

next IRP will include a 10-year clean energy action plan for implementing the GHG Neutral and 100 Percent Clean standards at the lowest reasonable costs and at an acceptable resource adequacy standard. Future IRPs will also include new or expanded assessments and forecasts related to transmission capacity, energy storage, service area installations of distributed energy resources. In addition, IRPs must include an assessment, informed by the cumulative impact analysis tool developed under a separate CETA rulemaking, of energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities as well as long-term and short-term public health and environmental benefits, costs, risks and energy security and risk.

- **Clean Energy Implementation Plans (CEIP):** By January 1, 2022 and every four years thereafter, utilities must develop Clean Energy Implementation Plans (CEIP) to propose how they plan to meet CETA’s 2030 and 2045 standards. Each consumer-owned utility must develop a CEIP and submit it to its Governing Authority for adoption. Once its Governing Authority has approved the CEIP it is then submitted to the Department of Commerce. The statute requires utility CEIPs to (1) propose interim targets for meeting the GHG Neutral and 100 percent clean standards; (2) propose specific energy efficiency, demand response and renewable targets; and (3) identify specific actions that demonstrate progress toward meeting the GHG Neutral and 100 percent clean standards and the interim targets.

CETA also includes other requirements and details that are not described here. The latest information on CETA can be found at the WA Department of Commerce CETA website.⁷

Multiple rulemakings are currently underway to implement CETA. Stakeholders and state government officials from the departments of Commerce, Ecology, Health and the Washington Utilities and Transportation Commission are working together to establish the rules to implement CETA. The rulemaking process is scheduled to be completed by mid to late 2022. As a result, the 2020 IRP does its best to comply with the spirit of the law whenever possible but may not reflect all CETA requirements as they are ultimately defined in rulemaking. The IRP takes two important steps toward complying with new rules in CETA: (1) all portfolios considered in the 2020 IRP must comply with CETA’s 2030 carbon-neutral standard and (2) portfolio cost estimates include the social cost of carbon at the values determined in Department of Commerce rulemaking. Future IRPs will address other requirements as relevant rulemaking is finalized.

4.1.2 EV authority

SB 1512 was passed into law by the 2019 state Legislature and is codified as RCW 35.92.450. The law provides that customer-owned utilities can create their own *Transportation Electrification Plan* and, with the adoption by their governing body, promote transportation electrification through programs, advertising, and direct incentives.

The law strikes a balance by allowing utilities to promote electric vehicle adoption but seeks to uphold traditional utility principles that protect customers from program-related spending that could lead to significant rate increases. The restriction on use of utility funds in SB 1512 is consistent with other state laws that are intended to protect the public from the misuse of public funds. Notably, the law requires that spending on transportation electrification “*does not increase net costs to ratepayers in excess of*

⁷ <https://www.commerce.wa.gov/growing-the-economy/energy/ceta/>

one-quarter of one percent” but does not clarify how revenues and expenses related to transportation electrification should be treated.

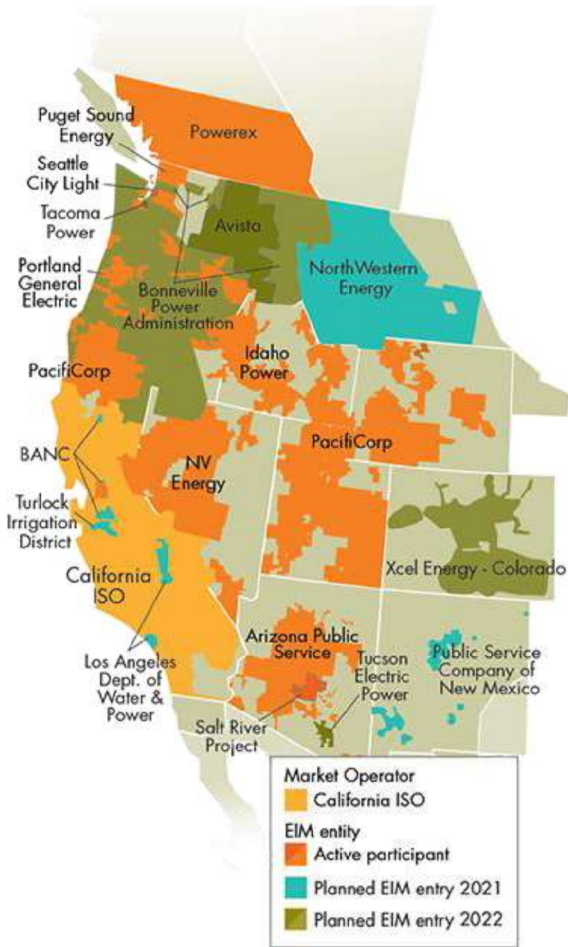
The law identifies five categories that a governing board may (at their discretion) consider in a transportation electrification plan. The five sections are included below with responses appropriate for current conditions:

- 1) The applicability of multiple options for electrification of transportation across all customer classes;
- 2) The impact of electrification on the utility’s load and whether demand response or other load management opportunities, including direct load control and dynamic pricing, are operationally appropriate;
- 3) System reliability and distribution system efficiencies;
- 4) Interoperability concerns, including the interoperability of hardware and software systems in the electrification of transportation proposals;
- 5) The overall customer experience.

On July 22, 2020 the Tacoma Public Utilities Board voted to adopt Tacoma Power’s first-ever Transportation Electrification Plan, which establishes guiding principles for utility action to design and deliver programs to support transportation electrification. The utility also developed its first Transportation Electrification Action Report in 2020 and will update it annually.

The 2020 IRP does not directly account for a ramping up of vehicle electrification, though it does consider scenarios of the future where load grows more quickly than our current projections. One action item in this IRP is to incorporate additional scenarios, including one with accelerated transportation and building electrification.

4.1.3 Energy Imbalance Market (EIM)



The California Independent System Operator (CAISO) Energy Imbalance Market (EIM) is an extension of the CAISO’s real-time centralized wholesale energy market to balancing authorities (BAs)⁸ outside of CAISO’s real-time market footprint. A BA that has successfully completed all the complex tasks necessary to participate in the EIM is referred to as an EIM Entity. The EIM automatically finds the lowest cost energy to serve customer demand by evaluating and accepting real-time bids of generators offering their supply into the centralized market. In short, it provides EIM Entities with an ability to transact real-time energy through a centralized and highly automated market operation. This improves the balancing of supply and demand within time intervals as short as five and fifteen-minutes.

Prior to development of the EIM and outside of the CAISO’s real-time market footprint, real-time energy was transacted bilaterally. This means that trading was arranged between two entities, one buying and one selling, typically by telephone. It generally entailed transactions lasting for one hour in duration. Within the markets that CAISO operates, however, real-time and day-ahead trading occurs through a centralized and automated market that optimizes the purchase and sale bids of all market participants.

Centralized market operation allows participants to buy and sell power with the market operator having visibility into the real-time needs, capabilities, and limits of the transmission system within the market footprint. This coordinated operation allows for improved reliability and a more efficient resource dispatch across a larger more diverse footprint than that of just two utilities transacting bilaterally.

To expand on the capabilities of its centralized energy trading system, the CAISO launched the EIM in 2014 in partnership with PacifiCorp. It has since grown to include 11 EIM Entities, with nine more committed to join by 2022, including the Bonneville Power Administration (BPA) and Tacoma Power. We have actively monitored development of the EIM since it was first established, paying attention to how we would be impacted and how we could participate in a manner that would produce benefit for our customers. Because of its data and automation intensive requirements for participation, becoming an EIM Entity is a very significant undertaking that typically, though not always, requires at least two years to accomplish. In 2019, Tacoma Power signed an EIM Implementation Agreement with the CAISO,

⁸ A balancing authority is defined as “the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” Each balancing authority is registered with the North American Electric Reliability Corporation (NERC) to perform this function and as such is subject to the mandatory reliability standards issued by NERC.

initiating this process. Our EIM implementation process is now fully underway, with a targeted EIM “Go Live” date of March 2022.

The 2020 IRP does not explicitly include the EIM in its modeling, but the impacts of resource decisions are evaluated in the context of our future as an EIM entity.

4.1.4 Northwest Resource Adequacy Program

Resource adequacy means having enough power resources available to serve electricity demands across a range of conditions. Resource adequacy can be measured in different ways and can be measured at different levels (utility by utility, regionally, etc.).

4.1.4.1 The Regional Challenge

Historically, utilities have focused on providing reliable service at least cost. In addition to these objectives, utilities now must also meet new state regulatory mandates while also promoting evolving consumer and local regulator preferences.

Most states in the West have passed renewable portfolio standards that mandate certain percentages of utility load be served by qualifying renewable sources. Several states, including California & Washington, have passed clean energy standards mandating the phase-out of coal and transition to 100% clean (non-carbon emitting) generation by 2045. These new regulations will affect regional resource mix. Solar and wind will constitute a greater percentage of supply, while coal and natural gas will constitute a smaller percentage of supply.

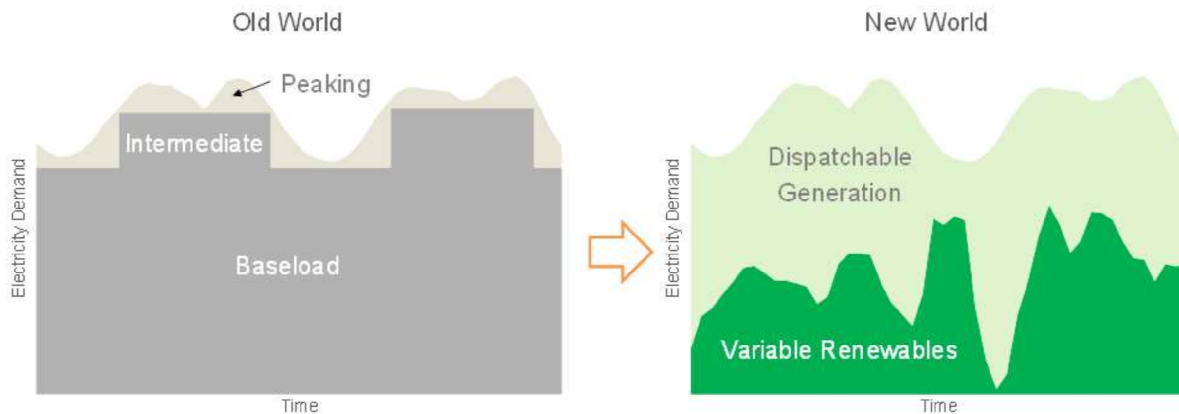


Figure 3: A system in transition

The way the industry thinks about the system and the resources it needs is changing. In the “old world”, load was served by a combination of baseload generation and resources that were dispatched to meet intermediate and peak loads. In the “new world” load will be met by a combination of variable renewable generation and clean dispatchable generation. This shift in regional resource mix is promising, but creates new challenges.

The Northwest Power and Conservation Council (NWPCC) publishes an annual resource adequacy assessment to provide an early warning to the region should resource development fail to keep pace with demand growth. In late 2019, NWPCC estimated that supply will become inadequate by 2021 due

to the announced retirements of coal-fired generating capacity. By 2024, additional coal plant retirements will compound the shortfall.

The region must replace the generating capacity that will be decommissioned. However, there are constraints on what utilities may use to provide dispatchable generation. In Washington, new natural gas generation is unlikely to be a feasible alternative in most cases. Transmission, which could increase access to favorable renewable generation outside the region, can take decades to build. Other promising solutions are either very expensive, are based on emerging technology or both.

Another major problem facing the region is a lack of proper price signals to incentivize investment in dispatchable generation. Currently, market prices do not fully reflect the value of investment in the resources needed to meet load. This is known as the “missing money” problem.

4.1.4.2 The Resource Adequacy Program Development Project (RAPDP)

A potential solution is the establishment of a regional resource adequacy program. Regional utilities through the Northwest Power Pool (NWPP) have launched an initiative to establish a program in the Northwest by 2022. Information about the effort can be found on the NWPP’s website.⁹

A resource adequacy program coordinates and directs utility investment in dispatchable generation a few years ahead of when electricity needs to be delivered. This lead time is necessary, as power resources can take a long time to build. The objective of a program is to ensure reliability and to do so at a lower cost and risk for ratepayers than an uncoordinated effort.

Utilities would voluntarily join the program and agree to a reliability metric and standard. An independent program administrator would be hired to run the program. The program administrator would develop a load forecast and determine a capacity requirement for each participant. The program administrator would validate the capacity contribution of participant generating resources. Participants that have insufficient capacity to meet the requirement could be subject to financial penalties. To avoid penalties, the utilities would need to procure existing capacity or build new generation. The program would create incentives necessary to develop and maintain sufficient capacity, reduce risk of blackouts, and better enable the transition to a lower carbon resource mix.

The RAPDP is still in the process of developing a detailed design and utilities are still in the process of evaluating participation in a program. As a result, we do not reflect the existence of the resource adequacy program in our current IRP modeling and analysis. Program compliance will be addressed in a future IRP if we elect to join.

4.1.5 Reductions in retail load due to COVID-19

On January 19, 2020, a 35-year-old man presented to an urgent care clinic in Snohomish County, Washington. The next day, the Centers for Disease Control and Prevention (CDC) confirmed the patient positive for the novel coronavirus, COVID-19, marking the first diagnosis of the virus within the United States. Within a matter of days, three more cases were identified in Illinois, Arizona, and California. In less than four months, the virus reached every state in the nation. To reduce the spread of the virus within their state, several governors announced statewide policies and orders. Under pandemic-related

⁹ <https://www.nwpp.org/about/workgroups/12>

orders and policies, the Washington State economy was largely closed and unemployment claims reached record highs.

After Washington’s ‘Stay Home, Stay Healthy’ order went into effect, we saw a reduction in retail load due to a shift in the retail electric customer base. In our service territory, over the course of a year, an average General Service customer consumes as much energy as 48 average Residential customers consume. As commercial activity shut d own, the associated Small General and General class commercial loads were lost and the relatively small uptick in Residential class activity was not enough to replace that loss. Table 3 details the difference in April 2020 to June 2020 monthly sales from the average 2015-2019¹⁰ monthly sales in the same month. For perspective, in May 2020, the observed increase Residential sales amounts to approximately one-quarter of the observed decrease in General Service sales.

Table 3: Difference in 2020 Monthly Sales and Average 2015-2019 Monthly Sales

Rate Class	Difference in Monthly Sales from Five-Year Monthly Sales Average			
	March 2020	April 2020	May 2020	June 2020
Residential	-0.8%	4.8%	2.9%	2.6%
Small General Service	-7.8%	-4.2%	-18.6%	-12.6%
General Service	3.9%	-8.7%	-15.2%	-11.0%

Due to these unusual circumstances, our long-term load forecast performance deteriorated. Prior to the pandemic, median long-term energy load forecast variance was -0.64%, weather-normalized. Since the pandemic, median long-term energy load forecast variance is -5.14%, weather-normalized. Economists expect economic recovery in North America might be slow, uneven, and fragile¹¹. Some specific industries may not recover for several years. As the economic reality deviates from the economic assumptions supporting the 2019 forecast, forecast variance will increase. As a result, we revised our long-term electric load forecast that accounts for the on-going pandemic and economic downturn. The revised forecast is between 2.0% and 5.0% below the October 2019 forecast.

The 2020 IRP inputs were finalized prior to the onset of COVID-19 and, while one scenario we evaluated included a future with lower loads, the load impacts of COVID-19 are not directly taken into account in this study’s modeling. While the recent changes to our load forecast are unlikely to worsen the performance of the preferred portfolio, they could impact the performance of portfolio options in terms of cost and financial risk.

4.2 CITY/PUBLIC UTILITY BOARD EQUITY INITIATIVES

In August 2019, the Tacoma Public Utility Board adopted Strategic Directive #1 pertaining to equity and inclusion.¹² Part of that directive applies directly to the IRP public stakeholder process and states that:

¹⁰ Small General Service sales in 2020 were compared to the five-year average spanning 2014-2018. For this particular rate class, the year 2019 was omitted from the comparison due to large billing errors and corrections.

¹¹ <https://www.spglobal.com/ratings/en/research/articles/200624-covid-19-heat-map-post-crisis-credit-recovery-could-take-to-2022-and-beyond-for-some-sectors-11535796>

¹² https://www.mytpu.org/wp-content/uploads/SD1-Equity_Inclusion-Final-6-14-19.pdf

*“TPU, in collaboration with city departments and community partners, **will pursue equity and inclusion in the workforce, service delivery, policy decision making, rate design and budgeting proposals, and stakeholder/community engagement.**”*

In addition to our internal commitments as an organization, there is also language in CETA that requires utilities to consider equity in resource planning. According to CETA, utilities must ensure that all customers benefit from the transition to clean energy through the equitable distribution of energy and non-energy benefits, and the reduction of burden to vulnerable populations and highly impacted communities.

Integrated resource planning consists of two processes in which we may apply an equity lens: the public stakeholder process and the analysis process. Each of these processes requires unique quantitative and/or qualitative metrics related to equity.

In terms of the stakeholder process, we took a qualitative approach, ensuring that the working group represented the various segments of our customer classes’ populations as well as representatives of local and regional environmental groups and organizations committed to economic justice. The resource planning group was intentional in its outreach efforts and organized an outstanding and diverse group of stakeholders. That said, the group still fell somewhat short of being fully representative of the community we serve and we strive to do even better moving forward.

Incorporating equity considerations into our analysis process calls for a quantitative metric or set of metrics. Currently, the WA Department of Health has been assigned the responsibility of leading a working group to develop a cumulative impact analysis from which “highly impacted communities” can be identified. That process is in progress and will not be complete before the filing of this IRP. Our resource planning group has participated in all public meetings related to developing equity metrics. These activities have slowed since the COVID-19 pandemic, but a draft outline of potential areas to apply equity in planning as well as possible metrics developed at a joint Department of Commerce and WA UTC meeting is available online.¹³ As these metrics are finalized, we will fully incorporate them in future resource plans.

5 MODELING TOOLS

5.1 OVERVIEW OF MODELING PROCESS

Our IRP modeling process is made up of 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) 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;

¹³ <https://www.commerce.wa.gov/wp-content/uploads/2020/02/Draft-Area-Metrics-and-Examples.pdf>

- 4) Post-process outputs from SAM to calculate resource adequacy metrics, portfolio costs and risk and emissions using a variety of tools (Excel, R, Stata, Python, etc.).



Figure 4: Overview of IRP modeling process

5.2 WECC MODEL: AURORA

AURORA is an electric system modeling, analysis, and forecasting software. We use AURORA for both long-term capacity expansion and for production cost modeling (wholesale electric price forecast). The capacity expansion model uses an iterative approach to converge on an optimal generation buildout solution. This can cause the simulation to take quite a long time to complete (the model can take 40 to 70 iterations to converge and *each* iteration at an hourly resolution can take up to 2 hours). To save time, the model resolution is set to be quite coarse either by selecting 1 to 4 hours of each day and/or by selecting 10 to 40 sample days of each year in the simulation horizon. The production cost model on the other hand, is not iterative. Therefore, the production cost model is run hourly for all days and years of the simulation horizon and produces an hourly price forecast.

Figure 5 shows a flowchart of the capacity expansion process in AURORA. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most market value (revenue less total costs). Inputs to the model include cost and technical parameters for existing generation and transmission resources, cost and technical parameters for new candidate generation resources, and various policy and reliability constraints to guide the buildout decisions (such as renewable policies and reserve requirements).

Figure 6 shows a flowchart of the production cost modeling process in AURORA. As with the capacity expansion model, this process simulates a competitive marketplace (Price Forecast Logic step in the flow chart). The build out of future resources selected in the capacity expansion step are included in the set of inputs. Resources are then dispatched in merit order to meet load at lowest cost, producing the price forecast. Separate dispatch logic is used for hydro, thermal and renewable resources. Intermittent renewables (and run-of-river hydro) are modeled as a fixed dispatch. Thermal resources are dispatched between their minimum and maximum capacities. And finally, storage hydro generation is modeled as monthly allocations of energy with the ability to shape that energy within the month. Any hydro not used in a given year is considered spilled.

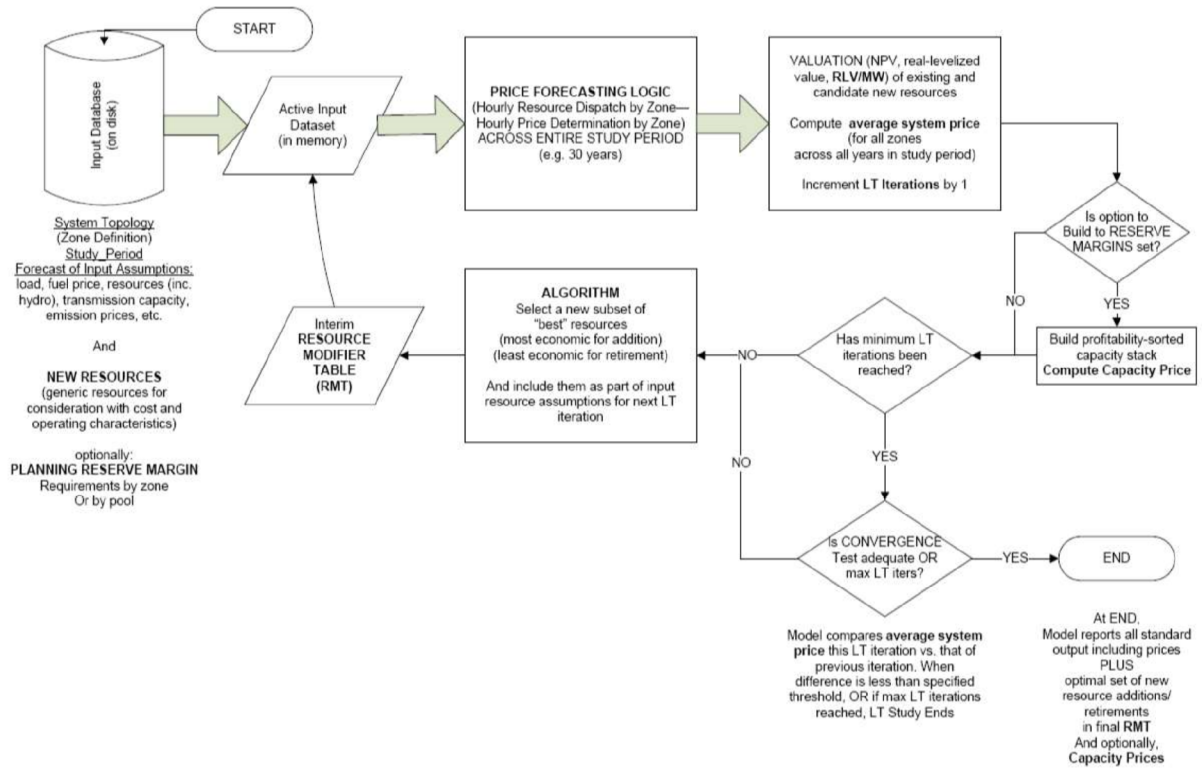


Figure 5: AURORA Capacity Expansion Model Flowchart (Source: Energy Exemplar)

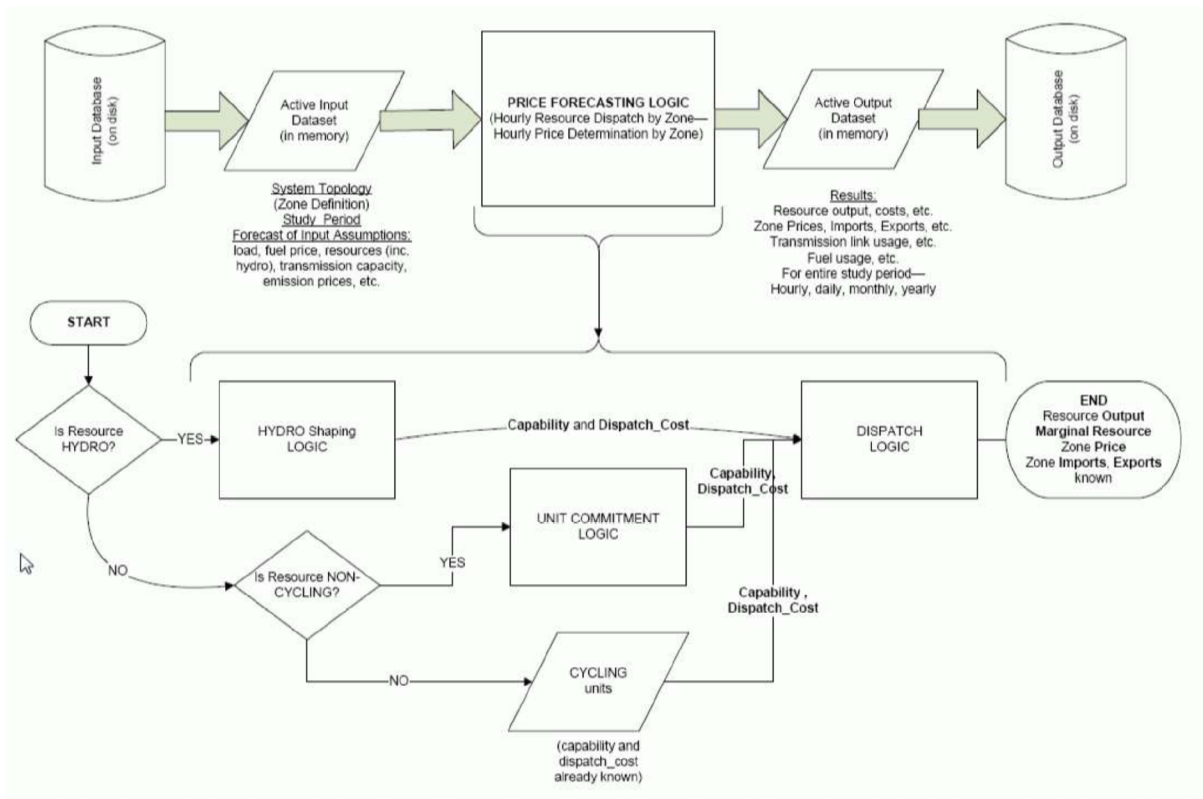


Figure 6: AURORA Production Cost Model Flowchart (Source: Energy Exemplar)

5.3 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. Given a set of resources, SAM simulates generation decisions to meet a specific signal. For resource adequacy studies, this signal is the hourly load. For revenue simulations, the signal is the market price of power in a given hour.

The model optimizes the system given a planning window, and an optimization period. For the IRP, we set the model to run 3.5 days at a time, with a 7-day planning window. This means that the system optimizer dispatches resources to meet all resource and system constraints within a 7-day planning window. Once the 7-day period is optimized to meet all constraints, the optimization slides 3.5 days past its original start, and dispatches its resources for its next 7-day planning period.

Within SAM, resources are modeled independently from each other. This allows us the ability to update how an individual resource is modeled. Currently, existing Tacoma Power-owned resources are modeled 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.

6 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 through **stochastic analysis**. 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.

6.1 STOCHASTIC ANALYSIS

The stochastic component of the IRP analysis takes into account the random year-to-year variability that creates uncertainty for utility operations. It takes into account variability in streamflow conditions, temperatures (which affect load), and natural gas prices (which are a major determinant of power prices). Each of these sources of variability is described in more detail below. For each scenario considered in the IRP, the IRP team runs 58 weather years (which includes both inflow conditions and temperatures seen in a historical calendar year) in combination with 5 different gas risk runs. Figure 7 provides an example of what is included in the stochastic component of the IRP analysis for a single scenario. All together, the IRP team runs 1,160 simulations for analysis of portfolio cost and risk (58 weather years across 5 gas risk runs and 4 future scenarios) and 232 simulations for analysis of resource adequacy (58 weather years across 4 future scenarios).¹⁴



Figure 7: Overview of stochastic component of IRP analysis for a single future scenario

¹⁴ The different gas risk runs are irrelevant, as our system model dispatches to load rather than price for the purposes of assessing resource adequacy.

6.1.1 Inflow variability

The vast majority of our power supply comes from hydro generation. Because inflows can vary substantially from year to year and from seasons to season, inflow variability is a critical source of uncertainty that we model in the IRP.

6.1.1.1 Inflow variability in AURORA

As previously mentioned, AURORA does not model hydro generation as a system of rivers and storage reservoirs. Rather than inflows, hydro generation in AURORA is modeled as monthly allocations of energy that can be shaped on an hourly basis and within certain physical generator constraints (such as ramp rate, minimum and maximum power). These monthly energy allocations are based on historic generation output between 1950 and 2007¹⁵. Figure 8 shows the monthly energy allocations, or “hydro capability”¹⁶, assigned to the Washington zone in AURORA and illustrates just how uncertain hydro generation can be in any given year. Some years (such as 2001) tend to have low hydro capability throughout the year, while other years (such as 1993) have a fair amount of hydro capability on average but severe shortages in certain months.

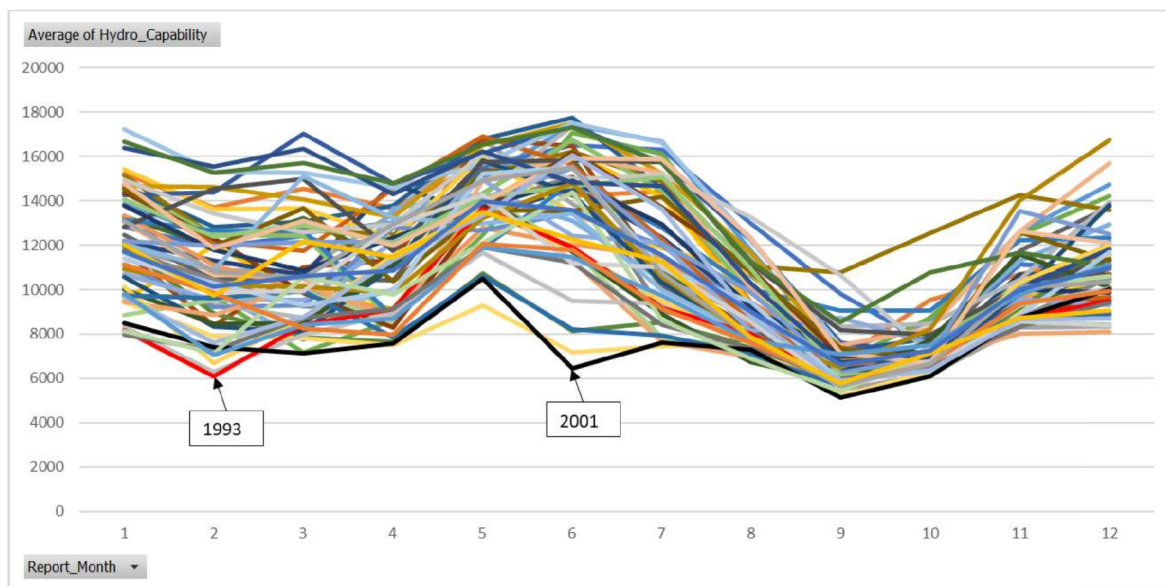


Figure 8: Historic monthly Washington hydro capability by year

6.1.1.2 Inflow variability in SAM

As input into our system model, SAM, we use historical daily inflow data into the upper dams of our Cowlitz River and Nisqually River projects. Additionally, we use historical inflows into Grand Coulee Dam and Ice Harbor Dam (Lower Snake River) as input into our Slice/Block resource simulation.

6.1.1.2.1 Cowlitz River Project (Mossyrock Dam)

Figure 9 presents inflows into the upper dam of the Cowlitz River Project, Mossyrock. The black curve illustrates the average inflow for a particular day across all historical weather years. Figure 10 presents

¹⁵ The ending year is 2007 because the AURORA dataset is based on publicly available data. Much of the data needed for hydro modeling comes from the NWPP which keeps its most recent 10 years of hydro data confidential.

