allow unlimited reliance on the market for up to roughly 50th percentile heat rates, 50MW for heat rates that fall roughly between the 50th and 75th percentile, 25MW for those between the 75th and 90th percentile and no market allowance for heat rates that fall above about the 90th percentile.

While the exact cutoffs we use to tier heat rates are simple and admittedly arbitrary, they do represent a more nuanced assumption than what we have used in previous IRPs and achieve our goal of distinguishing between times when market supply is ample and when it is limited. Figure 19 and Figure 20 provide an illustrative look at the distribution of heat rates in January and August 2022 for hour ending 9 (when energy tends to be in high demand across the West) vs. hour ending 3 (when power is in low demand). These figures show that our updated approach almost always applies a market reliance limit during peak hours and rarely during hours when demand for power tends to be lowest. During peak hours in the summer, we are almost never able to rely on market purchases at all.

TABLE 3. MARKET RELIANCE LIMITS FOR GIVEN HEAT RATE RANGES

Heat Rate Range	Market Reliance Limit	Months for which limit applies
HR <=10	Unlimited	All binding periods of WRAP[8]
10<HR<=13	50 MW	All binding periods of WRAP
13<HR<=17	25 MW	All binding periods of WRAP
HR>17	0 MW	All binding periods of WRAP
All heat rates	Unlimited	All non-binding periods for WRAP

[7] The market-implied heat rate is equal to the power price divided by the natural gas price. It provides a useful indicator of what is happening with power supply and demand in the market. When heat rates are high, there is generally less capacity available on the grid and vice versa.

[8] Note: The two WRAP binding periods are November 1 through March 15 and June 1 through September 15.

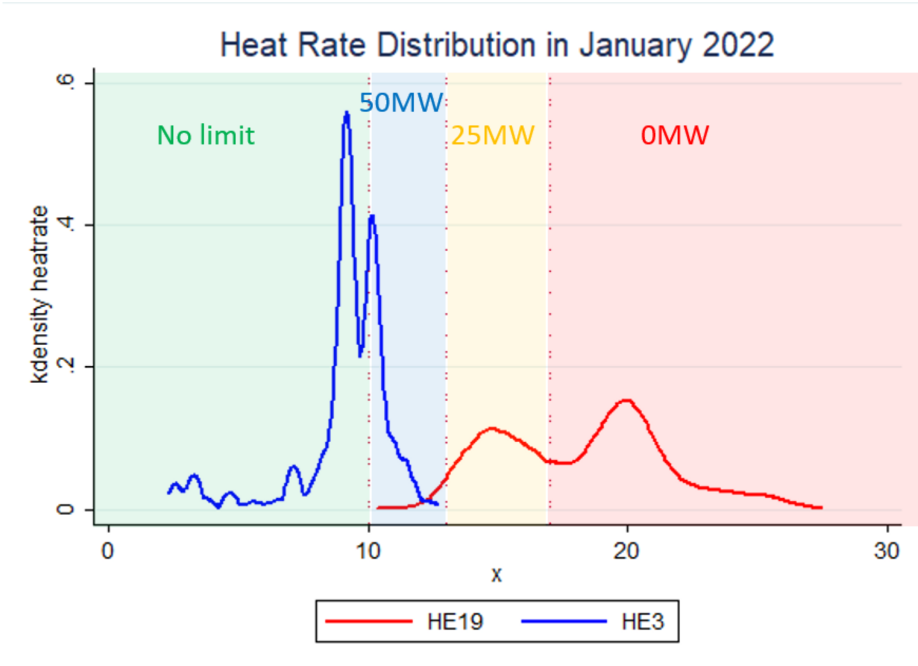

FIGURE 19. DISTRIBUTION OF AURORA MARKET-IMPLIED HEAT RATE IN WINTER DURING PEAK AND LOW DEMAND HOURS

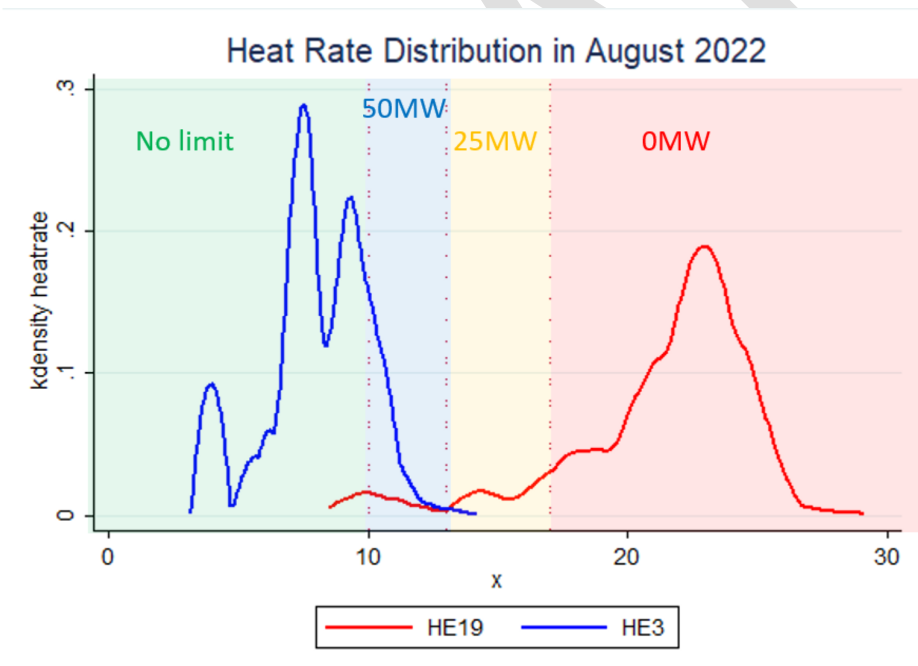

FIGURE 20. DISTRIBUTION OF AURORA MARKET-IMPLIED HEAT RATE IN SUMMER DURING PEAK AND LOW DEMAND HOURS

4 Resource Need

Because 2028 was many years away, recent IRPs prior to 2020 assumed that we would renew our BPA contract. While all of the analyses we have completed to date suggest that renewing our BPA contract in 2028 is likely to be the lowest-cost, least-risk approach to continue meeting customer demand into the future, the 2022 IRP assesses our resource need without assuming that we renew BPA in 2028. We then consider all of our options for meeting that need, including renewal of our BPA contract.

We conduct an analysis to get a general sense of how large our resource need is without renewal of the BPA contract. We progressively add pure capacity to the system until we reached a point where we passed our adequacy standard. Table 4 summarizes the amount of pure capacity needed in each scenario to meet our adequacy standard in all calendar years. To ensure that we are adequate across all possible futures, we would need approximately 550MW of pure capacity if we were to decide not to renew our BPA contract in 2028[9]. The scenario that requires the largest capacity addition is our "Carbon Policy Accelerates" scenario, in which we project the highest growth in load.

We use the term "pure capacity" to mean capacity that is available 100% of the time without interruption. Most of the resources considered in the IRP do not provide pure capacity. For example, wind in the Northwest typically contributes capacity equivalent to around 10% of its maximum generation at the times when it is needed (i.e. a 100MW wind plant would typically provide the equivalent of around 10MW of capacity during times of peak need). This assessment of need is useful primarily as a point of reference to begin estimating what it would take to replace BPA with other resources.

TABLE 4. RESOURCE NEED UNDER FOUR SCENARIOS OF THE FUTURE

Scenario	Pure capacity needed to meet adequacy standard in all calendar years
Cruise Control	Approximately 500 MW
Carbon Policy Accelerates	Approximately 550 MW
Reliability Reigns	Approximately 550 MW
Technology Solves Everything	Approximately 500 MW

5 Portfolios Considered

Figure 21 provides the list of portfolios we analyze in this IRP. We consider three major types of portfolios:

1) **Portfolios in which we renew our BPA contract at current levels:** This set of portfolios includes options where we renew our BPA contract in 2028 with the same product as we currently purchase from them (the Slice/Block product) and where we renew our BPA contract with an alternative Block-only option that BPA currently offers called Block with Shaping Capacity. Because we find that we do not always meet our resource adequacy standard under one of our scenarios, we also consider portfolios with resource additions of wind, battery storage or demand response. We iterated through various quantities of these resources until we found a quantity that allowed us to just meet our resource adequacy standard in all scenarios.
2) **Portfolios in which we renew our BPA contract at a lower level in an effort to diversify our future resource supply:** This set of portfolios includes options where we renew our BPA contract with one of the above BPA product options but also acquire another resource and identify it as a "declared resource" to BPA. This would change BPA's calculation for the amount of firm power generation that Tacoma Power is

[9] This is the capacity required to meet the most stringent of our three metrics—our frequency standard. We would need slightly less to meet both our duration (LOLH) and magnitude (NEUE) standards in all scenarios.

capable of producing and reduce slightly the amount of Block we would receive from BPA. We are unsure of precisely how BPA might count resources like wind and solar in this calculation. We assume in our models that it would be roughly equivalent to their approach to hydrogenation, in which a critical water year is used to set our firm capability. We assume that monthly fifth percentile generation would be used to calculate "critical wind" and "critical solar" generation and that our monthly Block shaping factors would be adjusted to account for the generating profile of the resource additions. In the case of solar, for example, we would see a reduction mostly to our summer Block amount and very little change to our winter Block amounts.

3) **Portfolios in which the BPA contract is not renewed:** We consider two portfolios in which we do not renew our BPA contract and instead replace it with large quantities of wind, solar, demand response and one other resource. In one portfolio, that other resource is 350MW of pumped storage hydro (PSH) and in another portfolio, we add 350MW of small modular nuclear reactors (SMR) instead. These portfolios would not be technically feasible to acquire by 2028 but are examined as hypothetical portfolios to understand what it might take to replace BPA with alternative resources and what that might mean for resource adequacy and resource costs.

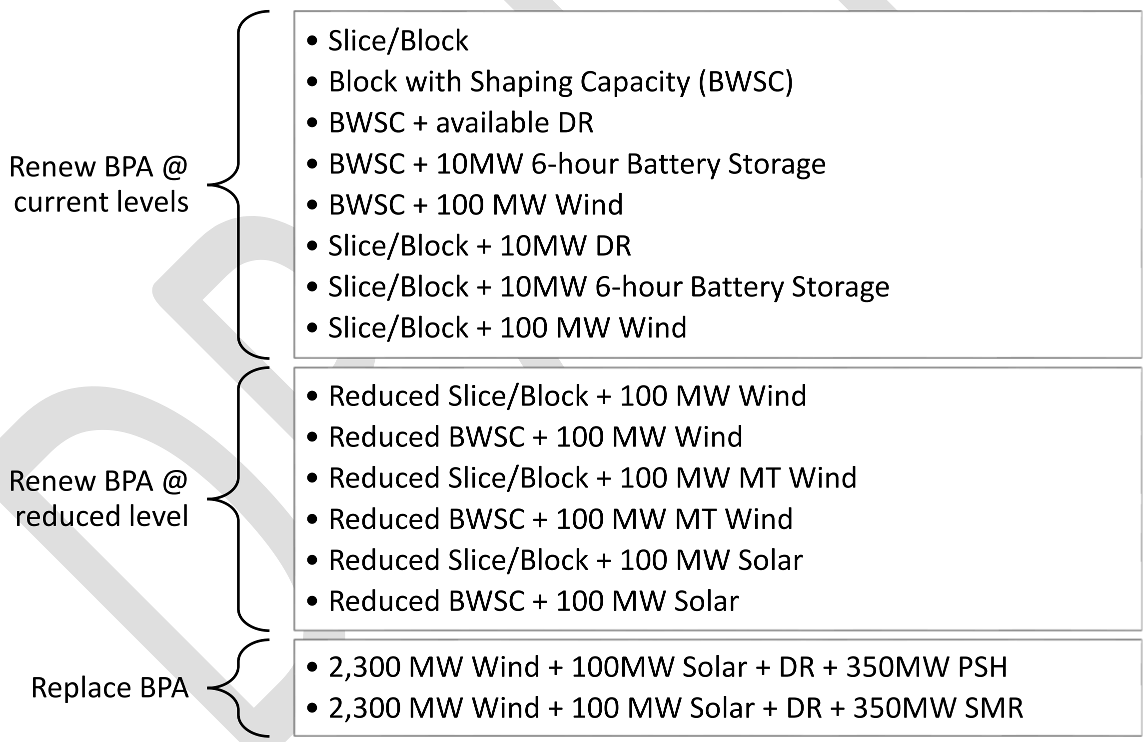

FIGURE 21. LIST OF PORTFOLIOS ANALYZED

6 RESOURCE ASSUMPTIONS

6.1 BONNEVILLE POWER ADMINISTRATION (BPA)

6.1.1 PRODUCTS CONSIDERED

Under our current BPA contract, we receive energy through a hybrid Slice/Block product. In the "Slice" part of the contract, we receive approximately 3% of the wholesale power that BPA produces, an amount that varies by year and by season depending on streamflow conditions. In the “Block” part of the contract, we are guaranteed a certain constant amount of energy every month that does not change with streamflow conditions. About half of the firm power we receive from BPA comes from the Slice portion of the contract and half comes from the Block portion in an average year.

Our 2022 IRP will model the same products as we did in 2020 IRP: the Slice/Block product that we currently purchase and the Block with Shaping Capacity product. We may also consider a more basic monthly diurnal product and one additional type of product that is not currently available today: a product that combines Slice and the monthly diurnal bock. While we do not know for sure whether such a product will exist in the post-2028 period, we think that this product (or something similar) would be a valuable addition to BPA’s list of product choices and is an option we should consider if BPA does offer it.

6.1.2 Contract Assumptions and Resource Dispatch

We model the Slice/Block product in two parts. The Slice portion is modeled as a profile that is simulated based on weather year, and is therefore based on historical inflows, demand, and right to power (RTP). The Block portion is modeled as a fixed amount that changes every year based on our load forecast and according the net requirement calculation set in our contract. Alternative block-only products are also modeled as a fixed annual amount that adjusts based on our load forecast. The monthly shape of that annual amount is set in our existing contract and was based upon the historical shape of our load. For the Block with Shaping Capacity, which allows some ability to shape block energy into heavy load hours (HLH), we use simulated load for a given run to determine how the resource is shaped.

In the 2022 IRP, we will continue to model BPA products using our current contract construct and current BPA assumptions regarding Slice capability under critical water. These assumptions will affect our net requirement calculation under Slice/Block (i.e. how much Block we receive for a given load) as well as our contract high water mark (i.e. the maximum amount of Block we could receive if loads were to continue to grow). We also assume that our monthly block shaping factors (i.e. what share of our annual Block energy comes in each month of the year) remain constant at current contract levels. However, we have advocated for BPA to allow block shaping factors to adjust in the next contract so that they can better meet utility needs as their load profiles change. We know that BPA will likely change their assumption regarding Slice capability under critical water and may change some contract terms, but we do not yet know exactly how these assumptions will change. We will incorporate updated contract assumptions into our 2024 IRP.

6.1.3 Cost Assumptions

For all of its current products, BPA charges are divided into 4 key components: (1) a composite charge, (2) a non-slice charge, which often ends up being a bill credit for Tacoma Power, (3) a load shaping charge, and (4) a demand charge. A detailed description of each component is available in Section 11.1.2 of our 2020 IRP. We maintain the same basic framework for calculating BPA costs as we used in the 2020 IRP and assume status quo terms for allocating costs but update values based on BPA’s BP-22 rate case.

In some of our analyses, we also explore how the cost differential between renewing our current Slice/Block and other options might differ if the lower Snake River Dam (LSRDs) were removed and our BPA costs were significantly higher. We use a simplified assumption that BPA costs rise by either 9% or 18%. These values are consistent with the range of most of the scenarios examined in a recent study estimating the cost impacts of LSRD removal[10]. We also

[10] Energy and Environmental Economics (2022, July). BPA Lower Snake River Dams Power Replacement Study (See Table 2)

simplify this exercise by assuming that these costs rise immediately at the beginning of 2029, following the transition to a new BPA contract. While we recognize that this is not realistic, it is sufficient for our purposes. In our IRP, we are interested in understanding whether LSRD removal might change our preferred resource strategy rather than precise when the LSRDs might be removed.

6.2 Wind and Solar

6.2.1 Generation Profiles

Wind and solar generation profiles were developed from simulated wind speed and global horizontal irradiance (GHI) values, respectively. NREL has produced these simulated data for thousands of locations across the US. This IRP will include wind sites from locations in Eastern Washington, Gorge, and Montana and solar sites from Eastern Washington only[11]. Because the NREL dataset only has six years of simulated data, several sites in these locations were selected to produce 90 unique 8760 hourly wind profiles and 20 unique 8760 hourly solar profiles for each location.

6.2.1.1 Wind Profiles

Figure 22 through Figure 27 compare the monthly capacity factors and distribution of wind across these various sites for each of the three aforementioned locations. From these profiles, Gorge wind provides more wind power on average during the spring and summer months. The opposite is true for Montana wind, which provides more power during the winter and fall months. Eastern Washington wind tends to have a flatter monthly profile, with a slight dip in average power output in part of the summer.

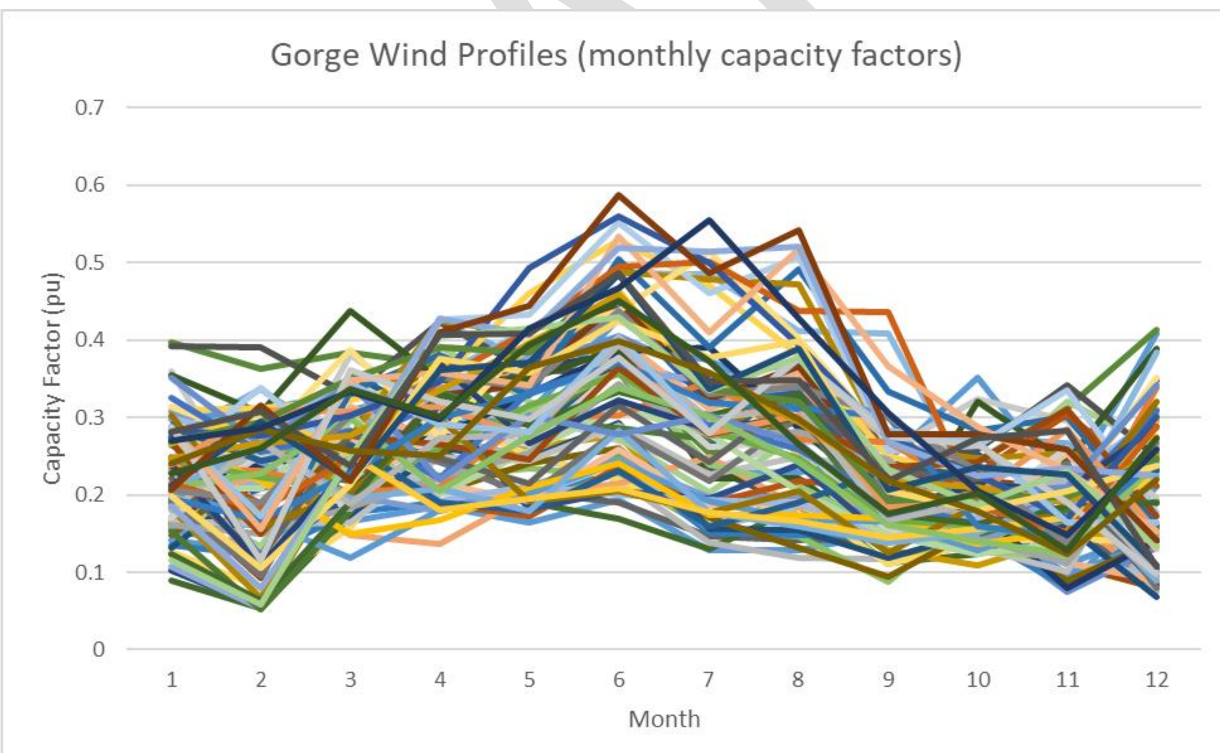

FIGURE 22. GORGE WIND MONTHLY CAPACITY FACTORS

[11] We selected just a single location to model solar because profiles across different locations were very similar, so long as the solar resource was located east of the Cascades.

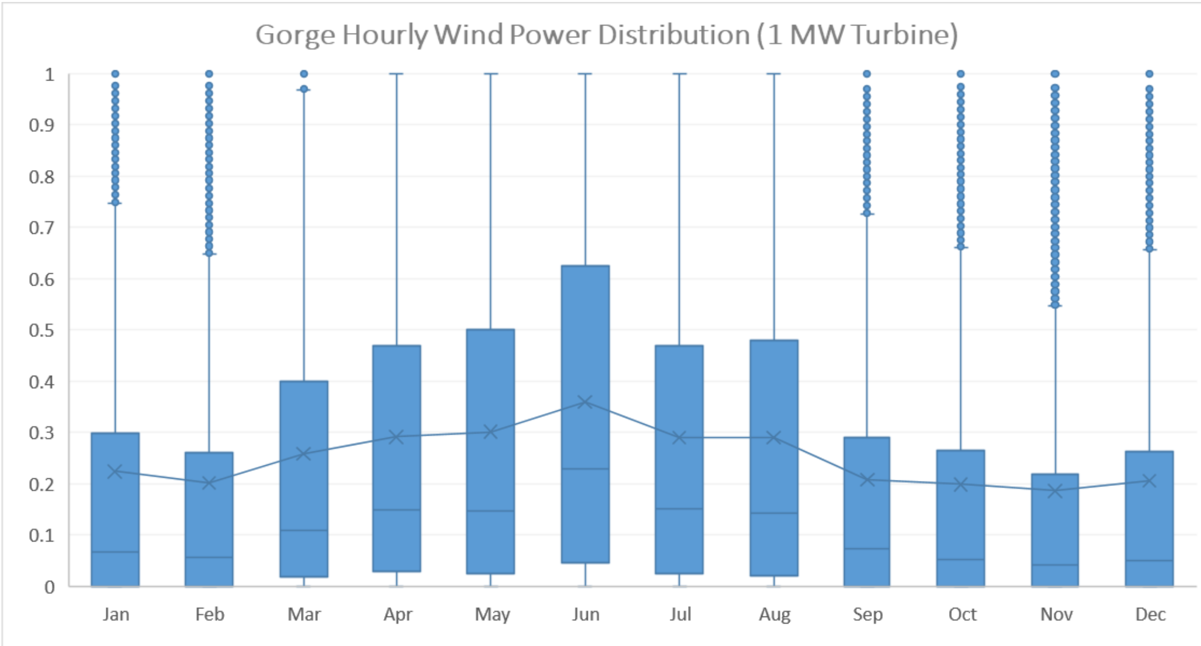

FIGURE 23. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - GORGE WIND

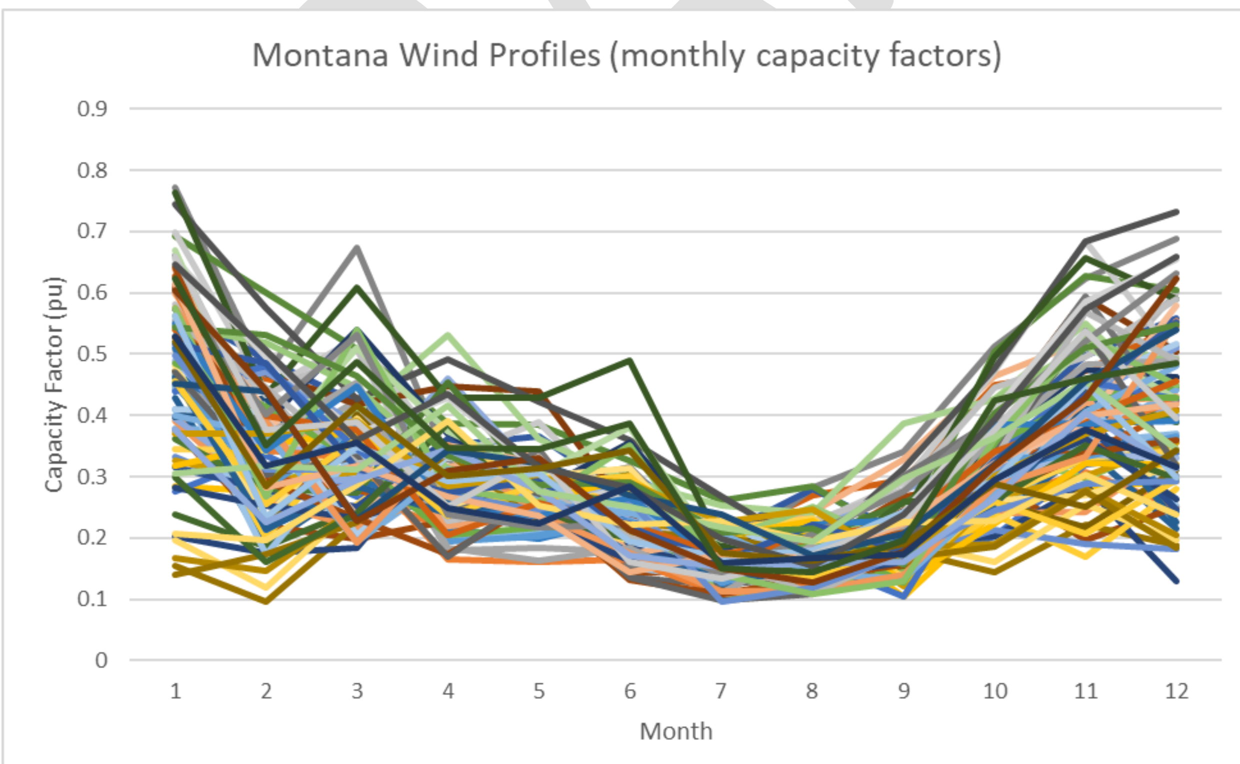

FIGURE 24. MONTANA WIND MONTHLY CAPACITY FACTORS

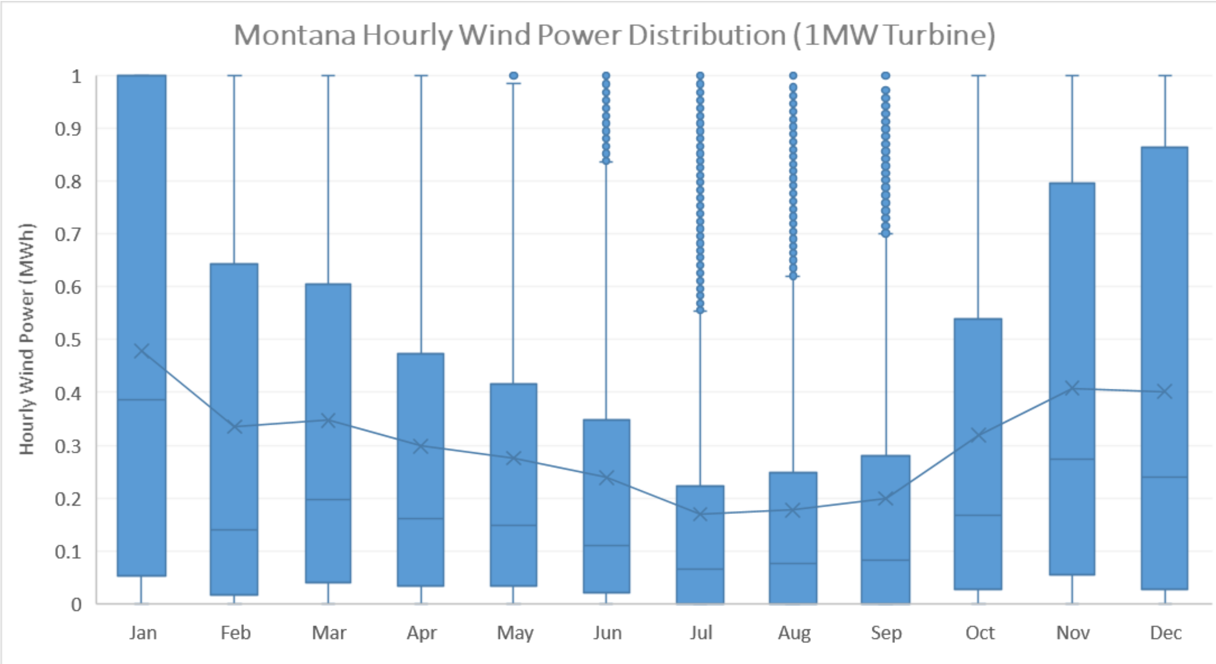

FIGURE 25. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - MONTANA WIND

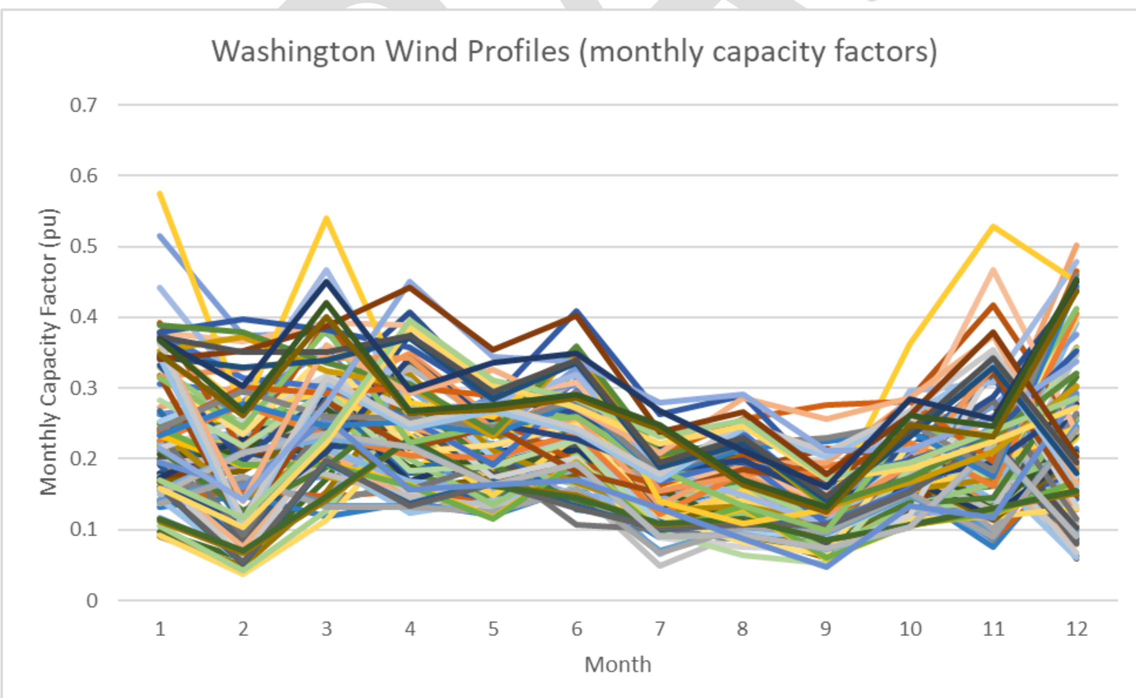

FIGURE 26. WASHINGTON WIND MONTHLY CAPACITY FACTORS

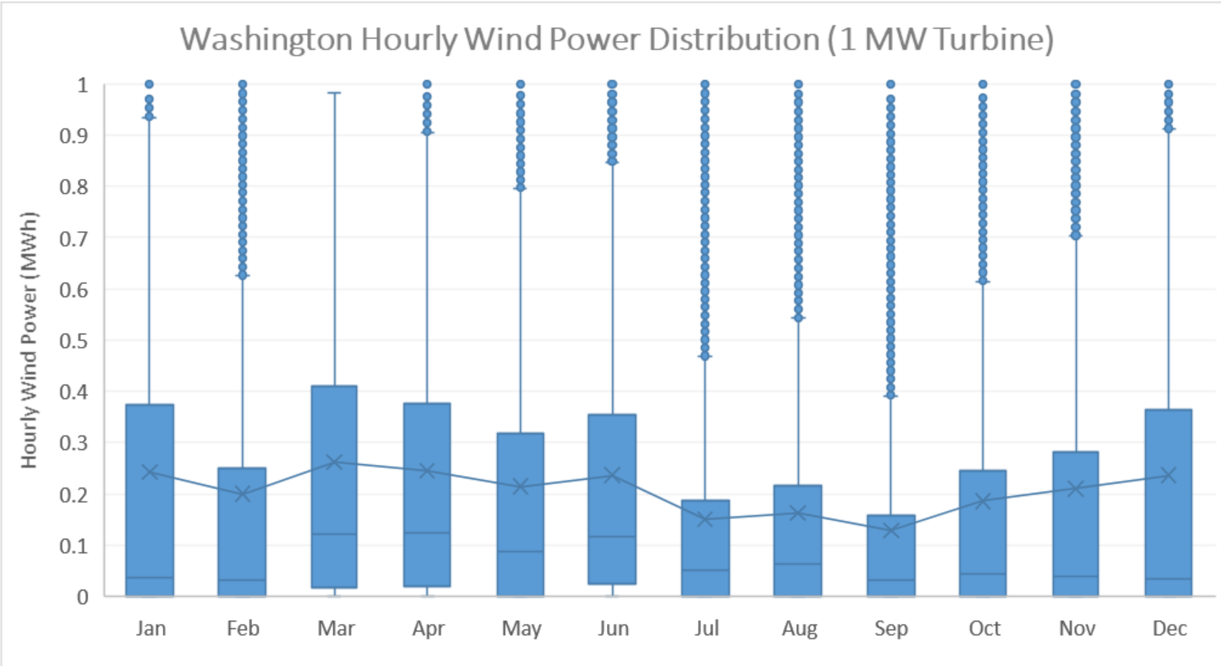

FIGURE 27. DISTRIBUTION OF HOURLY WIND POWER OUTPUT - WASHINGTON WIND

6.2.1.2 *Solar profiles*

Figure 28 and Figure 29 compare the monthly capacity factors and distribution of solar across various sites in Eastern Washington. Unlike the simulated wind profiles, there is not very much monthly variation in capacity factors for different sites. There is, however, still significant variation between sites on an hourly basis.

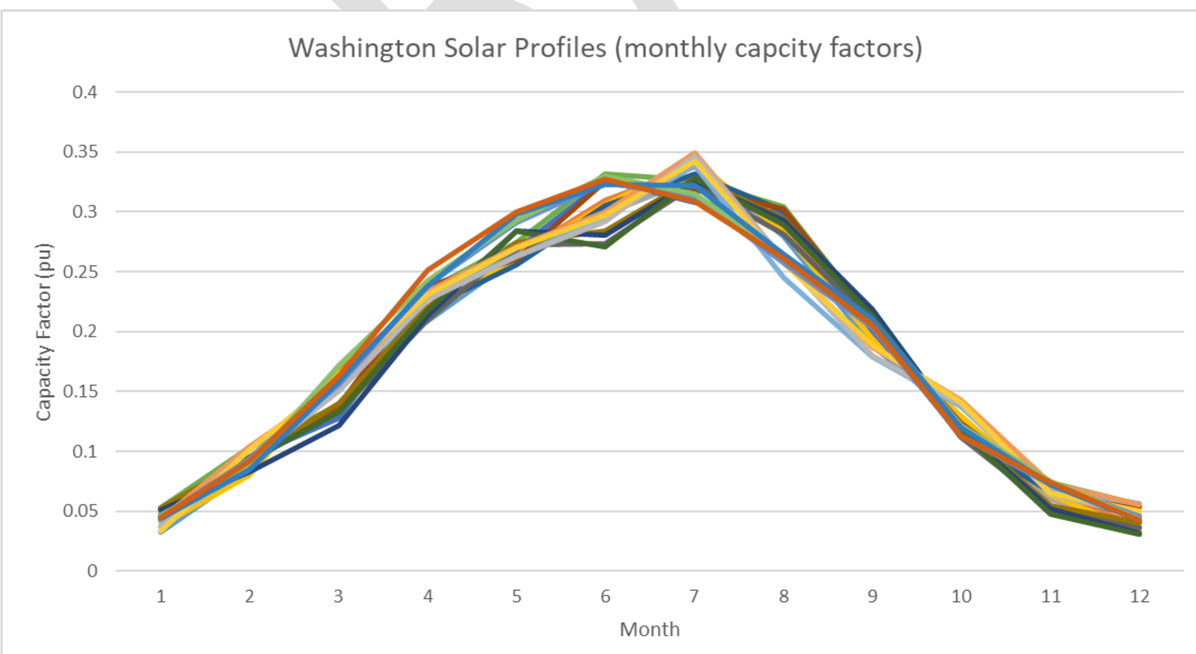

FIGURE 28. WASHINGTON SOLAR MONTHLY CAPACITY FACTORS

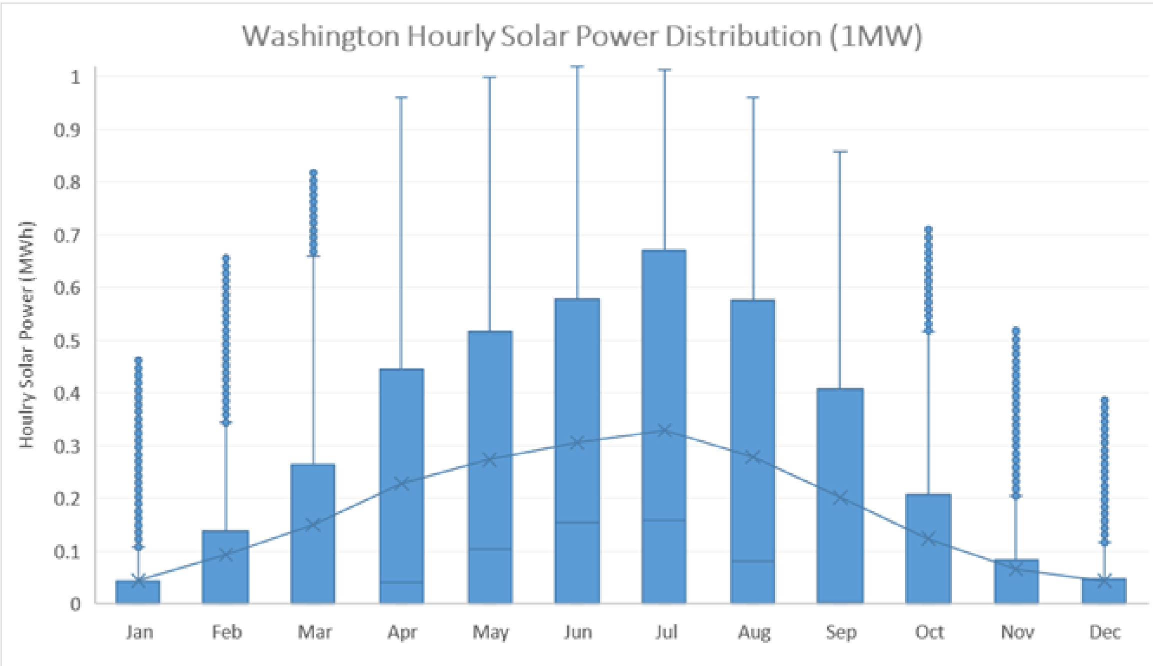

FIGURE 29. DISTRIBUTION OF HOURLY SOLAR POWER OUTPUT - WASHINGTON WIND

6.2.2 Generation Dispatch

Our system model (SAM)[12] selects a specific 8760 hourly profile from a site within a location (Gorge, Eastern Washington, etc.), and adds specific profiles from additional sites as the size of the requested resource increases. SAM iterates through solar resource sites for every 50 MW of capacity. For example, a 160 MW solar plant located in Eastern Washington for a specific simulation year (i.e. a specific weather profile) would be comprised of the following:

- 60 MW at Site 1 using Weather Profile 0
- 50 MW at Site 2 using Weather Profile 0
- 50 MW at Site 3 using Weather Profile 0

For wind, we have data on subsites within a site. SAM selects first from additional subsites within a site and adds profiles from those additional sub-sites in 20MW increments. Once all subsites within a site have been exhausted, SAM moves on to the next site within a location and repeats the process, iterating through sites and subsites in 20MW increments. For example, a 160 MW wind plant located at the Gorge for a specific simulation year (i.e. a specific weather profile) would be comprised of the following:

- 20 MW at Gorge Site 1, sub-site 1 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 2 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 3 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 4 using Weather Profile 0
- 20 MW at Gorge Site 1, sub-site 5 using Weather Profile 0
- 20 MW at Gorge Site 2, sub-site 1 using Weather Profile 0

[12] For more information on our system model, please see pre-workshop materials provided for our first 2022 IRP workshop on March 2, 2022.

- 20 MW at Gorge Site 2, sub-site 2 using Weather Profile 0
- 20 MW at Gorge Site 2, sub-site 3 using Weather Profile 0

For both solar and wind resources, SAM loops through the simulated profiles from our six different weather years through the end of the simulation period.

6.2.3 Cost Assumptions

We ground solar and wind costs in the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[13] and Version 15.0 of Lazard's Levelized Cost of Energy (LCOE) analysis[14]. Because we would either have to sign a Purchased Power Agreement (PPA) or build a resource ourselves at a specific point in time, we apply levelized energy cost from the relevant year when a resource would be acquired. For us that relevant year is either 2022 or 2028 because we only consider wind and solar resource acquisitions either at the beginning of the study period to solve an immediate resource need or in 2028 in conjunction with our BPA contract renewal decision. For solar, we use NREL's ATB estimates for Class 7 solar for the low, medium and high cases for both years. For wind, our low cost estimates come from the ATB estimates for Class 2 (Gorge and Eastern WA) and Class 1 (Montana) wind and for the medium cost case in 2028.

However, the 2022 ATB medium and the ATB's high cost estimates were significantly lower than Lazard's LCOE and informal price quotes we received from developers during our 2020 IRP data collection process[15]. For our high estimate of Class 2 wind in 2022, we replace ATB high case with our high cost estimate in the 2020 IRP ($40/MWh). This is equivalent to Lazard's LCOE high-cost case for subsidized solar. For our medium estimate in 2022, we take the average between the low and high case ($31/03/MWh). This is close to our low-case estimate of $30/MWh used in our 2020 IRP. To estimate costs in our 2028 high case for Class 2 wind, we apply the growth rate identified in NREL's ATB study to our 2022 cost estimate, yielding a 2028 high cost estimate of $47.42/MWh (just below the high end of Lazard's LCOE estimate for unsubsidized wind of $50/MWh). For our medium and high costs estimates of Class 1 wind, we apply a fixed discount factor of 92%. This is equivalent to the difference between the ATB's Class 1 and Class 2 estimates. Figure 30 summarizes these cost assumptions. Levelized cost estimates for wind and solar exclude transmission, other grid connection assumptions, and costs of integrating wind and solar. We account for transmission and integration costs separately (see Section 6.4).

[13] https://atb.nrel.gov/electricity/2022/index

[14] https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/

[15] See Section 11.1.3 of our 2020 IRP

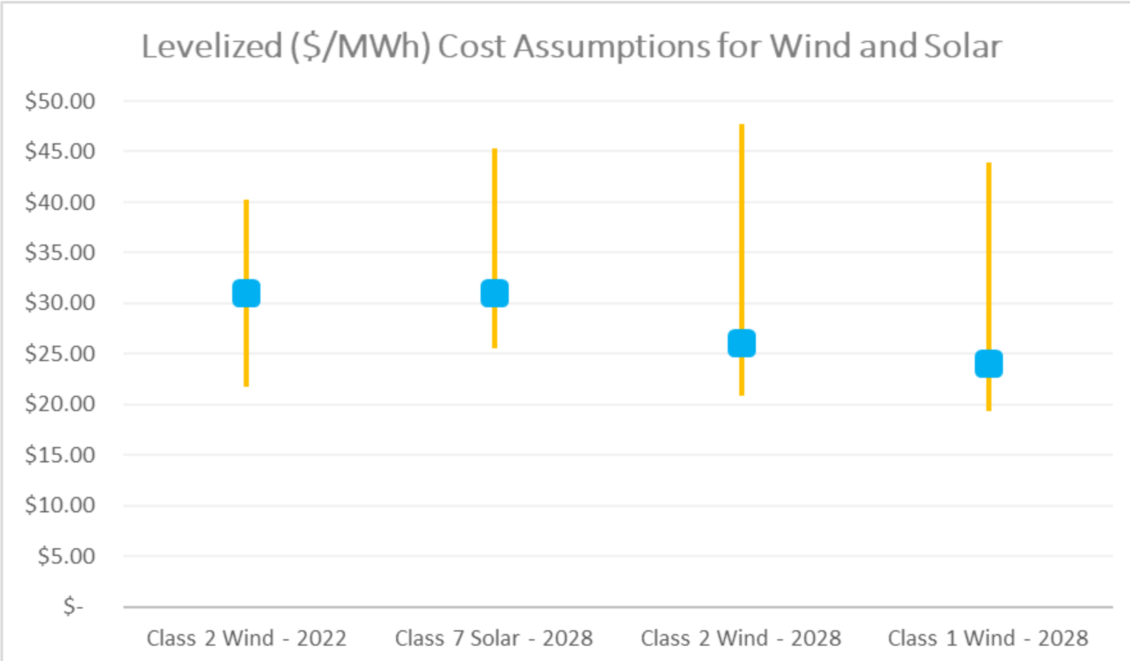

FIGURE 30. LEVELIZED COST ASSUMPTIONS FOR WIND AND SOLAR

6.3 Demand Response and Storage

6.3.1 Resource Dispatch

Our 2020 IRP modeled a very simple DR product that never dispatched and simply served as operating reserves, reducing the required level of operating reserves held by our generation by 1MW for every 1MW of DR. One of our 2020 IRP action items was to improve upon how we model DR in SAM. SAM now models three distinct types of DR resources: “Economic”, “Auto Recover” and “Time Between Calls”. From these three basic model structures, various types of storage, flexible load and DR programs can be represented in SAM. One of the primary features distinguishing different types of DR resource is whether the dispatch logic considers a resource’s “remaining energy equivalent” that is available in a given period. The remaining energy equivalent is the DR resource's peak load reduction in MW multiplied by the total duration of hours available for dispatch in a given period (month or year). If that energy equivalent is low, it becomes expensive to dispatch the resource because it is scarce and more valuable. Likewise, if the energy equivalent is abundant it becomes cheap to dispatch.

All DR resources (whether economic or reliability programs) are dispatched in the model when economic. Dispatch is considered economic when the market price is above the resource’s “offer price”. That offer price differs depending upon the type of DR being considered. The offer price is defined as the sum of the resource’s opportunity cost (e.g. retail electricity price) and an “offer adder”. The offer adder is a function of the remaining number of DR dispatches available in a given period (month or year) as well as the “energy equivalent” of those remaining dispatches (in the case of economic type DR). In the IRP, we assume that resources are required for resource adequacy and set the opportunity cost for demand response and battery storage quite high ($150/MWh). This ensures that resources are only dispatched during times when the system is under stress rather than to take advantage of market opportunities.

After a DR event, the DR resource is allowed to recover load curtailed during the event. Conditions for recovering load dispatched during DR events depends on the type of DR program modeled as follows:

a) **Economic:** Load is recovered when it is economic, where economic means that market price is below the "Bid Price". Here, the bid price is a function of the remaining "energy equivalent" of the resource.
b) **Auto Recover:** Load is recovered automatically after the end of DR event
c) **Time Between Calls:** Load is recovered when it is economic, where economic means that the market price is below the "Bid Price". Here, the bid price is NOT a function of the remaining "energy equivalent" of the resource.

Figure 31 shows a sample period of dispatch for an industrial DR program. The very high (and low) offer (and bid) prices is a direct results of our choice to set opportunity cost of the resource to $150/MWh assumption to ensure it is only dispatched for reliability purposes. Note that both the Industrial Load and Water Heater Load use the "auto recover" DR model type in SAM. The dispatch logic for "auto recover" resources does not consider the Bid Price when recovering load, so load will recover immediately after the end of DR regardless of whether market price is below the bid price.