¹⁶ Hydro Capability is the amount of generation that was possible given inflows and storage volume.

the monthly distribution of inflows, and Figure 11 presents the annual distribution in different weather years. In general, inflows into Mossyrock vary the most between the months of October and April. The highest historical inflows into Mossyrock occur during the colder months, with some of the highest inflows recorded in 1996.

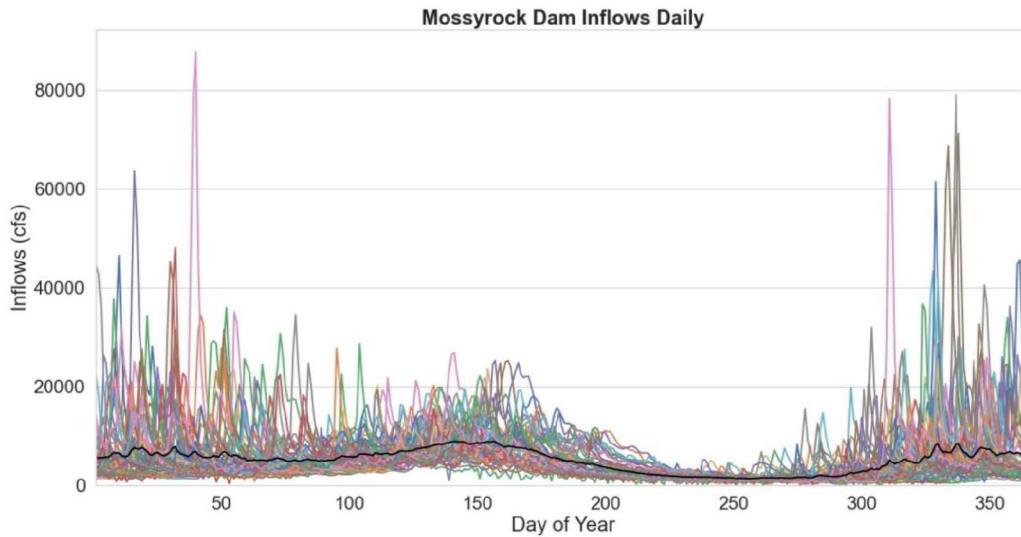


Figure 9: Historical daily inflows into Mossyrock Dam from 1950 - 2007

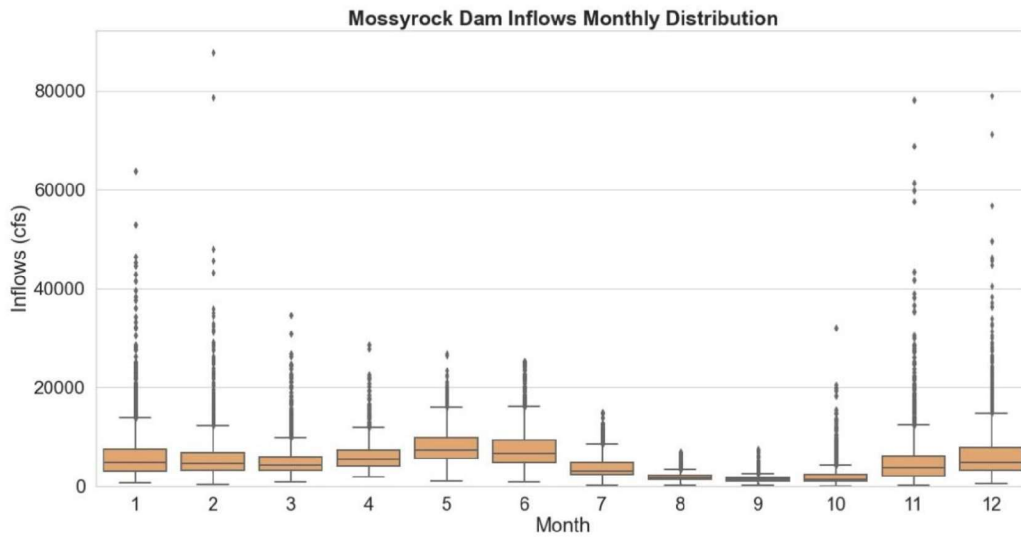


Figure 10: Monthly distribution of inflows into Mossyrock Dam from 1950 – 2007

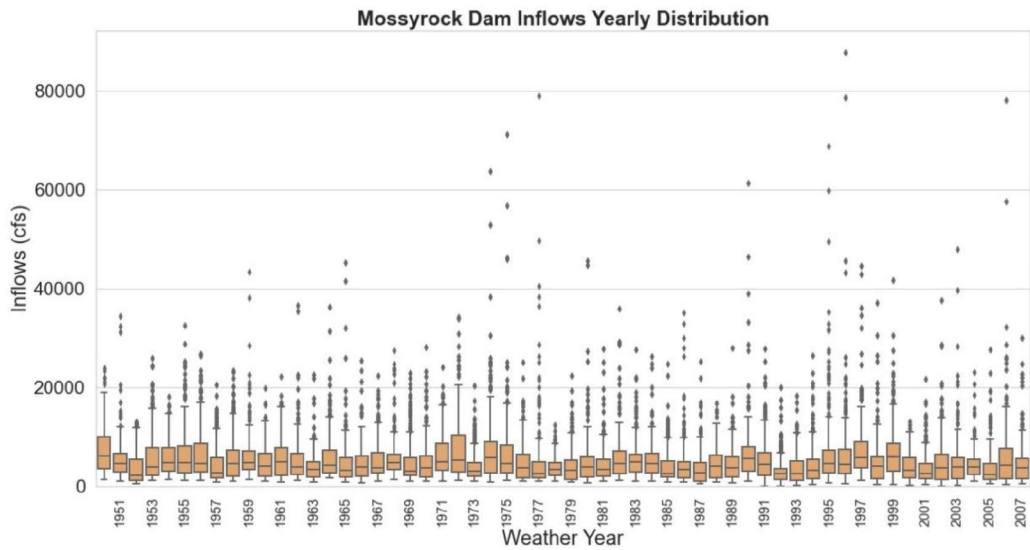


Figure 11: Distribution of inflows into Mossyrock Dam from 1950 – 2007 by Weather Year

6.1.1.2.2 Nisqually River Project (Alder Dam)

Inflows into Alder Dam are generally greatest between the months of October and June. Similar to the inflows into Mossyrock Dam, the greatest variability in inflows into Alder Dam occurs during colder months.

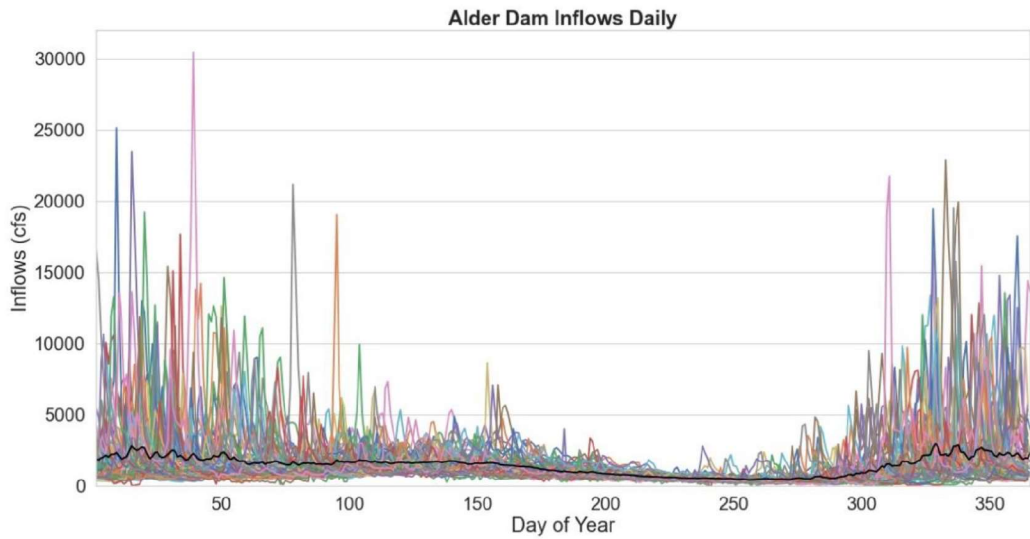


Figure 12: Historical daily inflows into Alder Dam from 1950 – 2007

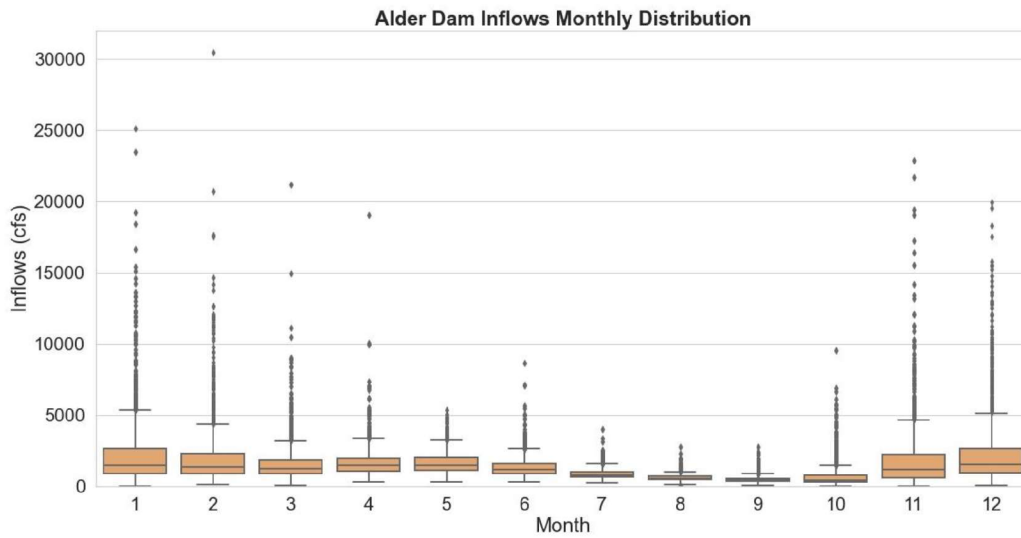


Figure 13: Monthly distribution of historical daily inflows into Alder Dam from 1950 - 2007

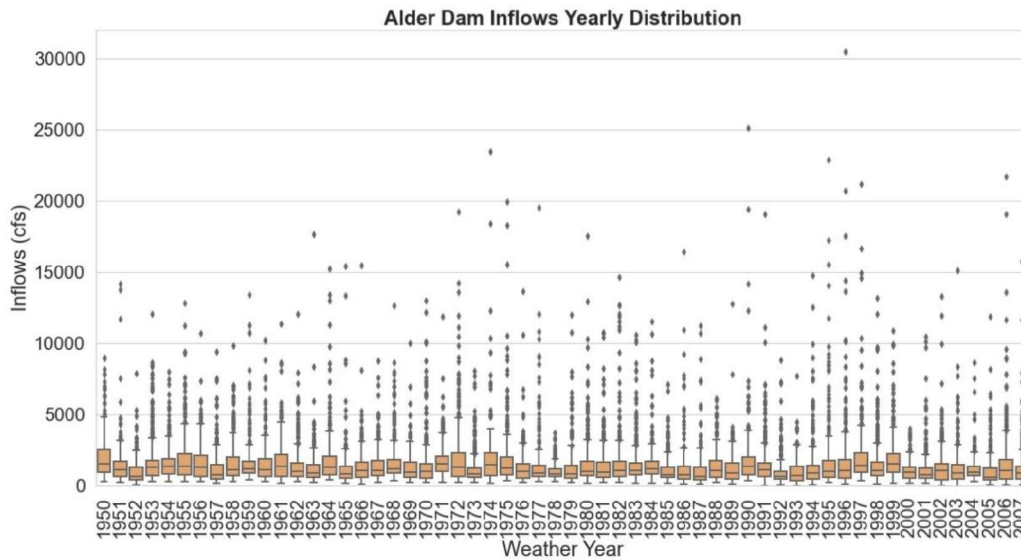


Figure 14: Distribution of historical daily inflows into Alder Dam from 1950 – 2007, by weather year

6.1.1.3 Inflows into Grand Coulee Dam

In general, inflows into Grand Coulee Dam are greatest between April and August and most variable in the summer. Although average peak inflow is about 325,000 cubic feet per second (cfs), maximum recorded inflows during the observed time period are more than twice the average at 755,987 cfs.

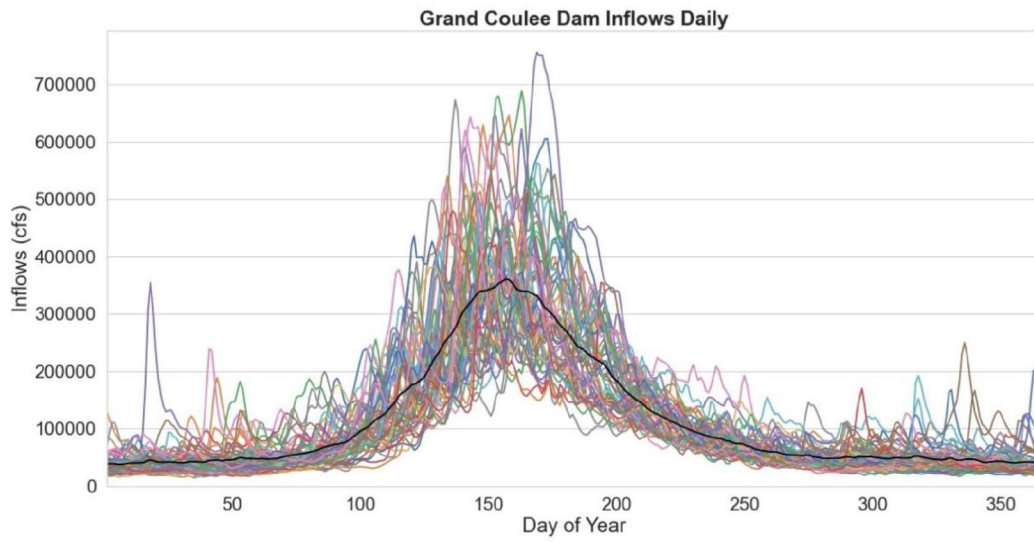


Figure 15: Historical daily inflows into Grand Coulee Dam from 1950 - 2007

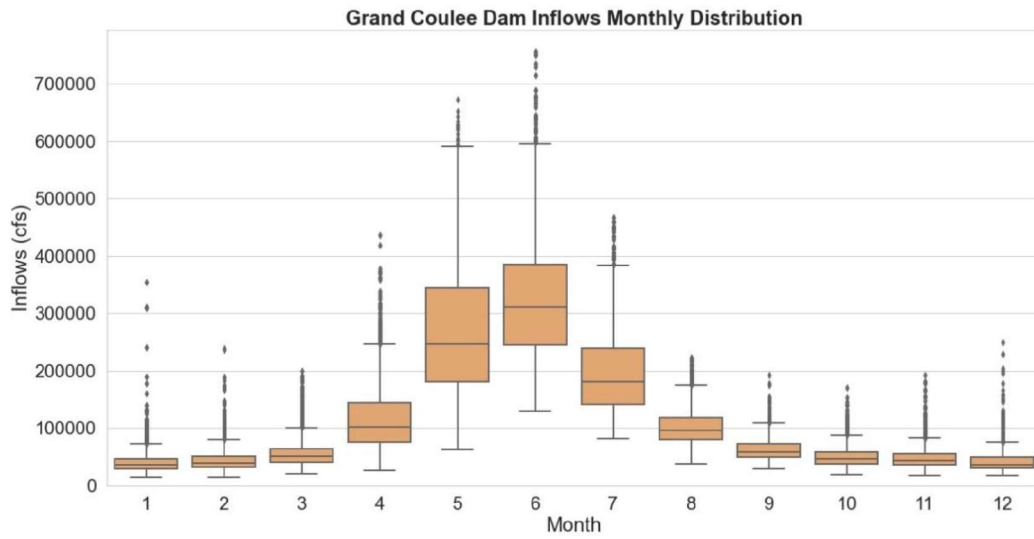


Figure 16: Monthly distribution of historical daily inflows into Grand Coulee Dam from 1950 - 2007

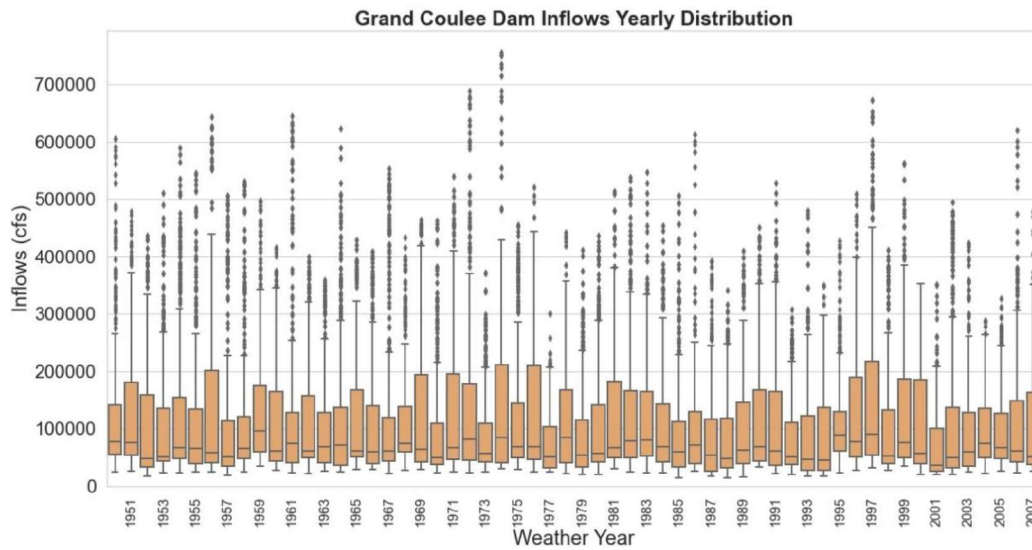


Figure 17: Distribution of historical daily inflows into Grand Coulee Dam from 1950 – 2007, by weather year.

6.1.1.4 Inflows into Ice Harbor Dam¹⁷

Because historical inflow data at Ice Harbor Dam were only available after 1963, we simulated Ice Harbor Dam inflows for 1950 through 1963 using a simple linear regression of daily inflows into Grand Coulee Dam versus Ice Harbor Dam from 1964-2007.

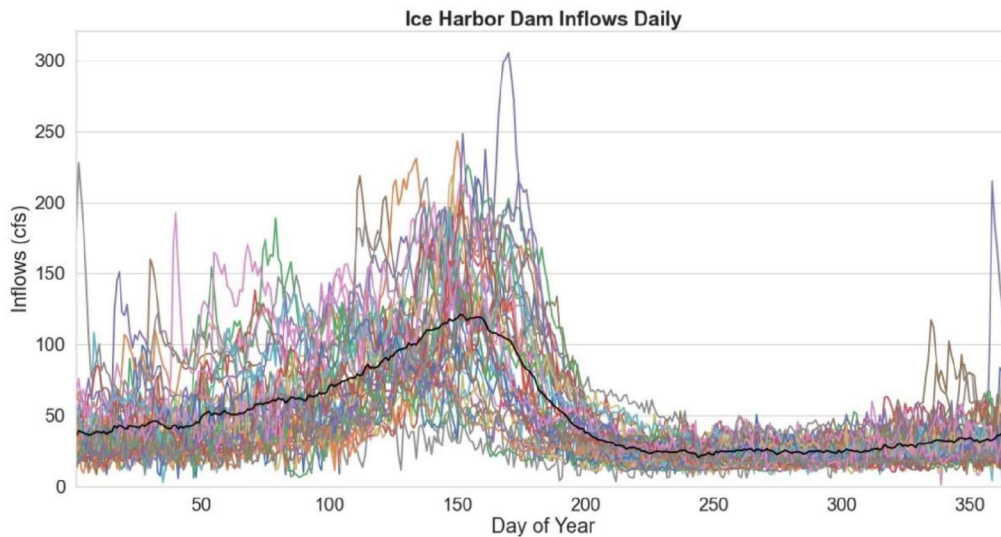


Figure 18: Historical daily inflows into Ice Harbor Dam from 1964 - 2007.

¹⁷ https://www.fpc.org/river/flowspill/FlowSpill_Query.html

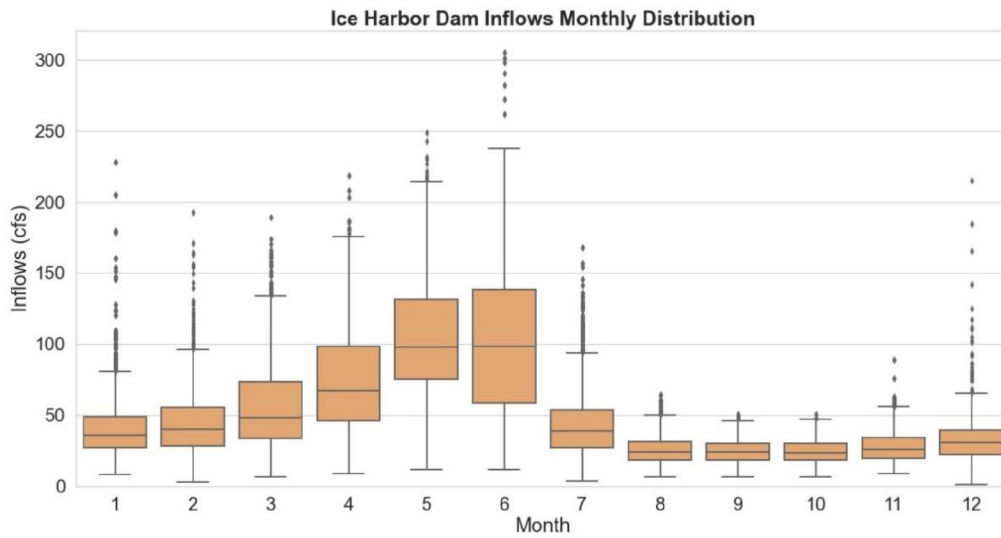


Figure 19: Monthly distribution of historical daily inflows into Ice Harbor Dam from 1964 - 2007.

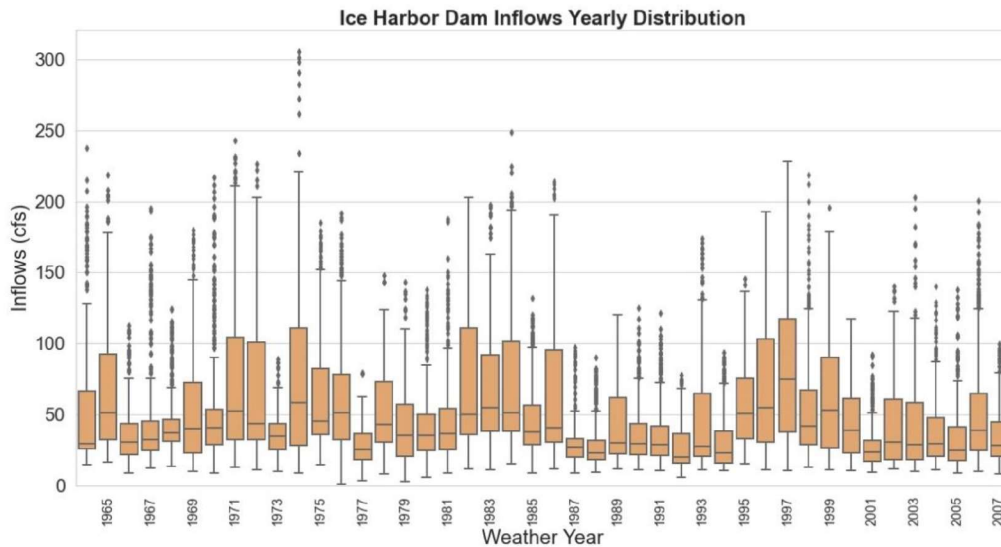


Figure 20: Distribution of historical daily inflows into Ice Harbor Dam from 1964 - 2007, by weather year.

6.1.2 Temperature variability

In this IRP, we used historical daily high and low temperatures to establish a relationship between temperature and hourly historical load for Balancing Authorities within the Western Interconnection from 2013-2018. Historical temperatures were obtained from the National Oceanic and Atmospheric Administration (NOAA)¹⁸ for major cities within or near Balancing Authorities' service areas.

¹⁸ <https://www.ngdc.noaa.gov/ftp.html>

For every International Organization for Standardization (ISO) week, for each day of the week, and each hour in a day, we use a linear regression to represent the relationship between the daily high and low temperature and the load in that particular hour. With this load model, we project loads for our study period using sequential 20-year subsets of historical daily temperatures from 1950 through 2007. This produces 58 hourly load simulation profiles for 2020-2039 for each balancing authority.

Figure 21 presents our projected peak monthly load in 2030 for 58 weather years (1950-2007), and Figure 22 presents our average monthly load. In both graphs, the black line represents the average across all weather years.

As a winter-peaking utility, we experience peak loads during cold temperature events. Figure 23 presents the distribution of hourly loads in January across different weather years and Figure 24 presents the same distribution for July. We sometimes find that our load model may overpredict what our load would look like in cold snaps and so we set the ceiling of possible peak load to be no more than 10% higher than loads seen from 2013-2018. The 10% ceiling is incorporated into the results below.

As an input into the AURORA model, we condense the hourly load output to an annual peak load and annual average energy for each weather year (1950-2007) and future year (2020-2040) combination. This information is then adjusted to reflect the projected load of each Balancing Authorities' forecast. As input into SAM, we adjust the set of 58 hourly profiles to follow the forecast trajectories of each future scenario described in Section 6.2. Tacoma Power loads across the four scenarios are presented in Figure 25.

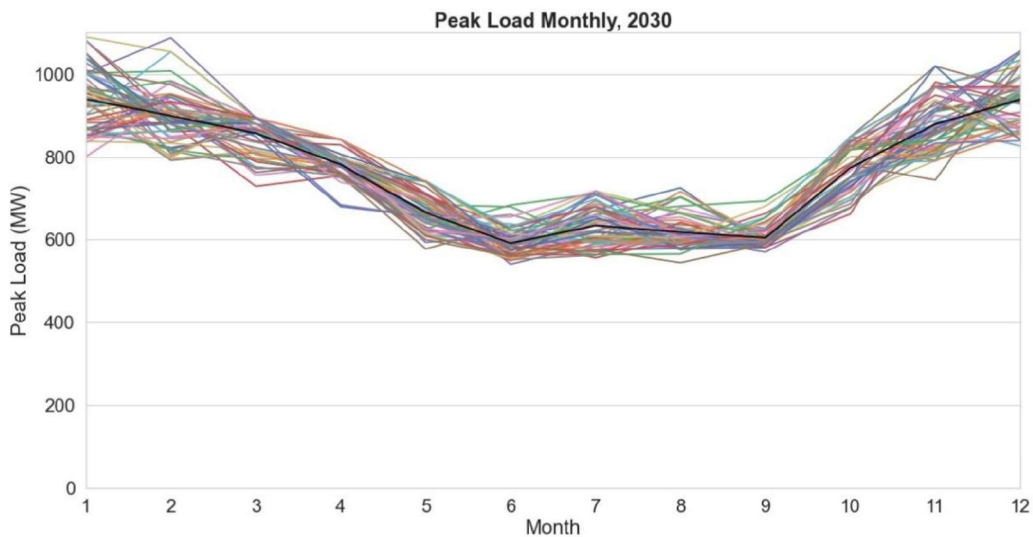


Figure 21: Monthly peak load in 2030 for 58 weather years (1950-2007)

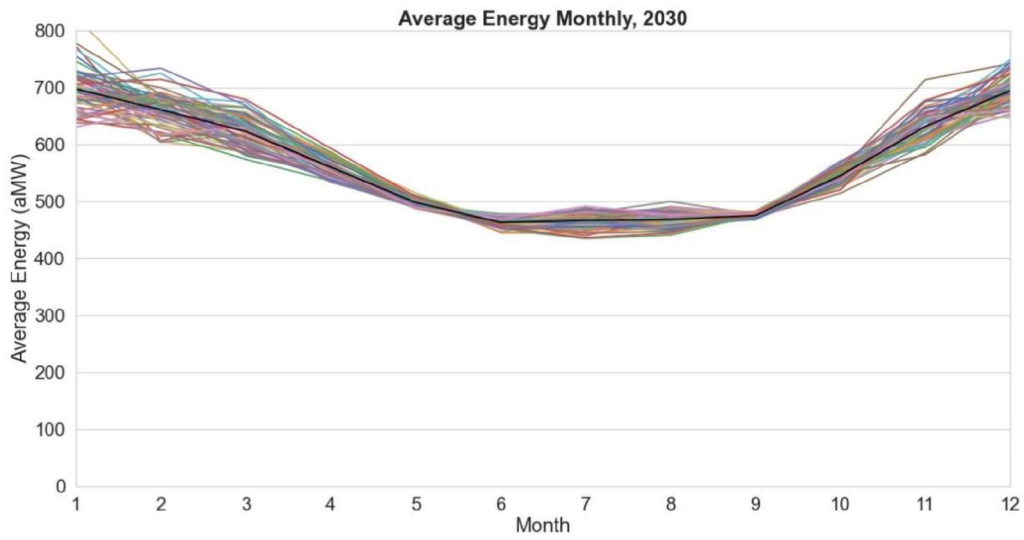


Figure 22: Average monthly energy in 2030 for 58 weather years (1950-2007)

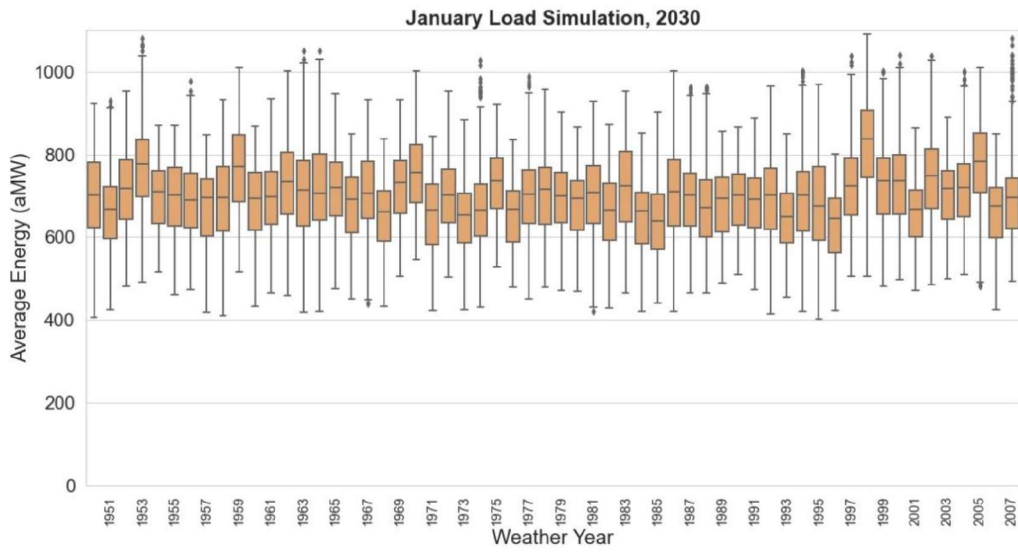


Figure 23: Distribution of simulated hourly load for January 2030

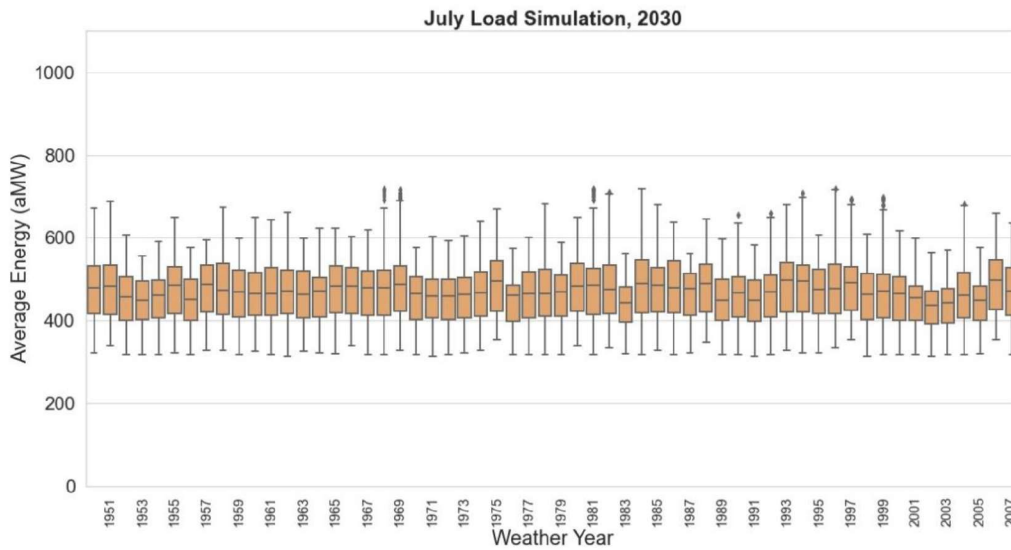


Figure 24: Distribution of simulated hourly load for July 2030

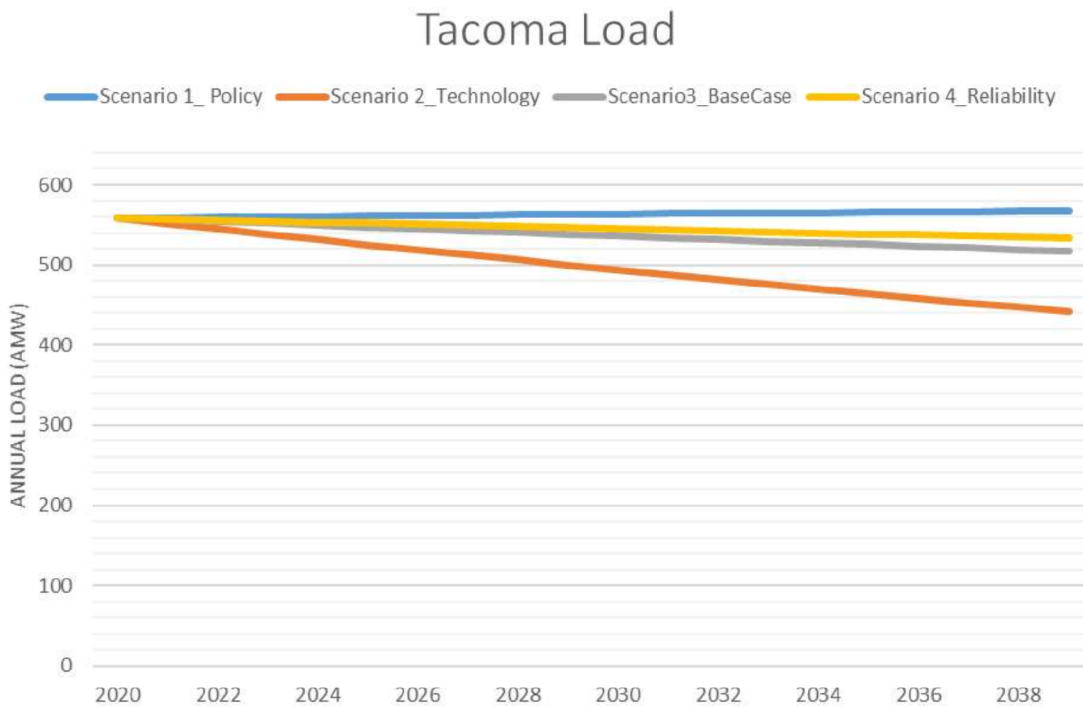


Figure 25: Tacoma Power load across future scenarios

6.1.3 Gas price variability

Over the past 20+ years, natural gas prices have gone from increasing to decreasing due to hydraulic fracturing (fracking). Prices have also exhibited extreme volatility due to pipeline disruptions and other factors. Given the importance of natural gas prices to wholesale electricity prices, it is important that

this variability be captured in the production cost model. AURORA has a built-in function called “risk runs” to generate random draws of natural gas prices from a given distribution. We used this function to generate five random sets of monthly natural gas prices with a log normal distribution, the standard deviation derived from historic natural gas prices at Henry Hub, and a mean that is simply our expected natural gas price forecast for a given scenario. A description of the base case natural gas price forecast is described in Section 8.