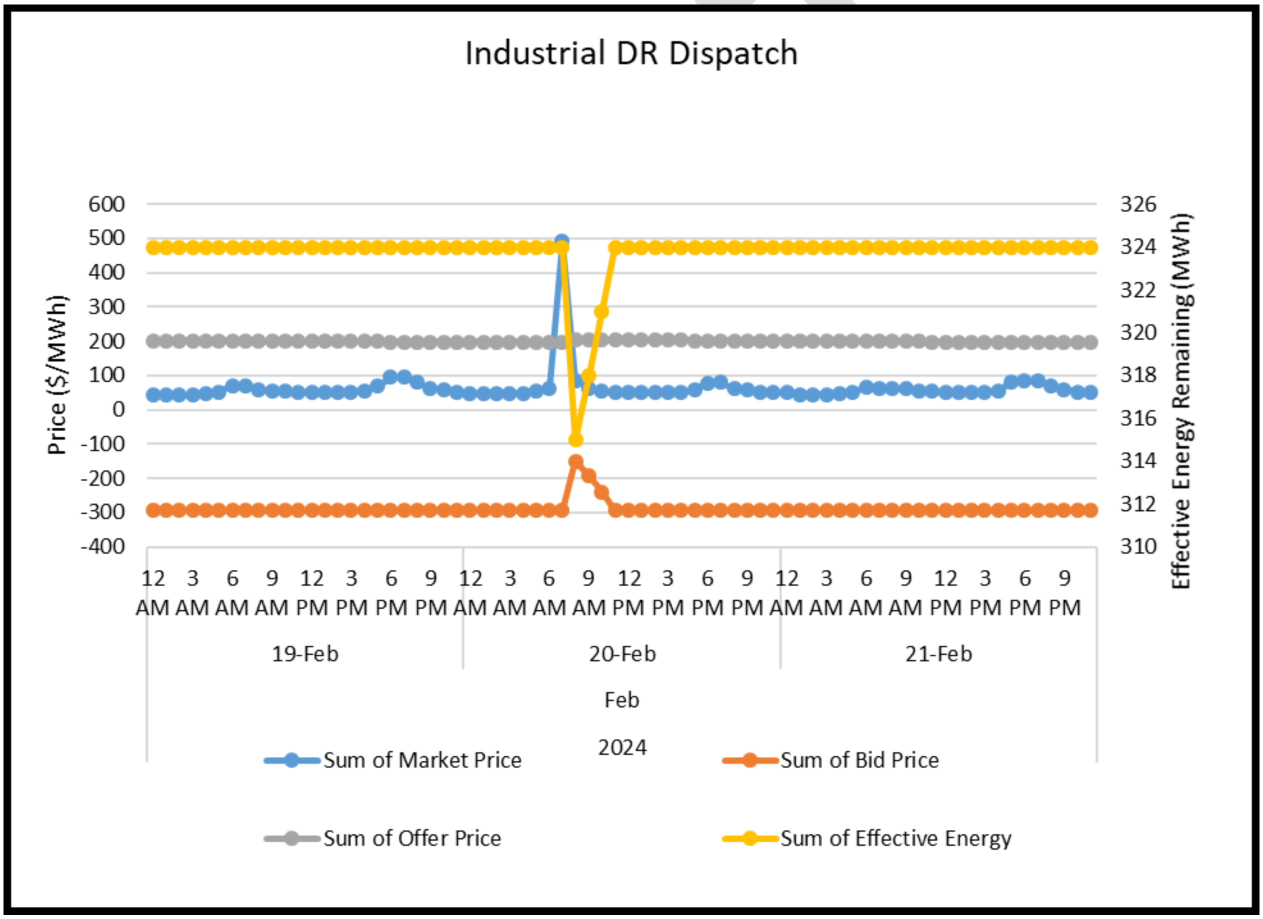

FIGURE 31. SAMPLE DISPATCH OF INDUSTRIAL DEMAND RESPONSE

6.3.2 COST ASSUMPTIONS

For the 10MW of demand response we identify in our preferred resource strategy, we assume a mix of industrial and residential DR in this IRP. For the industrial demand response product, we maintain the same medium cost assumption as in our 2020 IRP, which reflects the Power and Conservation Council's assumptions for the cost of industrial demand response. Tacoma Power also recently completed a DR potential assessment. This assessment identifies 19.6 MW of total potential for electric resistance water heaters in both the summer and winter. This residential DR offering is the basis for our assumptions for non-industrial DR. Cost assumptions developed in the potential assessment include fixed program costs and variable incentive costs. Unlike other resource investments that we would likely finance or purchase through a PPA, we assume larger up-front costs for demand response products. We use available data to produce a medium case cost estimate and then scale our estimates up by 40% in the high case and down by 20% for the low cases. Figure 32 provides a summary of the effective weighted average cost of demand response. Costs drop steeply between 2026 and 2027 when there are no more program startup costs. The small rise in costs between 2027 and 2031 reflects a transition in the residential water heater program from a program relying primarily on switch-based technology to one relying primarily on grid-enabled technologies.

Figure 33 presents the effective cost in $/kW-year that we assume for battery storage. We rely on NREL's 2022 ATB estimates for the capital cost of installing batteries in 2022 ($1,927 $/kW, $2,036/kW and $1,934/kW for the Advanced, Conservative and Moderate cases, respectively) and amortize that capital cost over the 20-year study period. We take current-year ATB estimates for O&M (i.e. in the year 2030, we use ATB estimates for O&M cost projections for 2030). NREL's O&M estimates include battery replacement costs.

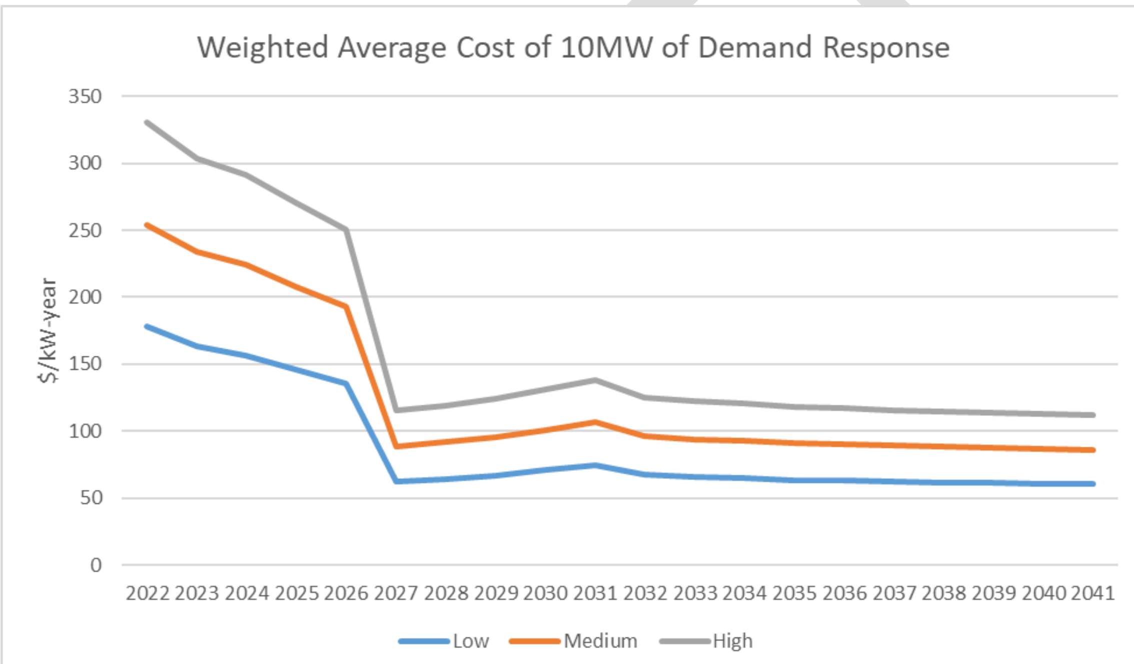

FIGURE 32. SUMMARY OF DEMAND RESPONSE COST ASSUMPTIONS

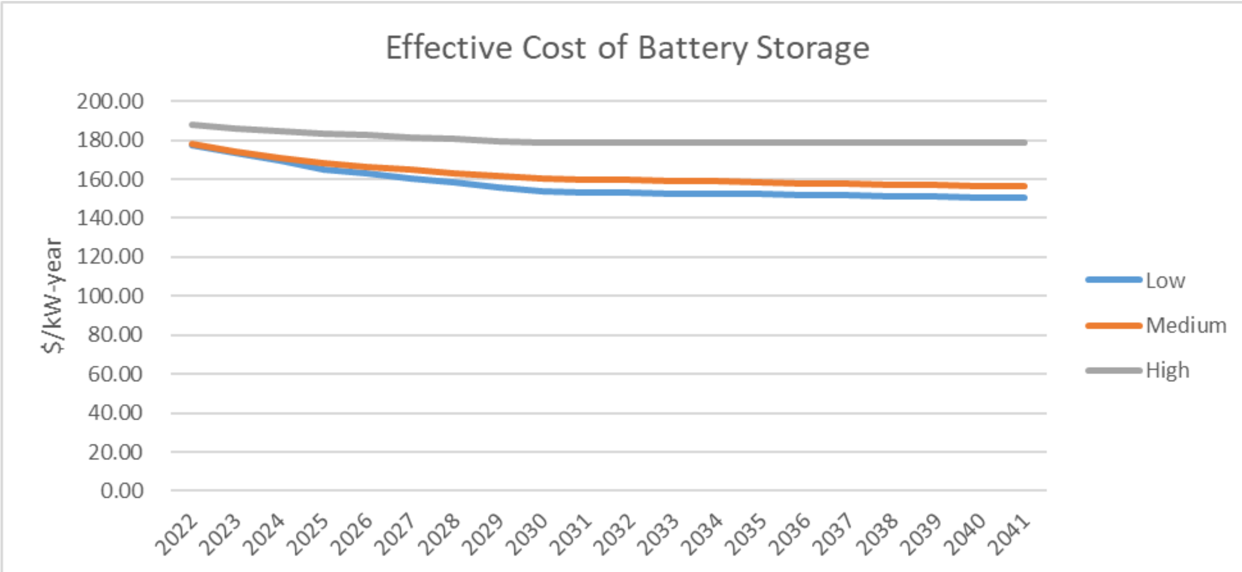

FIGURE 33. EFFECTIVE $/KW-MONTH COST ASSUMED FOR BATTERY STORAGE

6.3.3 SMALL MODULAR NUCLEAR REACTORS

While nuclear power is a well-understood technology that is both carbon-free and reliable enough to serve as a baseload plant, small modular reactors (SMRs) are a relatively new technology. The Utah Associated Municipal Power Systems (UAMPS)[16] project with NuScale Power to develop a SMR facility in Idaho serves as the basis for the SMR resource we model in the IRP. While the modular nature of SMRs could allow them to be more flexible than a traditional nuclear plant, we assume a constant fixed generation profile because the cost of operating SMRs at a low load factor would be prohibitively high. Recognizing this and given that available price data is indicative for a plant with 24/7 operations, we modelled the SMR plant as a constant power generation output. Because refueling can be batched by module, we assume constant operation at a constant capacity factor of 95%.

Recent cost estimates of the UAMPS project with NuScale range from $40/MWh to $65/MWh[17], but there is still quite a bit of uncertainty around what final costs will be for small modular nuclear reactors. Costs for these types of projects have often ended up significantly higher than what was initially projected—anywhere from double to twenty times higher. In our 2022 IRP, we start with the $65/MWh and assume that costs are 15% lower ($55.25/MWh) in our low-cost case and 20% higher than the current estimate ($78/MWh) in the medium cost case and twice as high as current estimates ($130/MWh) for our high-cost case. We assume values stay constant across our IRP study period in real terms (i.e. costs rise at the rate of inflation). For reference, estimates of NuScale's technology developed by an independent study commissioned by Australia's Royal Commission[18] come in even higher at $182/MWh after adjusting for inflation.

It is common for very large generation investments of any kind (and especially nuclear generation investments) to experience not only cost overruns but also build times that are longer than expected. At the time we finalized our 2020 IRP, UAMPS had planned to have twelve modular reactors built and in operation by 2027, just prior to the end of the region's BPA contracts. There have been delays since then, however, and UAMPS has both scaled back the

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[16] https://www.uamps.com/

[17] https://www.powermag.com/commercial-nuscale-smr-in-sight-as-uamps-secures-1-4b-for-plant/

[18] http://nuclearrc.sa.gov.au/app/uploads/2016/05/WSP-Parsons-Brinckerhoff-Report.pdf

size of their project and delayed its start date. They currently expect to have six reactors in operation before the end of 2030.

6.3.4 PUMPED STORAGE

For the 2022 IRP, we model pumped storage as a contracted resource and not as an owned resource. The contract resource is roughly based on Goldendale Energy Storage's proposed pumped storage to be located on the Oregon-Washington border. The proposed project is expected to be 1,200MW with over 25,000 MWh of storage (12-20 hours of storage). To approximate this proposed project's parameters, we model the pumped storage contract as a 350MW, 16-hour battery. As a monthly economic resource, it is charged and dispatched according to prices. Figure 34 shows the dispatch of a 100 MW pumped storage contract modeled as 16-hour battery. We use NREL's 2022 ATB as the basis of our cost estimates (Table 5). The ATB assumptions for pumped storage do not change over time.

TABLE 5. PUMPED STORAGE COST ASSUMPTIONS

	CAPEX	Fixed O&M	Variable Cost
Low	$1,938/kW	$17.82/kW-year	$0.5125/MWh
Medium	$1,999/kW	$17.82/kW-year	$0.5125/MWh
High	$1,999/kW	$17.82/kW-year	$0.5125/MWh

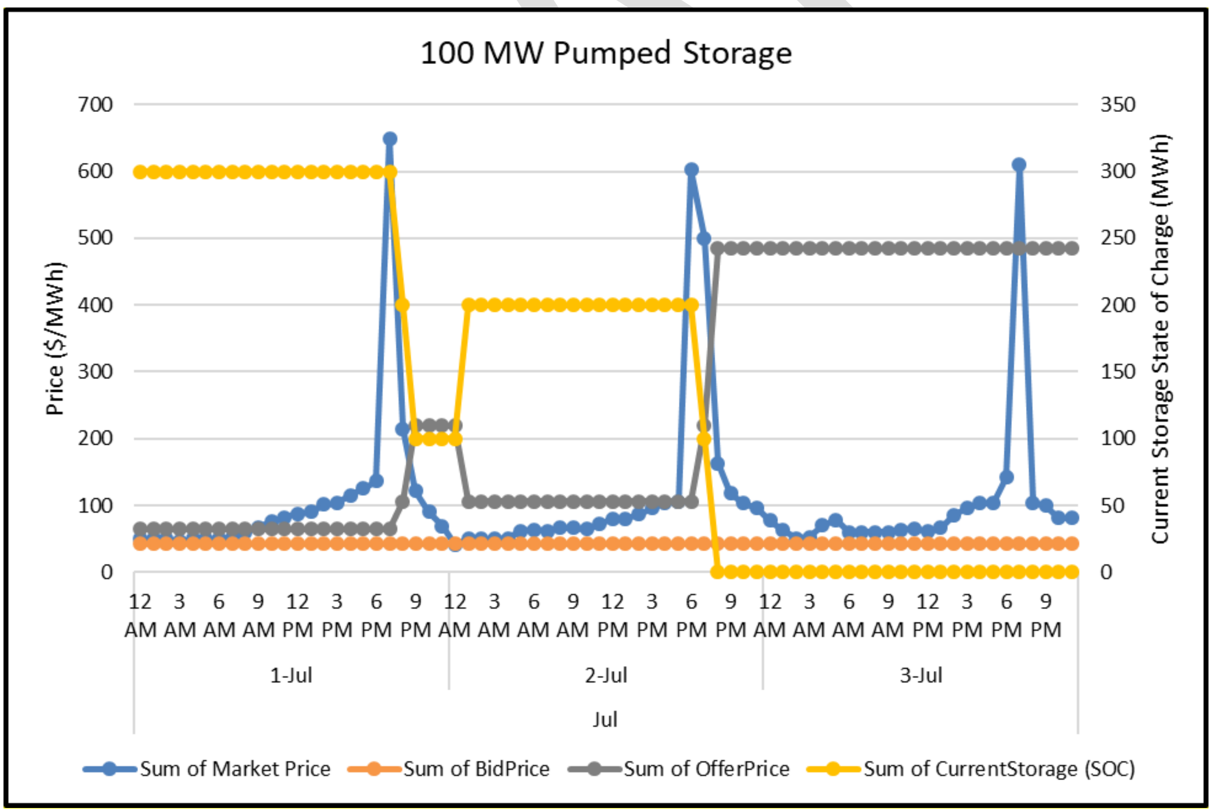

FIGURE 34. SAMPLE 100 MW PUMPED STORAGE DISPATCH

6.3.5 Energy conservation

Energy conservation is one of our first-choice energy resources. It is the only resource that we have acquired for many years and remains a priority resource in the 2022 IRP. Energy conservation helps limit load growth, which defers the need to acquire more costly generating resources, supports the local economy and is good for the environment. Our customers also benefit because conservation helps them reduce their heating, lighting and other costs.

The IRP model currently takes the total cost-effective conservation potential identified in our most recent Conservation Potential Assessment (CPA)[19] as a given and deducts it directly from our load forecast. As in earlier years, the CPA uses a bottom-up approach that includes (1) a sector-level characterization of the residential, commercial, industrial, street lighting, and JBLM sectors, (2) a baseline projection of energy consumption by sector, segment, end use, and technology, (3) identification of several hundred energy conservation measures to be applied to all sectors, segments, and end uses and (4) and estimate of Technical potential, Technical Achievable potential, and Economic Achievable potential energy savings at the measure level. The 2022-2041 CPA identified a ten-year potential of 226,174 MWh, or 25.8 aMW, by 2031. Key opportunities for savings included residential building shell measures (insulation, ducting, etc.), commercial and industrial lighting, commercial refrigeration, industrial motor upgrades and commercial and industrial strategic energy management programs.

6.4 Other Costs

6.4.1 Transmission

We assume that transmission costs remain constant in real terms for existing Tacoma Power resources and existing purchase power contracts (BPA contract, etc.). In portfolios where we contemplate replacing a small part of our BPA contract with another resource, we assume that transmission costs associated with our BPA contract are slightly lower (equivalent to the reduction in what we receive from BPA). Transmission costs for other resources are assumed to be $1.964/kW-month ($1.648 for BPA firm point-to-point transmission[20] plus $0.316 for scheduling, system control and dispatch service[21]) when they are located within Oregon or Washington (solar, Eastern Washington wind, Gorge wind, etc.). For resources located in Montana and Idaho (wind and small nuclear reactors, respectively), transmission is assumed to cost $50/kW-year[22] to get generation into Oregon and Washington plus $1.964/kW-month for transmission within Oregon and Washington.

6.4.2 Integration/balancing costs

Integration costs are added to variable energy resources (i.e. wind and solar). We considered different alternatives to modeling integration costs and determined the best proxy for integration costs would be to assume that we purchase integration services from BPA. As of BPA's most recent BP-22 rate case, these services are referred to as Variable Energy Resource Balancing Service (VERBS). We apply BPA's integration charge to 100% of the wind or solar capacity. VERBS charges are currently $0.753/kW-month for wind ($0.358 for regulating services and $0.395 for non-

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[19] The 2022-2041 CPA is available on our IRP webpage (https://www.mytpu.org/about-tpu/services/power/integrated-resource-plan/) under "Other Resources".

[20] See page 15 of BPA's 2022 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions

[21] See page 42 of BPA's 2022 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions

[22] This assumption was taken from a 2019 study conducted by E3 for Public Generation Pool (https://static1.squarespace.com/static/5e9fc98ab8d9586057ba8496/t/5ee52f8fdd4fcc4948f809e2/1592078233508/E3_NW_RA_Presentation-2018-01-05.pdf , slide 19)

regulating services) and $0.456/kW-month for solar ($0.282 for regulating services and $0.174 for non-regulating services).[23] We assume no escalation in the real value of VERBS charges over the period of the IRP.

6.4.3 Social cost of carbon

Because our own generation is 100% carbon-free and the resources we consider are entirely carbon-free generating resources, the main source of carbon in each of the portfolios examined is unspecified market purchases—either Tacoma Power purchases or BPA purchases. We calculate the carbon content of market purchases using an annual emissions rate assumption that is equal to the average of the hourly Mid-C marginal emissions rate modeled in each year for each scenario in our AURORA model. For emissions associated with the BPA contract, we assume a fixed mix of resources based on BPA's 2021 fuel mix[24] and charge 6% of BPA power (5% non-specified purchases and 1% wind without RECs) the market emissions rate. Emissions are charged the social cost of carbon prescribed by the Department of Commerce in Phase 1 rulemaking for CETA.[25] Values escalate from $84.25/MT in 2022 to $111.20/MT in 2041[26].

7 Portfolio Performance

7.1 CETA Compliance

We calculate the percentage of the load that is served by renewable and nonemitting power for each portfolio using the methodology described in Section 7.1. We expect each portfolio considered in this IRP to serve more than 80% of the load with renewable and nonemitting power in every month of every calendar year for all weather years modeled in our IRP. Figure 35 illustrates the distribution of the percent of monthly generation across weather years that is CETA-Compliant in the 20-year IRP study period.

[23] See pages 61 and 62 of BPA's 2022 [Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions]()

[24] See "Hydropower Fuel Mix" at https://www.bpa.gov/energy-and-services/power/hydropower-impact

[25] https://www.commerce.wa.gov/wp-content/uploads/2019/12/2019-12-30-CETA-Phase-One-Rule-Making-Order.pdf (WAC-194-40-100)

[26] Values are in 2022 dollars.

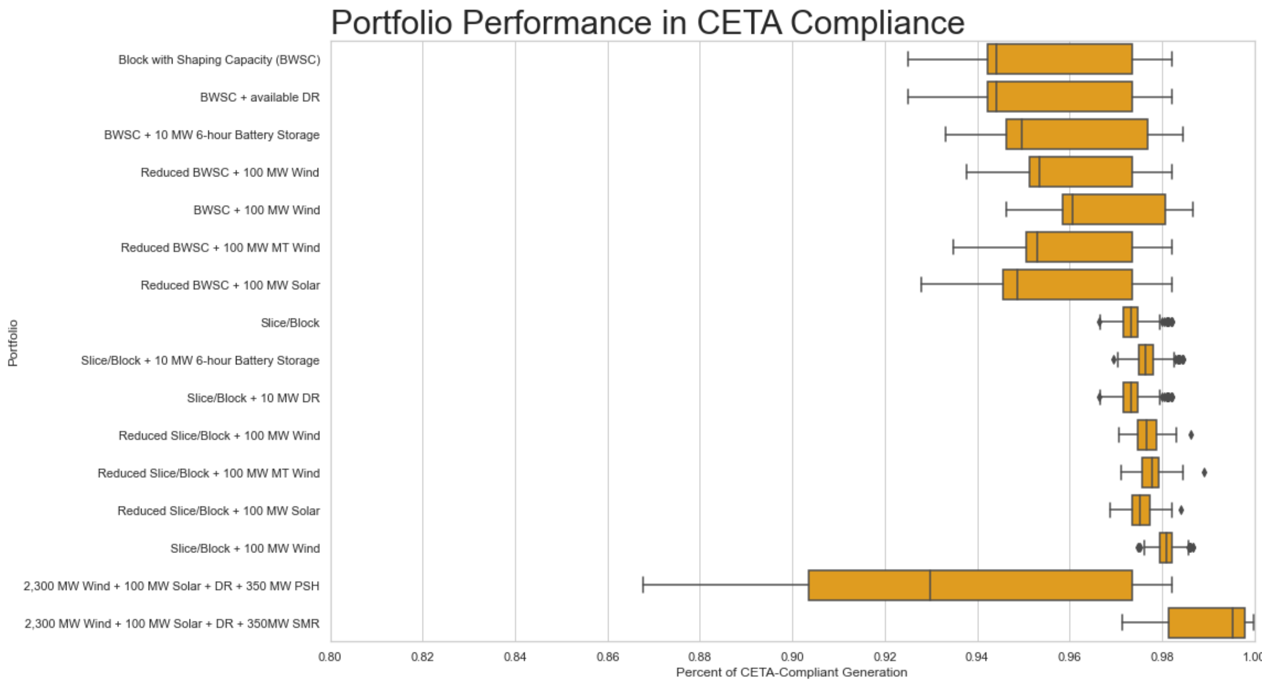

FIGURE 35 CETA COMPLIANCE BY PORTFOLIO

7.2 Resource Adequacy

We evaluate the resource adequacy of each potential portfolio described in Section 5 using our three resource adequacy metrics (LOLH, NEUE and LOLD) described in Section 2.1. Our key resource adequacy findings are:

(1) Renewing our current BPA contract at current levels with either Slice/Block or Block with Shaping Capacity leaves us adequate in most but not all scenarios of the future. We tend to fail the frequency component of our standard under our Reliability Reigns scenario, in which insufficient the Western grid as a whole is not reliable and our ability to rely on purchases from the wholesale power market to maintain adequacy is very limited. This means that renewing our BPA contract at current levels could put us at risk of experiencing shortfalls that are typically small and short-lived but occur too often when the Northwest grid is not reliable.

(2) Acquiring 100MW of wind, 10MW of battery storage or 10MW of demand response all succeed in solving the adequacy risk we face.

(3) Reducing our BPA Block purchase and replacing it with a wind or solar resource does not improve our resource adequacy position.

We show a selection of figures in the rest of this section to explore these findings. The full set of results for all portfolios are available in Appendix [Appendix not yet available].

7.2.1 BPA Renewal at Current Levels

Figure 36 through Figure 38 present resource adequacy results for the Slice/Block portfolio (i.e. the portfolio where we renew our BPA contract with the same Slice/Block product as we purchase today). This portfolio represents a continuation of our current portfolio. We present results for each of our three metrics for each calendar year across each of our four scenarios. In each graph, values that fall above the dashed line identify years when we fail our adequacy standard. Our current portfolio passes the duration and magnitude components of our RA standard, results are mixed for our frequency standard. The Slice/Block portfolio passes this component of our RA standard in most cases but frequently fails it in our scenario where insufficient resources are built in the West over the first ten years.