Figure 26 shows the resulting five random gas price forecasts for the Base Case scenario. Each of the four scenarios have a different underlying expected natural gas price, and therefore different random draws around that expected price.

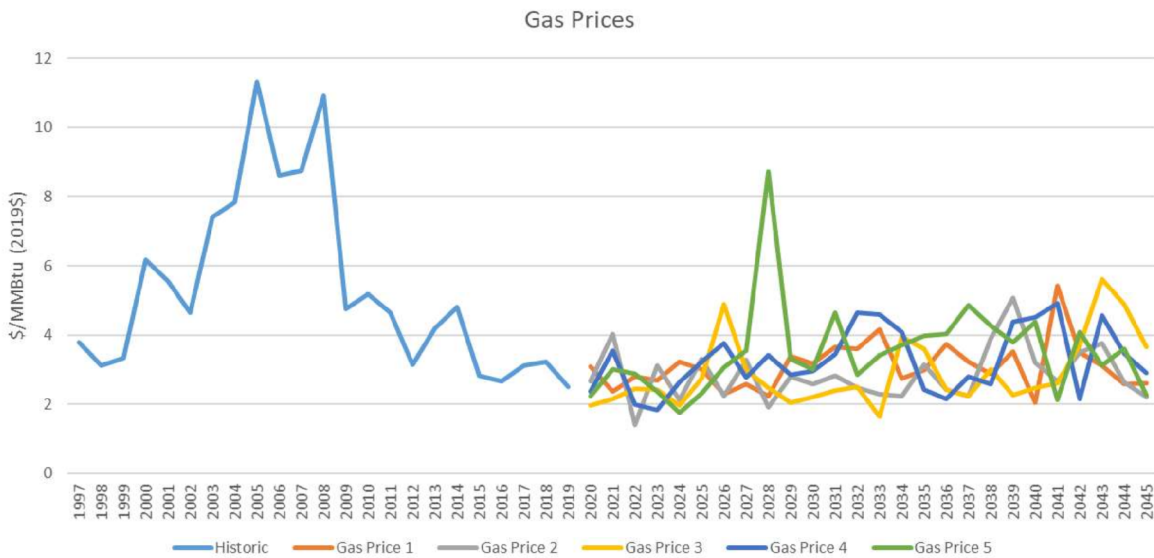


Figure 26: Comparison of historic natural gas prices and five random natural gas price forecasts

6.2 SCENARIO ANALYSIS

In resource planning, a scenario is a potential future state of the electric grid and is developed by considering the social, economic, technological, regulatory and policy environments that shape that future. The goal with scenario analysis is not to predict the future, but to ensure that our preferred portfolio can perform well in a variety of very different futures.

In the past, we have developed different scenarios by starting with our existing environment and first assuming that current trends and conditions persist. This is usually termed the “Base Case or Business as Usual” scenario. We then looked at how the economy, technology, policy and customer baselines could potentially shift away from “business as usual”. These shifts were then combined into cohesive stories to describe potential future scenarios. In the 2020 IRP, we chose to instead develop scenarios that would allow us to test the range of future price outcomes we might experience. Because we have surplus energy in most years, we frequently transact in the wholesale market, and future price outcomes have a major impact on the net cost of our portfolio. Furthermore, wholesale electricity price forecasts underpin a wide range of critical decisions at the utility ranging from establishing cost effective conservation targets to setting retail rates. These factors motivated us to develop four scenarios that

would cover the range of potential combinations of price level and price volatility. Figure 27 illustrates where each future scenario falls on the price level vs. price volatility spectrum and Figure 28 lists the narrative behind each scenario. Table 4 summarizes the key input assumptions for each scenario.

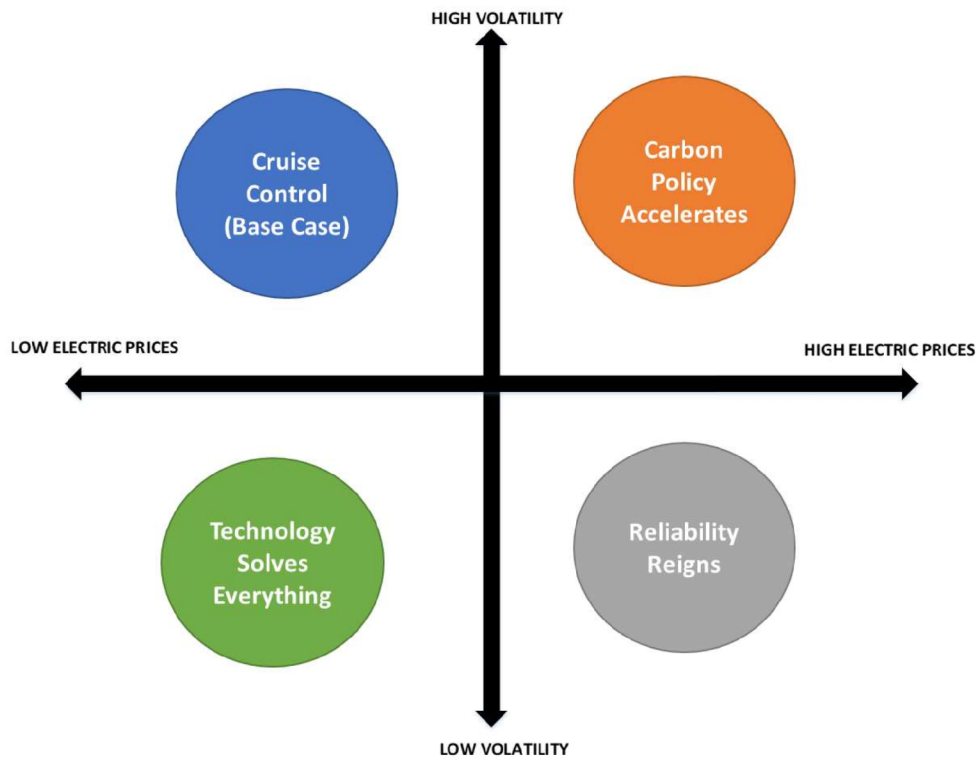


Figure 27: 2020 IRP scenarios

Carbon Policy Accelerates: (high price, high volatility)

- Renewable energy policies are extremely strong and spread to almost every state in the WECC. Policies are numerous, fast approaching, costly to implement, and there is a very limited opportunity for new thermal generation buildout. In fact, carbon taxes force existing thermal generation to economically retire.

Technology Solves Everything: (low price, low volatility)

- Renewable energy policies are strong, but it is low cost of clean energy technologies that drive resource buildout. Both renewable energy developers and utilities plan for and implement programs to efficiently and cost effectively integrate large amounts of renewable resources. This includes a large amount of demand side resources optimized for grid integration services - (ie electric vehicles, demand response, large flexible loads, long and short duration storage options, etc). Because of the diversity of demandside resources as well as significant investments in renewables, load decreases, energy market prices are both stable and low

Cruise Control (Base Case): (low price, high volatility)

- Business as usual. Environmental policies continue as they exist today with no additional changes - including impacts of climate change. *Note, that although the 2020 pandemic has caused decreased load and energy prices, these impacts were not included in this business as usual case.

Reliability Reigns: (high price, low volatility)

- Poor planning and a series of unfortunate gas events lead to power shortages, outages and price extremes. Low income customers' accessibility to power becomes a fundamental equity issue. With storage technology still expensive, policy makers decide to roll back clean energy policies (including RPS and Carbon Tax rules) in favor of more inexpensive and reliable resources.

Figure 28. Scenario narratives

Table 4: Summary of key scenario assumptions

Factors:	Carbon Policy Accelerates	Technology Solves Everything	Cruise Control (Base Case)	Reliability Reigns
Demand				
Peak Growth Rate	2.13%	0.00%	0.85%	1.28%
Energy Growth Rate	1.74%	-0.79%	0.79%	1.11%
Storage Resources				
2hr (by 2045)	5 GW	28 GW	2 GW	2 GW
16hr (by 2045)	0 GW	28 GW	0 GW)	0 GW
Carbon Policy				
SCC (in price) pre 2030	yes	no	No	yes
SCC (in price) post 2030	yes	no	No	no
Min RPS by 2045	50%	base	base	Base 2030
Natural Gas Prices				
Growth Rate	400% higher	50% lower	base	300% higher
Capital Costs				
Wind	base	30% lower	base	base
Solar	base	30% lower	base	base
RA Standard				
Planning Reserve Margin	15%	15%	15%	5% then 15%
Coal Retirements				
NW Coal	All by 2025	base	base	none post 2030
WECC Coal	All by 2030	base	base	none post 2030

7 PORTFOLIO SELECTION CRITERIA

We assess portfolios using several metrics. While the metrics we use evolve over time, they always include two fundamental criteria: that portfolios leave us with enough resources to meet customer needs (resource adequacy) and that costs are as low as possible given other constraints and priorities. For the 2020 IRP, we assess portfolios based on 5 metrics described in Figure 29 below: (1) resource adequacy, (2) compliance with Washington’s Clean Energy Transformation Act (CETA), (3) expected portfolio cost, (4) financial risk and (5) carbon emissions. The first two criteria (resource adequacy and CETA compliance) are treated 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. Each criterion is discussed in more detail below.

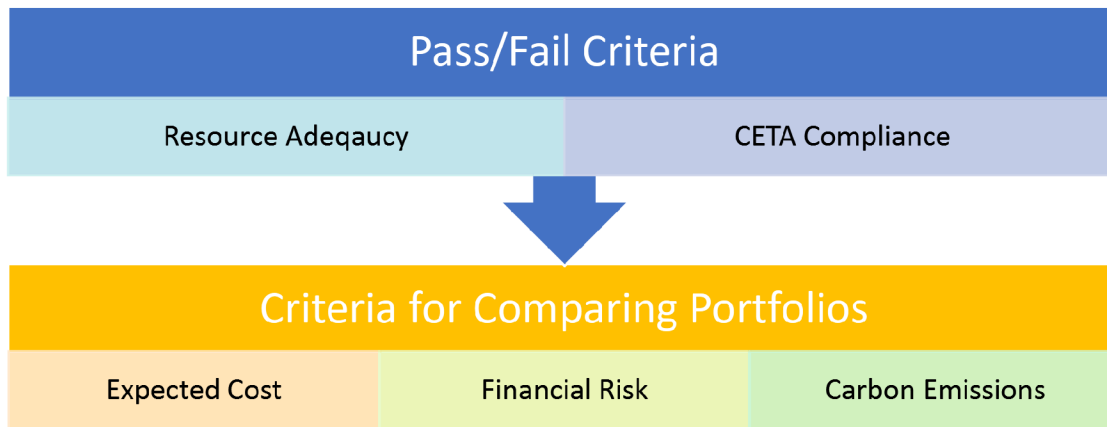


Figure 29: Portfolio performance metrics

7.1.1 Resource adequacy

A resource adequacy (RA) standard tests whether a utility has enough resources to meet loads based on some objective criterion. Like many utilities in the Northwest, we have in the past used critical water planning to assess resource adequacy. Critical water planning assesses whether we have enough resources to serve expected load under a “critical water year” in which water supply was particularly low.¹⁹ But like many of our peers, we have begun to embrace probabilistic metrics to assess adequacy. We first moved toward probabilistic adequacy metrics in our 2015 IRP because (1) it is a more sound approach to quantifying the uncertainties faced by utilities, especially those with significant hydroelectric generating resources; (2) critical water planning standards assume a single specific streamflow outcome profile for the year rather than what is in fact a probabilistic distribution of potential outcomes over the course of the year; and (3) probabilistic approaches allow us to represent multiple factors (load, inflows, etc.) in a more statistically rigorous framework.

For the 2020 IRP, the utility continued on this path toward using probabilistic approaches to assessing adequacy but has updated the metrics used to evaluate portfolios from ones that are unique to Tacoma Power to ones that are commonly used across the industry today. The 2020 IRP adequacy metrics assess inadequacy events along three dimensions: their magnitude, their duration and their frequency:

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

¹⁹ The 2015 IRP and 2017 IRP update used 2001 as Tacoma Power’s critical water year.

For each of the above standards, we follow recent NERC recommendations²⁰ and includes loss of load across all hours rather than just over certain time periods. If a portfolio meets all three standards, it is considered adequate. If it fails to meet one of the standards, it is considered inadequate. In some limited cases, portfolios that fail the standard in certain conditions only and in certain years only are still considered, with the understanding that these potential adequacy risks need to be addressed.

Equation 1: Calculating annual NEUE

$$NEUE = \frac{\sum_{s=1}^S \sum_h UE_{sh}}{\sum_{s=1}^S \sum_h Load_{sh}} \bigg/ S_{total}$$

Where S_{total} is the total number of simulations in a given year and $UE_{sh} = MAX(0, Load_{sh} - Capacity_{sh} - Reserves_{sh})$.

Equation 2: Calculating annual LOLH

$$LOLH = \sum_{s=1}^S H_s \bigg/ S_{total}$$

Where S_{total} is the total number of simulations and $H_s=1$ in each hour that Capacity - Reserves - Load < 0 and =0 otherwise.

Equation 3: Calculating annual LOLE

$$LOLE = \sum_{s=1}^S D_s \bigg/ S_{total}$$

Where S_{total} is the total number of simulations and $D_s=1$ in each day that Capacity - Reserves - Load < 0 in at least one hour of the day and =0 otherwise.

7.1.1.1 Market reliance

A critical assumption for resource adequacy calculations concerns the extent to which a utility can rely on the wholesale market to buffer potential inadequacy events. For the 2020 IRP, we assume that up to 50MW of power could be purchased from the market at any time (the same assumption that it used in the 2015 IRP and 2017 IRP update). This is equivalent to approximately 5% of the utility’s peak load, a somewhat more conservative assumption than many other utilities make. The IRP team confirmed with its trading team that an assumption of 50MW was a reasonable, conservative assumption. Section 14.2 examines how a small change in that assumption could affect resource adequacy results. In future IRPs, we will consider using a more nuanced approach to determining its market reliance assumption.

²⁰ NERC (2018) *Probability Adequacy and Measures: Technical Reference Report*. Retrieved from: <https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf>

7.1.2 CETA compliance

Any portfolio we acquire must meet the requirement that at least 80% of our load is served by carbon-free power. CETA will eventually require that 100% of load be served by carbon-free power by 2045, but that is outside of the 2020 IRP study period. In future IRPs, once the rules for how CETA will treat market purchases are settled, we will begin to address CETA compliance post 2045.

7.2 EXPECTED COST

The expected cost of each portfolio is calculated as the net present value (NPV) of portfolio costs, averaged across all simulations. NPV of portfolio costs is defined in each simulation by Equation 4.

Equation 4: NPV of portfolio costs

$$NPVC = \sum_{y=1}^{20} \frac{ExpectedGenExpense_y + Trans_y + Integr_y - (Rev_y - GET_y)}{(1+r)^{(y-1)}} + \sum_{y=1}^{20} SCC_y$$

Where:

- $ExpectedGenExpense_y$ is the total expense for generation in a given portfolio (capital investments, O&M expenses, contract purchases, etc.) in year y . Low, medium and high cost estimates are developed for most resources, and the *expected* cost is a weighted average of the three cost estimates (see Equation 5 below)
- $Trans_y$ represents transmission costs for a given portfolio in year y
- $Integr_y$ represents integration costs for a given portfolio in year y (applied only to portfolios that include wind or solar)
- Rev_y represents net revenues from market purchases and sales in year y
- GET_y represents gross earning tax paid to City of Tacoma for market sales in year y , equal to 7.5% of revenues from market sales
- SCC_y represents the societal cost of carbon emissions of a given portfolio in year y (see discussion in Section 11.4 for more detail on how the social cost of carbon is calculated)
- r represents the utility's discount rate. The IRP analysis assumes a 3% discount rate

Equation 5: Expected cost of generation

$$ExpectedGenExpense_y = 25\% * LowGenExpense_y + 50\% * MediumGenExpense_y + 25\% * HighGenExpense_y$$

In addition to the net present value, average annual costs in the post-2028 period (described by Equation 6) are also reported.

Equation 6: Net annual cost

$$AnnualNetCost = \frac{\sum_{y=1}^Y (ExpectedGenExpense_y + Trans_y + Integr_y - (Rev_y - GET_y)) + SCC_y}{Y}$$

7.3 PORTFOLIO RISK

Financial risk of each portfolio is measured as the average cost across the 10% highest-cost outcomes in each year.

7.4 CARBON EMISSIONS

Because nearly all of the portfolios considered in this IRP contain only non-emitting resources, the only mechanism through which carbon enters our portfolio in almost all cases 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 was 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.

For emissions associated with the BPA contract, a fixed mix of resources is assumed based on BPA's official fuel mix report.²¹ 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 was unnecessarily complex given the small amount of emissions associated with the BPA contract.

8 AURORA INPUTS AND OUTPUTS

8.1 INPUTS: CAPACITY EXPANSION MODEL

The AURORA model comes “out of the box” with a built-in WECC database. This database contains all of the inputs needed to model the WECC, including loads, generation parameters, monthly historic and expected hydro generation, renewable portfolio standard (RPS) constraints, fuel prices and a network model of zones and transmission links between the zones. Building on this initial database, we made various modifications to the inputs to reflect our unique input assumptions as well as changes in the planning landscape not yet reflected in the AURORA database. Figure 30 summarizes the major inputs and outputs of interest in the Capacity Expansion Model. Inputs highlighted in orange were modified from their original database values are described below.

²¹ <https://www.bpa.gov/p/Generation/Fuel-Mix/FuelMix/BPA-Official-Fuel-Mix-2019.pdf>

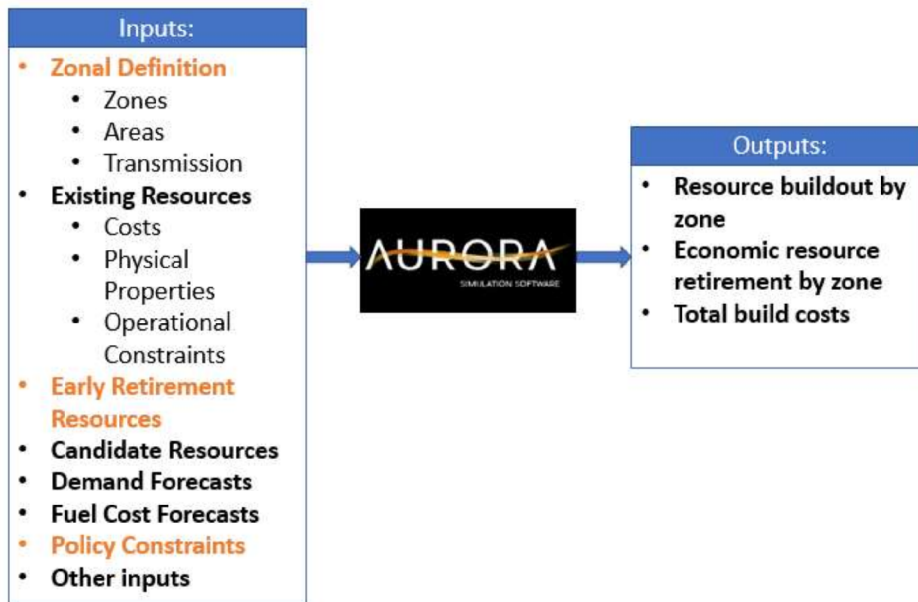


Figure 30: Important inputs and outputs to capacity expansion model

8.1.1 Zones and transmission links

The default zonal setup in AURORA combines WA, OR and ID into a single zone. This is likely due to Bonneville’s resources spread over that region. However, in order to model energy policy constraints at a state level, it was necessary to split the “OWI” zone into three separate zones. This meant allocating Bonneville resources to each of the separate zones. Our staff worked with Energy Exemplar to determine the appropriate split based on the loads in each of the three states. Because transmission links are modeled at a balancing authority (BA) level, they automatically updated once the zones were redefined. The transmission links in AURORA’s zonal model are not expected to be precise given the simplified nature of the model regardless. Figure 31 shows the modified zonal model.

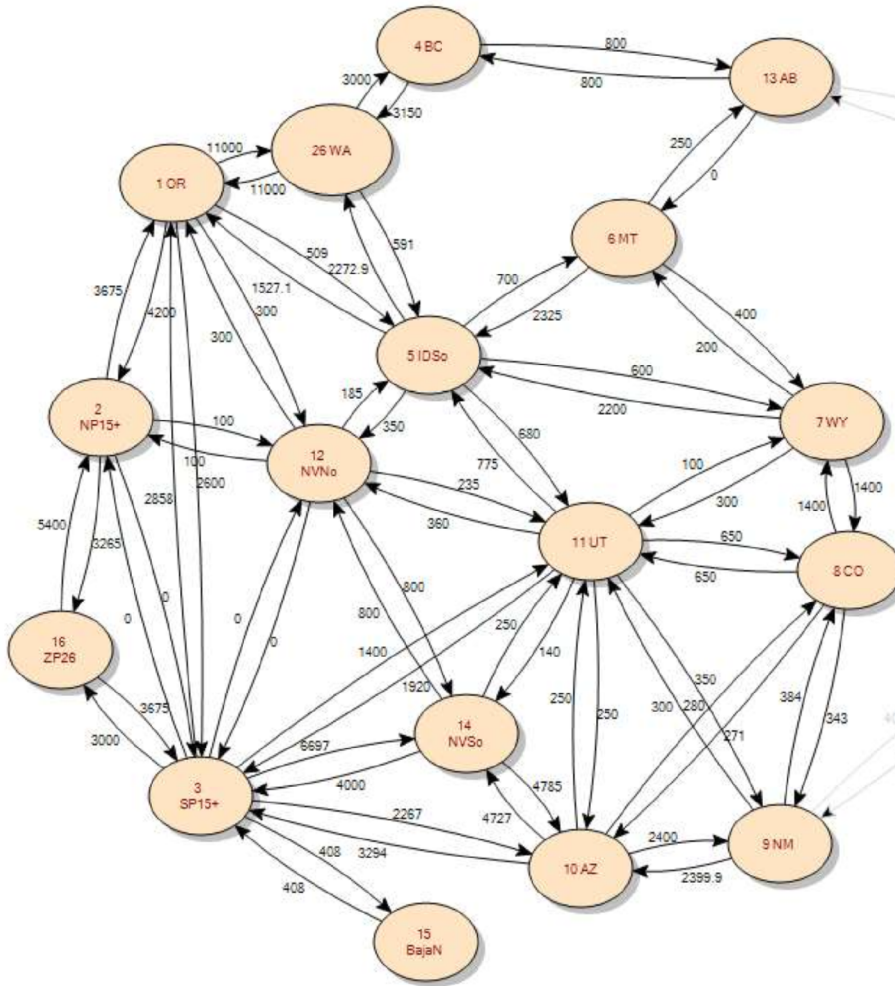


Figure 31. Modified Zonal Model and updated transmission link values

8.1.2 Coal retirements

Because the AURORA database consists only of publicly available data, the generation parameters are often not accurate at an individual resource level. That is true for Tacoma Power generation. However, since we do not use the AURORA model to assess our own generation portfolio, it was not necessary to modify or add detail to our footprint in the model. The only changes to existing generation that we made were to coal retirements. After AURORA's release of the spring 2019 WECC database (which is the database used in this analysis) new and/or accelerated coal retirements were announced. Figure 32 shows updates we made to the coal retirements in AURORA. In total, there was almost 7GW of new or accelerated coal retirement by 2030.

Updated Coal Retirements

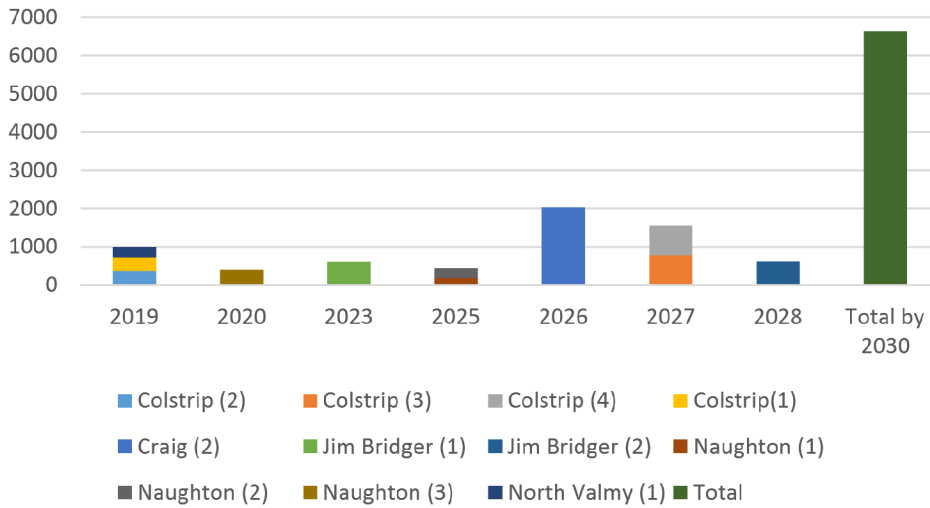


Figure 32: Coal retirement updates to AURORA database

8.1.3 Energy policy constraints

One of the most important updates to the database was to include the most recent energy policies, including CETA (described in Section 4.1.1) as well as various increased state renewable energy portfolio standards. This process required changing the way these constraints are modeled. Originally, the AURORA database modeled RPS constraints as *fixed quantities of energy* from renewable energy sources. These values were “hardcoded” and would not reflect changes to load in each of the scenarios. To improve model flexibility for scenario analysis, these constraints were updated and modeled as a percentage of load. Figure 33 shows the RPS requirements for each state.

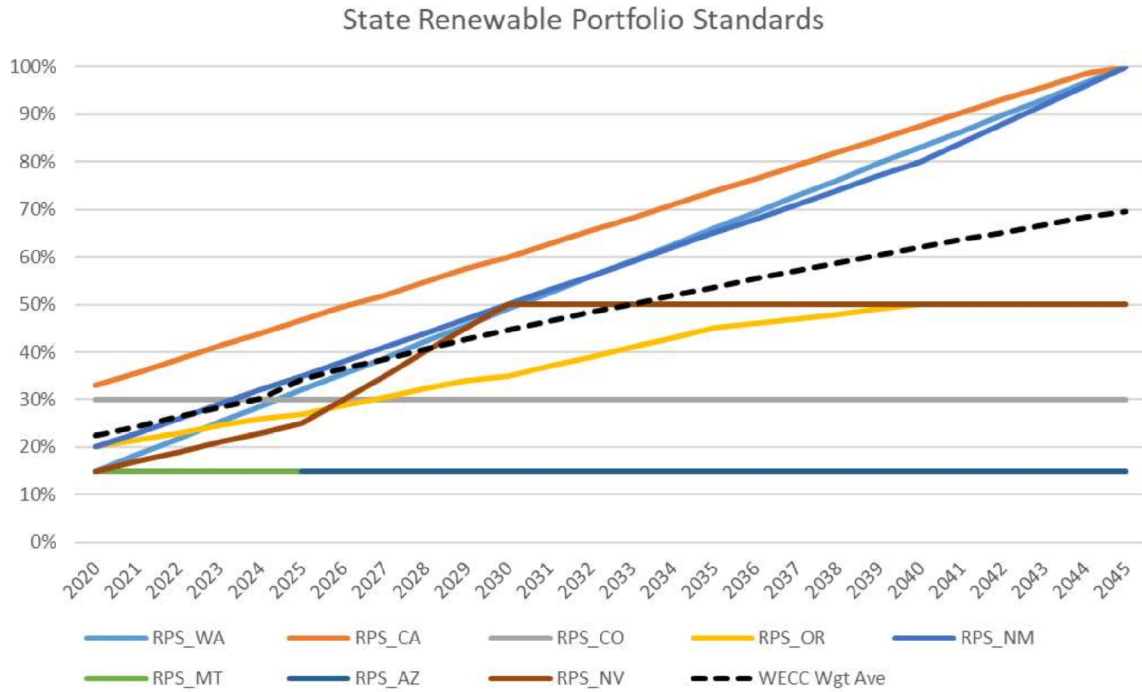


Figure 33: Updated renewable portfolio standards across the WECC as of 2019

It is important to note that the definition of qualifying renewable in each state differs – particularly in Washington, where legacy hydropower will qualify as renewable under CETA. For consistency in modeling RPS constraints in each zone as only wind and solar as a percent of generation, we calculated an “effective RPS” for WA State. This “effective RPS” was determined by calculating the amount of renewable energy needed (in excess of existing WA clean generation) to serve 100% of Washington load. This calculation (illustrated in Figure 34) is nuanced, and depends in part on how much of Washington’s existing clean energy (including hydro and nuclear) is assumed to serve WA load. If we assume that *all* clean energy generated in Washington will be used to serve WA load, the light blue bars represent the amount of additional renewable energy Washington needs to comply with CETA. If we instead assume that only the amount of clean energy currently reported in the WA Fuel Mix Disclosure will be used to serve WA load and the rest is exported, then the dark blue bars represent the amount of additional renewable energy Washington needs to comply with CETA.

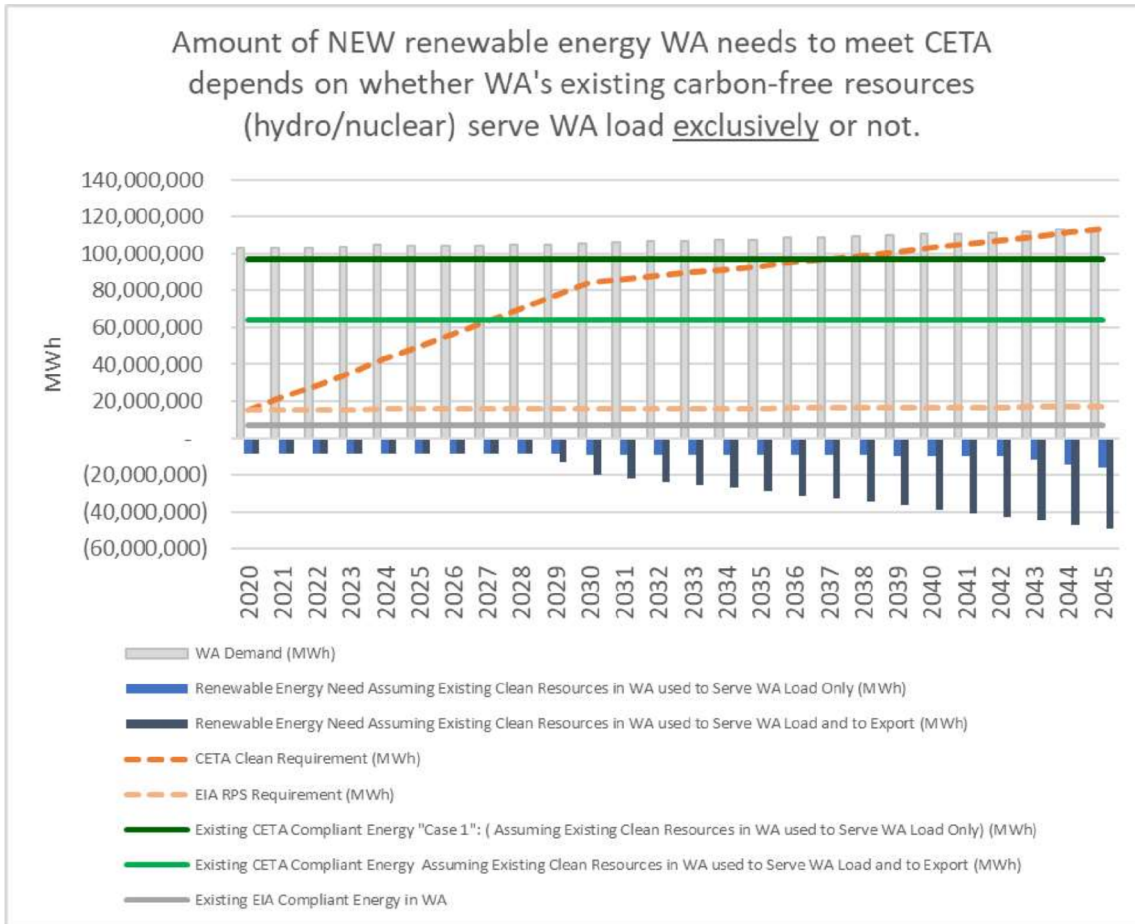


Figure 34: Renewable energy needed to meet CETA requirements based on treatment of existing clean resources

Given the amount of renewable energy needed in excess of hydro, we then calculated an effective RPS as a percentage of load. Figure 35 shows the effective RPS under three assumptions:

- 1) **All hydro** stays in WA to meet WA load and **100%** of load is met with clean resources by 2045.
- 2) **Hydro net of exports** meet WA load and **100%** of load is met with clean resources by 2045.
- 3) **Hydro net of exports** meet WA load and **80%** of load is met with clean resources by 2045.

The blue line represents the effective RPS if all WA hydro generation is kept in Washington to serve load. In this case, there is no need for additional renewables to meet CETA. In this case, the 15% RPS is the maximum of what would be required to meet EIA requirements, though current CETA rulemaking would likely result in a value lower than 15% starting in 2030 (See Section 12.1). The orange line shows the effective RPS if Washington continues to export hydro generation and meets 100% of load with clean energy. Finally, the gray line illustrates the effective RPS if hydro net of exports serves load but only 80% of load is met with clean energy. Because the rules governing the 2045 requirement in CETA are still

unknown, we chose to assume that hydro net of exports would be used to meet CETA and that 80% of load would be met with clean energy. This assumption represents a middle between the two extremes.

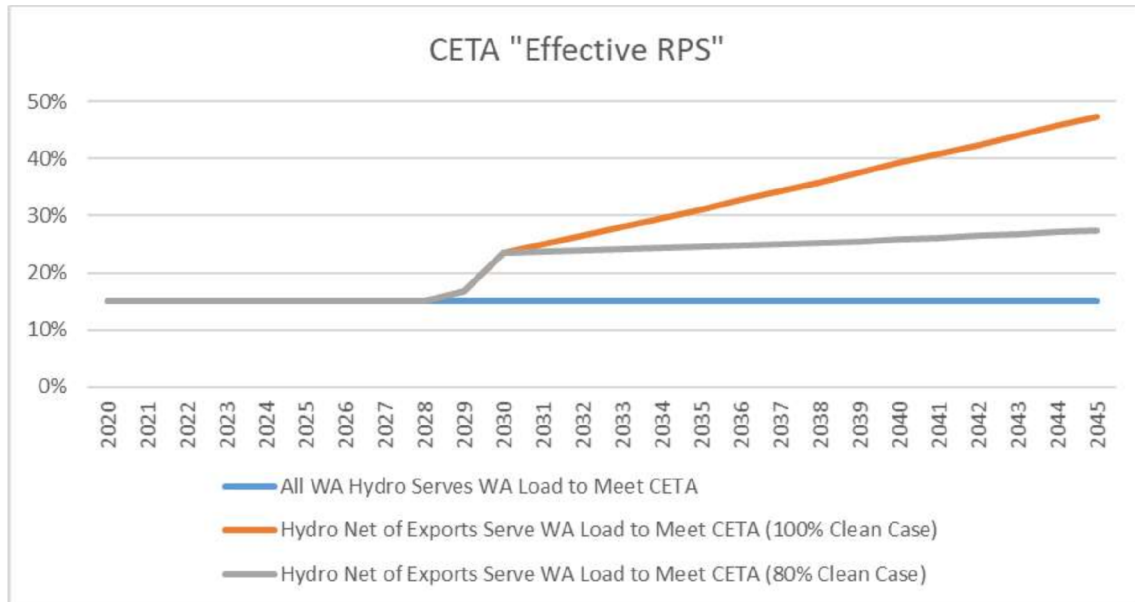


Figure 35: Effective RPS for WA State based on treatment of hydro exports and percent clean by 2045

8.1.4 Social Cost of Carbon (SCC)

Another important input to the model specific to the WA zone is the social cost of carbon (SCC)²². The Social Cost of Carbon (SCC) is an estimate of the economic and social impacts of carbon expressed in \$/MT CO₂ and developed by the Interagency Working Group on the Social Cost of Greenhouse Gases (formerly the Interagency Working Group on the Social Cost of Carbon) under Executive Order 12866. This cost represents the monetized damages associated with a number of social impacts, including changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change. For each study year, the Interagency Working Group developed four values: the first three represent the expected social cost of carbon at 5%, 3% and 2.5% discount rates, while the fourth value represents the high impact low probability cost of carbon at a 3% discount rate. In accordance with draft CETA rulemaking around SCC, this IRP incorporates the expected cost of carbon at a 3% discount rate, adjusted for inflation.²³

When incorporating the SCC into the planning process and analyses, it is important to understand that while it allows us to evaluate the costs and benefits of various resource and policy decisions, it is not an actual tax. Though there are some regions in the WECC that have some form of a carbon tax (albeit much lower than the SCC), there is currently no carbon tax in the Pacific Northwest states. Because the SCC is not a real tax on carbon, fuel and energy price inputs do not reflect the social cost of emissions. This means that on its own, the SCC is unlikely to affect new resource decisions or the operation of existing resources that are optimized for least cost and economic production, respectively. Given this

²² The Social Cost of Carbon (SCC) is an estimate of the economic and social impacts of carbon, typically expressed in \$ per metric ton of CO₂.

²³ <https://www.commerce.wa.gov/wp-content/uploads/2019/12/2019-12-30-CETA-Phase-One-Rule-Making-Order.pdf> (WAC-194-40-100)

reality, there are a number of ways to consider the social cost of carbon in the integrated resource plan analysis so that it can affect resource decisions:

- 1) Apply social cost of carbon as a tax to new WA generation resources in the capacity expansion step
- 2) Apply social cost of carbon as a tax to both new WA generation resources and retirement of existing WA plants in the capacity expansion step
- 3) Apply social cost of carbon as a tax on all emissions in the production cost model step
- 4) Apply social cost of carbon as a cost adder applied to all emissions **after** the production cost model step

Each of the above methods has its merits and drawbacks. Applying SCC in the capacity expansion step makes carbon-emitting resources appear more expensive to build and results in reduced levels of new emitting generation. In order for the capacity expansion model to project a resource buildout that is likely to occur, it is important that model inputs adequately reflect regional policies as the decision drivers they are. To that end, this option entails applying SCC to new resources built in WA State only. However, this method results in gas resources built just outside of Washington to import power. It also fails to capture the cost of carbon for existing resources. Ideally, we want a method that reflects the cost of both new build decisions as well as dispatch decisions while also producing realistic results overall (in both the build and dispatch results). Table 5 summarizes the advantages and disadvantages of the aforementioned potential methods. For this IRP, we chose method one for considering SCC in build decisions and method four for considering the cost of carbon in dispatch decisions. This allowed us to capture the cost of carbon while still producing realistic model results. Figure 36 shows the selected SCC used in this analysis.

Table 5. Summary of the advantages and disadvantages of potential ways to consider SCC in planning.

Apply SCC to:	Advantages	Disadvantages
1) New resources only in capacity expansion as a carbon tax	<p>Results in little or no gas buildout in WA</p> <p>Results in more realistic solutions since retirement decisions are more complex than the AURORA model</p>	<p>May result in extra gas buildout in neighboring provinces and states</p> <p>Does not consider cost of existing emitting resources</p>
2) New and existing resources in capacity expansion/retirement as a carbon tax	<p>Results in little or no gas buildout in WA</p> <p>Impacts decisions for both new and existing resources (build or retire)</p>	<p>Results in extra gas buildout in neighboring areas that import to WA</p> <p>Results in some “unrealistic” solutions such as retiring existing units needed for resource adequacy</p>
3) All emissions produced in the production cost model (PCM) as a carbon tax	Captures cost of new and existing resource emissions	Will result in dispatch of resources in unrealistic ways
4) All emissions produced as a damage cost after PCM step	Captures cost of dispatching emitting resource	Does not impact build decisions

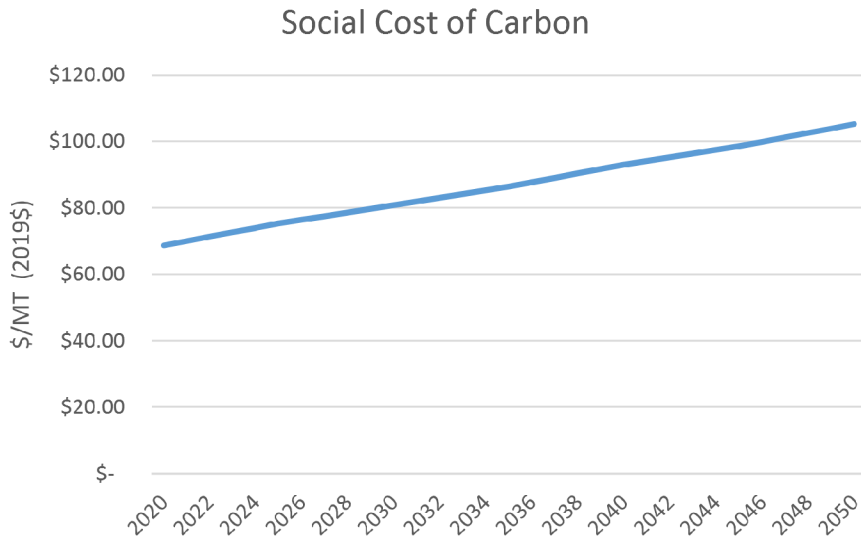


Figure 36: Social cost of carbon adjusted for inflation

8.2 INPUTS: PRODUCTION COST MODEL

In addition to some of the changes carried over from the capacity expansion model, the production cost model required additional changes to inputs, particularly those that are important to hourly outputs.

Figure 37 summarizes the major inputs and outputs of interest in the Production Cost Model. Inputs highlighted in orange were changed from the default AURORA database values.

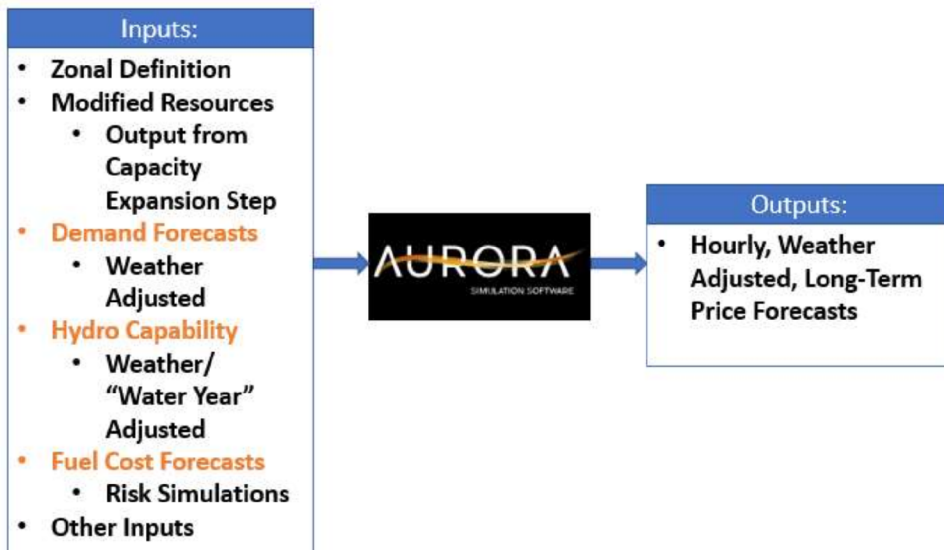


Figure 37: Important inputs and outputs to production cost model

8.2.1 Load forecasts

There were two main changes made to the load forecast inputs. First, separate forecasts of annual energy peak and average annual energy were created for each of the scenarios described in Section 6.2.

Second, each of the load forecasts were then weather adjusted to each of the 58 historic weather years 1950-2007. Figure 38 and Figure 39 show the WECC-wide annual peak by scenario and WECC wide average annual energy by scenario, respectively. Figure 40 shows the distribution of weather-normalized loads for each of the zones (normalized as a percentage of the base case forecast). Because of limited information available for Canada, the Canadian zones, Alberta and British Columbia were not weather-adjusted.

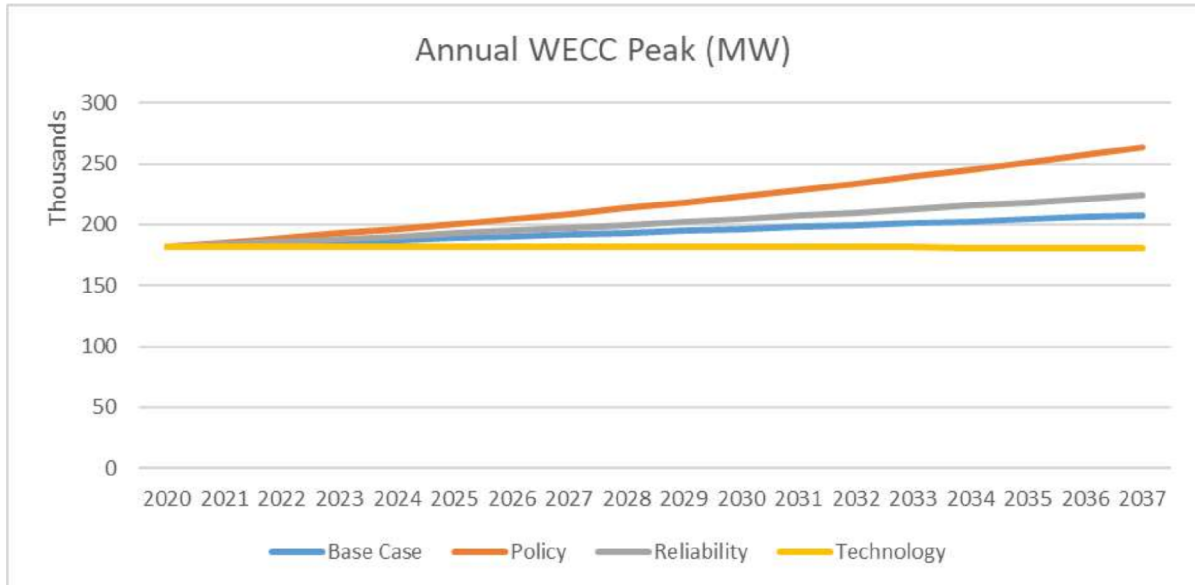


Figure 38: Total WECC-wide peak energy by year

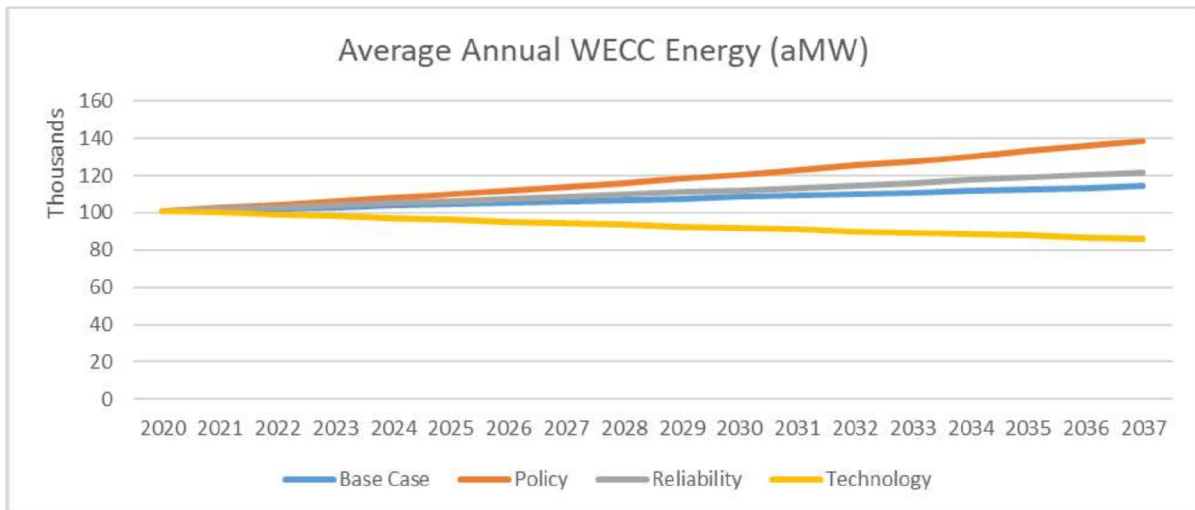


Figure 39: Total WECC-wide average annual energy

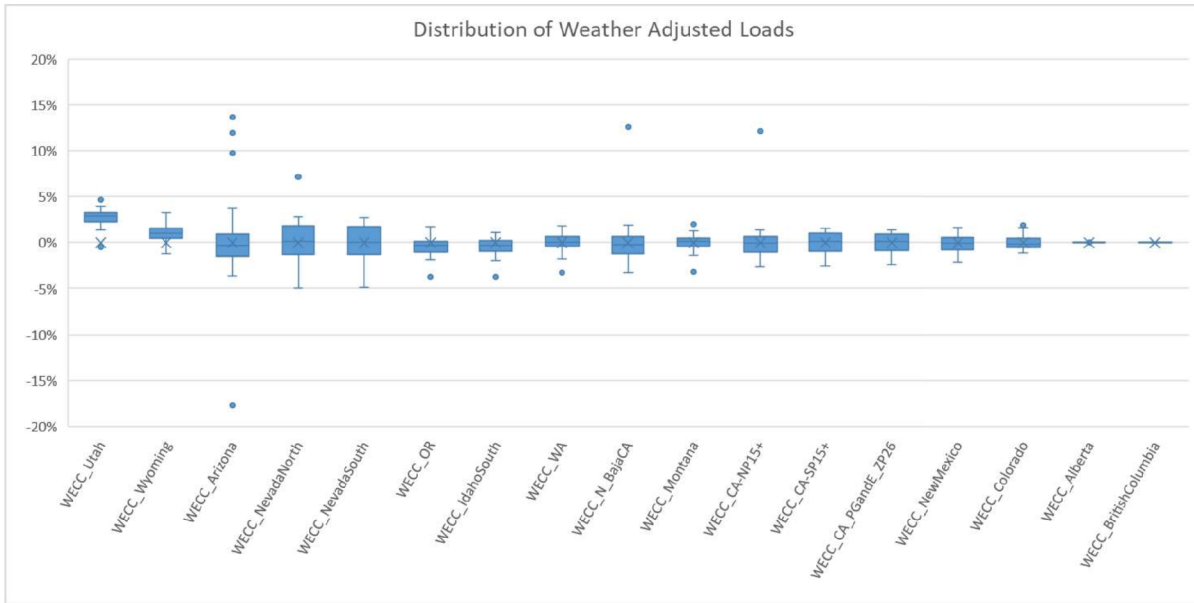


Figure 40: Normalized distribution of weather-adjusted loads (annual energy) as a percentage of the weather-normal load forecast

8.2.2 Fuel prices

Uncertainty in natural gas prices are modeled through AURORA risk runs. As discussed in Section 6.1.3 on modeling uncertainty, these risk runs take random draws from a defined distribution, standard deviation, and expected value. For each scenario, we assumed a different expected natural gas prices as shown in Figure 41.²⁴

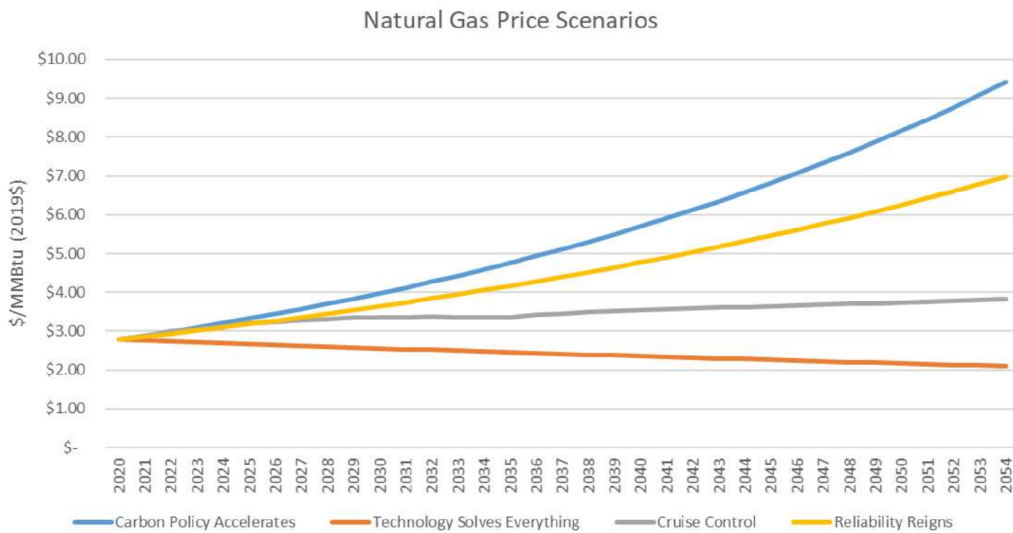


Figure 41: Expected natural gas price by scenario.

²⁴ Note that these prices do not include a carbon tax. The cost of carbon is a separate input and added to fuel costs during dispatch of gas generation.

8.2.3 Hydro capability

Although hydro generation resources exist in several regions in the WECC, the AURORA database only contains 1950-2007 generation for hydro resources in the Northwest. This means that hydro generation outside the Northwest are modeled assuming average water conditions. Unlike other load and gas price inputs, there are no scenarios around hydro generation. Each scenario made use of the same 58 historic water years discussed in Section 6.1.1.1. In future IRPs, we will consider how to incorporate alternative water scenarios into our WECC model using climate change projections.

8.3 OUTPUTS: CAPACITY EXPANSION MODEL

As of 2017, peak demand in the WECC was about 155GW and the total WECC nameplate generation capacity was about 256 GW. Based on the assumptions of our four scenarios, an additional 150 GW to 350 GW of new generation is needed to meet demand growth and policy constraints and offset any announced or economic resource retirements. Figure 42 shows new generation capacity built out by 2045 under each future scenario. The Carbon Policy Accelerates scenario exhibits the largest expected buildout of resources, primarily due to the relatively large amount of retirements combined with a very high growth in demand. The remaining three scenarios do not differ much in the magnitude of buildout. However, the Reliability Reigns scenario does show a significantly higher buildout of gas. In this case, it is due to relatively high demand combined with a reigning-in of carbon policies that drive higher penetrations of renewables.

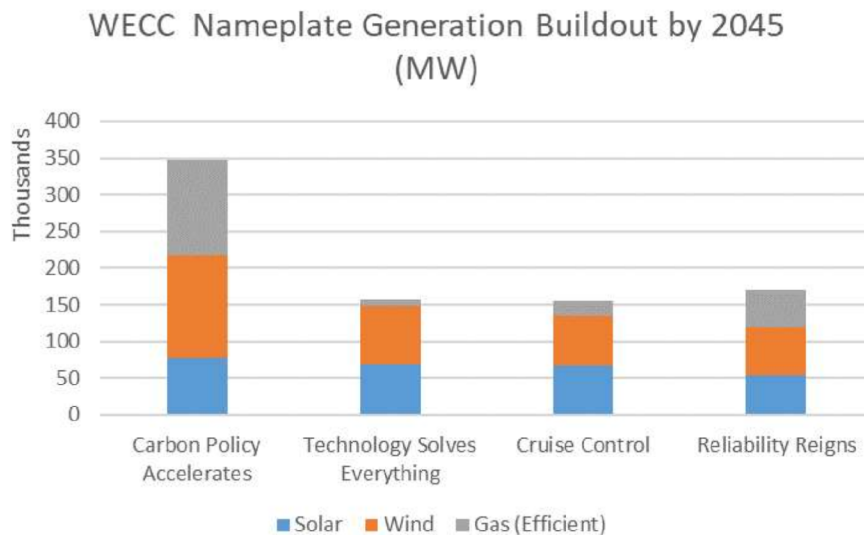


Figure 42. WECC 2045 buildout of resources by scenario

Figure 43 shows the economic retirement of gas and coal resources by scenario. Economic retirement is retirement selected by AURORA’s optimization algorithm and is added to the retirements included as updates to the database (Figure 32). According to these results, up to 20 GW of coal and gas capacity would economically retire under a Carbon Policy Accelerates scenario. Here, the Base Case scenario is less aggressive in terms of carbon policy and therefore results in the least amount of economic retirements. Technology Solves Everything has similar carbon policies as the Base Case, but because the

cost of renewables is assumed to be drastically lower, this scenario results in a relatively high economic retirement of older, less efficient gas and coal generation.

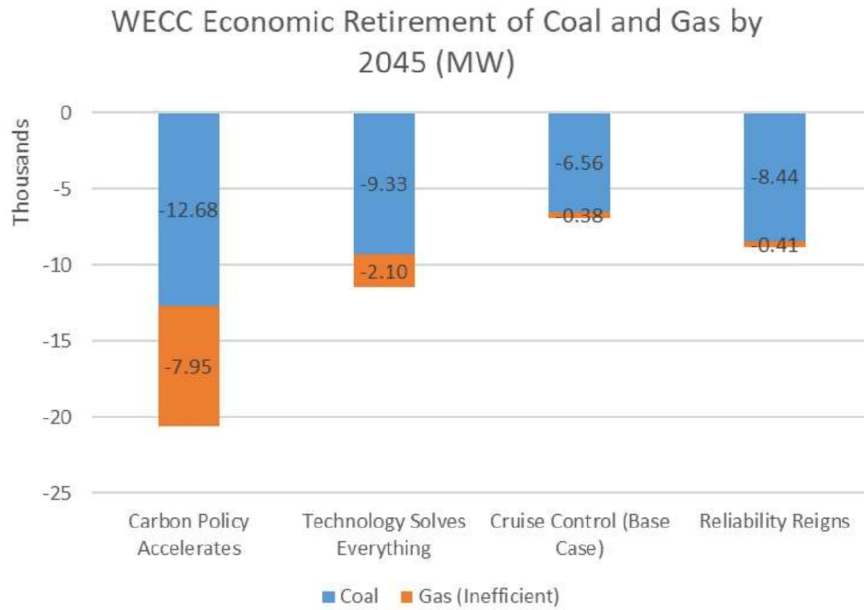


Figure 43: WECC wide economic retirement of emitting resources (coal and gas) by 2045

In addition to understanding generation changes at a WECC-wide level, it is also of interest to understand changes to Washington’s generation buildout. As of 2017, the total nameplate generation capacity in WA State was about 30 GW, roughly two thirds of which were hydro generation. According to our modeling results, between 9 GW and 30 GW of generation capacity buildout is needed by 2045 to meet projected demand. Notably, the Base Case and Technology Solves Everything scenarios do not result in any emitting resources. However, a lack of energy storage or other peaking capacity in the Carbon Policy Accelerates scenario necessitates almost 4.5 GW of gas to meet the projected growth in peak demand.