As in previous IRPs, we continue to find that our risk of shortfalls in the wintertime. While we have less surplus energy available in the summertime and typically expect large surpluses in the winter, there is greater variability in our position in the wintertime, and we sometimes are at risk of being short on capacity. We generally find that shortfall risk is not due exclusively to low water conditions or high load but rather the combination of the two in the context of an unreliable grid. Our system is able to handle our normal loads even under low water conditions and is able to handle relatively high loads under normal water conditions. It is when we experience especially low water conditions combined with a drop in temperature (and the resulting spike in load) that we are at risk. These conditions can cause use to fail the frequency component of our adequacy standard in our Reliability Reigns scenario. This scenario represents conditions in which the WECC fails to build enough capacity to meet West-wide adequacy needs and, as a result, we are less able to rely on the wholesale market as a backup to our own power supply. In recent years, we have seen several indications that capacity may not always be plentiful in the market. We actively participate in efforts like the Western Resource Adequacy Program (WRAP) to ensure that the region builds sufficient capacity and avoids market conditions represented in the Reliability Reigns scenario. Should these efforts fail, we are likely to find market conditions that increasingly resemble this higher-risk scenario.

Results are similar for the Block with Shaping Capacity (BWSC), in which we renew our BPA contract without reducing our net requirement but replace our current Slice/Block product with the BWSC product. While the BWSC portfolio passes the LOLH and NEUE components of our standard (graphs not shown), it also consistently fails our standard for LOLD under the Reliability Reigns scenario. Because we originally created the Reliability Reigns scenario to model a world where poor planning leads to a “backsliding” of carbon policies rather than to test our adequacy under a future with an unreliable grid, heat rates are highest in the first half of the period and thus create the highest risk of failing our adequacy standard. This also happens to fall mostly in the period before we would be renewing or changing our BPA contract. It is thus difficult to separate out the impacts of switching to BWSC from the impacts of improved heat rates in the latter half of the period under the Reliability Reigns scenario. We run a hypothetical BWSC portfolio where we purchase BWSC starting in 2022 to confirm that switching to BWSC would not improve our adequacy position if heat rates remained as high at the end of the period as they are at the beginning of the study period and find that the results do not change.

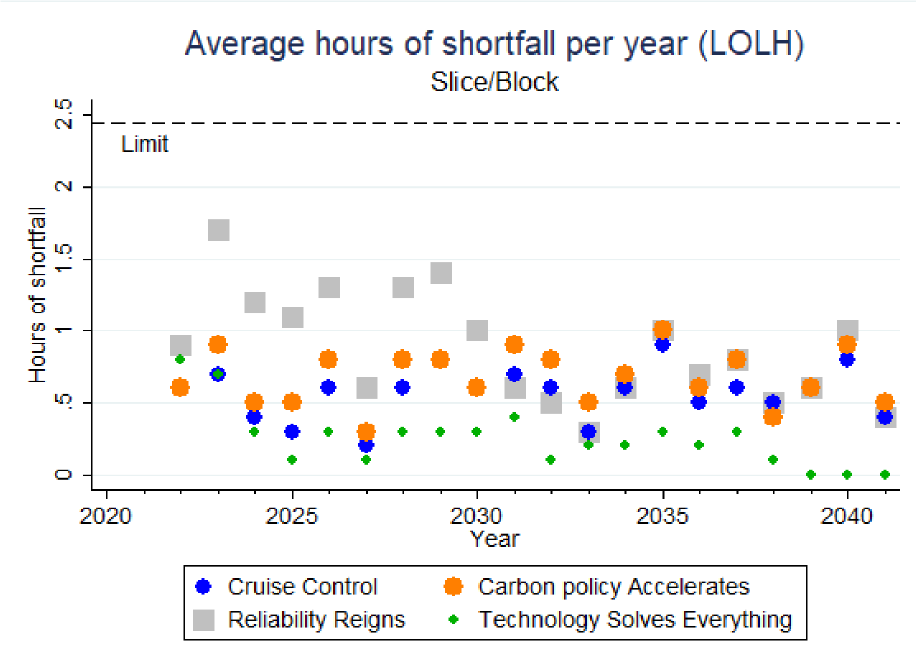

FIGURE 36. DURATION METRIC (LOLH) FOR SLICE/BLOCK PORTFOLIO

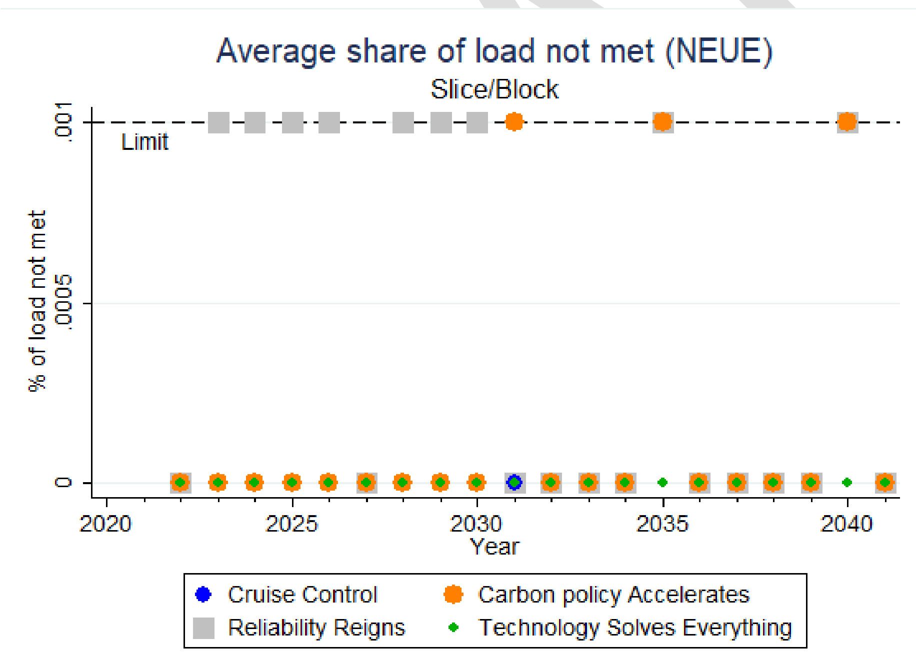

FIGURE 37. MAGNITUDE METRIC (NEUE) FOR SLICE/BLOCK PORTFOLIO

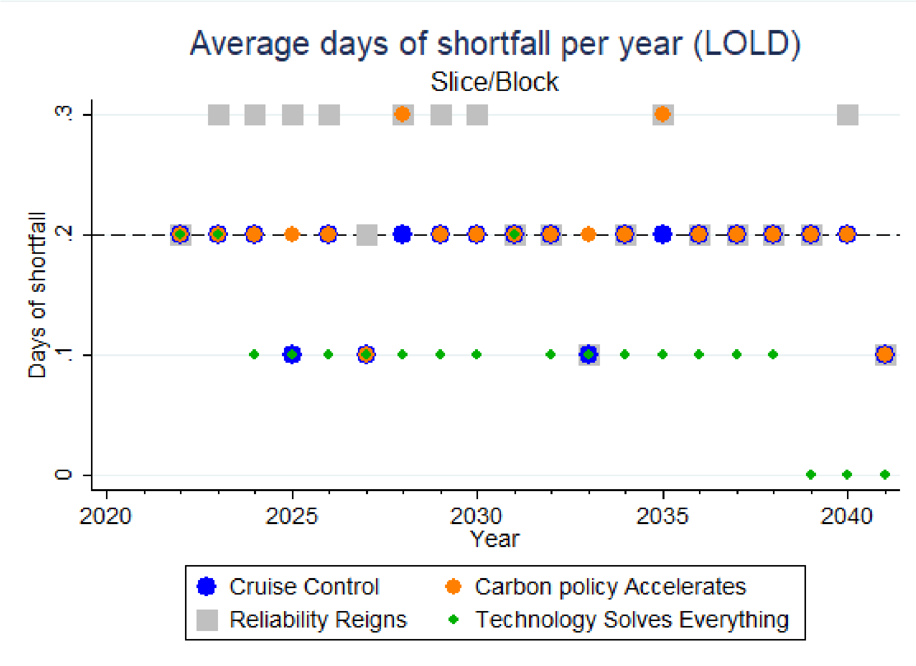

FIGURE 38. FRQUENCY METRIC (LOLD) FOR SLICE/BLOCK PORTFOLIO

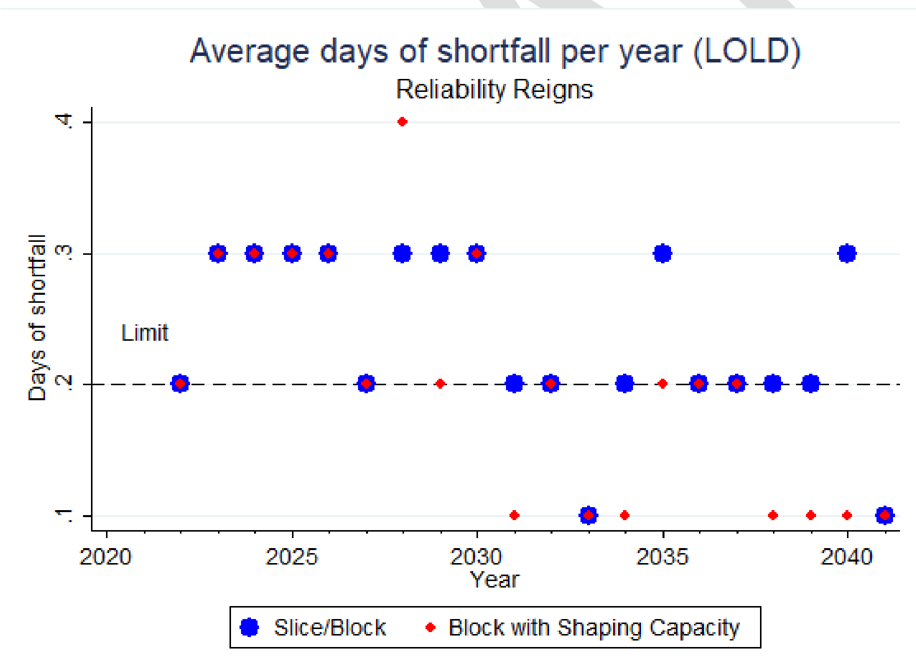

FIGURE 39. FREQUENCY METRIC (LOLD) FOR BWSC PORTFOLIO VS. SLICE/BLOCK PORTFOLIO – RELIABILITY REIGNS

7.2.2 BPA RENEWAL AT CURRENT LEVELS AND ADDITION OF A RESOURCE

Figure 40 presents LOLD results under the Reliability Reigns scenario for portfolios in which we renew our BPA Slice/Block contract using the same net requirement calculation as BPA uses today but also add a resource to ensure we meet our RA standard under all of the scenarios we model. We find that all three resource additions we consider

(10MW of battery storage, 10MW of demand response or a 100MW wind project) would improve our LOLD metric enough to meet our RA standard.

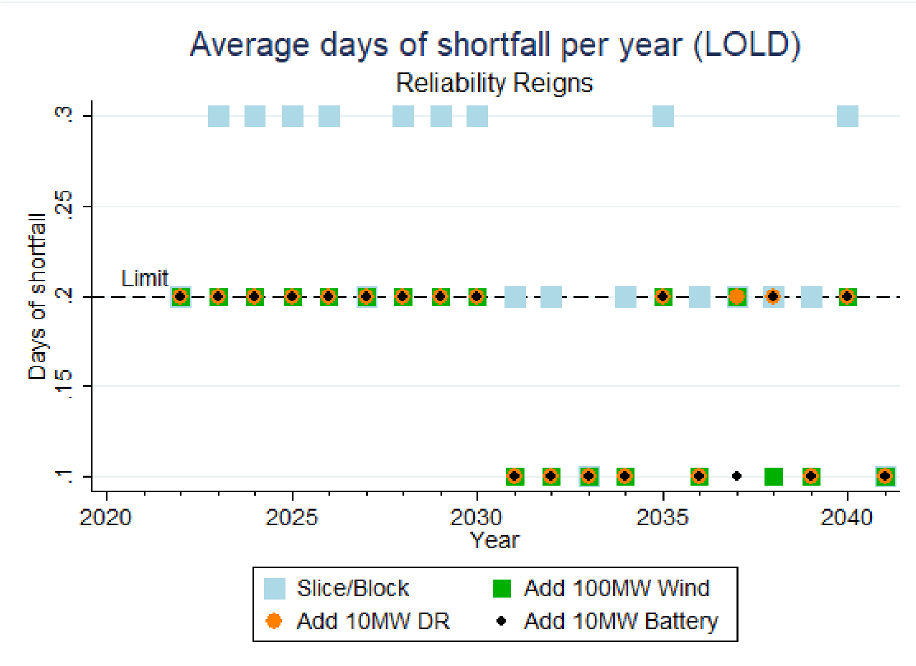

FIGURE 40. LOLD RESULTS FOR SLICE/BLOCK PORTFOLIOS WITH RESOURCE ADDITION - RELIABILITY REIGNS SCENARIO

7.2.3 BPA RENEWAL AT REDUCED LEVELS AND PARTIALLY REPLACED BY WIND OR SOLAR

Figure 41 presents LOLD results for portfolios in which we acquire a wind or solar resource, renew our BPA Slice/Block contract and declare the new wind or solar resource as a dedicated resource to BPA as way to reduce our net requirement calculation and purchase slightly less Block. We find that our BPA "diversification" portfolios do not change the overall resource adequacy picture much. All of the "diversification" portfolios considered pass the LOLH and NEUE components of our RA standard (graphs not shown) and continue to fail the LOLD component of our standard under the Reliability Reigns scenario. Results for parallel portfolios where we renew our BPA contract with Block with Shaping Capacity instead of Slice/Block are not shown but are similar to results for Slice/Block that are presented below. Note that diversification portfolios look identical to our Slice/Block portfolio prior to 2028 because we assume that the resource do not come online until 2028, when we would be able to count them against our net requirement calculation for Block.

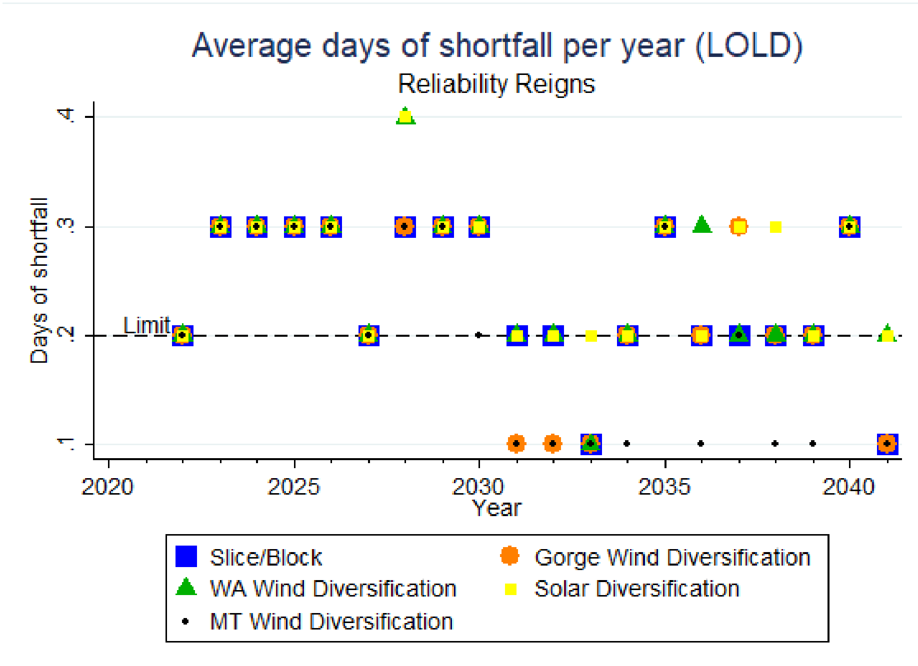

FIGURE 41. LOLD RESULTS FOR SLICE/BLOCK "DIVERSIFICATION" PORTFOLIOS - RELIABILITY REIGNS SCENARIO

7.2.4 Portfolios without BPA

Figure 42 and Figure 43 present results for LOLD for the two hypothetical portfolios in which we rely on extremely large quantities of wind, solar and other carbon-free capacity (small modular nuclear reactors and pumped storage hydro). As explained in Section 5, the quantities of resource in these portfolios are not technically possible for us to acquire today and are unlikely to be available by 2028. Nonetheless, we run them through our model as a hypothetical exercise. If we were able to acquire the amount of resources identified in these hypothetical portfolios, we would pass all three components of our RA standard under the Cruise Control and Technology Solves Everything scenarios but consistently fail under Reliability Reigns and Carbon Policy Accelerates scenarios. Resource adequacy would be especially compromised under our load growth scenario (Carbon Policy Accelerates). This is particularly concerning given the potential load growth we may see over the next twenty years if vehicle and building electrification accelerates. Results for LOLH and NEUE are not shown but are similar.

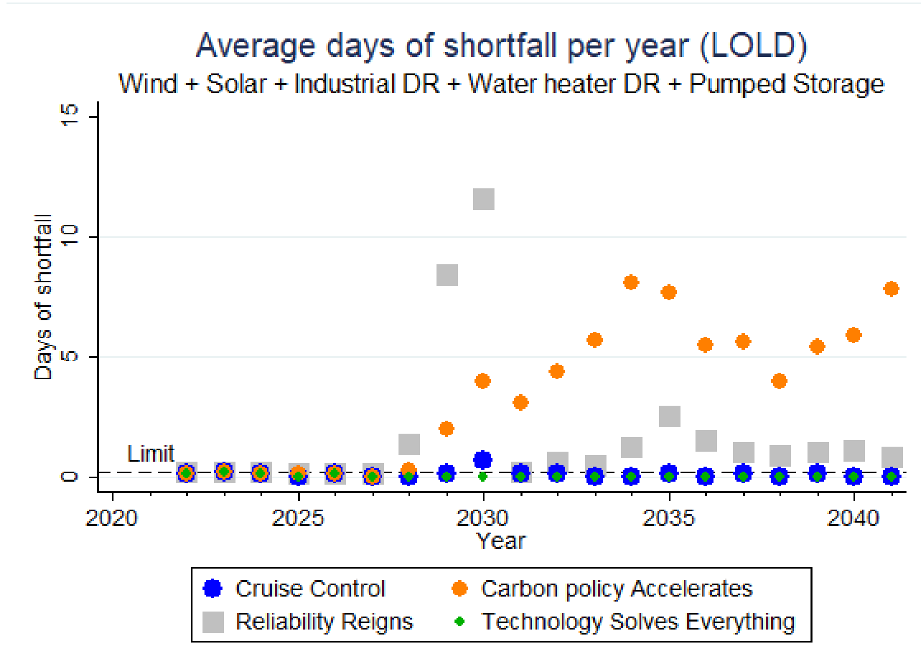

FIGURE 42. LOLD RESULTS FOR HYPOTHETICAL PORTFOLIO WITH WIND, SOLAR, DR & PSH

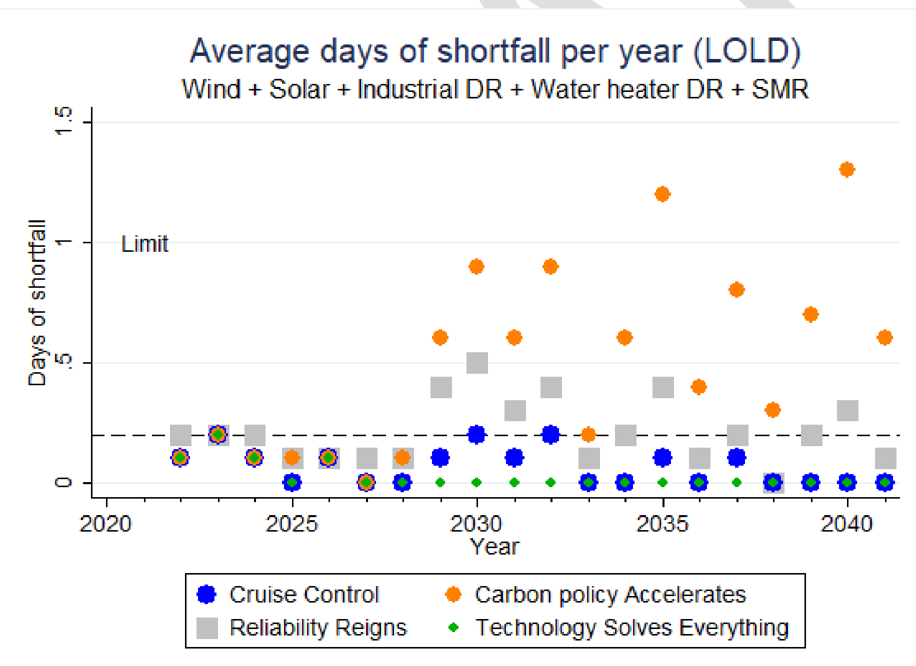

FIGURE 43. LOLD RESULTS FOR HYPOTHETICAL PORTFOLIO WITH WIND, SOLAR, DR & SMR

7.2.5 WRAP Position

We calculate forward showing program compliance based on what we know today about how the program would work. Because many of the specific program requirements are still in development, this analysis is exploratory rather than a forecast of our expected position as a potential WRAP participant. Given the limitations in what we know, we estimate our WRAP position for the winter season only.

Our first step is to determine what our peak load forecast would be under WRAP across the 20-year study period and all historical weather simulations included in the IRP analysis. The WRAP methodology for calculating peak in the forward showing involves scaling the median of maximum seasonal load over the last five years by average and maximum peak loads over the same five years. Because forward showing requirements are calculated from historical peak loads but only forecasted peak loads are available for future periods, the results of this exercise may be different from actual program requirements. Figure 44 presents a comparison of IRP scenario peak load forecasted versus the associated WRAP forecast averaged across weather simulations. Results of this calculation show that based on the projected peak loads across IRP scenarios, the WRAP load forecast is consistently higher in both summer and winter seasons. This is likely because the WRAP's methodology of using the past five years of data lags the downward trend observed in most of our scenario forecasts. It is likely that WRAP will develop process for correcting its peak forecasts when loads are rising or declining quickly to avoid this mismatch.

The forward showing program calculates a LSE's capacity requirement based on the peak load forecast described above plus a planning reserve margin. A LSE must ensure it has enough capacity to meet its capacity requirement, which is calculated based on the nameplate capacity of the entity's resources and the WRAP-determined qualifying capacity contribution[27] values for those resources. A LSE's qualifying capacity also accounts for contracts to buy or sell power.

We estimate each portfolio's forward showing compliance over our 20-year study period for each load scenario and historical weather year. We next calculate the likelihood that WRAP requirements are met as the percentage of weather year simulations in each month that display greater supply than the WRAP obligation. The results are summarized as the conditional probability across these likelihoods, to determine the chances that WRAP obligations are not met in any month during a given season and year. It is important to note that these results are hypothetical and may differ from actual loads and WRAP obligations if Tacoma Power were to participate. Figure 45 summarizes those results.

We find it more challenging to meet our forward showing requirement when loads are declining than when they are rising for portfolios that include BPA. This is a result of the mismatch between the WRAP's lagged load forecast approach and the forward-looking nature of the load forecast used to determine our BPA Block purchases. While our expected Block purchase is based on what we expect our load to be, the WRAP capacity requirement is based on historical loads. When historical loads are higher than future loads, the WRAP methodology can overestimate our capacity requirement. Our Block purchase, on the other hand, is sized to meet our actual need.

We generally find that there is a high likelihood that we would meet the WRAP winter forward-showing requirement with our current BPA Slice/Block product. Partially replacing our BPA Block with wind or solar reduces our likelihood of passing slightly. Switching to Block with Shaping Capacity could put us at higher risk of not meeting our WRAP forward-showing obligation in all of our scenarios. It is likely that this is a least in part due to the fact that, with BWSC, all of our BPA purchases are suffering from the mismatch between a lagged load for our WRAP requirement and a forward-looking load forecast for Block. In our hypothetical portfolios where we replace BPA with other resources in 2028, we find that the portfolio in which we complement wind and solar with SMRs fares better than the one in which we complement it with pumped storage because SMRs are expected to receive a much higher WRAP QCC than pumped storage.

[27] The QCC is a percentage of the nameplate value that is expected to count towards meeting regional capacity needs. Nameplate capacity is discounted by the QCC.