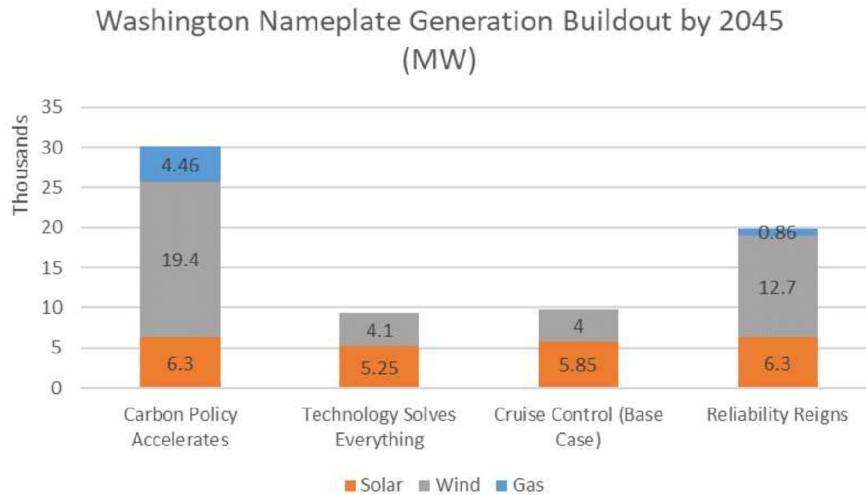


Figure 44: Washington only buildout of resources by 2045

8.4 OUTPUTS: PRODUCTION COST MODEL

Ultimately, our goal in developing the four scenarios in this analysis was to stress test portfolio performance in four conceivable future worlds defined by different combinations of price levels and volatility. This goal was accomplished for the most part, though we did not achieve as low of volatility as desired in the Reliability Reigns scenario. Figure 45 compares the resulting price forecasts for each of the four scenarios. The extremely high volatility of the Base Case scenario is notable. This is largely due to a lack of storage or other peaking capacity combined with high penetration renewables. Though volatility is also quite high in the Carbon Policy Accelerates scenario, it is less so due to the build out of more gas resources in that scenario. Both price level and volatility are low for the Technology Solves Everything scenario, though volatility would be even lower with the addition of more energy storage. As for the Reliability Reigns scenario, this world was supposed to have low price and high volatility, and that is the case on average. However, a more accurate description of this scenario is a world in which prices start high and volatility begins to increase overtime causing a regulatory shift in priorities that brings both price and volatility to lower levels.

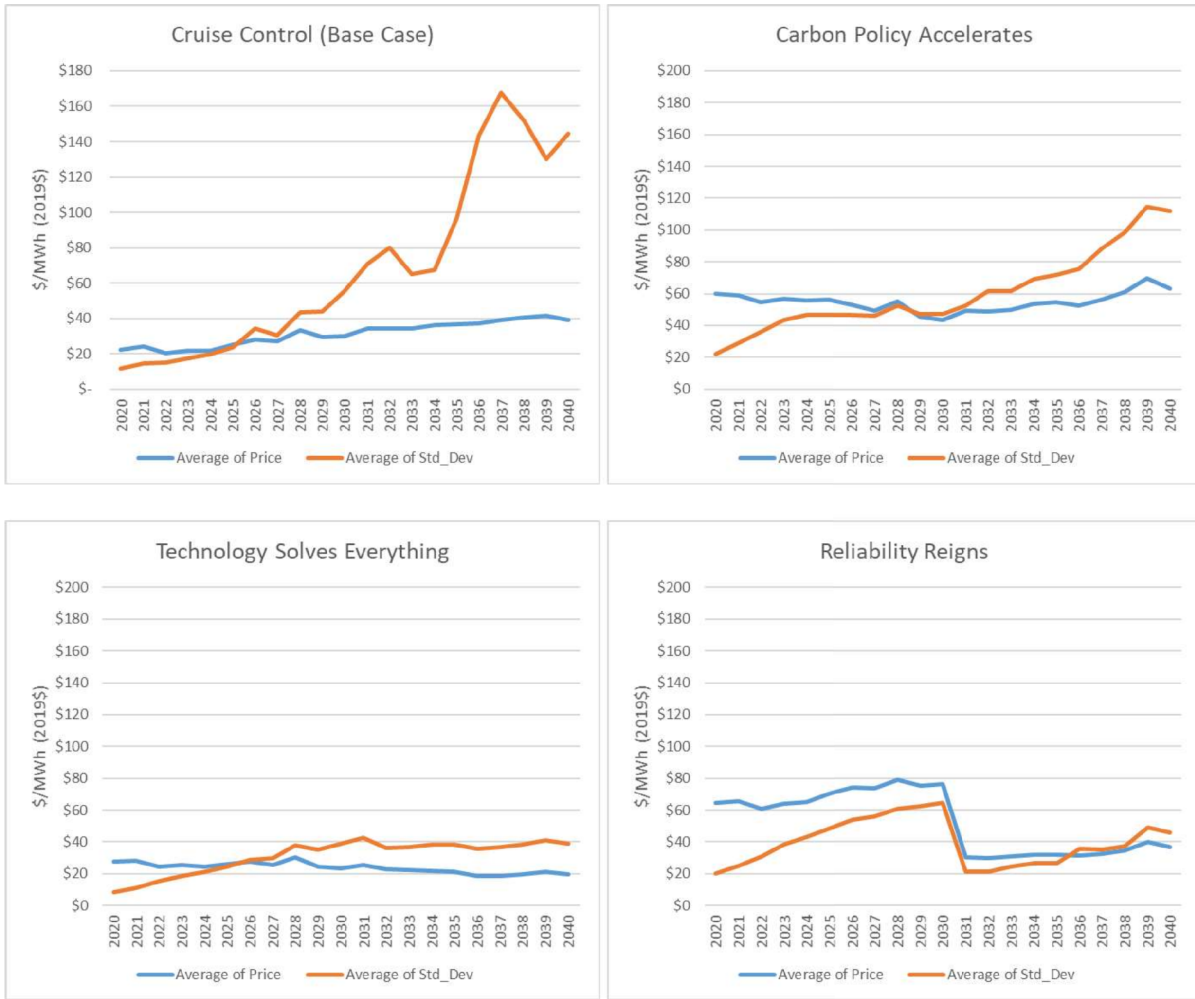


Figure 45: Comparison of price forecast by scenario

Lastly, the emission rates shown in Figure 46 represents *average* emissions WECC-wide. Average emissions rates were calculated by dividing the total amount of WECC emissions in a year by the total load in that same year. For our purposes, we are also interested in the *marginal* emissions at Mid-C. The marginal emission rate is the emission rate of the marginal generator (or the last, most expensive generator to turn on) in any given hour. Because our current modeling does not take calculate emissions hourly, we calculate emissions associated with market purchases as the average of all of the hourly marginal emission rates over a given year. Figure 47 compares the annual average of the marginal emission rate at Mid-C across the four scenarios. In the case of marginal emissions, both Technology Solves Everything and Carbon Policy Accelerates result in the lowest emission rates by 2040, while Reliability Reigns and the Base Case both have higher emission rates. For all scenarios, the marginal emission rates reduce substantially over time.

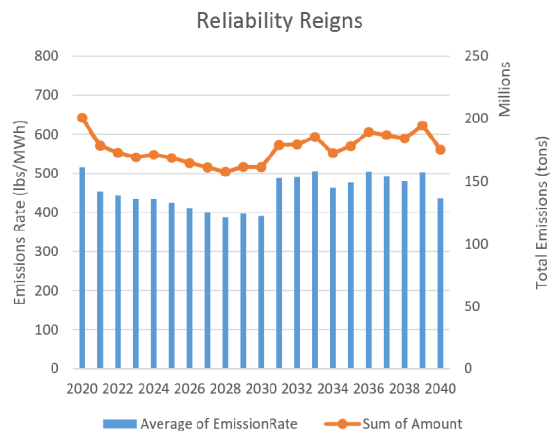
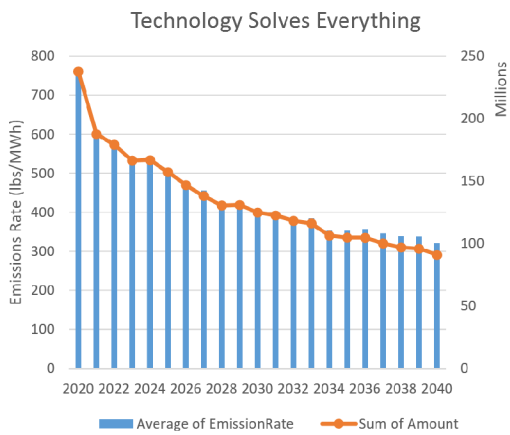
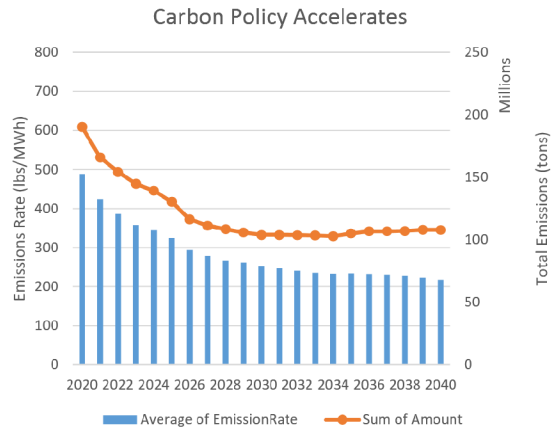
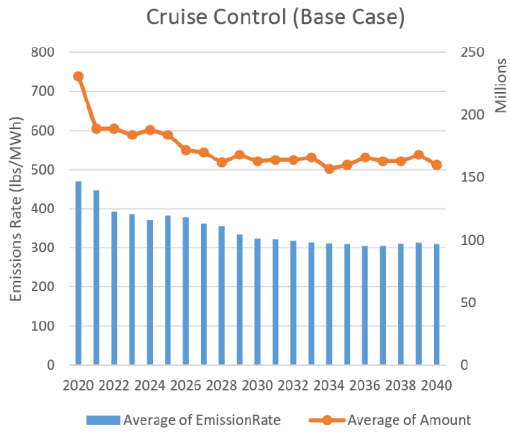


Figure 46: Comparison of WECC average annual emissions rates across scenarios

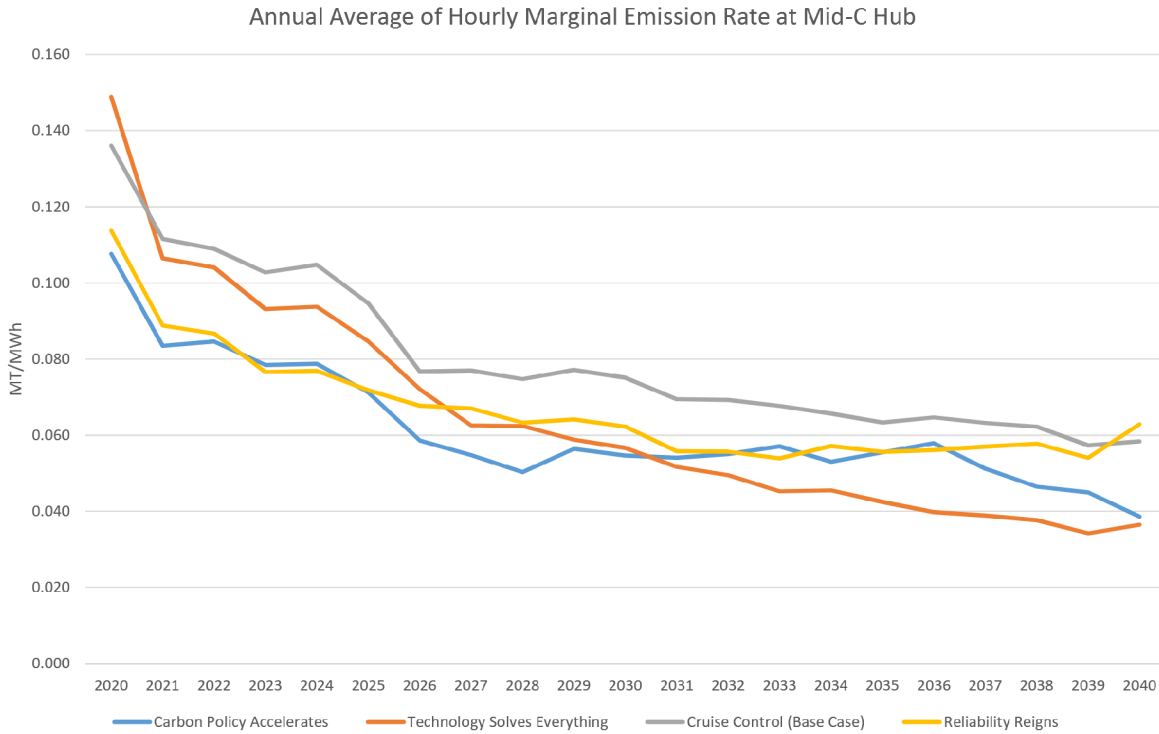


Figure 47: Comparison of annual average of hourly marginal emissions rates at Mid-C across scenarios

9 TACOMA POWER'S RESOURCE NEED

Because 2028 was many years away, our recent IRPs prior to this one assessed our resource need assuming that we would renew our BPA contract. In the 2020 IRP, we assess resource need without making the assumption that our current contracts are renewed when they expire.

9.1 RESOURCE ADEQUACY

Figure 48 through Figure 50 present resource adequacy results for our portfolio without contract renewals for each of the three metrics we use. The results indicate that simply letting the BPA contract expire without replacing it with anything leaves us severely inadequate. This is true even for the future scenario with substantial load decline (Technology Solves Everything). In 2028, when BPA comes offline towards the end of the year, NEUE goes up to around 5%, LOLH goes up to nearly 2,000 and LOLE goes up to nearly 100. After 2028, NEUE rises to between 10 and 25, depending on the scenario and year. This is approximately 10,000 to 25,000 times our NEUE cutoff of 0.001. LOLH rises to between 3,000 and 7,100 hours of shortfall per year, which is 1,300 to 3,000 times higher than our cutoff of 2.4. Finally, LOLE rises to between 185 and 335 days per year, which is 900 to 1,700 times higher than our cutoff of 0.2. To put these results in context, in the best-case scenario (the Technology Solves Everything scenario), between 10% and 16% of load would go unserved on average across years, and we would have shortfalls in approximately 3,000 to 5,000 hours per year (or in 35% to 57% of the 8,760 hours in a year) and in approximately 185 to 268 days per year (or in 53% to 71% of the 365 days in a year). In the

worst-case scenario, around 25% of load would go unserved in an average year, we would have shortfalls in around 80% of the hours in a year and in around 91% of days in a year. These results mean that we have a very large resource need once the BPA contract expires.²⁵

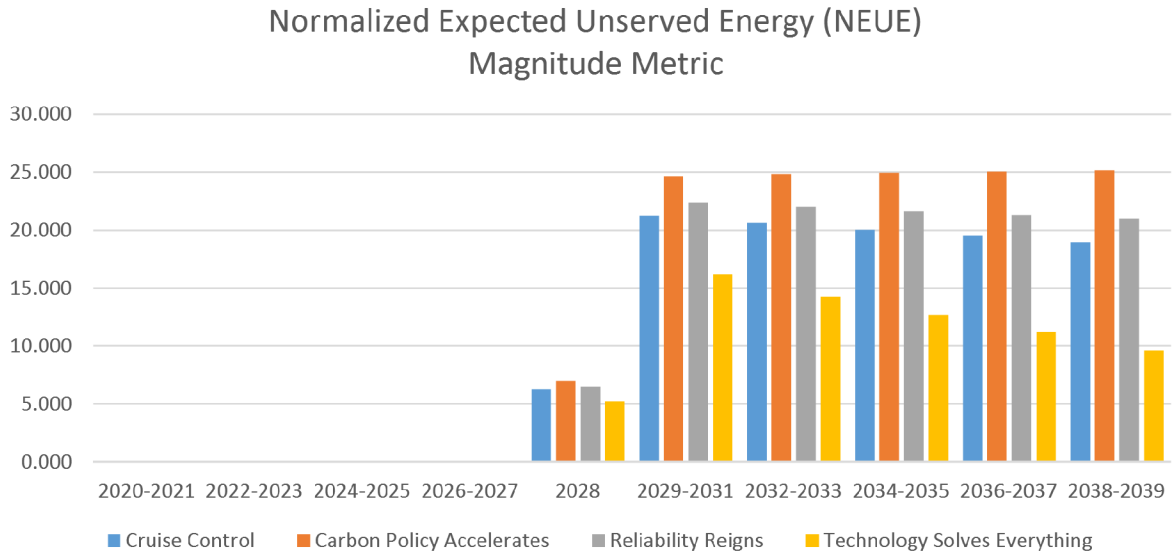


Figure 48: NEUE without contract renewals

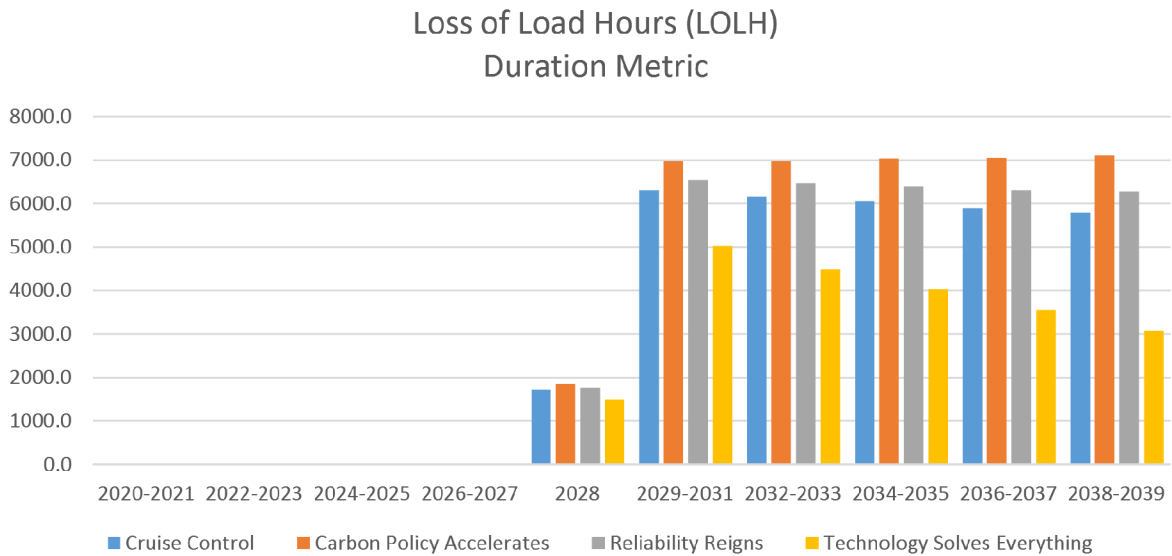


Figure 49: LOLH without contract renewal

²⁵ Occasional small failures of the adequacy metric are also found in the pre-2028 period. These are discussed in more detail in Section 12.2.1.

Loss of Load Expectation (LOLE) Frequency Metric

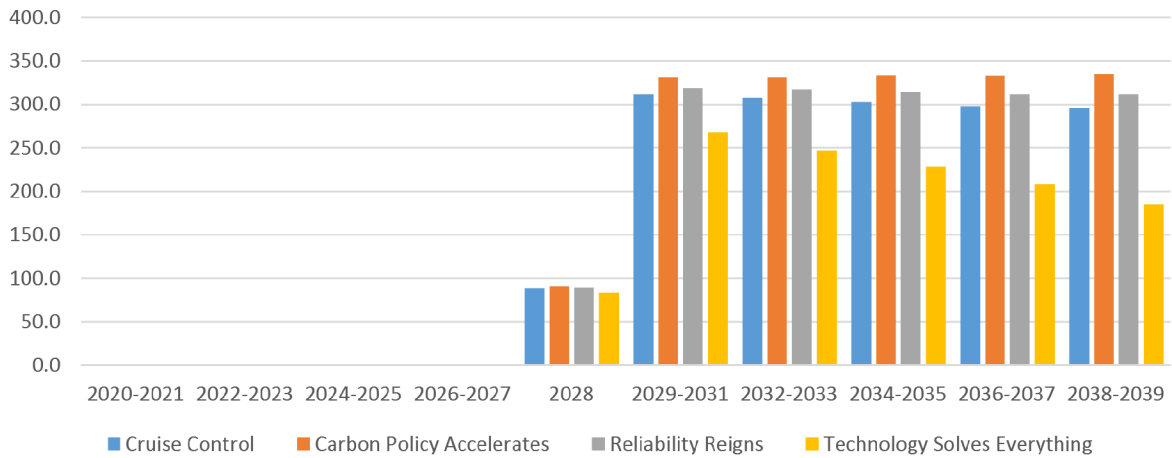


Figure 50: LOLE without contract renewals

9.2 WHEN IS THE NEED?

Figure 51 presents the average amount of unserved energy (i.e. the amount of load we wouldn't be able to serve with existing capacity) across different months of the year after 2028. Results indicate that there is a need for resource in every month of the year without the BPA contract, but the biggest shortfalls are mostly in the winter, when loads are higher. Shortfalls are also high in October, when loads are often starting to rise as temperatures drop but the rains have not always started, and in March, when loads are also often still high but snowmelt has not always started.

Unserved Energy by Month

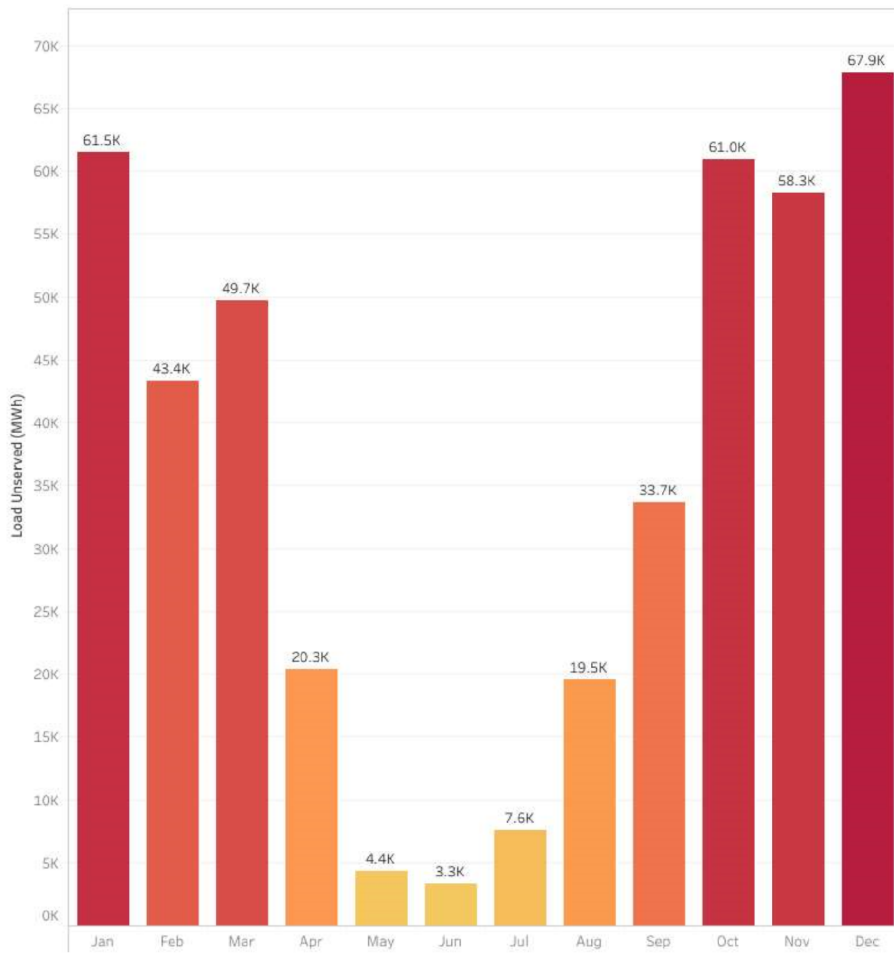


Figure 51: Shortfalls across months of the year

9.3 HOW BIG IS THE NEED?

We conducted an analysis to get a general sense of how large our resource need is without renewal of the BPA contract. Pure capacity²⁶ was added progressively to the system until the portfolio reached a point where it passed the utility’s adequacy standard. Figure 52 presents results from this exercise for one of our resource adequacy metrics—the LOLE metric—for the Cruise Control (Base Case) scenario. For this scenario, approximately 625 MW of pure capacity is needed to ensure that we are adequate in all years after 2028. Results differ slightly by scenario and metric. Most of the resources considered in the IRP do not provide pure capacity, however, and this assessment of need is useful primarily as a point of reference.

²⁶ For the purposes of this analysis, pure capacity means capacity that is always available.

Loss of Load Expectation (LOLE) Frequency Metric

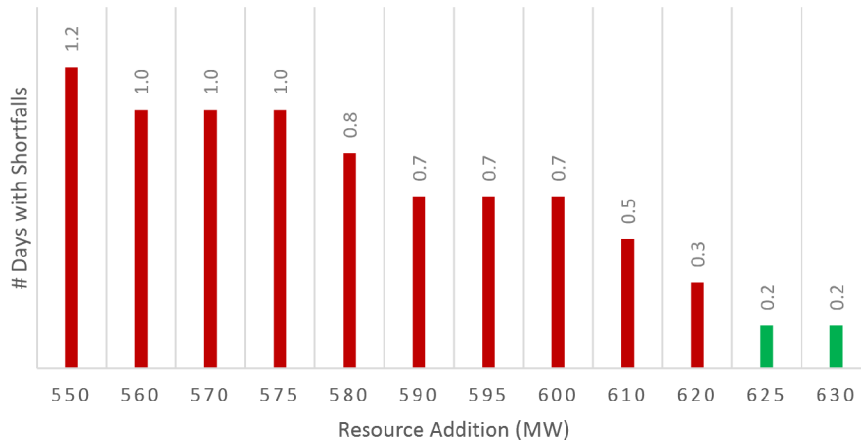


Figure 52: Assessment of resource need

10 PORTFOLIO OPTIONS

10.1 RESOURCES CONSIDERED

We considered many different utility scale renewable and nonrenewable generating technologies as well as demand-side resources. Resources that were ultimately selected for further consideration are described in this section. Certain resources (Columbia Basin Hydro, BPA, etc.) can only be acquired as purchased power. Others (for example, enhancements to existing Tacoma Power generating resources) are most practically acquired as a Tacoma Power-owned resources while others (wind, solar, natural gas, etc.) could be acquired either as purchased power or as a resource we build.

10.1.1 Columbia Basin Hydro (CBH)

We receive a small amount of generation from Columbia Basin Hydropower (CBH) through contracts for 50% of the output from five hydroelectric projects on irrigation canals. Supply is limited to the irrigation season (mainly summer months). The contracts being to expire in 2022 and fully terminate in 2027. The CBH contract is represented in our system model by its two largest resources, Summer Falls and Main Canal. Each resource is modeled as a fixed amount of available energy during certain periods of the year, as described in Table 6.

Table 6: SAM model of available CBH energy

	Oct 26 – Apr 30	May 1 – Jul 31	Aug 1 – Sep 14	Sep 15 – Oct 14	Oct 15 – Oct 25
Summer Falls	0 aMW	47 aMW	47 aMW	25 aMW	25 aMW
Main Canal	0 aMW	11 aMW	12 aMW	7 aMW	0 aMW

10.1.2 Bonneville Power Administration (BPA)

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.

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, based on the BPA net requirement and our load forecast, which changes every year.

The alternative BPA product we model is the Block with Shaping Capacity product (referred to as Shapeable Block in the IRP). The Shapeable Block is modeled based on a monthly diurnal shaping factor and with shaping capacity, allowing Heavy Load Hour (HLH) Block to be shaped more flexibly than the Block portion of the Slice/Block product. Tacoma Power’s historical weather-normalized retail loads determine how this resource gets shaped.

10.1.2.1 Considerations

Some of the portfolios considered include the addition of wind or solar resources that partially offset our BPA power supply (i.e. use these new resources to reduce BPA’s net requirement calculation for Tacoma Power). An assumption implicit in these portfolios is that we will be able to reduce its net requirement, but there is some minor risk that this will not be the case. Federal statute leaves a great deal of discretion to the BPA Administrator in determining how to interpret BPA’s responsibility to meet public entities’ needs, and it’s possible that a resource acquired after a certain date (which is not known at this time) would not count towards reducing our net requirement. There is also a risk that, if we were able to reduce our net requirement, we would not be able to increase our supply of BPA power in future contracts by ridding ourselves of other resources. If the need for flexible, carbon-free resources like hydropower grows in the future, which is likely, we could find ourselves without the same access to a valuable product. This is a risk that is not captured in the 2020 IRP analysis but should be carefully considered prior to acquiring other new resources and using them to replace BPA either fully or partially.

10.1.3 Wind and solar

Since they are intermittent and not easily dispatched, wind and solar were modeled as fixed profiles. The solar profiles were based on potential generation in Eastern Washington. For wind, we considered three different locations, each with different capacity factors and profile shapes: Eastern Washington wind, Gorge wind, and Montana wind. For each resource in each location, we selected six random yearlong hourly profiles. Some profiles came from actual historic generation output while other profiles, particularly Montana wind, came from modeled NREL data. While most of the modeled data were similar to actual generation data, it is worth noting that the six Montana profiles were all from NREL’s modeled data and exhibited a significant number of hours where the wind output was either zero or maximum power. This was not observed in the profiles based on actual generation and has serious implications in terms of resource adequacy. Moving forward, we will need to consider whether our current modeled profiles need to be adjusted.

It is important to note that some of the portfolios considered in the 2020 IRP (those in which BPA is replaced primarily by wind and demand response) require very large quantities of wind resources (up to 1,500MW of wind across Oregon, Washington and Montana). The amount of renewable generation and transmission required in these portfolios is likely to be difficult or even impossible for us to acquire.

10.1.4 Cowlitz River Project enhancements

A number of potential enhancements to our existing capacity were considered, of which two were selected for inclusion in the IRP—the addition of a third generator in an open bay at our Cowlitz River Project and the addition of a simple pumped hydro unit in the same location. The IRP analysis assumes that any addition to the Cowlitz River Project would be owned and operated by Tacoma Power, as this is the most practical option given that we wholly own the Cowlitz River Project.

The generator addition is simply modeled as an additional, third generator at the Cowlitz River Project. The pumped hydro resource is modeled to move water from the lower pond (Mayfield) back into the upper pond (Mossyrock). Though initially set up similarly to the third generator resource, the pumped hydro resource takes into account that a pump is not 100% efficient, and resets hydro generation resource parameters accordingly. In its current iteration, it is important to note that the pumped hydro resource model is prone to over-optimize during non-resource adequacy runs. This is most likely a result of the assumption that there is a liquid market at the single price of power for a specific hour.

We conducted a mini-analysis of different potential generator sizes for the Cowlitz River Project enhancements in order to choose an optimal generator size for the IRP analysis. While none of the initial assessments was found to be cost-effective, the 150MW generator performed best from a cost-benefit perspective. A great deal of additional analysis would need to be performed to fine tune the appropriate generator size if we were to seriously consider either a generator addition or development of pumped storage at the Cowlitz River Project.

10.1.4.1 *Transmission considerations*

When considering any expansion to our existing projects, it is important to understand whether we will have the transmission available to transport the additional generation. Energy produced at the Cowlitz River Project is delivered to Tacoma by an exchange agreement with BPA, which is currently limited to 560MW of transfer capability. To assess whether additional transmission capacity would be needed to support additional generation, we looked at modeled generation plus operating reserves at Cowlitz in several different years and assessed how often we are up against the current 560MW limit. We also compared generation plus reserves held at Cowlitz to a potential higher limit of 620 MW.

In the weather years with the most generation among those we looked at (1995 and 1996), we had at least 40 MW of room 90% of the time (i.e. in 90% of hours for that year) and at least 5 to 9 MW of room 99% of the time. In most other weather years we looked at, we had at least 70 MW of room 90% of the time and at least 25 MW of room 99% of the time. This suggests that we could likely manage an 85MW generator addition (25MW + 60MW) within an expanded 620MW transmission limit easily and could manage a 100MW generator addition without too much trouble. However, it is likely that we would start running up against our transmission limit more often if we installed a generator of 120MW or more unless BPA were to allow us to use more than 620MW of transmission. Because the size of the generator addition considered in this IRP is 150MW, it may be that transmission limits would constrain additional generation in a way that is not reflected in our current modeling. If the utility were to

investigate such an investment in more detail, a more thorough analysis of this problem would be needed.