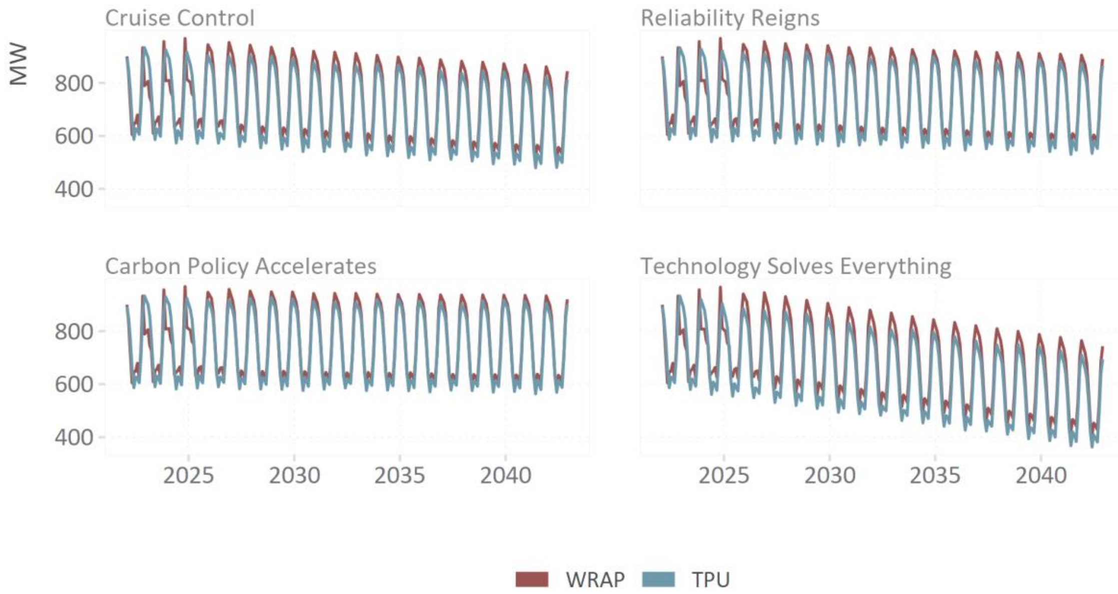

FIGURE 44. WRAP VS. 2022 IRP PEAK LOAD FORECASTS

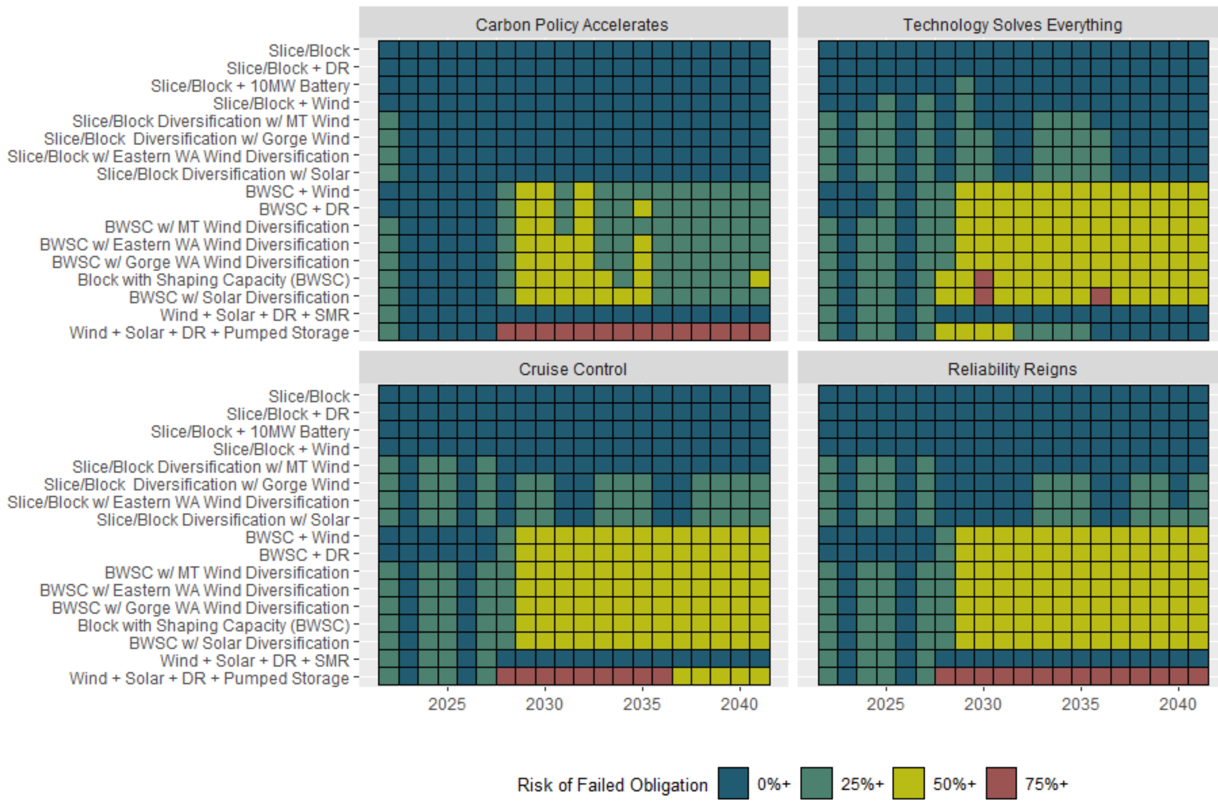

FIGURE 45. IRP PORTFOLIOS AND RISK OF FAILED WRAP COMPLIANCE

7.3 Cost and Financial Risk

We calculate expected costs individually for each simulation using a weighted average of our low, medium and high resource cost assumptions. We assign 25% weights to our low and high-cost assumptions and 50% weights to our medium-cost assumptions. We present average cost results both annually and summed up across the twenty-year study period. All values presented are discounted to the year 2022 using a 3% discount rate and are presented in $2021 dollars.

7.3.1 BPA Slice/Block vs. Block with Shaping Capacity

Figure 46 presents expected costs and high cost outcomes for both Slice/Block and Block with Shaping Capacity portfolios. Across all scenarios and runs, renewing with Block with Shaping Capacity (BWSC) is between $4.5 and $5 million higher in cost than renewing Slice/Block. While total portfolio costs vary across scenarios, the difference in cost between the two options is very similar. The BPA contract works in such a way that BPA customers are treated almost like "owners" of the federal system, with rights to its output. Under the Slice/Block contract, we would take output from the federal system in-kind and then market any surplus energy ourselves. Under the Block contract, BPA markets power on our behalf and credits us with the value of wholesale marketing activities, in the same way as we do by using wholesale revenues to keep retail rates lower. Whether BPA or Tacoma Power markets the power, the result ends up being about a wash in terms of cost, with the exception of the fact that we must pay the City of Tacoma's 7.5% Gross Earnings Tax (GET) on revenues when it markets the power under Slice. The key difference in costs between the two products are the additional capacity and risk-related charges (load shaping charges, demand charges and risk and balancing charges) associated with the Block with Shaping Capacity product. With the Slice/Block product, we take on most or all of the responsibility for managing the variability of our load itself. With Shapeable Block, BPA would take these responsibilities on instead and charge us for the costs of doing so. The major difference in cost across scenarios is that we incur a slightly higher charge for this service in our scenarios with higher loads.

Table 6 summarizes average costs among the worst 25%, 10% and 5% outcomes for each portfolio across all runs[28]. High-cost outcomes are also consistently $5 million higher on average for the portfolio in which we replace our Slice/Block contract with BWSC.

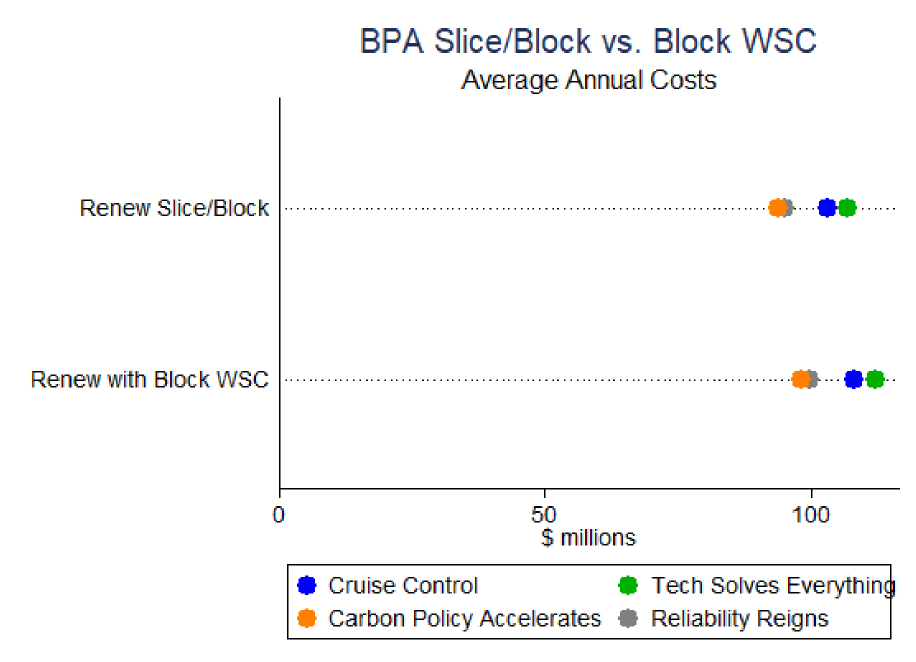

FIGURE 46. EXPECTED PORTFOLIO COSTS UNDER SLICE/BLOCK RENEWAL VS. SWITCHING TO BWSC

TABLE 6. COMPARISON OF PORTFOLIO RISK - AVG OF HIGH-COST OUTCOMES

Portfolio	Avg of High-Cost Outcomes		
	Highest 25%	*Highest 10%*	*Highest 5%*
Block with Shaping Capacity	152.9	161.2	166.0
Slice/Block	147.8	156.0	160.7

7.3.2 BPA RENEWAL AT CURRENT LEVELS AND ADDITION OF A RESOURCE

We next examine costs for the three resource additions that shore up the small resource adequacy risks we face when the grid is unreliable. Figure 47 presents expected annual incremental costs across our four scenarios of the future. Expected costs are very similar for our Cruise Control (Bases Case) scenario and are similar across all scenarios for the addition of 10MW of battery or demand response but vary considerably across scenarios for the wind

[28] High-cost outcomes are calculated separately for each calendar year and averaged across the 20-year period.

addition. The wind resource often generates energy in excess of what we need, and we sell that excess energy on the wholesale markets. Without accounting for revenues, we estimate the annualized cost of acquiring the 100MW wind resource to be between $7 million and $9 million including transmission and integration versus approximately $1.0 million and $1.3 million for the DR and battery resources, respectively. Once we take into account revenues from the excess generation, the net cost of the wind resources is sometimes higher and sometimes lower than the other two options. In scenarios when prices are high (Carbon Policy Accelerates and Reliability Reigns), revenues from the extra energy sales more than pay for the cost of the cost of the wind resource and actually reduce total portfolio costs. When wholesale prices are low, on the other hand, the wind addition costs more than double what the 10MW DR and battery storage options we model cost. The net cost of the wind addition is also much more variable than the other two resources even within a single future scenario. Figure 48 presents the range of costs of each resource addition across all simulations just within our Cruise Control case, when expected costs are roughly equivalent across our three potential resource additions. Table 7 summarizes average costs among the worst 25%, 10% and 5% outcomes for each portfolio across all runs[29]. High-cost outcomes are consistently just under $3 million more costly for the wind resource addition than for the other two resource additions.

This analysis points to adding the 10MW of demand response as the lowest-cost and least-risk alternative. Demand response also has several other advantages over the battery and wind resources for our needs. It keeps the investment we make local, it has less environmental impact than building, transporting and eventually recycling or disposing of wind generation or battery storage equipment and it provides more optionality. With a wind or battery resources, once we have built it, we cannot easily change course. With demand response, although we do incur some costs to set up new programs, we have a lot more ability to throttle it down if we later find we do not need it or do not need as much of it. On the other side of the coin, as we see loads start to grow from electrification, we will also be able to throttle it up if we need to we once have the infrastructure in place to run demand response programs.

[29] High-cost outcomes are calculated separately for each calendar year and averaged across the 20-year period.

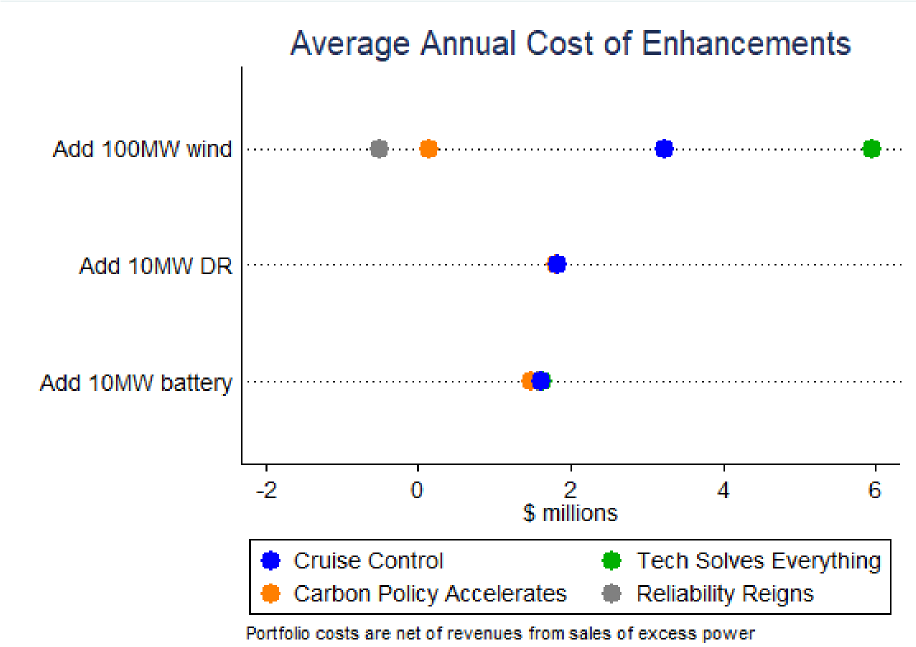

FIGURE 47. INCREMENTAL COST OF RESOURCE ADDITIONS

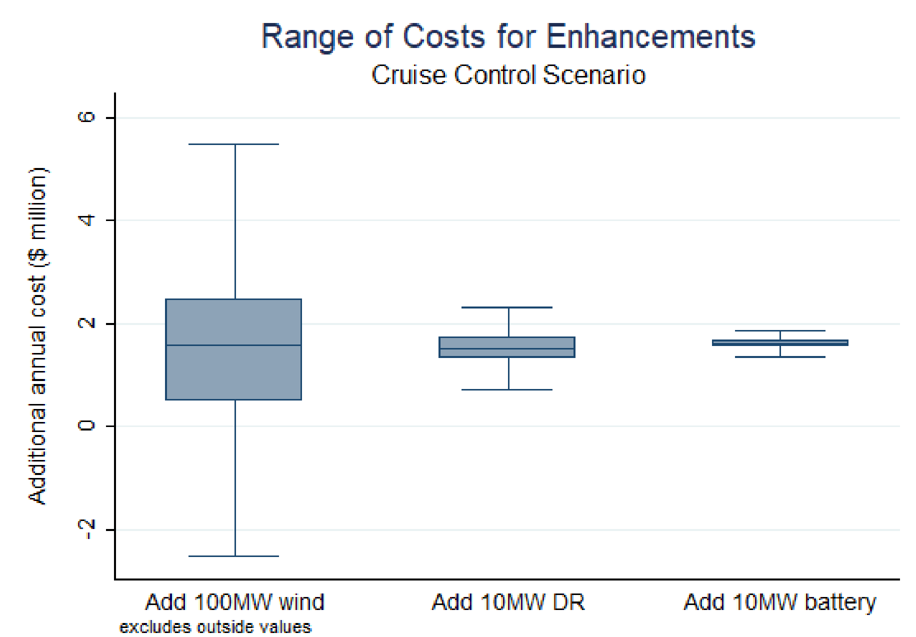

FIGURE 48. RANGE OF INCREMENTAL COSTS OF RESOURCE ADDITIONS

TABLE 7. COMPARISON OF PORTFOLIO RISK - AVG OF HIGH-COST OUTCOMES

	Avg of High-Cost Outcomes		
Portfolio	***Highest 25%***	***Highest 10%***	***Highest 5%***
Slice/Block	165.2	172.5	176.6
Add 100MW Wind	169.4	176.7	180.7
Add 10MW DR	166.6	174.0	178.0
Add 10MW Battery	166.5	173.9	178.0

7.3.3 BPA RENEWAL AT REDUCED LEVELS AND PARTIALLY REPLACED BY WIND OR SOLAR

This section examines the expected annual costs of replacing a portion of the Block component of our BPA Slice/Block product with wind or solar, which we refer to in the IRP as "diversification" portfolios. We compare costs under these diversification portfolios to costs under the Slice/Block product under our current net requirement calculation. The incremental different in annual costs is presented in Figure 49. With one exception, expected costs are higher for these diversification portfolios across the board, though results vary across scenarios and depending on which resource we assume replaces Block. The single exception is when we diversify with Gorge wind in our Carbon Policy Accelerates scenario. In this scenario only, diversifying with wind could be neutral for costs over the long run. The higher transmission costs associated with diversifying with Montana wind make it the most costly of the options modeled.

Figure 50 presents similar results but assumes BPA costs increase by 9% or 18% to reflect what BPA costs might look if the Lower Snake River dams (LSRD) were removed. While replacing part of our Block purchase with wind or solar would be less costly if the LSRDs were to be remove than it would be under our core cost assumptions, this diversification strategy would generally not be lower cost. The one exception is in our portfolios where we diversify with Gorge wind and find ourselves in a world with steeply escalating power prices (our Carbon Policy Accelerates). If we were to see 20 years of steeply escalating prices and the LSRDs were removed, it is possible that diversifying with Gorge wind could reduce overall portfolio costs. In all other cases, Note that our sensitivity analysis does not address whether or not we would need to acquire any additional resources if the LSRDs were removed and what that might cost.

Table 8 summarizes average costs among the worst 25%, 10% and 5% outcomes for each portfolio across all runs[30]. High-cost outcomes are roughly $5 million higher on average for the portfolio where we partially replace Block with Montana wind and $2.5 to $3 million more costly for the other diversification portfolios we model.

[30] High-cost outcomes are calculated separately for each calendar year and averaged across the 20-year period.

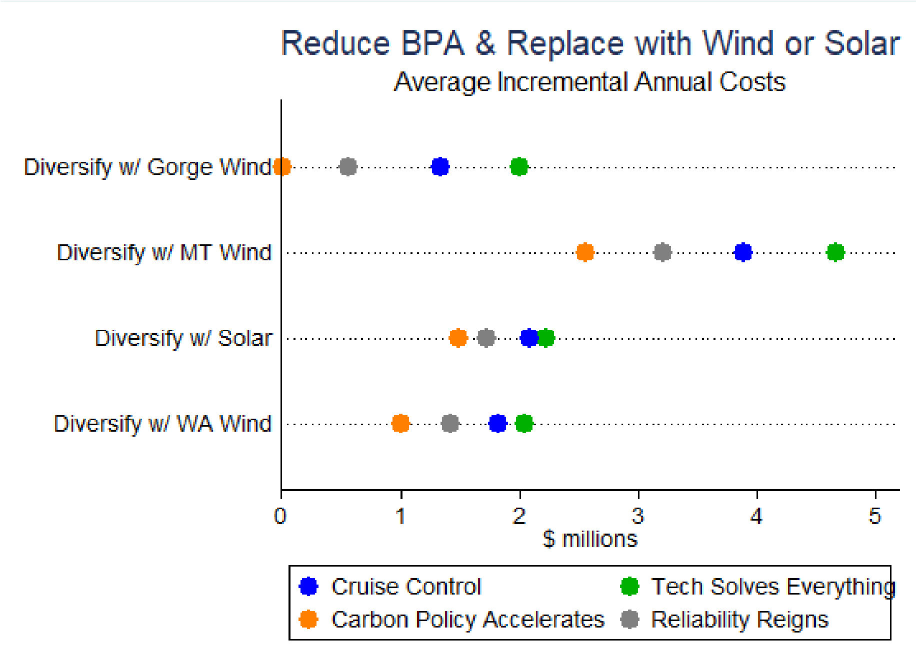

FIGURE 49. INCREMENTAL COST OF PARTIALLY REPLACING BLOCK

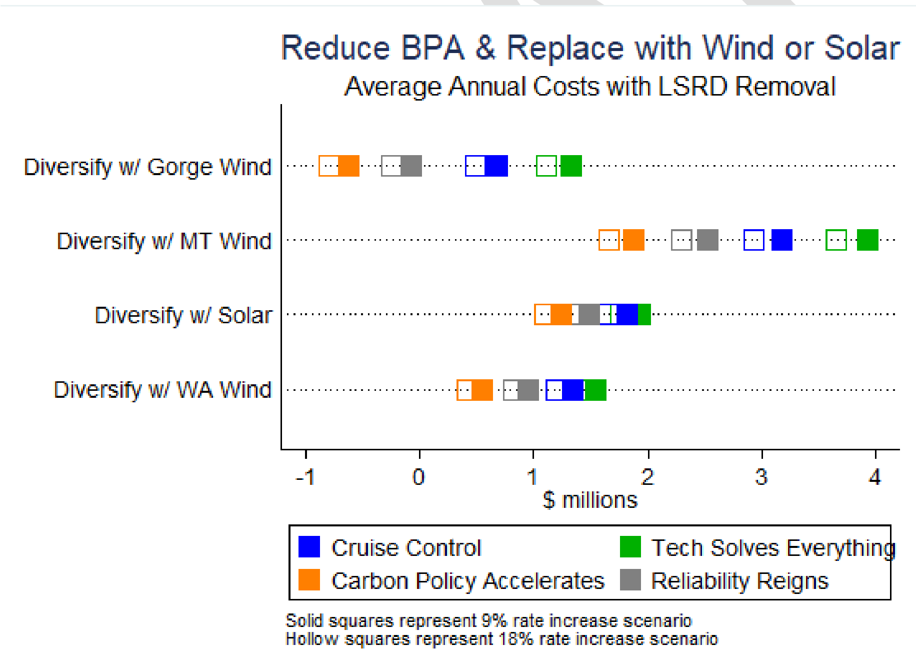

FIGURE 50. INCREMENTAL COST OF PARTIALLY REPLACING BLOCK WITH LSRD REMOVAL

TABLE 8. COMPARISON OF PORTFOLIO RISK - AVG OF HIGH-COST OUTCOMES

	Avg of High-Cost Outcomes		
Portfolio	***Highest 25%***	***Highest 10%***	***Highest 5%***
Slice/Block	147.8	156.0	160.7
Diversify w/ Gorge Wind	150.8	158.8	163.5
Diversify w/ MT Wind	153.3	161.4	166.0
Diversify w/ Solar	150.4	158.5	163.2
Diversify w/ Eastern WA Wind	150.8	158.9	163.5

7.3.4 Portfolios without BPA

Figure 51 compares average annual portfolio costs after 2028 for our two basic BPA portfolios (the Slice/Block portfolio and the Block with Shaping Capacity portfolio) versus the two hypothetical "No BPA" portfolios we modeled. Costs for both of these "No BPA" portfolios are considerably higher than our two BPA portfolios. The portfolio in which we model replacing BPA with wind, solar, demand response and small modular nuclear reactors are double to nearly triple the cost of renewing Slice/Block. While the portfolio in which we supplement renewables with pumped storage instead of nuclear reactors is less costly than the former, it is still between $33 million and $60 million (between 35% and 63%) more costly per year than renewing Slice/Block.

Table 9 summarizes average costs among the worst 25%, 10% and 5% outcomes for each portfolio across all runs[31]. Our financial risk metrics are approximately $85 to $87 million higher than Slice/Block in our hypothetical portfolio where we replace BPA with other renewables, DR and pumped storage and around $320 million higher when we instead replace it with other renewables, DR and small modular nuclear reactors.

[31] High-cost outcomes are calculated separately for each calendar year and averaged across the 20-year period.

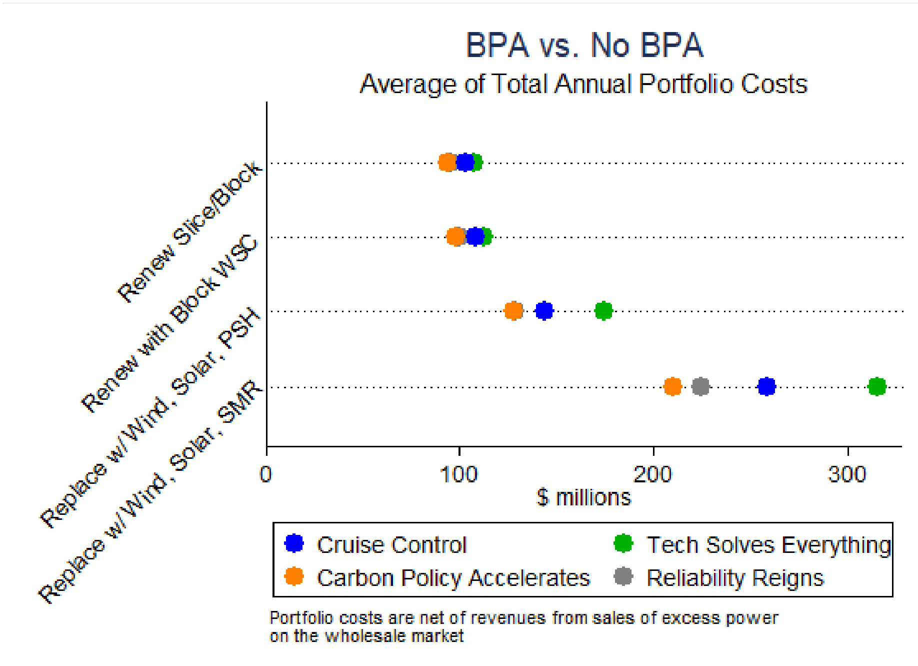

FIGURE 51. ANNUAL COST OF PARTIALLY REPLACING BLOCK WITH LSRD REMOVAL (POST-2028 PERIOD)

TABLE 9. COMPARISON OF PORTFOLIO RISK - AVG OF HIGH-COST OUTCOMES

	Avg of High-Cost Outcomes		
Portfolio	***Highest 25%***	***Highest 10%***	***Highest 5%***
Slice/Block	147.8	156.0	160.7
Wind + Solar + DR + PSH	235.2	243.1	246.6
Wind + Solar + DR + SMR	465.1	479.2	484.4

7.4 CARBON EMISSIONS

As explained in section 2.4.1, carbon emissions enter our either though unspecified wholesale power market purchases we make to balance supply and demand or through similar purchases made by BPA that then get transferred to us in our BPA purchase. We calculate carbon emissions for a select number of portfolios using the product of total annual purchases for each portfolio (MWh) from our model runs plus the share of BPA's portfolio that comes from unspecified purchases or renewable generation stripped of RECs[32], the average marginal emissions factors (metric tons/MWh) described in Section 3.3.3.

Figure 52 presents average unspecified market purchases across simulations. For a given scenario, the trajectory of purchases over time follows the general trajectory of our load in that scenario. The portfolio in which we switch to BWSC in 2028 has higher market purchases. This is likely because BWSC provides less total energy and more wholesale market purchases are required to balance our loads compared to the other portfolios. Figure 53 shows total emissions for each scenario and future year under our various simulations. The darker line shows the median value across each of the individual simulations, which are dimly plotted. Within a scenario, emissions are similar

[32] We assume a combined 6% share based on BPA's 2021 fuel mix report (https://www.bpa.gov/energy-and-services/power/hydropower-impact) and assume that value is fixed over the 20-year period.

across portfolios. Across the board, all of the portfolios have very low emissions relative to total generation. Figure 54 shows the average rate of emissions (total emissions per MWh of generation) in each portfolio across simulations and study years. The Slice/Block portfolios' average emissions rate is roughly between 0.002 and 0.006, depending on the scenario. Switching to Block with Shaping Capacity yields an average emissions rate that is only slightly higher. For context, the WECC-wide emissions rate in our models is around 0.4 MT/MWh on average in 2022 and gets as low as 0.15 MT/MWh in our Technology Solves Everything (Section 3.3.3).

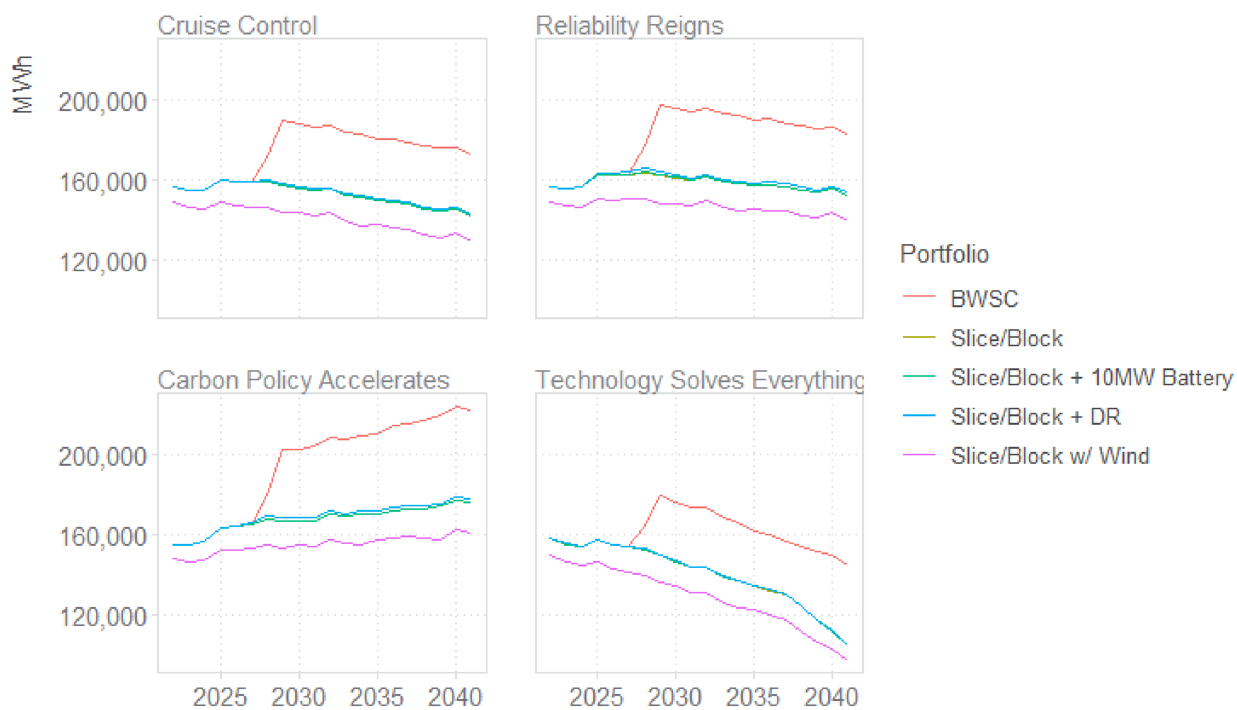

FIGURE 52. AVERAGE CARBON EMITTING ENERGY PURCHASES

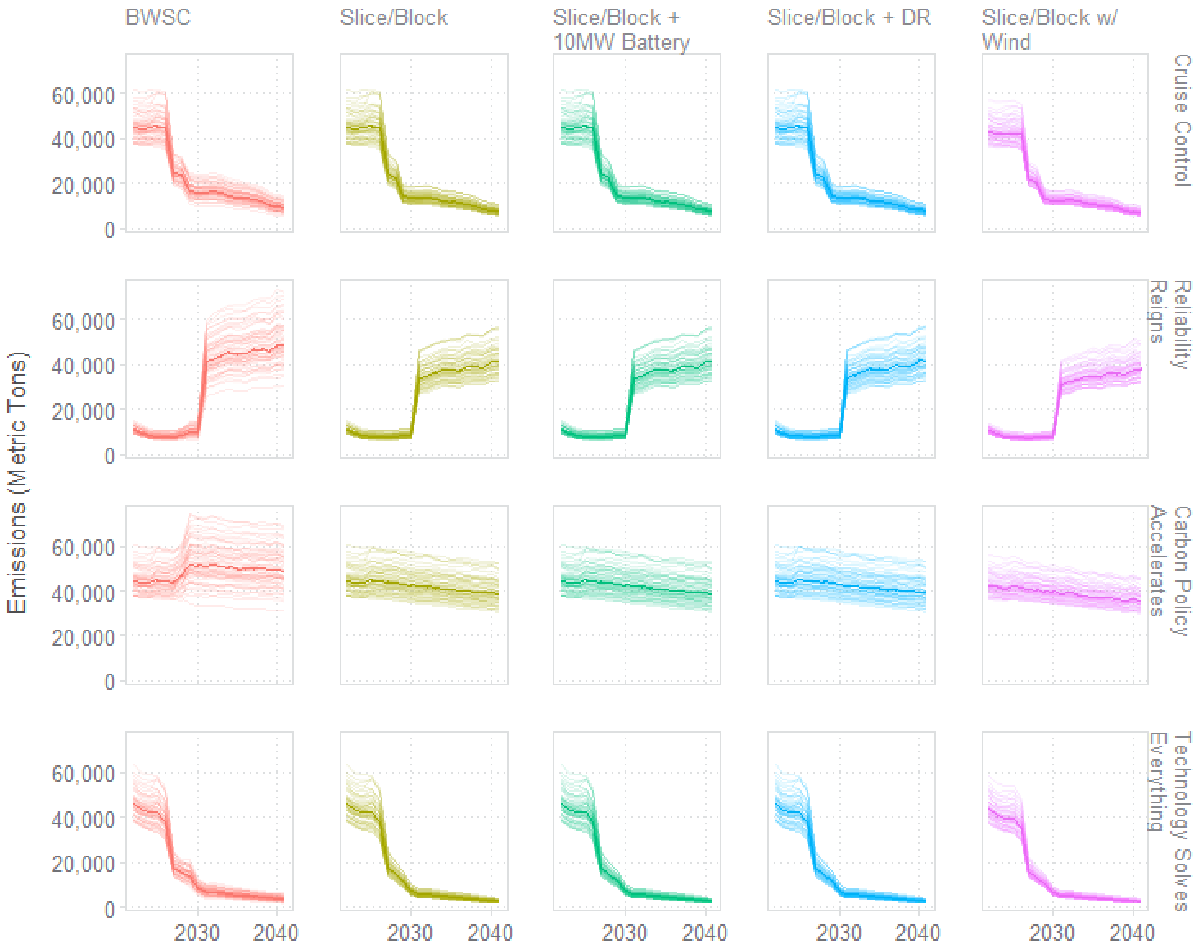

FIGURE 53. ESTIMATED CARBON EMISSIONS FROM MARKET PURCHASES FOR SELECT PORTFOLIOS

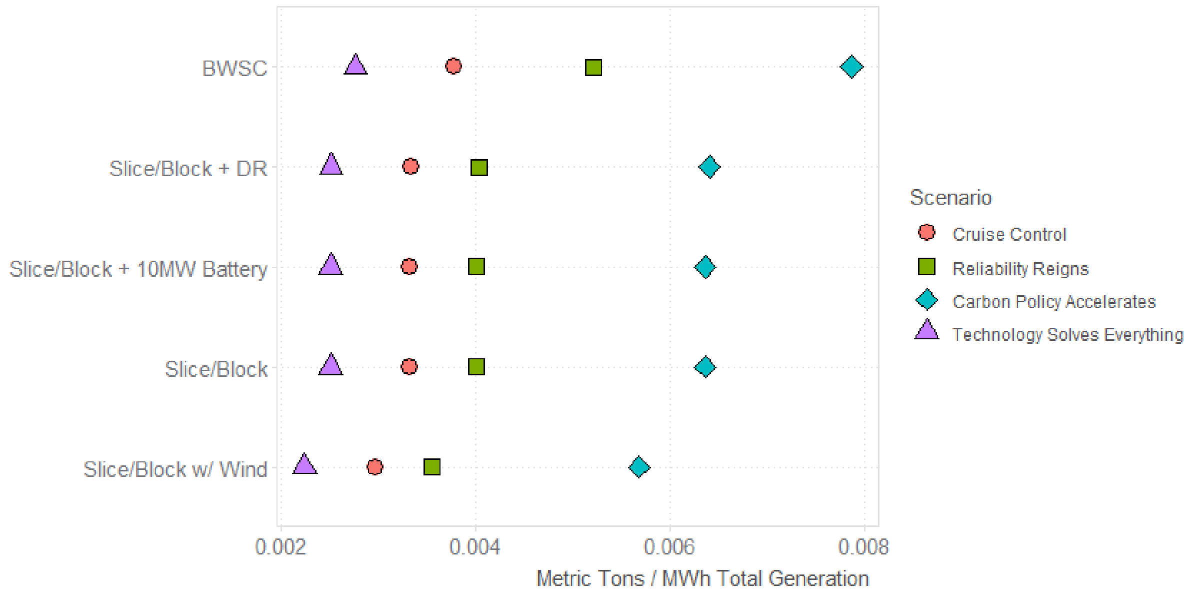

FIGURE 54. AVERAGE PORTFOLIO EMISSIONS RATE

8 SENSITIVITY ANALYSES

Not all uncertainties can be addressed even with the thousands of simulations run in the IRP. To address some of the key factors that were excluded from the core analysis in the preceding sections, we investigate how our resource adequacy position might change due to (1) climate change and (2) a large-scale conversion from natural gas and gasoline to using electricity. While helpful first steps, these sensitivity analyses primarily point to the need for additional work on our part to better understand the potential impacts of a rapidly changing world.

8.1 CLIMATE CHANGE

We currently climate change as a sensitivity because the process of fully incorporating projected climate change impacts into IRP models is far from simple. Our 2015 IRP took some first steps in considering climate change in our resource planning by conducting a study to understand qualitatively what the impacts might mean for resource adequacy[33] and our 2020 IRP took the next step and made a first attempt at including climate change projections directly into our system model. Our 2022 IRP repeats this exercise. We use the same streamflow and temperature projections from the 2018 Columbia River Climate Change (CRCC)[34] study as we used in our 2020 IRP. As with our 2020 IRP, we model three of the 172 projections produced for that study and select the same three sets of projections as the Northwest Power and Conservation Council (NWPCC) selected for their 2021 Power Plan. We refer to these three sets of projections by the Global Climate models used to produce them: CCSM4, CanESM2 and CNRM5.[35] The NWPCC selected these projections because they had high concentration of extreme outcomes for generation and temperatures. We plan to conduct additional work for our next IRP to (a) determine which climate projections to include in our modeling, (b) determine how climate change can be incorporated into our WECC model,

[33] A synopsis of the findings is available in the 2015 IRP at https://www.mytpu.org/wp-content/uploads/2015-final-IRP-1.pdf , and the full study report can be found on Tacoma Power's IRP website at https://www.mytpu.org/wp-content/uploads/2015TechnicalAppendix_ClimateChange.pdf

[34] https://www.hydro.washington.edu/CRCC/

[35] A more detailed description of the projections is available in our 2020 IRP.

and (c) refine how temperatures and inflows are translated into loads and generation, respectively, when projected values fall outside the range that our current models are tuned to consider.

8.1.1 LOAD AND GENERATION IMPACTS

We generally find that warmer temperatures reduce our load in the winter months and increase our load in summer months, but the changes are not dramatic enough to shift our peaks from winter to summer (Figure 55). The climate change models generally result in lower peak loads, but one of the three models (CNRM_CM5) projects more variability in temperatures, and we see a higher likelihood of elevated peak loads despite lower expected peaks (Figure 57). We also find that warmer temperatures are generally shifting the pattern of inflows at our dams, which changes our generation patterns (Figure 56). The shape and extent of the seasonal shift varies across models. All three models show results in much spring generation as runoff comes earlier and slightly lower fall generation. Two of the models (CCSM4 and CanESM2) project substantially higher generation in the winter and lower summer generation. This pattern reflects the narrative that we typically hear regarding the impacts of climate change on power generation in the Pacific Northwest and for our own hydro projects.[36] The two models differ in the extent of the shift, however, with CCSM4 exhibiting the most dramatic shift in winter generation. The third model (CNRM_CM5) projects a different pattern of similar or even slightly lower winter generation and higher summer generation.

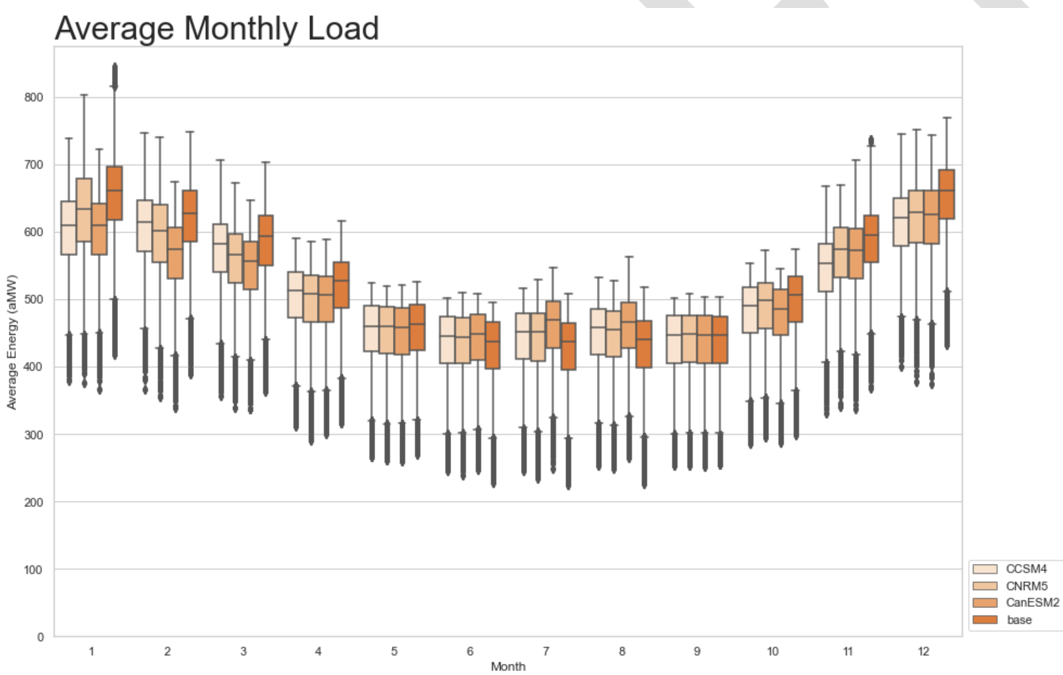

FIGURE 55: AVERAGE MONTHLY LOADS ACROSS CLIMATE MODELS

[36] See, for example, a study we commissioned in 2015 to analyze the impacts of climate change on our system: https://www.mytpu.org/wp-content/uploads/2015TechnicalAppendix_ClimateChange.pdf

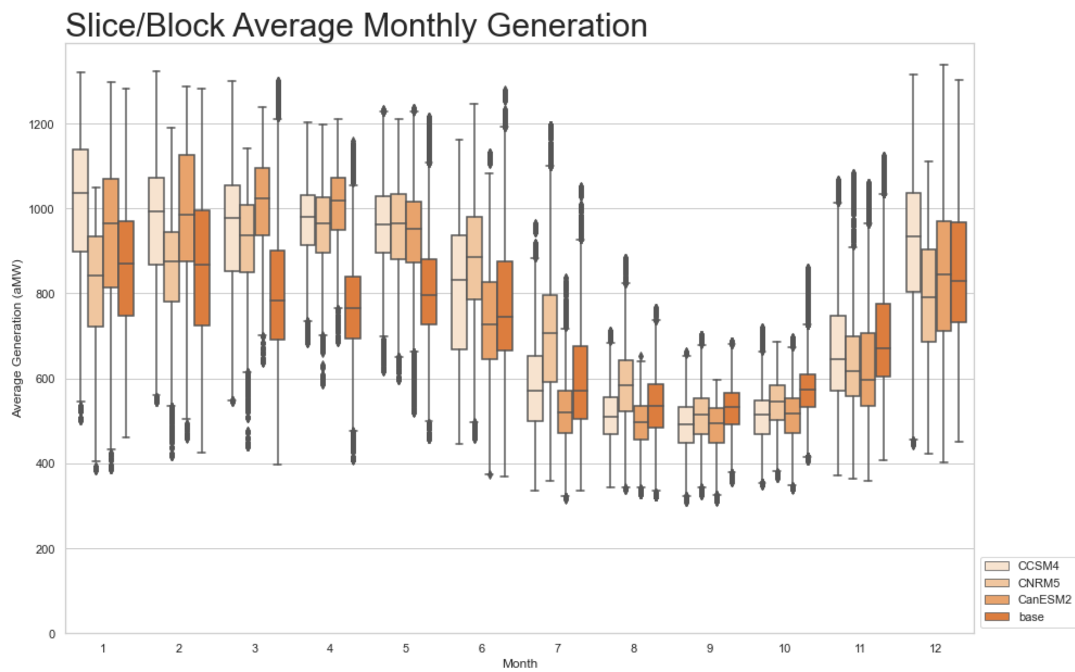

FIGURE 56: SLICE/BLOCK PORTFOLIO AVERAGE MONTHLY GENERATION ACROSS CLIMATE CHANGE MODELS

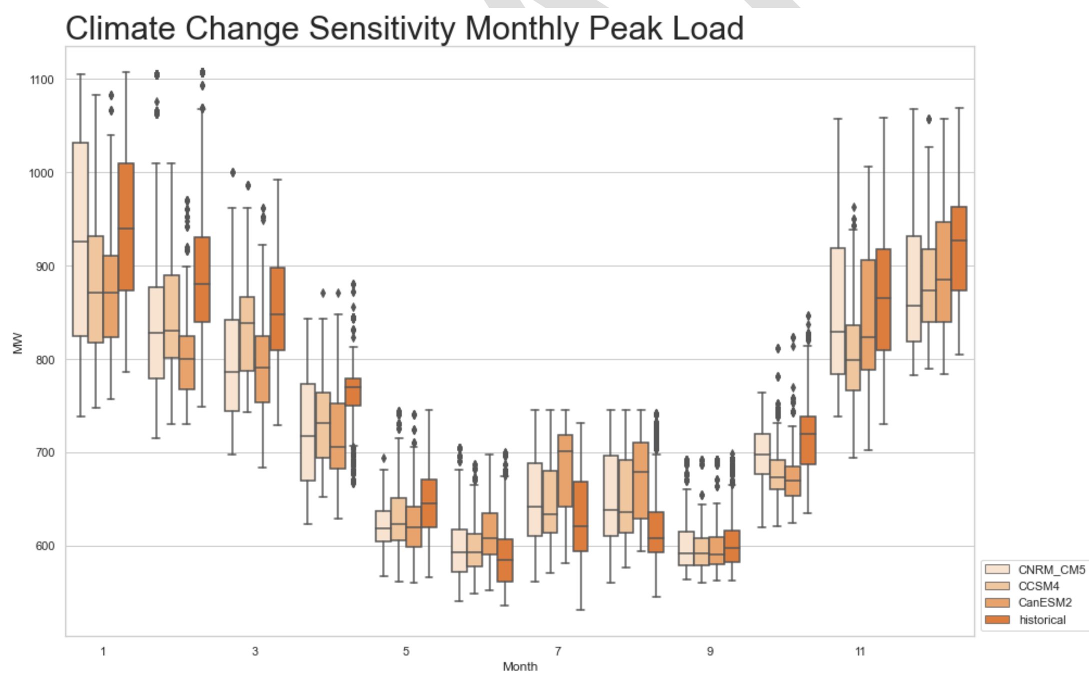

FIGURE 57. PEAK LOAD IMPACTS ACROSS CLIMATE CHANGE MODELS

8.1.2 Resource Adequacy Impacts

Figure 58 presents results for the Slice/Block portfolio without the addition of 10MW of demand response. We present results for the metric that was the most binding component of our standard (LOLD) for the scenario that causes us the most adequacy risk (Reliability Reigns). We find that the impacts of climate change could vary considerably based on which set of projections we use. In one set of projections (CCSM4), the general trend of winter warming causing lower winter loads and more winter precipitation (i.e. more precipitation coming down immediately as rain as opposed to be stored as snow) seems to dominate. This set of projections suggests that climate change will actually improve our resource adequacy position and eliminate the need to acquire any additional resource beyond energy conservation. In another set of projections (CNRM5), on the other hand, the occurrence of extreme cold weather events dominates the picture and suggests we could see severe resource adequacy challenges as a result of climate change. The third set of projections (CanESM2) produces resource adequacy results that are generally similar to what we see under historic weather conditions. Results for our other adequacy metrics and other scenarios are not presented below but are substantively similar. These mixed results indicate the need for additional work to select the best set of projections to represent the most realistic range of future potential outcomes under climate change—one of the items on our two-year action plan.