10.1.4.2 FERC Licensing considerations

FERC issued a new license to Tacoma Power for the Cowlitz River Project in 2002 for a term of 35 years. While the enhancements modeled in the IRP would require only an amendment to our current FERC license for the Cowlitz River Project rather than a full relicensing of the project, the amendment process can be a lengthy and complex process that is nearly equivalent to a full licensing process, depending on the degree of opposition to the proposed amendment. The licensing process can take many years (even decades). We expect that the amendment process would take at least two years and could easily take five years or longer. Not only could an amendment be time-consuming, but it could also result in substantial costs to the utility if it turns into a process akin to a full relicensing. Assumptions for the potential costs associated with the licensing amendment process are discussed in Section 11.1.4.3.

10.1.5 Other resources to support renewables (natural gas, nuclear, DR)

10.1.5.1 Natural gas

The gas plant modeled in SAM is a flexible unit set up to economically dispatch. Given the heat rate of the gas plant and its various operating costs, the generator will dispatch when the wholesale price of electricity is high enough to offset those costs. Included in the costs are fuel costs, variable O&M costs and start-up costs.

While natural gas is a flexible, reliable and lower carbon than some other sources of thermal generation like coal, it is much higher carbon than other resources considered in the 2020 IRP portfolios. This raises a number of potential concerns, including potential customer distaste for adding natural gas to the portfolio and potential difficulties in complying with CETA in the future (after 2044).

10.1.5.2 Nuclear

Nuclear power is a well-understood technology that is both carbon-free and reliable enough to serve as a baseload plant. Currently, the Utah Associated Municipal Power Systems (UAMPS)²⁷ is working with NuScale Power to develop a 720 MW facility with 12 small nuclear modular reactors in Idaho. This project served as the basis for the nuclear resource we considered in the IRP. Recent advancements in nuclear technology include small modular reactor nuclear (SMR), which not only has all of the properties of traditional nuclear but does also does not require periods when the plant does not generate, as refueling can be batched by module. It also can be flexible unlike traditional nuclear. However, because the cost of nuclear power is so high, it would be unlikely for Tacoma to operate a SMR plant at a low load factor. 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.

It is common for very large generation investments of any kind (and especially nuclear generation investments) to experience cost overruns and build times that are longer than expected, and these risks should be considered in the case of small modular nuclear. Cost risks are accounted for in the price assumption for nuclear (described in Section 11.1.6). While UAMPS plans to have all small modular reactors built and in operation by 2027²⁸, just prior to the end of the region's BPA contract, there is

²⁷ <https://www.uamps.com/>

²⁸ <https://www.nuscalepower.com/newsletter/nucleus-fall-2018/uamps-update>

some risk that the project could experience unforeseen delays. This potential build delay is not taken into account in the 2020 IRP analysis but should be considered carefully. Finally, while nuclear is a reliable source of carbon-free power, it is not without environmental risks, and customer sentiment about nuclear power should be sought and weighed carefully before acquiring this resource.

10.1.5.3 Demand response

There are many types of demand response, each requiring a different level of modeling complexity. For this IRP, we modeled a very simple type of industrial demand response product that can reduce load on short enough notice to serve as operating reserves. We model this resource in SAM by simply reducing the required level of operating reserves held by our generation by 1MW for every 1MW of demand response.

For future resource plans, we expect to improve the modeling complexity of SAM to include other types of demand response. Large industrial demand response programs are the low hanging fruit, but they do not cover the wide range of DR possibilities. Incorporating this in the IRP however, requires a fundamental shift in how we model loads and the constraints that define their flexibilities.

10.1.6 Energy conservation

Energy conservation is our first choice energy resource. It is the only resource that we have acquired for many years and remains a priority resource in the 2020 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 amount of cost-effective conservation identified in our Conservation Potential Assessment (CPA)²⁹ as a given and deducts it directly from loads. A priority objective for the next IRP is to model conservation directly as a resource in the IRP and allow it to compete directly with other resources.

The 2020 CPA was developed using a bottom-up approach that included (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) an estimate of Technical potential, Technical Achievable potential, and Economic Achievable potential energy savings at the measure level for 2020-2039. The 2020 CPA identified a ten-year potential of 233,660 MWh, or 26.7 aMW, by 2029. Key opportunities for savings included the continuation of LED lighting programs, implementation of strategic energy management initiatives in the large commercial sectors, efficient HVAC technologies, industrial motor VFDs, and compressed air system upgrades.

10.2 HOW ARE RESOURCES COMBINED INTO PORTFOLIOS?

The final list of portfolios modeled in the 2020 IRP is provided in Table 7. Three major types of portfolios were evaluated:

²⁹ <https://www.mytpu.org/wp-content/uploads/Tacoma-Power-2020-2039-CPA-Report-FINAL.pdf>

- 1) Portfolios in which BPA is renewed with the same product as our current contract (the Slice/Block product)
- 2) Portfolios in which BPA is renewed with a different product—a Block product that provides a more consistent supply power across different water years, with some flexibility to shape when we get the power across certain hours of the day (referred to in this analysis as the Shapeable Block product), and
- 3) Portfolios in which the BPA contract is not renewed

Table 7: Final list of portfolios analyzed

Portfolio Name	Resources in Portfolio
Slice/Block Only	Tacoma Power Hydro + BPA Slice/Block
Slice/Block + CBH	Tacoma Power Hydro + BPA Slice/Block + renew CBH
Slice/Block + 50MW DR	Tacoma Power Hydro + BPA Slice/Block + 50 MW Demand Response
Slice/Block + Pumped Storage	Tacoma Power Hydro + BPA Slice/Block + 150 MW Pumped Storage at Cowlitz River Project
Slice/Block + Add Generator	Tacoma Power Hydro + BPA Slice/Block + 150 MW 3rd Generator at Cowlitz River Project
Reduce Slice/Block with E. WA Wind	Tacoma Power Hydro + BPA Slice/Block + 100 MW Eastern WA Wind (partially replace BPA)
Reduce Slice/Block with Gorge Wind	Tacoma Power Hydro + BPA Slice/Block + 100 MW Gorge Wind (partially replace BPA)
Reduce Slice/Block with Solar	Tacoma Power Hydro + BPA Slice/Block + 60MW Solar (partially replace BPA)
Slice/Block + 10MW DR	Tacoma Power Hydro + BPA Slice/Block + 10 MW Demand Response
Slice/Block + 80MW Wind	Tacoma Power Hydro + BPA Slice/Block + 80 MW WA Wind
Slice/Block + 60MW Wind +10MW DR	Tacoma Power Hydro + BPA Slice/Block + 60 MW WA Wind + 10 MW Demand Response
Shapeable Block Only	Tacoma Power Hydro + BPA Shapeable Block
Shapeable Block + 50MW DR	Tacoma Power Hydro + BPA Shapeable Block + 50MW Demand Response
Shapeable Block + Pumped Storage	Tacoma Power Hydro + BPA Shapeable Block + 150MW Pumped storage at Cowlitz River Project
Shapeable Block + Add Generator	Tacoma Power Hydro + BPA Shapeable Block + 150MW 3rd Generator at Cowlitz River Project
Reduce Block with E. WA Wind	Tacoma Power Hydro + BPA Shapeable Block + 100 MW Eastern WA Wind (partially replace BPA)
Reduce Block with Gorge Wind	Tacoma Power Hydro + BPA Shapeable Block + 100 MW Gorge Wind (partially replace BPA)
Reduce Block with Solar	Tacoma Power Hydro + BPA Shapeable Block + 60MW Solar (partially replace BPA)
Wind + DR (no BPA)	Tacoma Power Hydro + 650MW WA Wind + 650MW Gorge Wind + 100MW MT Wind + 300MW DR

Portfolio Name	Resources in Portfolio
Wind + PSH + DR (no BPA)	Tacoma Power Hydro + 700MW WA Wind + 700MW Gorge Wind + 100MW MT Wind + 250MW DR + 150MW Pumped storage at Cowlitz River Project
Wind + Add Gen + DR (no BPA)	Tacoma Power Hydro + 700MW WA Wind + 700MW Gorge Wind + 100MW MT Wind + 250MW DR + 150MW 3rd Generator at Cowlitz River Project
Wind + SMN + DR (no BPA)	Tacoma Power Hydro + 700MW WA Wind + 700MW Gorge Wind + 100MW MT Wind + 200MW DR + 100MW Small Nuclear
Wind + Gas + DR (no BPA)	Tacoma Power Hydro + 650MW WA Wind + 650MW Gorge Wind + 100MW MT Wind + 100MW DR + 200MW Natural Gas

10.2.1 Portfolios with BPA

Eighteen of the twenty-three final portfolios include BPA renewal. Of those, 11 renew BPA with our current Slice/Block product while 7 renew BPA with the Shapeable Block product instead. For both sets of portfolios, renewal of the relevant BPA product is either (1) renewed at current net requirement levels as our only additional resource besides conservation (2 portfolios), (2) renewed at current net requirement levels and another resource is added (7 of the Slice/Block portfolios and 3 of the Shapeable Block portfolios) or (3) renewed at a reduced net requirement level, with another resource added to partially replace the reduce BPA take (3 of the Slice/Block portfolios and 3 of the Shapeable Block portfolios).

After the initial set of portfolios was run, early results indicated that Slice/Block was outperforming other options in terms of cost and financial risk but presented some minor adequacy risks in extreme low water conditions. Three additional portfolios were added, each with small amounts of additional capacity, to assess whether these small capacity additions were sufficient to shore up the minor adequacy risk. These three portfolios are *Slice/Block + 10MW DR*, *Slice/Block + 80MW Wind* and *Slice/Block + 60MW Wind + 10MW DR*.

10.2.2 Portfolios without BPA

In order to determine the appropriate quantities of resources in portfolios where our BPA contract is not renewed, a combination of judgment and an iterative process to minimize unserved energy was used. Judgement was used to estimate the maximum amount of transmission that we would likely be able to get for out-of-state resources (namely, Montana wind and small modular nuclear energy located in Idaho). For both of these out of state resources, a maximum size of 100MW was assumed due to transmission constraints. For other resources (Eastern Washington wind, Gorge wind, solar, demand response and natural gas), an iterative process was used to incrementally add resources until a portfolio passed our resource adequacy standard for a smaller set of the weather years than the 58 included in the full analysis. A number of the iterations included solar resources, but solar contributed very little to resource adequacy and was dropped as part of the non-BPA portfolios. In all cases, large quantities of wind are required. The amount of renewable generation and transmission needed in these portfolios would be difficult or impossible for us to acquire. Unrealistically large quantities of demand response (up to 300MW) are also needed. This is equivalent to approximately one third of Our typical peak load and far larger than what is likely available within our service area. Thus, the five portfolios without BPA should be thought of as portfolios that ask what it might take to completely replace BPA with other non-

emitting resources and are not feasible at this time. Their performance is nonetheless evaluated to understand whether they might present a competitive option if they were feasible.

11 RESOURCE COSTS

11.1 GENERATION AND CONTRACT COSTS

11.1.1 Columbia Basing Hydro (CBH)

Our contract with CBH includes charges to cover operating and capital costs and an additional incentive charge. Rather than project different types of charges separately, CBH costs are simply modeled as a single per-MWh charge that escalates over time. Projections of the future cost of CBH are based on the historic trajectory of CBH costs. Per-MWh cost assumptions for the 20-year period are presented in Table 8 below.

Table 8: Columbia Basin Hydro (CBH) cost assumptions

Year	CBH Cost (\$/MWh)
2020	\$31.06
2021	\$31.71
2022	\$32.36
2023	\$33.03
2024	\$33.72
2025	\$34.42
2026	\$35.13
2027	\$35.86
2028	\$36.60
2029	\$37.36
2030	\$38.13
2031	\$38.92
2032	\$39.73
2033	\$40.55
2034	\$41.39
2035	\$42.25
2036	\$43.12
2037	\$44.01
2038	\$44.93
2039	\$45.86

11.1.2 Bonneville Power Administration (BPA) products

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.

11.1.2.1 TOCA

Our TOCA (Tier One Cost Allocator) is a key determinant of the share of resources to which we are entitled and BPA costs for which we are responsible. The TOCA is calculated as our net requirement divided by BPA's Rate Period High Water Mark of 7,027 aMW (Equation 7). Our net requirement is calculated as the difference between our expected load under normal weather and the amount of resources the utility has under critical water conditions (Equation 8). In our modeling, we adjust our net requirement by adjusting loads for each of our four scenarios of the future and the amount of resources we have for any portfolio that displaces some of our BPA purchases with an alternative resource post-2028. These adjustments to our net requirement adjust our TOCA in turn.

Equation 7: BPA TOCA calculation

$$TOCA^{TPWR} = NR^{TPWR} / RHWM$$

Equation 8: Net Requirement calculation

$$NR^{TPWR} = TotalLoad^{TPWR} - CriticalWaterResources^{TPWR}$$

11.1.2.2 Composite charge

The composite charge is by far the biggest component of costs. It is calculated as a fixed share of BPA's operating costs. The share of costs is determined by a utility's TOCA (Equation 9).

Equation 9: BPA composite charge

$$Composite_m = TOCA * 100 * BP20Final$$

The variable *BP20Final* is the same across all months and across most of BPA's products, including the two products modeled in the IRP. In the most recent rate case, *BP20Final* is equal to \$1,980,553 per month, or \$23,766,636 per year. Because it is based on operating costs that do not vary with power market conditions, we assume no change to costs over time other than inflation in our medium cost case. For the high cost case, we assume a real annual cost increase of 2%. For the low cost case, we assume only a very moderate decline of ½% per year because it is unlikely that BPA would be able to sustain a substantial reduction in operating costs over a 20-year period.

11.1.2.3 Non-Slice charge

The non-slice charge is a function of the "Non Slice Rate", which is a function of BPA's total costs and the non-slice TOCA (currently equal to 72.0686). We assume that the non-slice TOCA remains constant.

Equation 10: Non-Slice charge for Slice/Block product

$$NonSlice_m^{Slice} = (TOCA - SliceShare) * 100 * NonSliceRate$$

Equation 11: Non-Slice charge for Shapeable Block product

$$NonSlice_m^{Block} = TOCA * 100 * NonSliceRate$$

Equation 12: BPA non-Slice rate

$$NonSliceRate = TotalCosts / NonSliceTOCA$$

Total costs for BPA are divided into four buckets: (1) non-slice costs, (2) other revenues or costs, (3) firm surplus and committed resources and (4) secondary sales. The first two reflect certain operational costs and the latter two are a bill credit to customers based on wholesale power sales made by BPA.

Equation 13: BPA total costs for determining non-Slice rate

$$\text{TotalCosts} = \text{NonSliceCost} + \text{OtherCost} + \text{FirmSurplus} + \text{Secondary}$$

The values for Non-Slice Costs and Other Costs are assumed to be fixed at \$136,771,000 and \$15,997,000 per year, respectively. Because the value of power sales is dependent on market prices, however, the bill credit from wholesale revenues is more complicated to estimate accurately without directly modeling BPA operations.

We start with the simplifying assumption that the incremental credit we would receive from BPA with Block products is equal to the revenues we would make from selling the incremental energy received under the Slice contract, adjusted for transmission costs. This assumption implies that BPA and we are equally capable of marketing our share of the federal system. We assume transmission costs associated with marketing the power are equal to approximately \$750,000 for both Tacoma Power and BPA. From this assumption, we back out a value for Firm Surplus and Secondary sales using Equation 14: Calculating firm surplus + secondary sales below and use that to calculate the revenue credit under Slice and Shapeable Block (Equation 15 and Equation 16, respectively).

Equation 14: Calculating firm surplus + secondary sales

$$\text{FirmSurplus} + \text{Secondary} = \frac{(\text{Revenue}^{\text{Slice}} - \text{Revenue}^{\text{ShapedBlock}}) * \text{NonSliceTOCA}}{100 * \text{SliceShare}}$$

Equation 15: Calculating revenue credit under Slice/Block product

$$\text{RevenueCredit}^{\text{Slice}} = (\text{TOCA} - \text{SliceShare}) * 100 * \frac{\text{FirmSurplus} + \text{Secondary}}{\text{NonSliceTOCA}}$$

Equation 16: Calculating revenue credit under Shapeable Block product

$$\begin{aligned} \text{RevenueCredit}^{\text{Block}} &= \text{TOCA} * 100 * \frac{\text{FirmSurplus} + \text{Secondary}}{\text{NonSliceTOCA}} - 750,000 \\ &= \text{RevenueCredit}^{\text{Slice}} + (\text{Revenue}^{\text{Slice}} - \text{Revenue}^{\text{ShapedBlock}}) - 750,000 \end{aligned}$$

11.1.2.4 Load shaping charge

The load shaping charge is a separate fee for heavy load and light load hours, which is determined based on the difference between our heavy (or light) load hours and BPA's heavy (or light load hours) scaled to our TOCA in the case of the Shapeable Block product and scaled to our TOCA minus its share of Slice in the case of the Slice product. This difference is then multiplied by BPA's load shaping charge rate for heavy and light load hours. The charge varies across month and can be negative (a credit) or positive (a charge). Because this is a small component of BPA product costs, we will assume that load shaping charges remain constant in real terms (i.e. in 2020 dollars). The total monthly and annual load shaping charges for each product are listed in Table 9 below.

Table 9: Load shaping charge assumptions

Month	Slice/Block	Shapeable Block
January	(\$266,343)	(\$587,797)
February	(\$301,023)	(\$626,774)
March	\$537,449	\$1,302,050
April	\$775,043	\$1,862,097
May	\$608,052	\$1,435,252
June	\$554,175	\$1,310,462
July	\$487,429	\$1,144,276
August	(\$224,313)	(\$442,572)
September	(\$535,699)	(\$1,180,757)
October	(\$488,881)	(\$1,058,424)
November	(\$613,450)	(\$1,351,162)
December	(\$179,677)	(\$358,705)
Total	\$352,761	\$1,447,947

11.1.2.5 Demand charge

A demand charge applies only to two of BPA’s products: Shapeable Block, which we are modeling in the IRP, and Load Following, which we are not modeling. The demand charge is a small share of the cost of the product. It is fixed over the current contract period based on peak loads from the year 2010.

Because we do not know how the demand charge might differ in the future, we assume that it will remain the same in the next contract period. We have estimated the current annual cost of the demand charge that we would pay to be \$3,246,597.

11.1.3 Wind and solar

We weighed the risks and benefits of purchasing power vs. building its own wind or solar resource and found that it would be most prudent to consider power purchase agreements (PPAs) rather than a Tacoma Power-owned resource build. The key reasons for this assessment were (1) we have substantial expertise in the management and operation of hydropower resources but none in the construction, management or building of utility-scale wind or solar resources, and (2) securing a fixed price PPA from a wind or solar developer was determined to be less risky than asking our customers to take on the build cost risk.

Wind and solar generation costs are thus modeled as simple \$/MWh PPA costs. Members of our resource planning group met with several wind and solar developers to learn more about what projects were being built and the typical terms around projects, including indicative pricing. We received three indicative pricing estimates for smaller-sized (less than 100MW) solar projects and four indicative estimates for wind projects. Because we signed non-disclosure agreements with each developer before entering into conversations with them, the indicative pricing estimates provided by developers are not stated. We used the range of prices provided by developers to independently estimate low, medium and high per-MWh costs that range from \$39 for our low estimate to \$43.50 for our high estimate for small solar PPAs East of the Cascades in Washington or Oregon and from \$30 to \$40 for our low and high estimates for larger wind PPAs in Washington and Oregon when the solar or wind resource is acquired prior to the expiration of tax credits in 2024. While indicative pricing for smaller-scale wind PPAs was not available, we found that indicative pricing estimates for larger-scale solar PPAs (i.e. 100MW or larger)

tended to be roughly 10% less expensive than smaller PPAs due to economies of scale and applied a similar 10% cost adder to small (less than 100MW) wind PPAs, bringing the range of costs for smaller wind contracts to between \$33 and \$44 per MWh for the low and high cost estimates, respectively.

The following adjustments were also made:

- (1) **Adjustments for inflation:** Most pricing estimates we received were in fixed terms. Because other IRP outputs are in real (2020) dollars rather than nominal dollars, all future prices were discounted by inflation (assumed to be 2.1% annually).
- (2) **Adjustments for changes to tax credits:** We adjust PPAs that start in 2028 to account for expiration of tax incentives in the following ways:
 - a. **Solar:** For solar, we assume that costs are 20% higher in the high cost estimate case³⁰, 10% higher in the medium cost estimate case (assuming that the tax credit expires but that incremental technological/cost saving improvements make up much of the difference) and no higher in the low cost estimate case.
 - b. **Wind:** For wind, we assume that costs are \$1.50 higher in the high cost estimate case³¹, \$0.75 higher in the medium cost estimate case (assuming that the production tax credit expires but that some incremental technological/cost saving improvements make up part of the difference) and no higher in the low cost estimate case.

For Montana wind, cost estimates were derived by adjusting Oregon/Washington wind cost estimates for the higher capacity factor of Montana wind. We use the same capacity factor assumptions as those proposed for the NW Power and Conservation Council's 2021 Power Plan: 45.5% for Montana wind, 41.2% for SE Washington wind and 39.8% for Gorge wind³². Each cost estimate for Oregon/Washington wind was divided by 1.12, which is equal to the assumed Montana wind capacity factor divided by the average of the SE Washington and Gorge wind capacity factors. This yields a range of \$26.70 to \$36.94 per MWh for Montana wind acquired in 2028. Based on estimates from other recent IRPs and discussions with developers, these estimates are in the correct range of potential costs.

11.1.4 Cowlitz River Project enhancements

Cost assumptions made for investments to enhance the capabilities of our Cowlitz River Project are based on limited data. Because costs for hydropower projects vary considerably and are highly site-specific, the cost assumptions used in this IRP should be considered highly uncertain. If the utility were to find that a Cowlitz River Project enhancement is an option that warrants more investigation, substantially more work would need to be done to refine these "first-pass" cost estimates.

11.1.4.1 Cost assumptions for adding a generator

Table 10 summarizes capital and O&M cost estimates. Cost estimates are based on a combination of previous internal analyses that we conducted and nationwide studies conducted on the cost of hydropower. In 2003, we commissioned a study on the potential value of making upgrades to Mossyrock

³⁰ The current solar investment tax credit is 26% for projects that start construction by 2020, so long as the project is operational by 2024. (See <https://www.seia.org/initiatives/solar-investment-tax-credit-itc>)

³¹ The current wind incentive is 1.5 cents/kWh (\$1.50 per MWh) for wind projects that begin construction by the end of 2020. (See <https://windexchange.energy.gov/projects/tax-credits>)

³² https://www.nwcouncil.org/sites/default/files/2019_1112_p3.pdf

Dam, including adding a generator in the open bay. The study was conducted by Acres International (now Hatch Acres), an independent consulting firm. Cost estimates from that study, along with information provided in the Department of Energy’s 2016 *Hydropower Vision* report³³ served as the basis for estimating the up-front costs of installing an additional generator. The 2003 Tacoma Power study estimated that the addition of a generator would cost approximately \$40.7 million (\$542/kW) and \$57.2 million (\$272/kW) for a 75MW and 210MW addition respectively, after adjusting for inflation. This is significantly lower than the low end of the cost range for hydro project upgrades described in the *Hydropower Vision* report, which finds a range of around \$950/kW to \$24,000/kW in 2020 dollars.³⁴ Using a simplified equation provided in the report would yield an average expected cost of \$1,256/kW for a 75MW upgrade and \$1,025 for a 210MW upgrade in 2020 dollars.³⁵ The report acknowledges, however, that cost estimates for hydropower projects are “*highly site-specific*”. Given that we already have a bay open and ready for a third generator, it is plausible that the cost of installing an additional generator at Mossyrock would be lower than installing a generator at many other projects. Based on the above information, the following capital cost assumptions were made for a 150MW generator addition:

- **Low Cost Case:** The average across the 75MW and 210MW costs estimates from the 2003 Acres study were used and adjusted for inflation, yielding a 2020 capital cost of \$407/kW.
- **Medium Cost Case:** An additional 50% was added to the low cost case estimates to account for certain costs rising more quickly than inflation, including higher fish mitigation costs, higher cost of steel and higher costs of engineering expertise due to diminishing supply of technical experts. The resulting capital cost is \$611/kW.
- **High Cost Case:** High cost estimates were calculated from the simple *Hydropower Visions* report equation to calculate cost described in Equation 17 below (the variable C represents the incremental capacity addition to a project), adjusted for inflation. The equation yields a 2020 capital cost estimate of \$1,096/kW for the 150MW generator addition modeled in this IRP.

Equation 17: *Hydropower Visions* cost estimation equation for generator additions

$$\text{CapitalCost}_{2014\$} = C^{-0.3} + 2230 * C^{-0.19}$$

Capital costs are amortized over a 30-year period at a 3% real discount rate (roughly equivalent to our real cost of long-term capital). Incremental operations and maintenance (O&M) costs are estimated to be between \$5/kW-year on the low end and \$9/kW-year on the high end, with a medium cost estimate of \$7/kW-year.

³³ <https://www.energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source>

³⁴ <https://www.energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-Appendices-10212016.pdf> , Appendix B, page 20.

³⁵ Using another cost equation developed in a separate 2015 study by Oak Ridge National Laboratory (<https://info.ornl.gov/sites/publications/files/Pub53978.pdf>) would yield cost estimates that are approximately 25% higher than those using the equation in the *Hydropower Vision* study.

Table 10: Capital and O&M cost estimates for 150MW generator addition at Cowlitz River Project

	Low	Medium	High
Capital Costs (2020\$)			
\$/kW	\$407/kW	\$611/kW	\$1,096/kW
Total Capital Cost	\$61,090,041	\$91,635,062	\$164,337,950
Amortized Annual Cost	\$3,081,064	\$4,621,596	\$8,288,351
O&M Costs (2020\$)			
\$/kW-year	\$5	\$7	\$9
Total Annual Cost	\$750,000	\$1,050,000	\$1,350,000

11.1.4.2 Cost assumptions for adding pumped storage

The costs of developing pumped storage hydro (PSH) are even less certain than the costs of a simpler upgrade like adding a generator. Typical cost estimates for developing pumped storage range from around \$1,600/kW to \$3,000/kW.³⁶ Because the pumped storage project contemplated in our IRP is much simpler and relies substantially on existing infrastructure at the Cowlitz River Project, it is reasonable to expect that it would cost less. In 2018, we began exploring a potential PSH project at Mossyrock that included building a new reservoir, and cost estimates for that project came in below the typical range of costs for a 250MW project.³⁷ The project modeled in this IRP is even simpler, as it would not require the construction of an additional reservoir. Capital cost estimates provided by the developer served as the basis for low and medium cost case assumptions. Estimates for the high cost case were calculated based on a generic equation (Equation 18 below, where the variable P is equal to the capacity of the pumped storage addition) provided in the Hydropower Vision study and then adjusted for inflation. The equation was developed based on the costs of past projects that added pumped storage to existing hydro projects.³⁸ Low and high cost case assumptions are provided in Table 11, but medium cost case assumptions are excluded in order to preserve the confidentiality of information provided by the developer.

Equation 18: Hydropower Visions cost estimation equation for pumped storage additions

$$\text{CapitalCost}_{2014\$} = 3,008,246 * P * e^{-0.0046 * P}$$

Capital costs are amortized over a 30-year period at a 3% real discount rate, and incremental O&M costs are estimated to be between \$6/kW-year on the low end and \$14/kW-year on the high end, with a medium cost estimate of \$10/kW-year. For reference, the NW Power and Conservation Council is planning to use an assumption of \$14/kW-year for the 2021 Power Plan.³⁹ Table 11 summarizes capital and O&M cost estimates.

³⁶ https://www.nwcouncil.org/sites/default/files/2019_12_p2.pdf

³⁷ Specific cost estimates are not provided because Tacoma Power signed a nondisclosure agreement with the developer.

³⁸ <https://www.energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-Appendices-10212016.pdf>, Appendix B, page 22.

³⁹ https://www.nwcouncil.org/sites/default/files/2019_12_p2.pdf

Table 11: Capital and O&M cost estimates for 150MW pumped storage addition at Cowlitz River Project

	Low	High
Capital Costs (2020\$)		
\$/kW	\$938/kW	\$1,708/kW
Total Capital Cost	\$150,078,834	\$256,219,558
Amortized Annual Cost	\$7,569,195	\$12,922,381
O&M Costs (2020\$)		
\$/kW-year	\$6	\$14
Total Annual Cost	\$900,000	\$2,100,000

11.1.4.3 Licensing costs

The licensing requirements for the modeled Cowlitz enhancements are described in Section 10.1.4.2. We assume in this analysis that an amendment to the current license would be sought and, as a result, a substantial licensing cost would be incurred. While it is difficult to get concrete data on the costs of relicensing hydro projects or amending existing licenses, available information suggests that relicensing costs are often equivalent to the cost of licensing and can easily cost around \$20 million.⁴⁰ For some projects, licensing costs can be substantially higher, exceeding \$50 million⁴¹ or even \$100 million.⁴² A 2015 analysis conducted by Oakridge National Laboratory provides a generic equation for estimating initial licensing costs, though they note that costs can vary considerably and that the equation should be used only to get a general sense of potential licensing costs. For a 150MW project, that study’s equation suggests licensing costs of approximately \$19.3 million in 2020 dollars. Based on the available information, rough estimates for potential license amendment costs are provided in Table 12 below. Although licensing costs would typically be incurred years before a project is built, they are treated the same as other lump-sum capital costs for the potential additions and amortized over 30 years.

Table 12: License amendment cost assumptions

	Fixed Licensing Cost	Amortized Cost
Low	\$11,148,259	\$564,292
Medium	\$18,580,431	\$940,487
High	\$50,000,000	\$2,530,853

If an enhancement to Cowlitz were to be licensed at the same time as project relicensing rather than separately prior to relicensing, the incremental licensing cost of such an enhancement would likely be substantially lower.

11.1.5 Simple cycle natural gas generator

For the purposes of the IRP analysis, the natural gas plant is modeled as if it were a Tacoma Power-owned resource. If we were to acquire natural gas, it would consider both an owned and contracted

⁴⁰ <https://news.bloomberglaw.com/environment-and-energy/permit-delays-dam-up-hydro-projects-relicensing-costs-millions>

⁴¹ Ibid.

⁴² <https://www.chelanpud.org/docs/default-source/default-document-library/reinvigorating-hydropower.pdf>

option, but the portfolio that did include natural gas generation was not found to be resource adequate and so was not considered further.

Table 13 summarizes cost assumptions for a simple cycle natural gas generator. Capital costs and fixed O&M assumptions for the simple cycle gas generator were taken directly from the 2019 Lazard Levelized Cost of Energy Analysis and adjusted for inflation.⁴³ Cost estimates were based on the Lazard estimates for a natural gas peaker plant. Costs are representative of a high-efficiency simple cycle CT, with a heat rate of between 8,000 and 9,804 Btu/kWh. Capital costs are amortized over a 20-year period at a 3% real discount rate. Variable O&M cost assumptions for the medium cost case were based on default assumptions used in the AURORA WECC model, and costs for the low cost case and high cost case were assumed to be 20% lower and higher, respectively. Fuel costs were calculated from the gas prices used in our WECC-wide modeling of power prices.