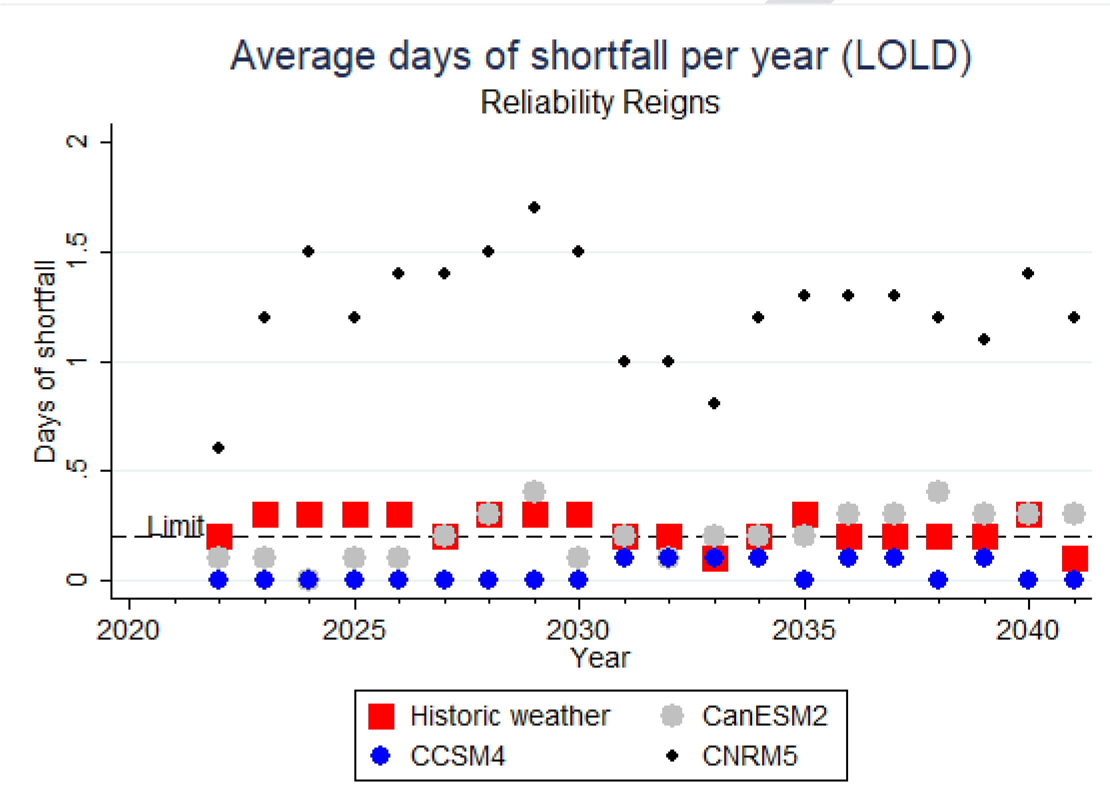

FIGURE 58: RESOURCE ADEQUACY IMPACTS OF CLIMATE CHANGE FOR SLICE/BLOCK PORTFOLIO

8.2 BUILDING AND VEHICLE ELECTRIFICATION

Our 2022 IRP considers a simplified sensitivity analysis of the potential load impacts of building and vehicle electrification. We estimate how many end uses could convert from natural gas or gasoline to electricity (the electrification potential) and estimate how much additional load we might see in a future world where many of these end uses have converted to electricity. We then take these load impacts and add then to our Cruise Control/Base Case load projections and run the adjusted loads through SAM to assess resource adequacy impacts. We consider four highly simplified cases that vary (a) adoption (i.e. do 100% or 50% of end uses convert to electric?) and (b) technology (i.e. is the natural gas-using technology replaced with a standard efficiency technology that puts higher demand on the system or a higher efficiency technology that puts lower demand on the system?[37]) to create four distinct cases:

- 100% penetration, higher demand
- 100% penetration, lower demand
- 50% penetration, higher demand
- 50% penetration, lower demand

Our sensitivity analysis considers building electrification in the residential and commercial sectors and electrification of light and medium-duty vehicles only and ignores the potential impacts of electrification at the port, in the industrial sector or of heavy-duty vehicles.

Our approach in this sensitivity analysis is admittedly simple and does not represent a forecast of the likely speed of electrification or the form it will take given city, state and federal policy or trends in customer adoption. We are currently in the early stages of a Tacoma Power-wide effort to refine our projections. We will use data from that study to inform our 2024 IRP.

8.2.1 RESIDENTIAL BUILDING ELECTRIFICATION

We contracted with Applied Energy Group (AEG) to estimate electrification potential in the residential sector. The results include estimates for single-family homes, 2-4 unit homes, low-rise and high-rise apartments, and manufactured homes. End uses considered include space heating, water heating, clothes drying, and light duty vehicle electrification. For the residential sector only, we consider two different technology cases—one based on the assumption that end uses are replaced with technologies that conform to current efficiency standards and one based in which end uses are replaced with even higher efficiency technologies. Table 10 describes the categories of end uses, potential of number of units that could convert, and assumptions on the split between standard efficiency and higher efficiency technologies in our two demand cases. Table 11 describes the specific technologies used to represent the standard and higher efficiency technology options for each end use category.

For residential heating and cooling only, we include weather sensitivity into our load impacts. We contracted with Larson Energy Research to run building simulations for the standard and higher efficiency heat pump technologies within a home based of the average characteristics of gas-heated homes in the Northwest[38]. Simulations were run for a small set of days representing a variety of weather conditions. We use the simulations to adjust our electric space heating load additions for a larger set of weather conditions.

TABLE 10. SUMMARY OF RESIDENTIAL BUILDING ELECTRIFICATION ASSUMPTIONS

Use	Technology	Units	Higher Demand Case	Lower Demand Case
Heating & Cooling	Code Heat Pump	36,663	100%	0%
Heating & Cooling	High Capacity Heat Pump		0%	100%
Water Heating	Greater than 55 Gal Electric resistance water heater	30,626	90%	0%

[37] Due to budget limitations, we were only able to estimate impacts of a higher efficiency option in the residential sector.

[38] Characteristics were developed based on a combination of Tacoma Power data, Pierce County Assessor data on home size and NEEA's regional Residential Building Stock Assessment (RBSA)

Water Heating	Greater than 55 Gal Heat Pump Water Heater		10%	100%
Water Heating	Less than 55 Gal Electric resistance water heater	9,320	90%	0%
Water Heating	Less than 55 Gal Heat Pump Water Heater		10%	100%
Appliances	Electric resistance clothes dryer	10,819	100%	0%
Appliances	Heat Pump Clothes Dryer		0%	100%

TABLE 11: TECHNOLOGY ASSUMPTIONS FOR RESIDENTIAL ELECTRIC END USES

Efficiency	End Use	Equipment	Source
Standard	Clothes Dryer	UCEF 3.3 - Heat Pump	AEG Residential Electrification Study 2021
Standard	Water Heater (<= 55 Gal)	NEEA Tier 3 Heat Pump (UEF 2.6)	AEG Residential Electrification Study 2021
Standard	Water Heater (> 55 Gal)	NEEA Tier 3 Heat Pump (UEF 2.9)	AEG Residential Electrification Study 2021
Standard	Space Heating	Code Compliant Heat Pump: 8.2 HSPF / 13 SEER, 3.4 ton	LER Space Heating Load Study, AEG Residential Electrification Study 2021
Standard	Space Cooling	Code Compliant Heat Pump: 8.2 HSPF / 13 SEER, 3.4 ton	LER Space Heating Load Study, AEG Residential Electrification Study 2021
Improved	Clothes Dryer	UCEF 3.3 - Heat Pump	AEG Residential Electrification Study 2021
Improved	Water Heater (<= 55 Gal)	NEEA Tier 3 No Resistance/Split-System CO2 Heat Pump	AEG Residential Electrification Study 2021
Improved	Water Heater (> 55 Gal)	NEEA Tier 3 No Resistance/Split-System CO2 Heat Pump	AEG Residential Electrification Study 2021
Improved	Space Heating	High Efficiency Heat Pump: 12 HSPF / 18 SEER, 3.9 ton	LER Space Heating Load Study, AEG Residential Electrification Study 2021
Improved	Space Cooling	High Efficiency Heat Pump: 12 HSPF / 18 SEER, 3.9 ton	LER Space Heating Load Study, AEG Residential Electrification Study 2021

8.2.2 COMMERCIAL ELECTRIFICATION

We contracted with TRC Consulting to estimate electrification potential in the commercial sector using a combination of Tacoma Power-specific and regional[39] data sources. Table 12 describes the commercial building

[39] https://neea.org/data/commercial-building-stock-assessments

types and the electric technology that is assumed to replace natural gas for a particular end use. For the commercial sector, we were not able to vary our assumption regarding the technology used to replace natural gas end uses and assumed that customers select the technology most likely to be cost-effective.

TABLE 12. TECHNOLOGY ASSUMPTIONS FOR COMMERCIAL ELECTRIC END USES

Efficiency	Business Type	End Use	Equipment	Source
Standard	Office	HVAC	Baseboard electric, PSZ-HP, Water source heat pumps fluid cooler with boiler	TRC Commercial Electrification Study 2021
Standard	Office	Water Heating	Central heat pump water heater	TRC Commercial Electrification Study 2021
Standard	Office	Kitchen	French fryer (4), Griddle, single sided (2), Half-size electric convection oven (1)	TRC Commercial Electrification Study 2021
Standard	Assembly	HVAC	Water source heat pump with ground source heat pump	TRC Commercial Electrification Study 2021
Standard	Assembly	Water Heating	Service Water Heating Fuel = Electricity	TRC Commercial Electrification Study 2021
Standard	Grocery	HVAC	PSZ-HP	TRC Commercial Electrification Study 2021
Standard	Grocery	Water Heating	SWH: Heat pump water heaters with storage tank - A.O. Smith CHP-120 - One 120-gallon tank	TRC Commercial Electrification Study 2021
Standard	Grocery	Kitchen	French fryer (4), Griddle, single sided (2), Half-size electric convection oven (1)	TRC Commercial Electrification Study 2021
Standard	Lodging	HVAC	PTHP	TRC Commercial Electrification Study 2021
Standard	Lodging	Water Heating	Heat pump water heater with storage	TRC Commercial Electrification Study 2021
Standard	Restaurant	HVAC	PSZ-HP	TRC Commercial Electrification Study 2021
Standard	Restaurant	Water Heating	SWH: Heat pump water heaters with storage tank - A.O. Smith CHP-120 - One 120-gallon tank	TRC Commercial Electrification Study 2021
Standard	Restaurant	Kitchen	French fryer (4), Griddle, single sided (2), Half-size electric convection oven (1)	TRC Commercial Electrification Study 2021
Standard	Retail	HVAC	PSZ-HP	TRC Commercial Electrification Study 2021
Standard	Retail	Water Heating	Point of use electric resistance	TRC Commercial Electrification Study 2021
Standard	School	HVAC	PTHP	TRC Commercial Electrification Study 2021
Standard	School	Water Heating	Heat pump water heater with storage	TRC Commercial Electrification Study 2021

Standard	Warehouse	HVAC	PSZ-HP	TRC Commercial Electrification Study 2021
Standard	Warehouse	Water Heating	Point of use electric resistance	TRC Commercial Electrification Study 2021
Standard	Mixed Commercial Other	HVAC	Weighted average of all prototypes	TRC Commercial Electrification Study 2021
Standard	Mixed Commercial Other	Water Heating	Weighted average of all prototypes	TRC Commercial Electrification Study 2021
Standard	Mixed Commercial Other	Kitchen	Weighted average of all prototypes	TRC Commercial Electrification Study 2021

8.2.3 Transportation Electrification

We rely on vehicle charging patterns developed in PNNL's EV Grid Capacity Phase 1 study and use their estimates for medium-duty vehicle electrification potential. For light duty vehicles, we assume that the potential for electrification is equal to one vehicle per residential premise. Table X describes our assumptions regarding the number of vehicles that could be electric and the weights we apply to various charging patterns from PNNL's study. As with commercial buildings, our transportation assumptions remain constant across our standard efficiency and improved efficiency cases.

TABLE 13.TRANSPORTATION ELECTRIFICATION ASSUMPTIONS

Use	Technology	Units	Standard Efficiency	Improved Efficiency
Light Duty Vehicle	Level 1 Home Charging	155,000	8%	8%
Light Duty Vehicle	Level 2 Home Charging		72%	72%
Light Duty Vehicle	Level 1 Workplace Charging		20%	20%
Light Duty Vehicle	Level 2 Workplace Charging		-	-
Medium Duty Vehicle	Level 2 Morning & Evening Charge Pattern	9,200	60%	60%
Medium Duty Vehicle	Level 2 Evening Only Charge Pattern		40%	40%

8.2.4 Load Impacts

Figure 59 presents the average incremental load associated with each of our electrification cases relative to our base 2041 load forecast, and Figure 60 presents incremental load disaggregated by sector. On average, between 50 and 230 aMW of load per month is added, roughly a 15% to 40% increase compared to our forecast load in 2041. Winter months display the greatest amount of added energy and variability. Transportation contributes most to total added load, while residential and commercial loads add seasonal variability due to cooling and heating end uses.

Demand impacts vary by weather simulation and scenario but we observe impacts between 170MW to 410MW or greater the top percentiles of load hours (Figure 61). The estimated electrification loads tends to add to our evening peak demand across all seasons (Figure 62). In our lower demand case, conversion to higher efficiency space heating technologies mitigates a secondary morning peak in winter months.

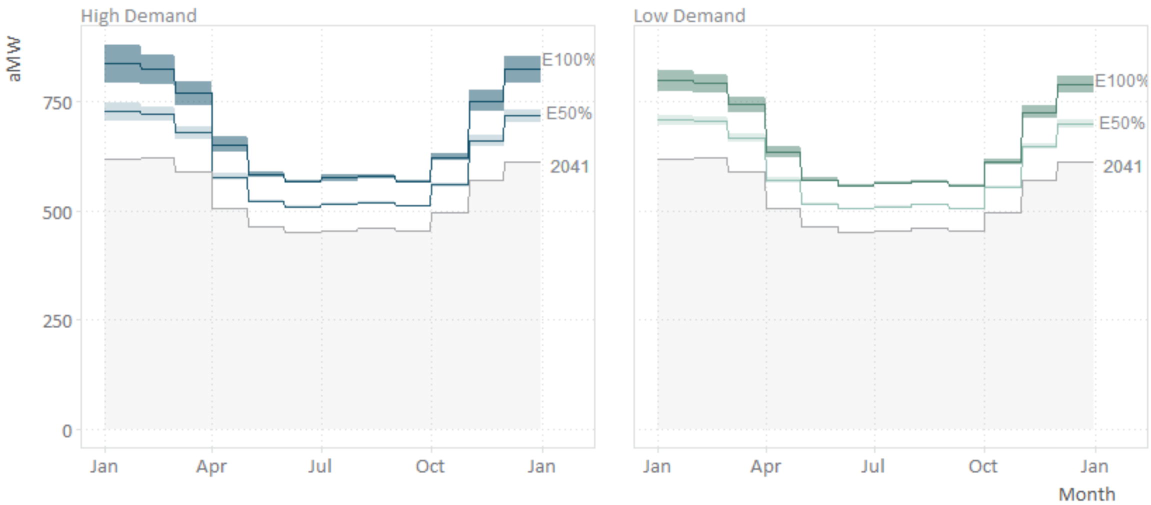

FIGURE 59. INCREMENTAL LOAD IMPACTS RELATIVE TO FORECAST 2041 LOAD

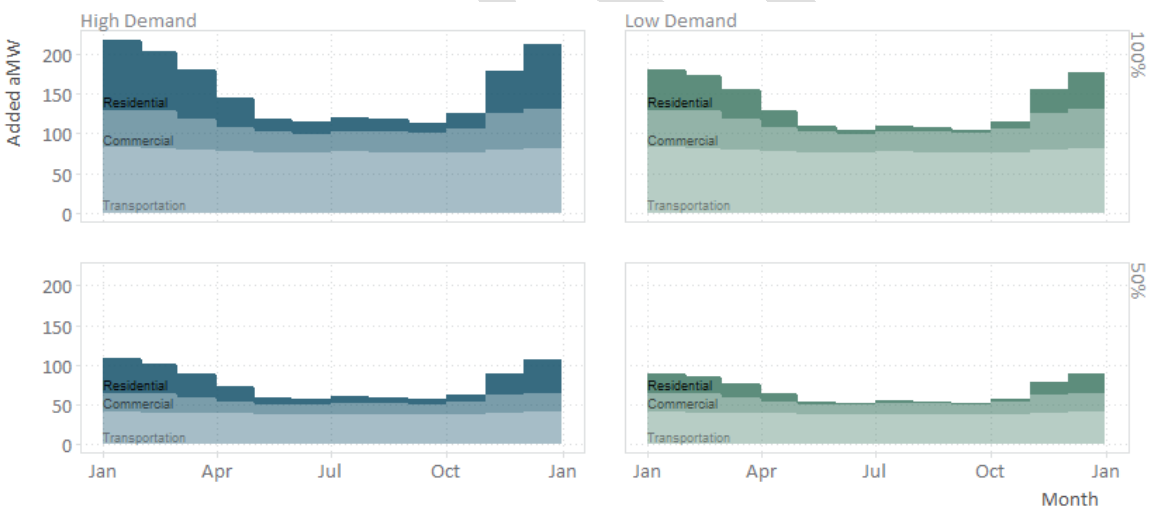

FIGURE 60. INCREMENTAL LOAD DISGGREGATED BY SECTOR

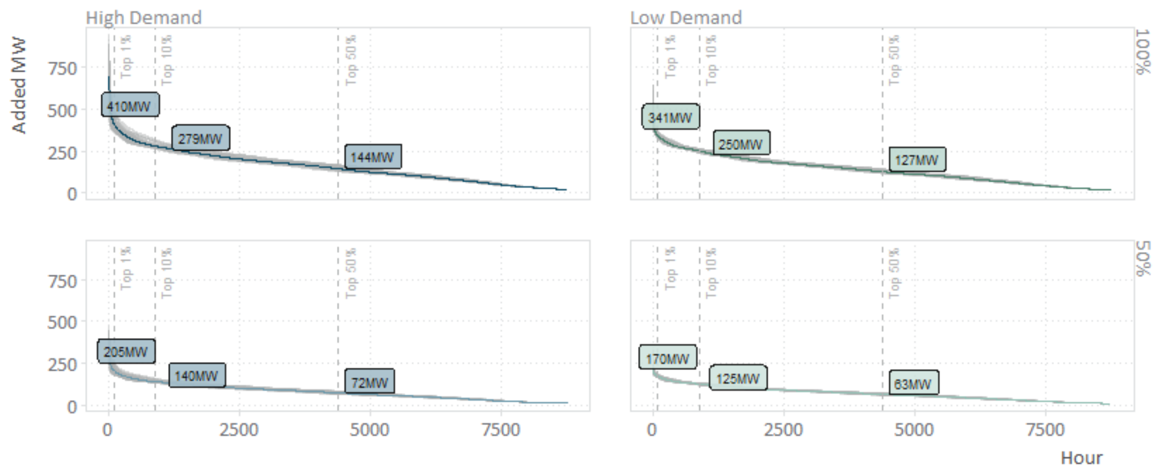

FIGURE 61. DISTRIBUTION OF DEMAND IMPACTS

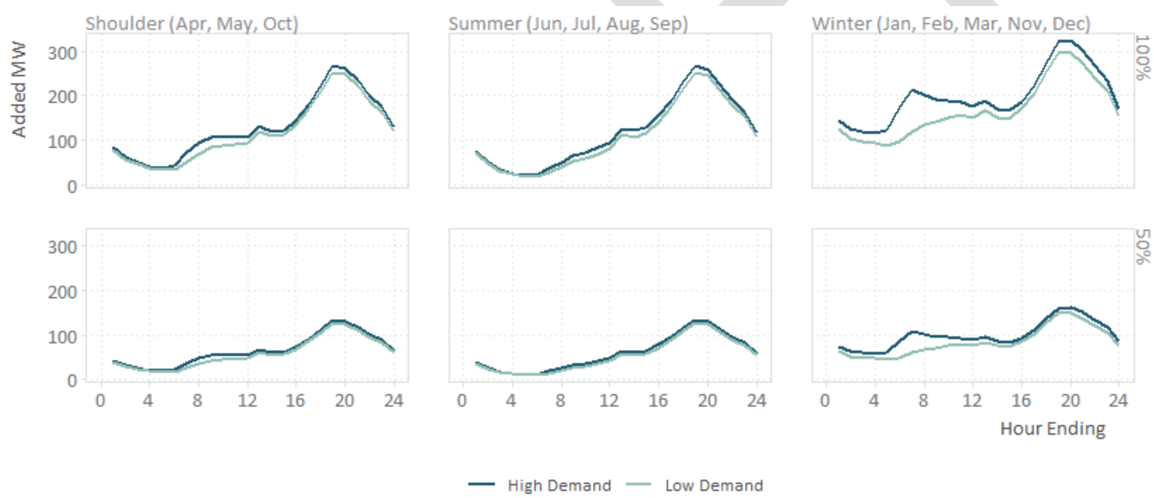

FIGURE 62. SEASONAL IMPACTS ON DEMAND

8.2.5 RESOURCE ADEQUACY IMPACTS

Figure 63 through Figure 65 present results for our three resource adequacy metrics. In all cases, the level of additional demand we would see in our simplified electrification cases would be more than our current portfolio could handle. Even in our lowest impact case (50% penetration with high-efficiency technologies installed in residential homes), our duration, magnitude and frequency metrics would be 28, 75 and 65 times higher than our maximum threshold, respectively. It will likely take a combination of demand-side resources like energy efficiency and demand response as well as supply-side resources to meet future power needs as electrification accelerates.

Ensuring that natural gas end uses in the residential sector are replaced with the most efficient technologies available today could help. The lighter shaded bars in Figure 63 through Figure 65 present our adequacy metrics under our "lower demand" scenario, in which residential natural gas end uses are replaced with the most efficient products available today rather than standard efficient products. Using these more efficient options cuts our shortfall metrics down by 40% to 60% in our lower (50%) penetration case and 20% to 50% in our 100% penetration case. However, that alone would not be sufficient to alleviate the need for more power resources. We also model out how demand response might help improve adequacy and find that it could also contribute to improving our adequacy metrics by another 30% to 40%.[40] A recent study conducted for the Department of Commerce also suggests that a combination of aggressive demand-side mitigation strategies (including converting to hybrid heat pumps that use natural gas as the backup source of heat and further improving the efficiency of the existing building stock) has the potential to mitigate most of the load impacts of electrification for Tacoma Power, at least for a case similar to our 50% penetration case. What the Department of Commerce study does not analyze is the relative costs of various mitigations strategies. Nor does it address the potential role of demand response programs and supply-side resource alternatives or how those compare.

While we do not assess the cost-effectiveness of various mitigation strategies in this IRP either, we do explore what it might take to restore resource adequacy using supply-side resources under these simplified electrification scenarios. To understand the magnitude of the resource gap we would be facing in this future scenario, we consider several potential resource additions and evaluate whether they are sufficient to bring our adequacy metrics down far enough to meet our RA standard. For this exercise, we consider Montana wind, small modular nuclear reactors and pumped storage as the supply-side options. These resources are only representative of the types of resources we might be able to use in the future and not necessarily the exact technologies that we would select to meet this new demand. Figure 68 presents results four our three resource adequacy metrics in our lowest impact case.[41] In our lower impact case, it would take approximately 250MW of an always-on resource like nuclear to meet our resource adequacy standard. When combined with the demand response we model, half of that quantity succeeds in meeting the thresholds for our duration and magnitude metrics and nears the threshold for our frequency metric. While even 1,000 MW of a high-quality wind resource like Montana wind is not even close to sufficient to meet our adequacy needs, half that quantity in combination with 100MW of a long-duration storage resource like pumped storage succeeds in meeting the threshold for our duration metrics and nears the thresholds for our magnitude and frequency metrics.

[40] Results are for the lower-demand, 50% penetration case.

[41] We conduct a similar analysis for our highest impact electrification cases and find that none of the resource additions modeled would bring us close to meeting our resource adequacy standard.

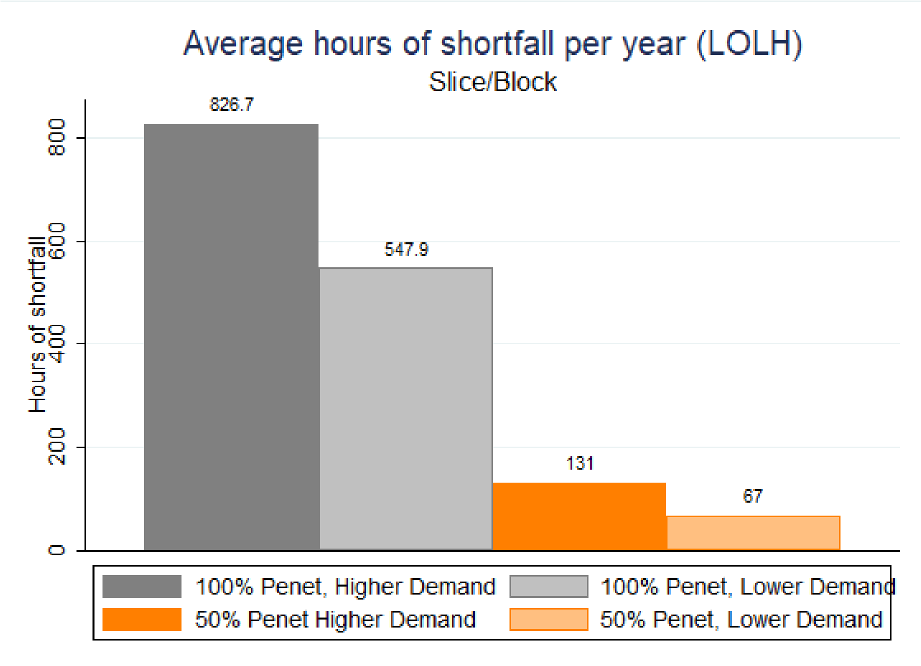

FIGURE 63: SHORTFALL DURATION (LOLH) METRICS FOR SIMPLIFIED ELECTRIFICATION CASES

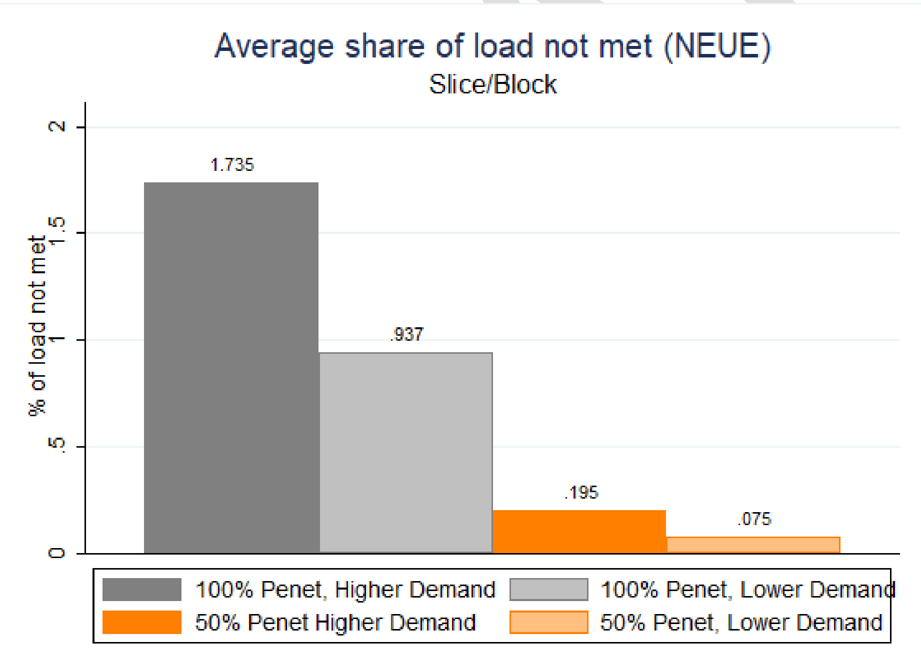

FIGURE 64: SHORTFALL MAGNITUDE (NEUE) METRICS FOR SIMPLIFIED ELECTRIFICATION CASES

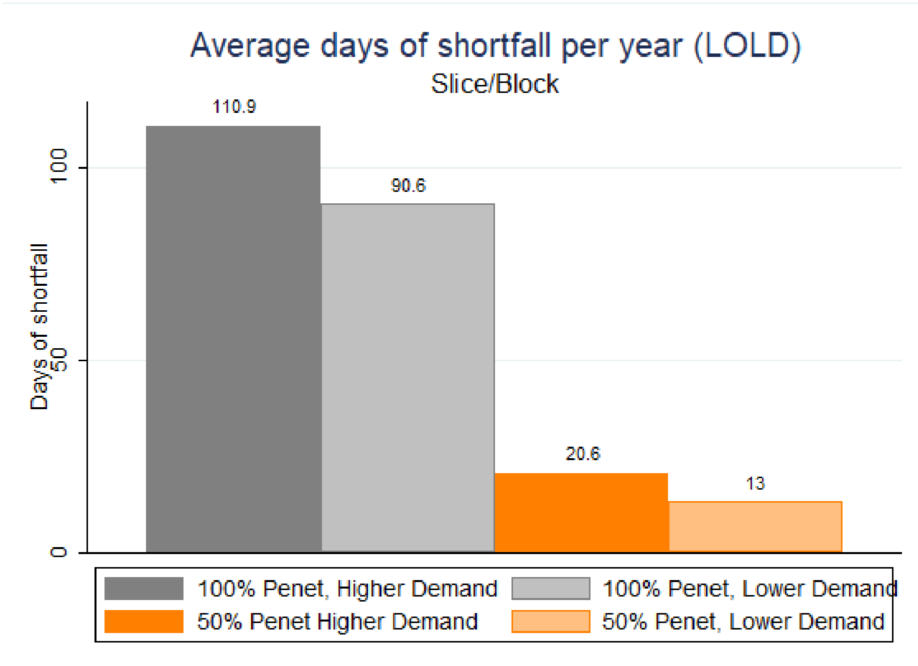

FIGURE 65: SHORTFALL FREQUENCY (LOLD) METRICS FOR SIMPLIFIED ELECTRIFICATION CASES

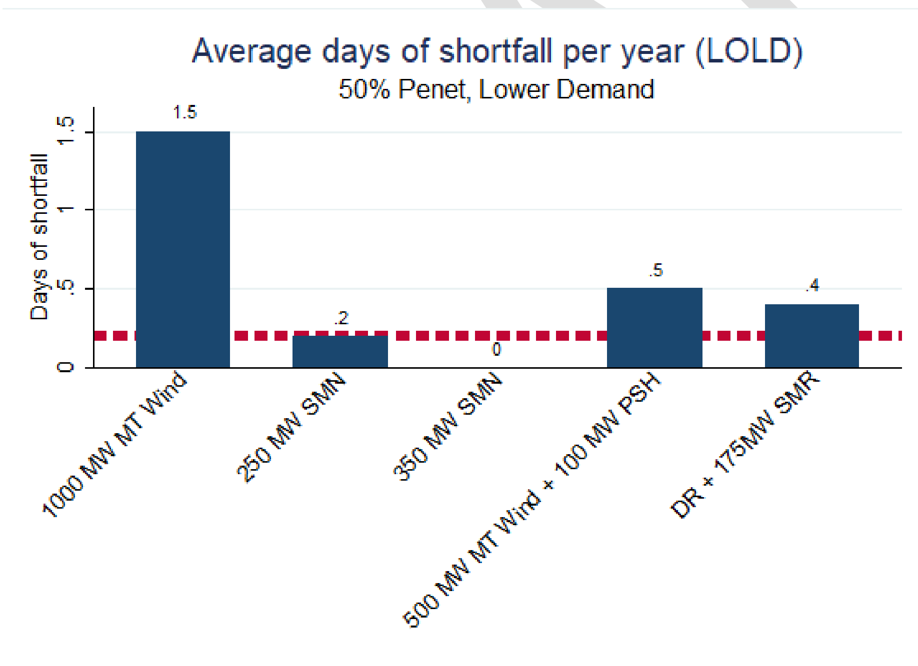

FIGURE 66: FREQUENCY RA METRIC FOR HYPOTHETICAL RESOURCE ADDITIONS

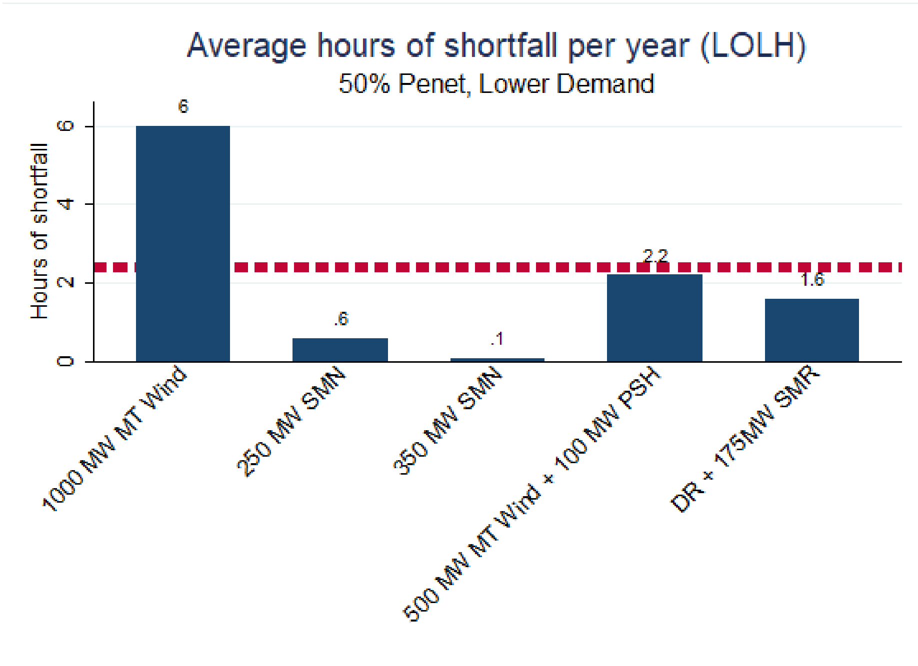

FIGURE 67. DURATION RA METRIC FOR HYPOTHETICAL RESOURCE ADDITIONS

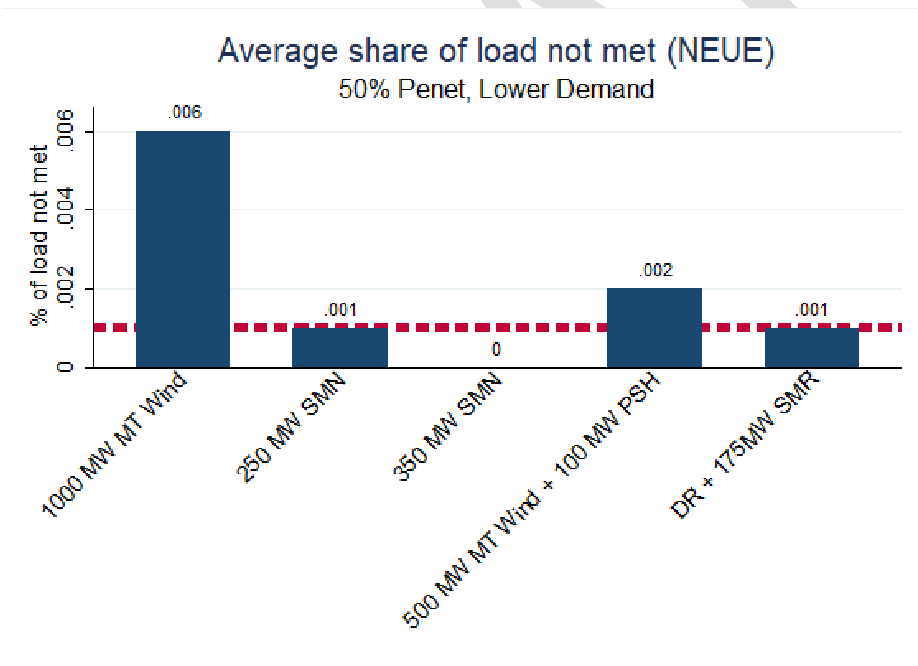

FIGURE 68. MAGNITUDE RA METRIC FOR HYPOTHETICAL RESOURCE ADDITIONS

9 PREFERRED RESOURCE STRATEGY

Figure 69 provides a summary of our resource strategy. We continue to find that renewing our BPA contract with the same Slice/Block product as we purchase today is likely to be our lowest-cost option to maintain resource adequacy under a variety of different future outcomes. We also find that partially replacing the Block portion of our

BPA contract with wind or solar would not improve our resource adequacy position and would add slightly to our costs in all states of the world we model. These findings are predicated upon the assumption that BPA's post-2028 contract and product offerings look similar to what they are today. We expect to have better information regarding potential future offerings in time for our 2024 IRP.

While renewing our BPA contract with the same Slice/Block product as we have today leaves us resource adequate in most future worlds, we do find that our system can be stressed when low water conditions and high loads combine. In the context of a future where insufficient capacity is built across the Western grid and we have almost no ability to rely on wholesale market purchases as a backstop, we fail the frequency component of our resource adequacy standard. Our preferred strategy to shore up this relatively small adequacy risk is to add 10MW of demand response to our portfolio. We find that DR is likely to be our lowest-cost and least risk option and puts us in the best position to be able to change course and decrease our DR engagement if we no longer need it. At the same time, acquiring a small amount of DR now will put us in a better lay the groundwork for us to eventually be able to acquire additional DR more rapidly should the need arise (for example, if vehicle and building electrification were to accelerate more quickly than expected).

Finally, there is an effort under way to create the WRAP. We may find that the success of this program and our potential participation in it reduces the likelihood of our Reliability (wanes then) Reigns scenario in which the grid is unreliable and mitigate or even eliminates any immediate need for a resource. We have been very involved in the development of the WRAP and plan to make a decision on whether or not to join by the end of 2022.

BPA

- Renew BPA contract with the same Slice/Block product as we purchase today if product offerings remain similar to current products

Energy Conservation

- Acquire all economic achievable conservation identified in CPA

Other Resources

- Continue to develop capability to acquire DR, with goal of acquiring 10MW of DR

Western Grid Reliability

- Make final decision on joining Western Resource Adequacy Program (WRAP) and continue involvement in the meantime

FIGURE 69. RESOURCE STRATEGY SUMMARY

9.1 Marginal supply-side resource

It is often necessary for us to value the capacity contribution of resource opportunities outside the context of the IRP (for example, when we value the capacity contribution of energy conservation in our Conservation Potential Assessment). Our preferred approach to do so would be to base our assumptions, but the absence of a transparent market for capacity makes estimating a market value difficult at best. The 2022 IRP identifies a marginal supply-side resource that can be used to value the capacity contribution of resources like energy conservation in the event that insufficient market data are available. While our preferred resource strategy is to acquire demand response, our IRP analysis suggests that our lowest-cost and least risk supply-side alternative would be **battery storage**.

9.2 I-937 Compliance

In 2020, our renewable portfolio standard under I-937 increased to 15%. Historically, our strategy has been to procure both short-term and long-term RECs to help meet our compliance goal. We also claim incremental hydro RECs from our hydro upgrades. While incremental hydro RECs must be used in the year they are generated, other RECs can be banked. This allows us to manage uncertainty and hedge risk. Figure 70 shows the quantity of RECs in MWh that we have purchased to date or are in the process of purchasing, as well as the year in which we have retired or plan to retire them by vintage (incremental hydro, retirement of banked REC or retirement of a REC in the year it was purchased). Figure 71 presents the same information by renewable type through 2026. Based on the REC purchases we have made to date or are in the process of completing, we expect to be fully compliant through 2026 and have acquired most of the RECs we need to comply in 2027. We plan to continue to seek additional REC purchase agreements in order to ensure we comply through 2029. Beginning in 2030, if a utility meets 100 percent of their load[42] with renewable resources, non-emitting resources or I-937 RECs for CETA, they are considered in compliance with both CETA and I-937. As a result, we will likely no longer need to procure additional I-937 RECs and will instead comply by using renewable properties of our hydropower, which is surplus in most years.

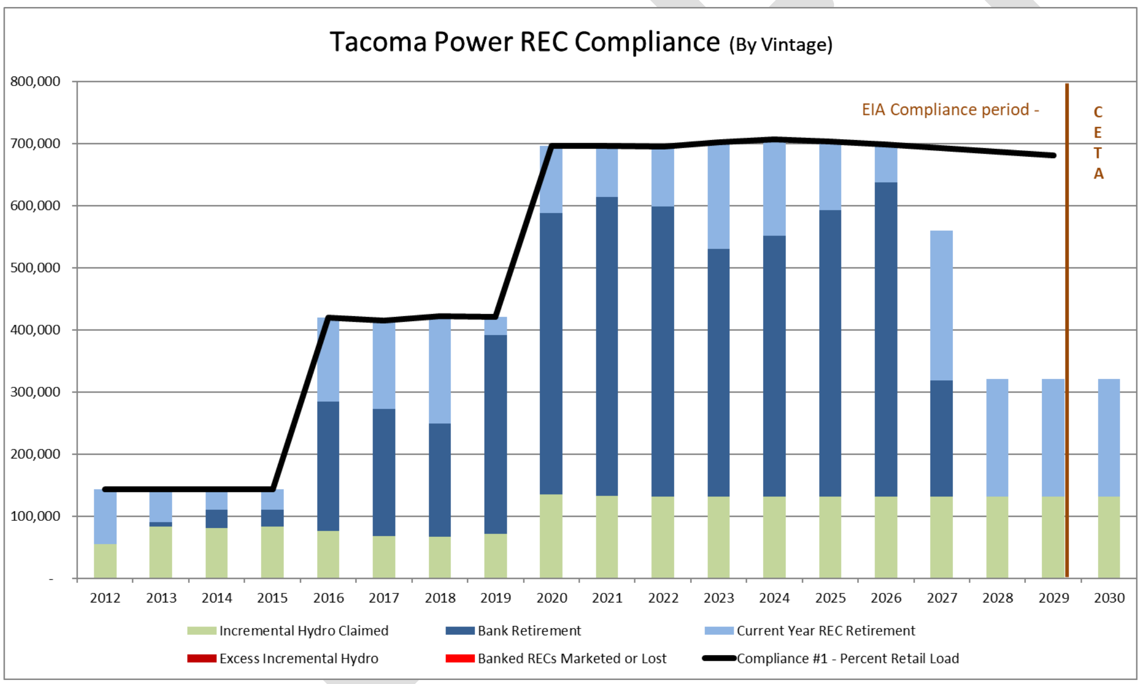

FIGURE 70. I-937 COMPLIANCE BY REC VINTAGE

[42] Note that our expected ability to meet CETA's 100% compliance requirement is different than our

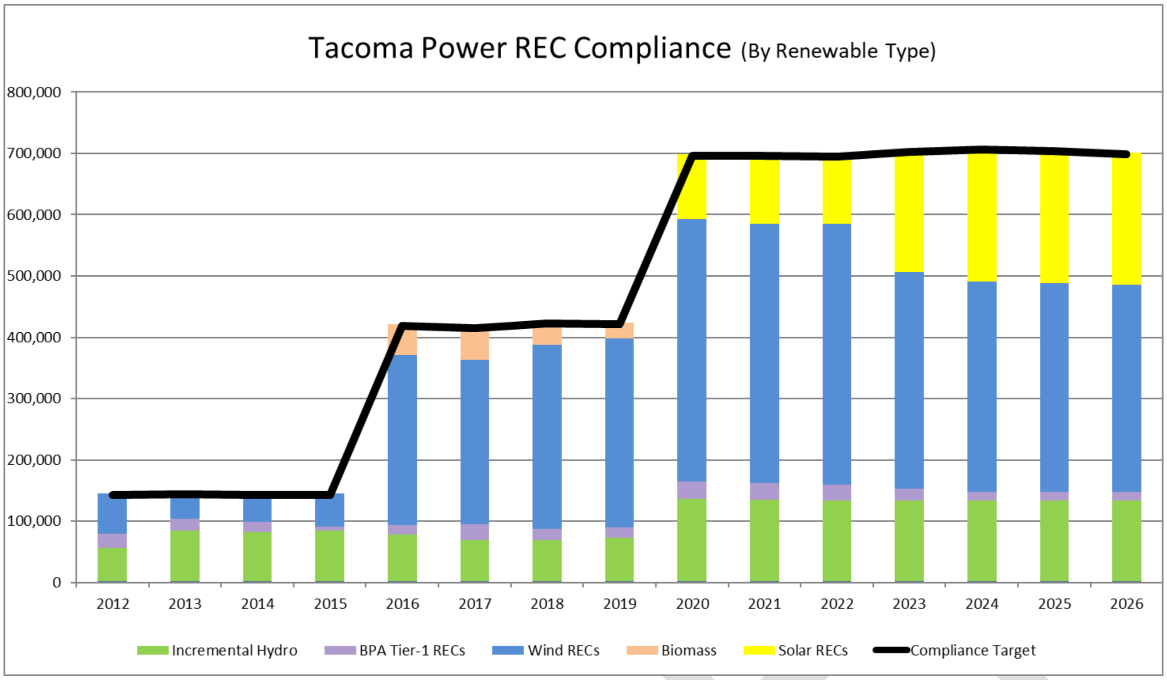

FIGURE 71. I-937 REC RETIREMENT BY RENEWABLE TYPE

10 IRP ACTION PLAN

Table 14 presents our action plan for the next two years, four and ten years. Our 2022-2041 Conservation Potential Assessment (CPA) identifies 226,174 MWh (25.8 aMW) of economic **energy conservation** achievable by 2031. We plan to acquire 53,114 MWh (around 6 aMW) of that potential over the 2022-2023 biennium. We will update our CPA for the 2024-2043 period and plan to continue to acquire all economic achievable energy conservation.

Our decision regarding whether and how to renew our **BPA contract** at the end of September 2028 is likely the most significant resource decision we face over the next ten years. Our 2022 IRP continues to identify renewal of our contract with the same Slice/Block product as we purchase today as our preferred strategy, but we will continue to participate actively in post-2028 contract discussions with BPA and will continue to evaluate our options as we learn more about what BPA is likely to offer in the next contract period. We expect to have sufficient information to have a near-final decision regarding contract renewal but expect to analyze this question again in both our 2024 and our 2026 IRPs.

Our preferred resource strategy includes the need for a small amount of **other resources** to shore up the risk of shortfalls that are small but too frequent in a world where we have very limited ability to rely on wholesale power markets as a backstop. Our IRP identifies 10MW of demand response as our preferred resource to meet this need. Over the next two years, we plan to continue to pursue opportunities for demand response through pilot programs with residential and/or commercial customers and through discussions with industrial customers on constructs that could be mutually beneficial. As part of our effort to explore opportunities for demand response, we will update our demand response potential assessment and will update our assessment regularly. By 2025, we plan to acquire the 10MW of DR identified in this IRP. In the meantime, we will also explore potential contract options to ensure we maintain resource adequacy in case we find we are not able to acquire all 10MW of DR.

Finally, we plan to conduct three key **analyses** that will affect our assessment of our future resource needs. The first is an analysis to inform a final decision regarding participation in the WRAP. The success of WRAP and our participation in the program should ensure that the Northwest grid remains reliable and may alleviate the immediate resource need identified in this IRP. In the longer-run, climate change and load growth from building and vehicle electrification will both impact our future resource adequacy position. We plan to conduct additional work over the next two years to improve the data we use in the IRP to model them.

TABLE 14: 2-YEAR, 4-YEAR AND 10-YEAR ACTION PLAN

	2-year action plan	4-year action plan	10-year action plan
Conservation	Acquire 53,114 MWh of energy conservation	Acquire all achievable economic conservation identified in CPA	Acquire all achievable economic conservation identified in CPA
BPA	Continue active participation in BPA post-2028 contract discussions	Near-final BPA decision	Renew or replace BPA contract with other low or no-carbon resource
Other Resources	Pursue additional opportunities for DR Update DR potential assessment Explore short-term contracts to shore up potential resource adequacy risks	Acquire 10MW of DR	Acquire additional DR if additional need is identified in IRP
Other Analyses	Final decision on joining WRAP Electrification Futures study Enhance climate change modeling		

10.1.1 Ten-Year Clean Energy Action Plan

The Clean Energy Transformation Act (CETA) requires utilities to develop a ten-year clean energy action plan (CEAP) for implementing CETA "at the lowest reasonable cost, and at an acceptable resource adequacy standard that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan." Our 10-year CEAP follows directly from the findings and recommendations in this IRP:

1. Acquire 226,174 MWh (25.8 aMW) of energy conservation by 2031. This is the ten-year economic achievable conservation identified in our 2022-2041 Conservation Potential Assessment.
2. Renew our BPA contract with the Slice/Block product in 2028 but continue to analyze this choice as more information becomes available on the structure and products that BPA will offer in its next contract.
3. Acquire 10MW of demand response by 2025.
4. Make a final decision regarding whether to join the Western Resource Adequacy Program (WRAP) and join the WRAP if we make the decision to join.

5. Conduct further research to understand the potential impacts of vehicle and building electrification on loads and resource adequacy and analyze possible strategies to prepare.

The resource strategy identified in our IRP and in this CEAP meets CETA’s clean energy standards while maintaining resource adequacy at the lowest reasonable cost to our customers. We will update our CEAP regularly as part of each IRP.