Table 13: Capital and O&M cost estimates for simple cycle natural gas generator

	Low	Medium	High
Capital Costs (2020\$)			
\$/kW	\$700/kW	\$825/kW	\$900/kW
Total	\$140,000,000	\$165,000,000	\$190,000,000
Amortized Annual Cost	\$9,333,034	\$10,000,647	\$12,666,261
O&M Costs (2020\$)			
Fixed O&M (\$/kW-year)	\$5.50	\$13.13	\$20.75
Annual Fixed O&M	\$1,100,000	\$2,625,000	\$4,150,000
Variable O&M (\$/MWh)	\$7.64	\$9.55	\$11.46
Fuel Price	AURORA gas price simulations		

11.1.6 Nuclear

Cost estimates for small modular reactor nuclear were based on discussions with the Utah Associated Municipal Power Systems (UAMPS)⁴⁴, which is working with NuScale Power to develop a 720 MW facility with 12 small nuclear modular reactors.⁴⁵ Because nuclear projects (even small modular nuclear projects) are typically developed on a large scale and there is one single project being developed in the region, it is assumed that we would acquire this resource per the standard arrangement that the developer proposes. While the agreement is more complex than a simple PPA, it is modeled as a PPA for cost purposes.

There is still quite a bit of uncertainty around what final costs will be for small modular nuclear reactors, and final costs for projects have often ended up significantly higher than what was initially projected—anywhere from double to twenty times higher.⁴⁶ Public cost estimates of the UAMPS project with NuScale are \$65/MWh.⁴⁷ This value was used as a base for developing cost estimates. It was assumed

⁴³ <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>, p.19

⁴⁴ <https://www.uamps.com/nu-scale-modular-reactor>

⁴⁵ <https://www.publicpower.org/periodical/article/uamps-sees-cost-and-safety-benefits-with-nuscale-smr-technology>

⁴⁶ <https://wiseinternational.org/nuclear-monitor/872-873/smr-cost-estimates-and-costs-smrs-under-construction>

⁴⁷ Ibid.

that costs are 15% lower than NuScale’s current \$65/MWh estimate (\$55.25/MWh) in the low cost case and 25% higher than the current estimate in the medium cost case (\$81.25/MWh). High estimates are equal to an estimate developed by an independent study commissioned by Australia’s Royal Commission and adjusted for inflation (\$174/MWh), approximately 2.5 times higher than NuScale’s current estimates.⁴⁸ It is assumed that the resulting per-MWh price estimates would rise at the rate of inflation in the future (i.e. remain constant in real terms).

11.1.7 Demand response

Because the type of demand response modeled in this IRP most closely resembles an industrial curtailment program, demand response cost assumptions were based on that type of program. Assumptions for the low and medium-cost cases reflect values that the NW Power and Conservation Council plan to use in the 2021 Power Plan⁴⁹, and the high cost estimates reflect the highest estimates seen in the Council’s review of other utilities’ assumptions for the same type of program. Table 14 summarizes these assumptions. Consistent with previous work we have conducted to consider what a demand response rate might look like, a minimum of 3 DR events per year for 4 hours each is assumed.

Table 14: Demand response (DR) cost assumptions

Cost Type	Low & Medium Cost Estimate (2020\$)	High Cost Estimate (2020\$)
Setup cost (one time up-front cost)	\$150,000	\$0
Equipment cost (one-time capital cost)	\$10/kW	\$0
O&M	\$10/kW-year	\$0
Annual incentives	\$40/kW-year + \$150/MWh per event	\$80/kW-year

It is important to note that a constant cost assumption for a single type of demand response is unlikely to reflect what costs would truly look like for the larger quantities of DR modeled in many of the portfolios considered in this IRP. Our best estimate of the technical potential for industrial demand response programs like this is around 10MW, whereas many of the portfolios modeled have 50MW to 300MW of DR in them. It is likely that the cost assumptions made in this IRP are valid for the first 10MW of industrial DR acquired, but it almost certain that the marginal costs of DR would rise as more and more was acquired.

11.1.8 Energy conservation

Assumptions for conservation costs are described in our 2020-2039 Conservation Potential Assessment, available at <https://www.mytpu.org/wp-content/uploads/Tacoma-Power-2020-2039-CPA-Report-FINAL.pdf>.

11.2 TRANSMISSION COSTS

Table 15 summarizes key assumptions made regarding transmission costs for different types of resources. Transmission costs are assumed to remain constant in real terms for existing Tacoma Power

⁴⁸ Ibid.

⁴⁹ <https://nwcouncil.app.box.com/s/cu4aqp23gfymbupmbaprwpwzq26jjps8>

resources and a small contract that does not expire during the IRP study period. Transmission costs associated with BPA generation are also assumed to remain constant when the amount of resource used to determine our net requirement remains at current levels. In portfolios where we contemplate replacing a small part of its BPA contract with another resource, BPA transmission costs are reduced slightly. Transmission costs associated with our CBH contract are assumed to remain at current levels for portfolios where CBH is renewed and are assumed to be zero otherwise. Transmission costs for other resources are assumed to be \$1.85/kW-month (the cost of BPA firm transmission) when these resources are located within Oregon or Washington (solar, Eastern Washington wind, Gorge wind and natural gas generation). For resources located in Montana and Idaho (wind and small modular nuclear, respectively), transmission is assumed to cost \$50/kW-year⁵⁰ to get generation into Oregon and Washington plus \$1.85/kW-month for transmission within Oregon and Washington. Table 16 provides the total annual transmission costs assumed for each portfolio after 2028. For portfolios in which CBH is not renewed, costs associated with CBH transmission are removed as of 2028, when the last contract ends. For the two portfolios with wind resources acquired in 2024, transmission costs are added to current portfolio transmission costs starting in 2024. Because the current BPA contract expires at the end of September 2028, transmission costs for 2028 are calculated as a pro-rated weighted average of pre-2028 costs and post-2028 costs (9/12 and 3/12, respectively).

Table 15: General transmission cost assumptions

	Renew BPA at Current Net Requirement Level	Renew BPA at Reduced Net Requirement Level	Don't Renew BPA
Assumption for Tacoma Power generation & Grant contract generation	Same as current TX costs for these resources	Same as current TX costs for these resources	Same as current TX costs for these resources
Assumption for BPA contract generation	Same as current TX costs for this resource	Small reduction in TX costs equal to ½ the size of the BPA reduction	No TX costs for this resource
Assumption for CBH contract generation	Same as current TX costs for this resource for portfolios with CBH renewal only	Same as current TX costs for this resource for portfolios with CBH renewal only	No TX costs for this resource
Assumption for wind, solar, nuclear contract generation and natural gas generation	TX costs charged at highest of summer, winter and spring/fall 95 th percentile capacity factor for the resource	TX costs charged at highest of summer, winter and spring/fall 95 th percentile capacity factor for the resource	TX costs charged at highest of summer, winter and spring/fall 99 th percentile capacity factor for the resource

⁵⁰ 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)

Table 16: Total portfolio transmission cost assumptions (post-2028)

Portfolio Type	Portfolio	Total Transmission Cost after 2028
BPA Block portfolios without change to Dedicated Resources (no reduction in BPA resources)	Shapeable Block Only	\$17,228,109
	Shapeable Block + DR	\$17,228,109
	Shapeable Block + Pumped Storage	\$17,228,109
	Shapeable Block + Add Generator	\$17,228,109
BPA Block portfolios with resource diversification (reduction in BPA resources)	Shapeable Block with E. WA Wind	\$17,948,652
	Shapeable Block with Gorge Wind	\$18,022,800
	Shapeable Block with Solar	\$18,354,616
	Shapeable Block with CBH	\$18,900,774
BPA Slice portfolios without change to Dedicated Resources (no reduction in BPA resources)	Slice/Block Only	\$17,228,109
	Slice/Block + DR	\$17,228,109
	Slice/Block + Pumped Storage	\$17,228,109
	Slice/Block + Add Generator	\$17,228,109
BPA Slice portfolios with resource diversification (reduction in BPA resources)	Slice/Block with E. WA Wind	\$17,948,652
	Slice/Block with Gorge Wind	\$18,022,800
	Slice/Block with Solar	\$18,354,616
	Slice/Block with CBH	\$18,866,370
Portfolios without BPA Renewal	Wind + DR (no BPA)	\$36,602,247
	Wind + PSH + DR (no BPA)	\$38,695,374
	Wind + Add Gen + DR (no BPA)	\$38,695,374
	Wind + SMN + DR (no BPA)	\$45,554,374
	Wind + Gas + DR (no BPA)	\$41,042,247
Slice/Block Portfolios with Additions to Address Minor Adequacy Concerns	Slice/Block + CBH (no reduction in NR)	\$18,900,774
	Slice/Block + 10MW DR	\$17,228,109
	Slice/Block + 80MW Wind (no reduction in NR)	\$18,863,982
	Slice/Block + 60MW Wind + 10MW DR (no reduction in NR)	\$18,455,014

11.3 INTEGRATION COSTS

Integration costs are added to all 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. In future IRPs, we may consider other approaches to integrating small quantities of renewables without the help of BPA. For large quantities of renewables, we would need third-party assistance with integration.

It is assumed that 100% of the wind or solar capacity is charged at BPA's integration charge. Relevant integration charges are added as of the start date of a wind or solar resource. While BPA currently offers different balancing service options, the assumption is made that a single EIM-compatible framework will be used in the future once BPA joins the EIM. Because it is likely that this new product will have a lower cost than many of the options available today, BPA's current 30/15 Committed Scheduling charge of

\$0.63/kW-month for wind and \$0.37/kW-month for solar⁵¹ is used as a placeholder for future integration costs.

11.4 SOCIAL COST OF CARBON

Because our own generation is 100% carbon-free and most of the portfolios considered are also comprised entirely of 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. Market purchases are charged at 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. Marginal emissions rate assumptions are described in Section 8.4. For emissions associated with the BPA contract, a fixed mix of resources is assumed based on BPA’s official fuel mix report.⁵² Resource shares for BPA’s portfolio are averaged across the past 4 years (2016 through 2019), yielding an assumption that 0.01% of BPA generation is charged a natural gas emissions rate and 4.11% of is charged the market emissions rate.

Carbon emissions from natural gas generation in the one portfolio that includes a simple cycle gas plant are charged at an emissions rate of 0.435 MT CO₂/MWh, which is calculated based on the plant’s modeled heat rate of 8.2 MMBTU/MWh. Fugitive methane emissions are not accounted for in that portfolio due to lack of reliable data, but it is important to recognize that fugitive emissions are another potential source of emissions from natural gas generation and would need to be taken into account if we were to consider a natural gas generator.

Emissions are charged the social cost of carbon prescribed by the Department of Commerce in Phase One rulemaking for CETA.⁵³ Values escalate from \$76.08/MT in 2020 to \$101.61/MT in 2039 (all values are in 2020 dollars).

12 PORTFOLIO PERFORMANCE

12.1 CETA COMPLIANCE THROUGH 2044

For any potential future portfolio to be CETA compliant, it must meet the following criteria:

- 1) Be at least 80% clean during 4-year compliance periods beginning in 2030.
- 2) Be offset by RECs (or other qualifying means) if not 100% clean (up to 20% offsets)

Because CETA only requires that utilities serve WA load with a carbon neutral portfolio by 2030, the amount of generation that must be offset is calculated as a percentage of load, not of generation. In other words, we use generation to calculate the percent clean to serve and we use load to calculate any required offsets (See Equation 19 and Equation 20).

⁵¹ <https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY20-21/2020%20Transmission%20Rates%20Summary.pdf>

⁵² <https://www.bpa.gov/p/Generation/Fuel-Mix/FuelMix/BPA-Official-Fuel-Mix-2019.pdf>

⁵³ <https://www.commerce.wa.gov/wp-content/uploads/2019/12/2019-12-30-CETA-Phase-One-Rule-Making-Order.pdf> (WAC-194-40-100)

Equation 19: Percent clean to serve load

$$Percent_Clean_to_Serve_Load = PctClean_{BPA} * GenShare_{BPA} + PctClean_{TP} * GenShare_{TP}, \%$$

Equation 20: Offsets required

$$Offsets\ Required = (1 - Percent_Clean_to_Serve_Load) * Load, \text{ MWh}$$

Where:

$$PctClean_{BPA} = \frac{BPA_Clean_Generation}{BPA_Total_Generation}$$

$$PctClean_{TP} = \frac{Tacoma_Clean_Generation}{Tacoma_Total_Generation_and_Purchases}$$

$$GenShare = \frac{Tacoma_Clean_Generation}{Tacoma_Total_Generation_and_Purchases}$$

$$GenShare_{BPA} = \frac{BPA_Contract_Generation}{Total_Tacoma_Portfolio_Generation}$$

$$GenShare_{TP} = 1 - GenShare_{BPA}$$

In the above equations, $PctClean_{BPA}$ is the percentage of BPA’s portfolio that is non-emitting; $PctClean_{TP}$ is the percentage of our portfolio (less BPA but including market purchases) that is non-emitting; $GenShare_{BPA}$ is BPA’s percent share of our total generation portfolio; and $GenShare_{TP}$ is the share of Tacoma Power’s total generation not met by BPA.

12.1.1 Criterion 1: Percent Clean to Load > 80%

Figure 53 shows the average annual percent clean to serve load between 2030 and 2040 for each of the 24 portfolios considered in the Base Case Scenario.⁵⁴ On average, all of the portfolios are CETA compliant for this period. The cleanest is the *Renewables + SMN + DR* portfolio while *Shapeable Block + Pumped Storage* and *Renewables + Gas + DR* portfolios have the lowest percent clean to load values.

The differences between each of the portfolios is primarily driven by differences in market purchases across the portfolios. In addition to market purchases, the *Wind + PSH + DR* portfolio also has a lower value of $PctClean_{TP}$, which also lowers the percent clean to load.

⁵⁴ Results are averaged across 290 simulations (58 weather years by 5 gas risk runs). Note: The “No Renewals” portfolio is excluded in this chart to zoom into portfolios with Percent Clean to Load greater than 80%)

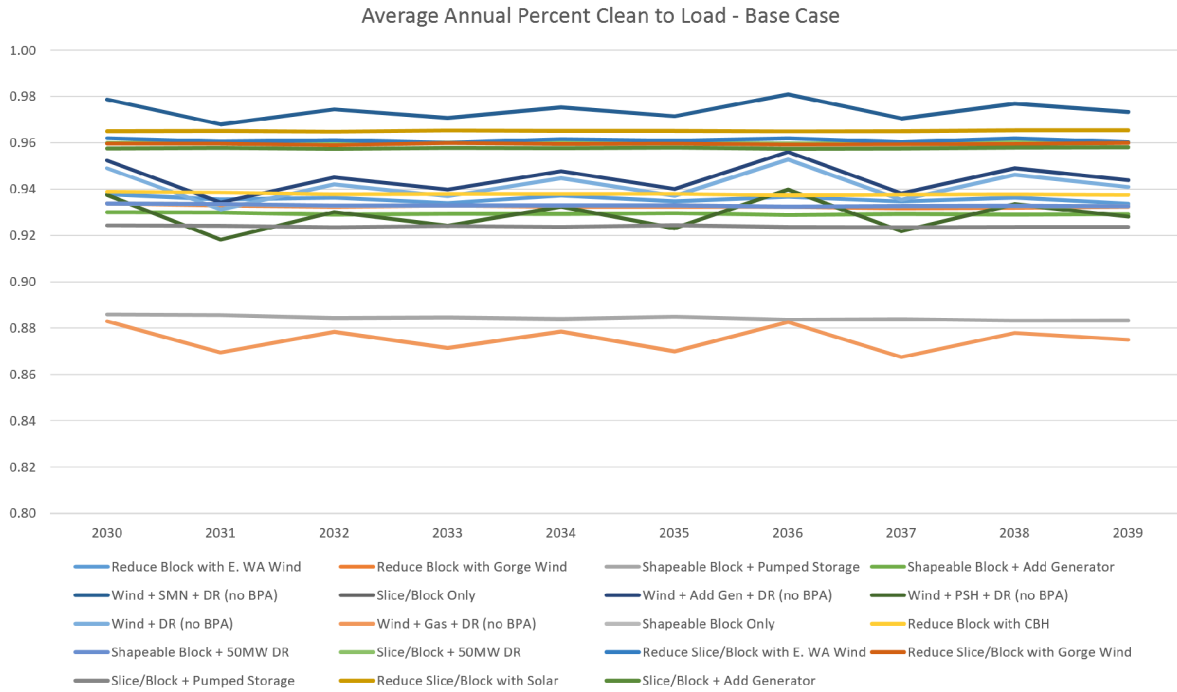


Figure 53: Average of annual percent clean to load

Figure 54 shows the distribution of each portfolio's percent clean to load across 10 years and 290 weather and gas price simulations. Even in the most extreme cases, all portfolios are at least 80% clean in all years. It follows that the 4-year average percent clean of these portfolios are also at least 80% clean for each of the 4-year compliance periods of our planning horizon.

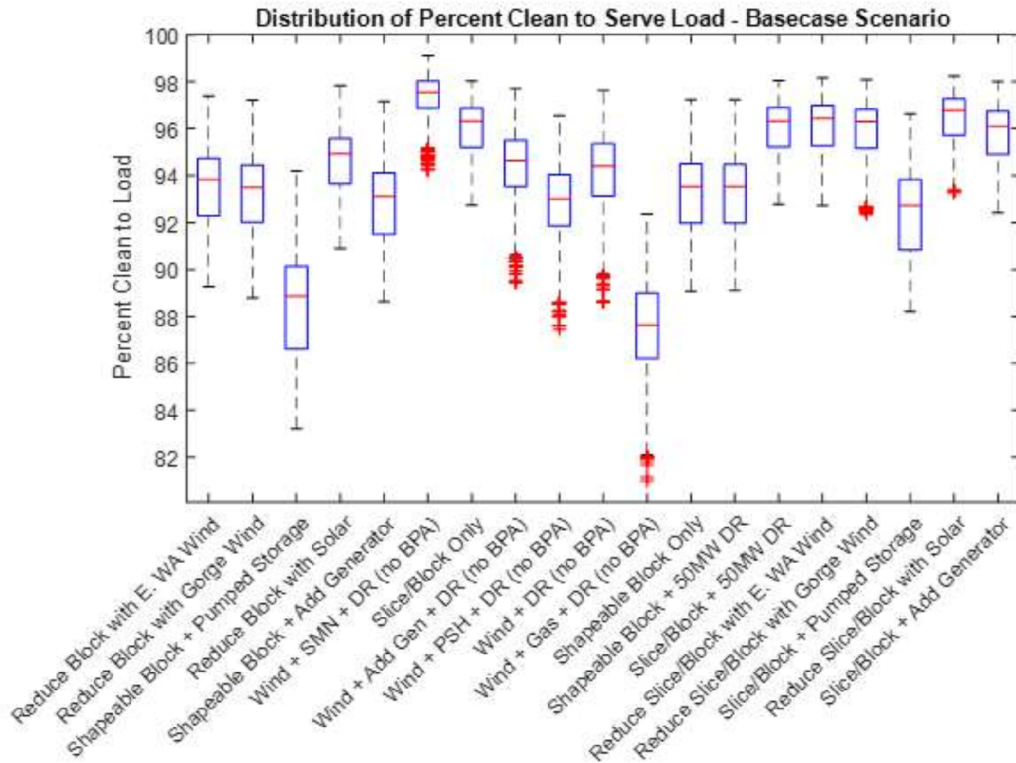


Figure 54: Distribution of percent clean to load

Figure 55 compares the average percent clean for each of the portfolios in each of the four scenarios. Market purchases are comparable for the portfolios that include a BPA product, resulting in little to no difference in percent clean values across scenarios. In contrast, portfolios without BPA – particularly *Renewables + Gas + DR* show significant differences in percent clean values across scenarios. This means that market price and volatility have a larger impact on our CETA compliance when BPA is not part of our portfolio.

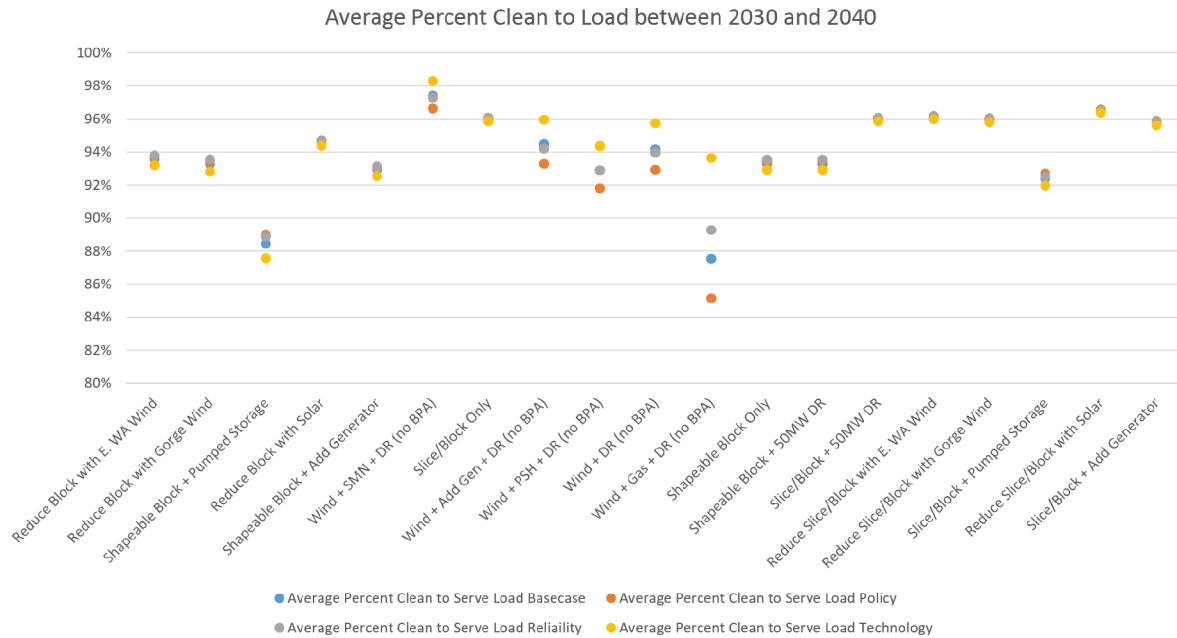


Figure 55: Comparison of average percent clean to load for each scenario.

12.1.2 Criterion 2: Offset emitting portion of the portfolio up to 20%

We could choose to offset the emitting portion of its portfolio through a number of mechanisms, including purchasing RECs or using excess Hydro/Renewable RECs from our own generation. This analysis assumes that we will offset the emitting portion of its portfolio using renewable properties of its excess hydro and renewable generation. Figure 56 compares the amount of hydro RECs available (orange lines) and offsets needed (blue lines) for all four scenarios. All portfolios have far more hydro RECs available than needed to offset emitting generation. Diversified portfolios without BPA have large amounts of renewable generation and therefore significantly more excess RECs available.

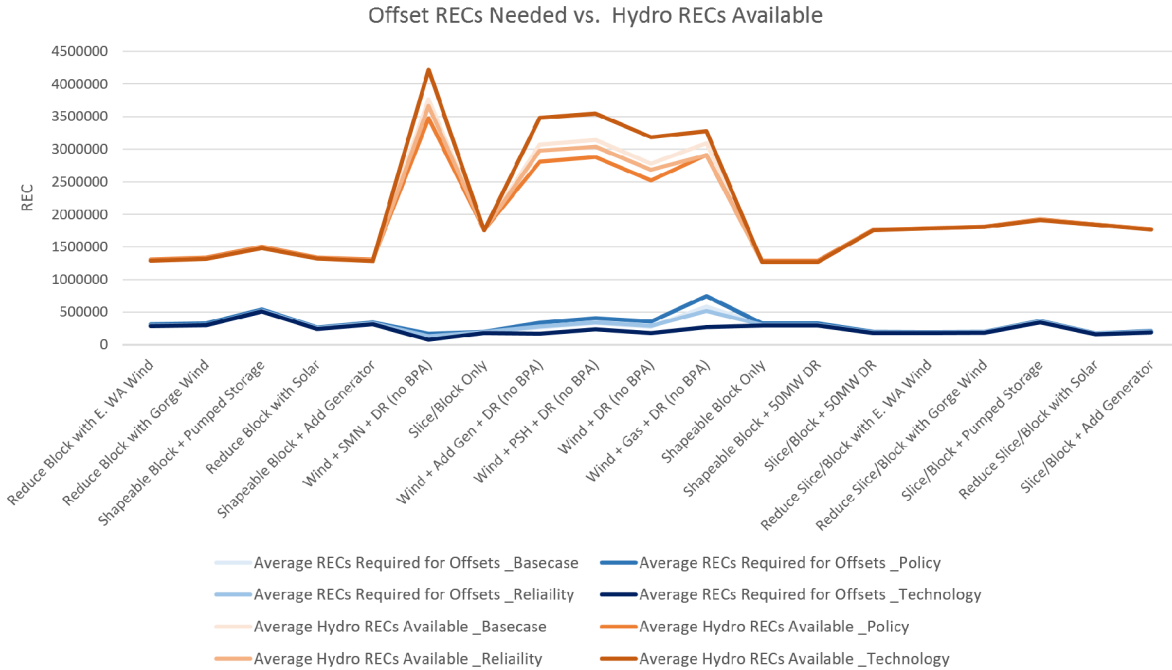


Figure 56: Comparison of available hydro and renewable RECs vs RECs needed to offset emitting generation for four scenarios

Finally, it is important to note that any generation associated with RECS used to offset our emissions cannot then be sold as carbon free or as a specified resource because this would be double counting of clean attributes. Figure 57 shows the net surplus hydro and renewable generation that is available to sell as specified after accounting for RECs used for our offsets. Portfolios replacing BPA with renewables have the largest surplus while Shapeable Block portfolios have the least. Regardless, all portfolios result in an available surplus that nearly meets or even exceeds maximum historic specified sales quantities. Figure 58 shows historic sales of ACS⁵⁵ power. Since 2015, we have sold between 125,000 MWh and 1.1 GWh annually in ACS sales.

⁵⁵ According to California regulation, utilities wanting the clean attributes of their resources recognized and paid a premium can register with the California Air Resources Board (CARB) and be assigned an annual Asset Controlling Supplier (ACS) emission factor value. For 2020, this value is 0.0168 MT CO₂e per MWh for our generation.

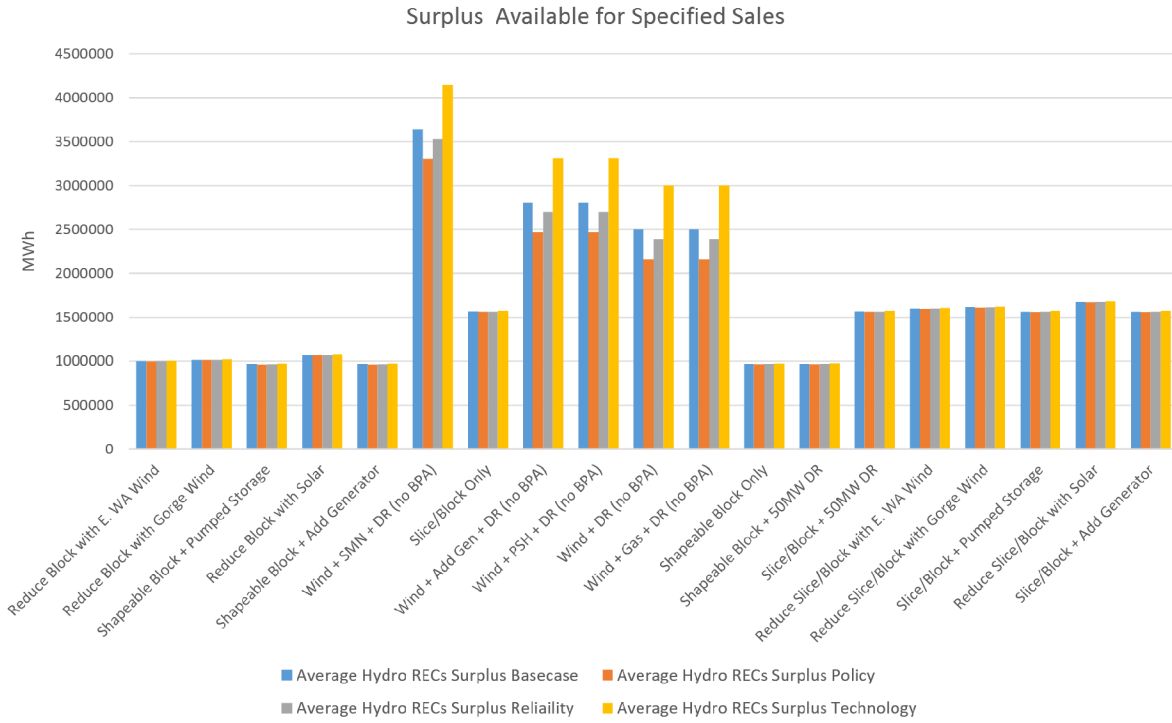


Figure 57: Net surplus generation available for sale as specified or carbon free

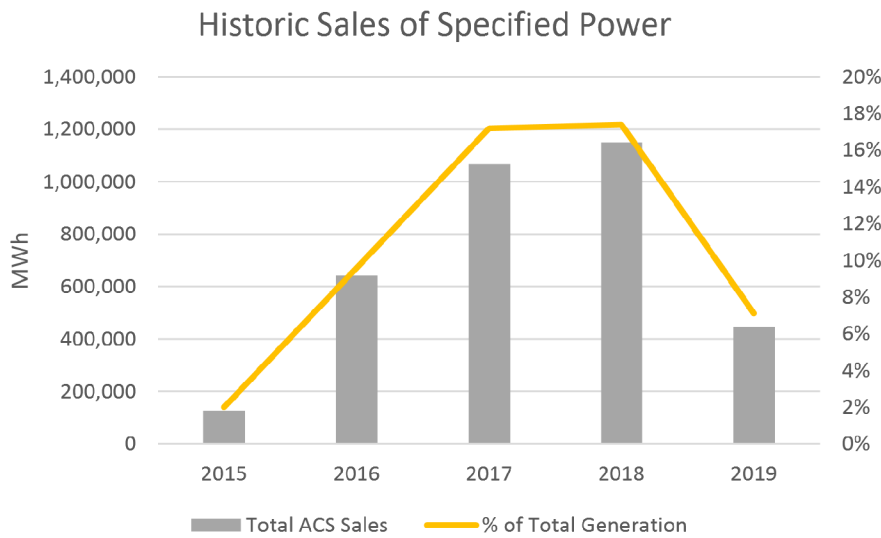


Figure 58: Tacoma Power's historic ACS sales

12.2 RESOURCE ADEQUACY

Any portfolio we consider must ensure that we have enough resources to meet customer needs into the future. Each potential portfolio was evaluated based on our three resource adequacy metrics that are always calculated using the assumption that, at all times of the year, up to 50MW of power will be

available for purchase in the market if it is needed to ensure adequacy. Because most of the resource decisions we considered revolve around the end of the current BPA contract, two separate time periods are considered in the analysis below: (1) the time period prior to the end of the current BPA contract (2020-2028) and (2) the next BPA contract period (2029-2039).⁵⁶ In the current contract period, the key question of interest is whether or not to renew the Columbia Basin Hydro (CBH) contract and, if not, whether to replace it with something else. In the second time period, a broader set of resources is considered. Portfolios in the second (post-2028) period are centered on the question of whether and how to renew our contract with BPA in 2028.

12.2.1 Current BPA contract period (2020-2028)

Only the subset of portfolios that include resource changes before 2028 are included in the analysis of the current BPA contract period. Table 17 through Table 21 present results for these portfolios.

Inadequacies (i.e. times when the resource adequacy standard is not met) are highlighted in orange. Key findings emerge for this period are:

- 1) The current Slice/Block portfolio occasionally fails our resource adequacy standard stating in the 2024-2025 period (Table 17). As discussed further in Section 9.2, the adequacy issues are driven by extreme low water conditions during the winter in one historic weather year.
- 2) Because the CBH contract provides power in the summertime and the minor adequacy issues found occur in the wintertime, renewing CBH does nothing to improve resource adequacy (Table 18).
- 3) Adding capacity that is available in the wintertime (wind and/or demand response) eliminates the minor adequacy concerns that show up in the analysis of the current portfolio (Table 19 through Table 21).

Table 17: 2020-2028 adequacy results for current portfolio without CBH renewal

Slice/Block Only		2020-2021	2022-2023	2024-2025	2026-2027	2028	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.002	0.001	20%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.002	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.002	0.002	
LOLH	Cruise Control	1.0	1.3	2.3	1.9	1.9	0%
	Carbon Policy Accelerates	1.1	1.2	2.1	1.7	1.6	
	Reliability Reigns	1.2	1.2	2.1	1.9	1.8	
	Technology Solves Everything	1.0	1.5	2.3	2.2	2.1	
LOLE	Cruise Control	0.1	0.2	0.3	0.2	0.2	5%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.2	0.2	
	Reliability Reigns	0.1	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.1	0.2	0.2	0.2	0.2	

⁵⁶ Because the BPA contract period ends nine months into the year on September 30, 2028, results for the year 2028 are included in the current contract period.

Table 18: 2020-2028 adequacy results for current portfolio with CBH renewal

Slice/Block + CBH		2020-2021	2022-2023	2024-2025	2026-2027	2028	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.002	0.001	20%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.002	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.002	0.002	
LOLH	Cruise Control	1.0	1.3	2.3	1.9	1.9	0%
	Carbon Policy Accelerates	1.1	1.2	2.1	1.8	1.6	
	Reliability Reigns	1.2	1.2	2.1	1.9	1.8	
	Technology Solves Everything	1.0	1.5	2.3	2.2	2.1	
LOLE	Cruise Control	0.1	0.2	0.3	0.2	0.2	5%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.2	0.2	
	Reliability Reigns	0.1	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.1	0.2	0.2	0.2	0.2	

Table 19: 2020-2028 adequacy results for current portfolio without CBH renewal and with addition of 10MW DR by 2024

Slice/Block + 10MW DR		2020-2021	2022-2023	2024-2025	2026-2027	2028	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.001	0%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	1.0	1.3	1.7	1.6	1.4	0%
	Carbon Policy Accelerates	1.1	1.2	1.5	1.3	1.3	
	Reliability Reigns	1.2	1.2	1.6	1.5	1.4	
	Technology Solves Everything	1.0	1.5	1.7	1.6	1.7	
LOLE	Cruise Control	0.1	0.2	0.2	0.2	0.1	0%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.2	0.1	
	Reliability Reigns	0.1	0.2	0.2	0.2	0.1	
	Technology Solves Everything	0.1	0.2	0.2	0.2	0.1	

Table 20: 2020-2028 adequacy results for current portfolio without CBH renewal and with addition of 80MW wind by 2024

Slice/Block + 80MW Wind		2020-2021	2022-2023	2024-2025	2026-2027	2028	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.001	0%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	1.0	1.3	1.6	1.4	1.0	0%
	Carbon Policy Accelerates	1.1	1.2	1.4	1.2	0.9	
	Reliability Reigns	1.2	1.2	1.5	1.3	1.0	
	Technology Solves Everything	1.0	1.5	1.5	1.5	1.2	
LOLE	Cruise Control	0.1	0.2	0.2	0.1	0.1	0%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.1	0.1	
	Reliability Reigns	0.1	0.2	0.2	0.1	0.1	
	Technology Solves Everything	0.1	0.2	0.2	0.1	0.1	

Table 21: 2020-2028 adequacy results for current portfolio without CBH renewal and with 60MW wind and 10MW DR by 2024

Slice/Block + 60MW Wind +10MW DR		2020-2021	2022-2023	2024-2025	2026-2027	2028	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.000	0%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.000	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.000	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	1.0	1.3	1.2	1.2	0.9	0%
	Carbon Policy Accelerates	1.1	1.2	1.1	1.2	0.7	
	Reliability Reigns	1.2	1.2	1.2	1.2	0.9	
	Technology Solves Everything	1.0	1.5	1.2	1.3	1.0	
LOLE	Cruise Control	0.1	0.2	0.2	0.1	0.1	0%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.1	0.1	
	Reliability Reigns	0.1	0.2	0.2	0.1	0.1	
	Technology Solves Everything	0.1	0.2	0.2	0.1	0.1	

12.2.2 Next BPA contract period (2029-2039)

Table 23 through Table 45 present post-2028 resource adequacy results portfolio by portfolio.

Inadequacies (i.e. times when the resource adequacy standard is not met) are highlighted in orange.

Several key findings emerge from the results:

- 1) **BPA Block portfolios without a reduction in BPA resources:** Portfolios in which we renew the BPA contract with the Shapeable Block product are always adequate whenever we don't partially replace BPA energy received with another resource (Table 23 through Table 26).
- 2) **BPA Block portfolios with resource diversification (i.e. reduction in BPA resources):** Adequacy outcomes are more mixed if we renew the BPA contract with the Shapeable Block product but partially replace it with another resource. Partially replacing BPA with wind worsens adequacy because it reduces the amount of guaranteed power received from BPA and replaces it with a more variable source of power in the wintertime, when we are most at risk of not having enough capacity to serve load. When Gorge wind is used to partially replace BPA (Table 28), resource adequacy is compromised substantially. The adequacy impacts are much less severe when Eastern WA wind is used instead (Table 27). Partially replacing BPA with solar, on the other hand, has no impact on adequacy (Table 29). This is because the amount by which BPA is reduced in the wintertime depends on how much a replacement resource produces at that time. Because solar produces very little in the wintertime, it changes the amount of BPA power received very little at that time of year. If there is a strong desire to "diversify" away from BPA partially, doing so with solar leaves us in a better resource adequacy position, but doing so with wind may be possible if BPA's Shapeable Block product is selected.
- 3) **BPA Slice/Block portfolios without a reduction in BPA resources:** Portfolios in which we renew the BPA contract with the current Slice/Block product result in some occasional adequacy concerns unless additional winter capacity is added to the portfolio. Table 30 shows results when Slice/Block is renewed at current levels and no additional capacity is added, and Table 31 through Table 37 show results when additional capacity is added. When no capacity is added to the Slice/Block portfolio, the portfolio fails our resource adequacy standard in certain limited cases, with failures showing up primarily in the

magnitude metric (NEUE). Results are similar when capacity is added only in the summertime through renewal of the CBH contract (Table 37) because capacity inadequacies are occurring in the wintertime. In all cases, adding capacity that is available in the wintertime improves adequacy results substantially (Table 31 through Table 36). Portfolios that still sometimes fail the standard (Table 34 and Table 35) do so only at the very end of the study period and only in one particular scenario of the future. This is not particularly concerning, since we would have plenty of time to make additional adjustments to the portfolio to ensure adequacy in the future if the world were headed toward that future scenario.

- 4) **BPA Slice/Block portfolios with resource diversification (i.e. reduction in BPA resources):** While adequacy results for Block portfolios indicated that it might be possible to partially replace BPA with either solar or wind, results for Slice/Block portfolios indicate that resource adequacy would suffer considerably if we were to replace part of its Slice/Block power with wind (Table 38 and Table 39). This result occurs because the Slice/Block portfolio already occasionally fails the adequacy standard because it is more variable than the Shapeable Block product. When the portion of Slice/Block contract that is not variable (the Block portion) is replaced with a variable resource in the wintertime, portfolios go from being occasionally inadequate to consistently inadequate. As with Shapeable Block, the adequacy impact of replacing BPA with solar is minimal because solar does not reduce meaningfully BPA resource take in the wintertime (Table 40). Replacing part of the Slice/Block contract with solar does not improve adequacy, however.
- 5) **Portfolios without BPA Renewal:** Portfolios in which BPA is replaced primarily with wind and other non-emitting resources were initially designed with substantial wind and demand response resources (likely more than could actually be required in reality). However, many still turned out to be inadequate much of the time (Table 41 through Table 43). The adequacy standard is met most of the time only when very large quantities of wind and demand response are combined with 150MW of additional capacity at our Cowlitz River Project in the form of either an additional generator or pumped storage (Table 44 and Table 45). As was discussed in Section 10.2.2, these portfolios were tested to understand what it would take if we were to replace BPA with other non-emitting resources. We do not expect to be able to acquire the quantity of demand response and the transmission needed to manage these portfolios.

Table 22 summarizes the adequacy results and identifies which portfolios are considered further. Portfolios that failed any single component of our RA standard (the NEUE limit of 0.001%, the LOLH limit of 2.4 hours/year and the LOLE limit of 0.2 days per year) more than 30% of the time were not considered further. Portfolios that failed each component of the standard less frequently were still considered further, with the understanding that small adjustments might need to be made to ensure adequacy.

Table 22: Summary of post-2028 Resource Adequacy Results

Portfolio Type	Portfolio	Share of Years with Inadequacies (2029-2039)			Consider Portfolio?
		NEUE	LOLH	LOLE	
BPA Block portfolios without change to Dedicated Resources (no reduction in BPA resources)	Shapeable Block Only	0%	0%	0%	YES
	Shapeable Block + 50MW DR	0%	0%	0%	YES
	Shapeable Block + Pumped Storage	0%	0%	0%	YES
	Shapeable Block + Add Generator	0%	0%	0%	YES
BPA Block portfolios with resource diversification (reduction in BPA resources)	Reduce Block with E. WA Wind	0%	0%	10%	YES
	Reduce Block with Gorge Wind	5%	0%	55%	NO
	Reduce Block with Solar	0%	0%	0%	YES
BPA Slice portfolios without change to Dedicated Resources (no reduction in BPA resources)	Slice/Block Only	30%	5%	5%	YES
	Slice/Block + 50MW DR	0%	0%	0%	YES
	Slice/Block + Pumped Storage	0%	0%	0%	YES
	Slice/Block + Add Generator	0%	0%	0%	YES
BPA Slice portfolios with resource diversification (reduction in BPA resources)	Reduce Slice/Block with E. WA Wind	100%	55%	50%	NO
	Reduce Slice/Block with Gorge Wind	85%	35%	45%	NO
	Reduce Slice/Block with Solar	30%	5%	10%	YES
Portfolios without BPA Renewal	Wind + DR (no BPA)	35%	0%	20%	NO
	Wind + PSH + DR (no BPA)	5%	0%	0%	YES
	Wind + Add Gen + DR (no BPA)	5%	0%	5%	YES
	Wind + SMN + DR (no BPA)	40%	5%	15%	NO
	Wind + Gas + DR (no BPA)	35%	0%	20%	NO
Slice/Block portfolios with slight modifications to improve adequacy	Slice/Block + CBH	25%	0%	0%	YES
	Slice/Block + 10MW DR	10%	0%	0%	YES
	Slice/Block + 80MW Wind	5%	0%	0%	YES
	Slice/Block + 60MW Wind +10MW DR	0%	0%	0%	YES

Table 23: Post-2028 adequacy results when BPA is renewed fully with Shapeable Block

Shapeable Block Only		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.000	0.000	0%
	Carbon Policy Accelerates	0.001	0.000	0.001	0.001	0.000	
	Reliability Reigns	0.001	0.000	0.001	0.001	0.000	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	0.7	0.7	0.7	0.4	0.6	0%
	Carbon Policy Accelerates	0.7	0.6	0.7	0.5	0.6	
	Reliability Reigns	0.7	0.5	0.6	0.6	0.7	
	Technology Solves Everything	0.7	0.7	0.5	0.7	0.8	
LOLE	Cruise Control	0.2	0.2	0.2	0.1	0.2	0%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.1	0.2	
	Reliability Reigns	0.2	0.2	0.2	0.1	0.2	
	Technology Solves Everything	0.2	0.2	0.2	0.2	0.2	

Table 24: Post-2028 adequacy results when BPA is renewed fully with Shapeable Block and 50MW of demand response is added

Shapeable Block + 50MW DR		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.2	0.2	0.2	0.2	0.1	0%
	Carbon Policy Accelerates	0.3	0.2	0.3	0.3	0.1	
	Reliability Reigns	0.2	0.2	0.1	0.2	0.1	
	Technology Solves Everything	0.2	0.2	0.1	0.2	0.1	
LOLE	Cruise Control	0.0	0.0	0.0	0.1	0.0	0%
	Carbon Policy Accelerates	0.0	0.0	0.1	0.1	0.0	
	Reliability Reigns	0.0	0.0	0.0	0.0	0.0	
	Technology Solves Everything	0.1	0.0	0.0	0.1	0.0	

Table 25: Post-2028 adequacy results when BPA is renewed fully with Shapeable Block and Pumped Storage is added at Cowlitz

Shapeable Block + Pumped Storage		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.1	0.1	0.0	0.2	0.1	0%
	Carbon Policy Accelerates	0.2	0.1	0.1	0.2	0.1	
	Reliability Reigns	0.1	0.1	0.1	0.2	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.2	0.1	
LOLE	Cruise Control	0.0	0.0	0.0	0.0	0.0	0%
	Carbon Policy Accelerates	0.0	0.0	0.0	0.0	0.0	
	Reliability Reigns	0.0	0.0	0.0	0.0	0.0	
	Technology Solves Everything	0.0	0.0	0.0	0.0	0.0	

Table 26: Post-2028 adequacy results when BPA is renewed fully with Shapeable Block and a 3rd generator is added at Cowlitz

Shapeable Block + Add Generator		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.1	0.1	0.1	0.1	0.1	0%
	Carbon Policy Accelerates	0.1	0.1	0.1	0.2	0.1	
	Reliability Reigns	0.1	0.1	0.1	0.1	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.1	0.1	
LOLE	Cruise Control	0.0	0.0	0.0	0.0	0.0	0%
	Carbon Policy Accelerates	0.0	0.0	0.0	0.0	0.0	
	Reliability Reigns	0.0	0.0	0.0	0.0	0.0	
	Technology Solves Everything	0.0	0.0	0.0	0.0	0.0	

Table 27: Post-2028 adequacy results when BPA is renewed with Shapeable Block and partially replaced with SE WA wind

Reduce Block with E. WA Wind		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.000	0%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.000	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	0.9	1.0	1.1	0.6	0.7	0%
	Carbon Policy Accelerates	1.1	0.8	1.0	0.7	0.7	
	Reliability Reigns	0.9	0.8	1.1	0.5	0.9	
	Technology Solves Everything	1.0	1.4	1.1	0.9	1.1	
LOLE	Cruise Control	0.2	0.3	0.2	0.2	0.2	10%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.2	0.2	
	Reliability Reigns	0.2	0.2	0.2	0.1	0.2	
	Technology Solves Everything	0.2	0.3	0.2	0.2	0.2	

Table 28: Post-2028 adequacy results when BPA is renewed with Shapeable Block and partially replaced with Gorge wind

Reduce Block with Gorge Wind		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.000	0.001	0.001	5%
	Carbon Policy Accelerates	0.001	0.001	0.000	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.000	0.002	0.001	
LOLH	Cruise Control	0.8	1.1	0.7	1.1	1.2	0%
	Carbon Policy Accelerates	1.0	1.0	0.5	0.9	0.9	
	Reliability Reigns	0.8	1.1	0.6	1.1	1.1	
	Technology Solves Everything	0.9	1.3	0.7	1.6	1.4	
LOLE	Cruise Control	0.2	0.3	0.2	0.3	0.3	55%
	Carbon Policy Accelerates	0.3	0.3	0.1	0.3	0.2	
	Reliability Reigns	0.2	0.3	0.1	0.3	0.3	
	Technology Solves Everything	0.2	0.3	0.2	0.3	0.2	

Table 29: Post-2028 adequacy results when BPA is renewed with Shapeable Block and partially replaced with solar

Reduce Block with Solar		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.000	0.000	0%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.000	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.000	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	0.7	0.9	0.6	0.5	0.6	0%
	Carbon Policy Accelerates	0.7	0.7	0.6	0.6	0.6	
	Reliability Reigns	0.7	0.9	0.7	0.6	0.6	
	Technology Solves Everything	0.7	0.5	0.6	0.7	0.8	
LOLE	Cruise Control	0.2	0.2	0.2	0.2	0.2	0%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.2	0.2	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.2	0.2	0.2	0.2	0.2	

Table 30: Post-2028 adequacy results when BPA is renewed fully with Slice/Block

Slice/Block Only		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.002	0.001	0.001	0.001	0.001	30%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.002	0.002	0.002	0.003	0.002	
LOLH	Cruise Control	2.3	1.6	1.7	1.8	1.8	5%
	Carbon Policy Accelerates	1.8	1.5	1.8	1.8	1.6	
	Reliability Reigns	2.0	1.6	2.0	1.7	1.8	
	Technology Solves Everything	2.4	2.1	2.1	2.5	2.3	
LOLE	Cruise Control	0.2	0.2	0.2	0.2	0.2	5%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.2	0.1	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.2	0.2	0.2	0.3	0.2	

Table 31: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and pumped storage is added at Cowlitz

Slice/Block + Pumped Storage		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.1	0.1	0.1	0.1	0.2	0%
	Carbon Policy Accelerates	0.1	0.1	0.1	0.0	0.1	
	Reliability Reigns	0.1	0.1	0.1	0.1	0.1	
	Technology Solves Everything	0.1	0.1	0.2	0.3	0.2	
LOLE	Cruise Control	0.0	0.0	0.0	0.0	0.0	0%
	Carbon Policy Accelerates	0.0	0.0	0.0	0.0	0.0	
	Reliability Reigns	0.0	0.0	0.0	0.0	0.0	
	Technology Solves Everything	0.0	0.0	0.1	0.1	0.0	

Table 32: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and a 3rd generator is added at Cowlitz

Slice/Block + Add Generator		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.1	0.1	0.1	0.0	0.0	0%
	Carbon Policy Accelerates	0.1	0.1	0.1	0.0	0.0	
	Reliability Reigns	0.0	0.1	0.1	0.0	0.2	
	Technology Solves Everything	0.1	0.1	0.2	0.0	0.2	
LOLE	Cruise Control	0.0	0.0	0.0	0.0	0.0	0%
	Carbon Policy Accelerates	0.0	0.0	0.0	0.0	0.0	
	Reliability Reigns	0.0	0.0	0.0	0.0	0.0	
	Technology Solves Everything	0.0	0.0	0.1	0.0	0.0	

Table 33: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and 50MW of demand response is added

Slice/Block + 50MW DR		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.000	0.000	0.000	0.000	0.000	0%
	Carbon Policy Accelerates	0.000	0.000	0.000	0.000	0.000	
	Reliability Reigns	0.000	0.000	0.000	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.4	0.1	0.3	0.3	0.4	0%
	Carbon Policy Accelerates	0.1	0.1	0.2	0.3	0.4	
	Reliability Reigns	0.3	0.2	0.3	0.2	0.4	
	Technology Solves Everything	0.4	0.3	0.4	0.2	0.6	
LOLE	Cruise Control	0.1	0.0	0.1	0.1	0.1	0%
	Carbon Policy Accelerates	0.1	0.0	0.0	0.1	0.1	
	Reliability Reigns	0.1	0.0	0.1	0.1	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.1	0.1	

Table 34: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and 10MW of demand response is added

Slice/Block + 10MW DR		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.001	10%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.000	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.002	0.002	
LOLH	Cruise Control	1.7	1.1	1.2	1.5	1.5	0%
	Carbon Policy Accelerates	1.4	1.0	1.0	0.9	1.2	
	Reliability Reigns	1.7	1.4	1.2	1.5	1.5	
	Technology Solves Everything	2.3	1.6	1.6	2.2	2.0	
LOLE	Cruise Control	0.2	0.1	0.1	0.2	0.1	0%
	Carbon Policy Accelerates	0.2	0.1	0.1	0.1	0.1	
	Reliability Reigns	0.2	0.1	0.1	0.2	0.1	
	Technology Solves Everything	0.2	0.2	0.2	0.2	0.2	

Table 35: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and 80MW of wind is added

Slice/Block + 80MW Wind		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.001	5%
	Carbon Policy Accelerates	0.001	0.001	0.000	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.000	0.001	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.002	0.001	
LOLH	Cruise Control	1.3	1.1	1.0	1.1	1.0	0%
	Carbon Policy Accelerates	1.3	1.0	0.8	1.3	0.8	
	Reliability Reigns	1.4	0.8	0.8	0.9	0.9	
	Technology Solves Everything	1.4	1.1	1.3	1.6	1.5	
LOLE	Cruise Control	0.2	0.1	0.1	0.1	0.1	0%
	Carbon Policy Accelerates	0.2	0.1	0.1	0.1	0.1	
	Reliability Reigns	0.2	0.1	0.1	0.1	0.1	
	Technology Solves Everything	0.2	0.1	0.1	0.2	0.1	

Table 36: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and 60MW of wind and 10MW DR are added

Slice/Block + 60MW Wind +10MW DR		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.000	0.000	0.001	0.001	0%
	Carbon Policy Accelerates	0.001	0.000	0.000	0.001	0.000	
	Reliability Reigns	0.001	0.001	0.000	0.000	0.001	
	Technology Solves Everything	0.001	0.001	0.001	0.001	0.001	
LOLH	Cruise Control	1.3	0.7	0.7	1.0	0.9	0%
	Carbon Policy Accelerates	1.1	0.8	0.8	1.2	0.7	
	Reliability Reigns	1.2	1.0	0.6	0.8	0.9	
	Technology Solves Everything	1.5	1.2	1.0	1.4	1.4	
LOLE	Cruise Control	0.2	0.1	0.1	0.1	0.1	0%
	Carbon Policy Accelerates	0.2	0.1	0.1	0.1	0.1	
	Reliability Reigns	0.2	0.1	0.1	0.1	0.1	
	Technology Solves Everything	0.2	0.1	0.1	0.2	0.1	

Table 37: Post-2028 adequacy results when BPA is renewed fully with Slice/Block and CBH contract is renewed

Slice/Block + CBH		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.001	0.001	25%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.002	0.002	0.002	0.002	0.002	
LOLH	Cruise Control	2.2	1.6	1.7	1.9	1.7	0%
	Carbon Policy Accelerates	1.9	1.5	1.8	1.6	1.6	
	Reliability Reigns	2.1	1.4	2.0	1.6	1.8	
	Technology Solves Everything	2.3	2.0	2.1	2.3	2.3	
LOLE	Cruise Control	0.2	0.2	0.2	0.2	0.2	0%
	Carbon Policy Accelerates	0.2	0.1	0.2	0.2	0.1	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.2	0.2	0.2	0.2	0.2	

Table 38: Post-2028 adequacy results when BPA is renewed with Slice/Block and partially replaced with SE WA wind

Reduce Slice/Block with E. WA Wind		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.003	0.002	0.002	0.003	0.002	100%
	Carbon Policy Accelerates	0.002	0.002	0.002	0.002	0.002	
	Reliability Reigns	0.003	0.002	0.002	0.003	0.002	
	Technology Solves Everything	0.003	0.003	0.003	0.004	0.004	
LOLH	Cruise Control	3.1	2.4	2.3	2.7	2.4	55%
	Carbon Policy Accelerates	2.7	2.2	2.1	2.3	2.2	
	Reliability Reigns	2.9	2.3	2.5	3.0	2.3	
	Technology Solves Everything	3.4	2.9	3.1	3.3	3.2	
LOLE	Cruise Control	0.3	0.2	0.2	0.3	0.2	50%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.2	0.2	
	Reliability Reigns	0.3	0.2	0.3	0.3	0.2	
	Technology Solves Everything	0.3	0.3	0.3	0.3	0.3	

Table 39: Post-2028 adequacy results when BPA is renewed with Slice/Block and partially replaced with Gorge wind

Reduce Slice/Block with Gorge Wind		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.002	0.002	0.001	0.002	0.003	85%
	Carbon Policy Accelerates	0.002	0.002	0.001	0.002	0.002	
	Reliability Reigns	0.002	0.002	0.001	0.002	0.002	
	Technology Solves Everything	0.003	0.003	0.002	0.004	0.004	
LOLH	Cruise Control	2.6	2.4	1.9	2.2	2.5	35%
	Carbon Policy Accelerates	2.3	2.3	1.6	2.0	2.1	
	Reliability Reigns	2.3	2.5	1.8	2.2	2.4	
	Technology Solves Everything	2.8	3.1	2.2	3.3	3.2	
LOLE	Cruise Control	0.3	0.3	0.2	0.2	0.2	45%
	Carbon Policy Accelerates	0.2	0.3	0.2	0.2	0.2	
	Reliability Reigns	0.2	0.3	0.2	0.2	0.2	
	Technology Solves Everything	0.3	0.3	0.3	0.4	0.3	

Table 40: Post-2028 adequacy results when BPA is renewed with Slice/Block and partially replaced with solar

Reduce Slice/Block with Solar		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.001	0.002	0.001	30%
	Carbon Policy Accelerates	0.001	0.001	0.001	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.001	0.001	
	Technology Solves Everything	0.002	0.002	0.002	0.002	0.002	
LOLH	Cruise Control	2.2	1.7	1.7	2.0	1.8	5%
	Carbon Policy Accelerates	2.0	1.6	1.6	1.7	1.6	
	Reliability Reigns	2.1	1.6	1.5	1.7	1.8	
	Technology Solves Everything	2.5	1.9	2.3	2.3	2.3	
LOLE	Cruise Control	0.2	0.2	0.2	0.2	0.2	10%
	Carbon Policy Accelerates	0.2	0.2	0.2	0.2	0.2	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.2	
	Technology Solves Everything	0.3	0.2	0.2	0.2	0.3	

Table 41: Post-2028 adequacy results when BPA is replaced with wind and demand response

Wind + DR (no BPA)		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.002	0.001	0.000	35%
	Carbon Policy Accelerates	0.002	0.002	0.003	0.002	0.002	
	Reliability Reigns	0.001	0.001	0.002	0.001	0.001	
	Technology Solves Everything	0.001	0.000	0.001	0.000	0.000	
LOLH	Cruise Control	0.9	0.7	1.2	0.5	0.5	0%
	Carbon Policy Accelerates	1.5	1.5	2.4	1.5	1.5	
	Reliability Reigns	1.0	1.0	1.5	0.8	0.7	
	Technology Solves Everything	0.5	0.2	0.5	0.2	0.0	
LOLE	Cruise Control	0.1	0.2	0.2	0.1	0.1	20%
	Carbon Policy Accelerates	0.2	0.3	0.3	0.3	0.3	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.0	0.0	

Table 42: Post-2028 adequacy results when BPA is replaced with wind, demand response and small modular nuclear

Wind + SMN + DR (no BPA)		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.002	0.001	0.000	40%
	Carbon Policy Accelerates	0.002	0.002	0.003	0.002	0.002	
	Reliability Reigns	0.002	0.001	0.002	0.001	0.001	
	Technology Solves Everything	0.001	0.000	0.001	0.000	0.000	
LOLH	Cruise Control	0.9	0.8	1.3	0.5	0.4	5%
	Carbon Policy Accelerates	1.5	1.3	2.5	1.3	1.8	
	Reliability Reigns	1.0	1.1	1.6	0.7	0.7	
	Technology Solves Everything	0.5	0.3	0.5	0.2	0.0	
LOLE	Cruise Control	0.1	0.2	0.2	0.1	0.1	15%
	Carbon Policy Accelerates	0.2	0.2	0.3	0.3	0.3	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.0	0.0	

Table 43: Post-2028 adequacy results when BPA is replaced with wind, demand response and a simple cycle natural gas plant

Wind + Gas + DR (no BPA)		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.001	0.002	0.001	0.000	35%
	Carbon Policy Accelerates	0.002	0.002	0.003	0.002	0.002	
	Reliability Reigns	0.001	0.001	0.002	0.001	0.001	
	Technology Solves Everything	0.001	0.000	0.001	0.000	0.000	
LOLH	Cruise Control	0.9	0.7	1.2	0.5	0.5	0%
	Carbon Policy Accelerates	1.5	1.5	2.4	1.5	1.5	
	Reliability Reigns	1.0	1.0	1.5	0.8	0.7	
	Technology Solves Everything	0.5	0.2	0.5	0.2	0.0	
LOLE	Cruise Control	0.1	0.2	0.2	0.1	0.1	20%
	Carbon Policy Accelerates	0.2	0.3	0.3	0.3	0.3	
	Reliability Reigns	0.2	0.2	0.2	0.2	0.1	
	Technology Solves Everything	0.1	0.1	0.1	0.0	0.0	

Table 44: Post-2028 adequacy results when BPA is replaced with wind, demand response and pumped storage at Cowlitz

Wind + PSH + DR (no BPA)		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.000	0.001	0.000	0.000	5%
	Carbon Policy Accelerates	0.001	0.001	0.002	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.000	0.000	
	Technology Solves Everything	0.001	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.7	0.6	0.8	0.3	0.3	0%
	Carbon Policy Accelerates	1.0	1.0	1.6	0.6	0.9	
	Reliability Reigns	0.7	0.7	0.9	0.4	0.5	
	Technology Solves Everything	0.4	0.1	0.3	0.0	0.0	
LOLE	Cruise Control	0.1	0.1	0.1	0.1	0.1	0%
	Carbon Policy Accelerates	0.1	0.2	0.2	0.1	0.2	
	Reliability Reigns	0.1	0.1	0.1	0.1	0.1	
	Technology Solves Everything	0.1	0.0	0.0	0.0	0.0	

Table 45: Post-2028 adequacy results when BPA is replaced with wind, demand response and a 3rd generator at Cowlitz

Wind + Add Gen + DR (no BPA)		2029-2031	2032-2033	2034-2035	2036-2037	2038-2039	Share of Years When Portfolio Fails Standard
NEUE	Cruise Control	0.001	0.000	0.001	0.000	0.000	5%
	Carbon Policy Accelerates	0.001	0.001	0.002	0.001	0.001	
	Reliability Reigns	0.001	0.001	0.001	0.000	0.000	
	Technology Solves Everything	0.000	0.000	0.000	0.000	0.000	
LOLH	Cruise Control	0.6	0.5	0.9	0.3	0.2	0%
	Carbon Policy Accelerates	1.0	1.0	1.8	0.7	0.9	
	Reliability Reigns	0.6	0.7	1.1	0.4	0.3	
	Technology Solves Everything	0.4	0.1	0.3	0.0	0.0	
LOLE	Cruise Control	0.1	0.1	0.1	0.1	0.1	5%
	Carbon Policy Accelerates	0.1	0.2	0.3	0.1	0.2	
	Reliability Reigns	0.1	0.2	0.1	0.1	0.1	
	Technology Solves Everything	0.1	0.0	0.1	0.0	0.0	

12.2.3 When are we at most risk for inadequacy events?

In order to better understand the type of inadequacy risk we could face with a given portfolio, this section examines in more detail when inadequacy issues show up in our IRP model. For illustrative purposes, results are presented for our Slice/Block portfolio without CBH renewal. Results for other portfolios are similar, though the size of shortfalls varies across portfolios. Figure 59 presents a scatterplot of load that cannot be served when there are shortfalls (called unserved energy) over time by weather year.⁵⁷ Capacity shortfalls occur exclusively in the 1992 and 1993 weather years and are concentrated primarily in the 1993 weather year. Figure 60 shows the distribution of shortfall amounts across months for the 1992 and 1993 weather years.⁵⁸ Shortfalls occur exclusively in December of 1992 and January 1993, with the bulk of unserved energy concentrated in January 1993. We reviewed the winter 1992/1993 inputs and, while total inflows across the entire October to October water year were not low enough to be considered a critical water year, we experienced some of its lowest winter inflows on record that winter. This was combined with cold (though not record-breaking) temperatures.

While limited information on the 1992/1993 winter period was available in a web search, several online articles confirm that the winter of 1992/1993 was both cold and dry for the region as a whole. A Bureau of Land Management report, for example, discussed a significant drought in the period leading up to winter 1992, though it did not mention low water conditions in the following winter period: “The 1992 drought occurred because of a hot and dry summer following a winter with low snowpack. It almost rendered Malheur Lake completely dry. The 1992 drought had its reach in the urban water utility sectors as well. Water shortage in the city of Seattle occurred because the city spilled water from its reservoir to comply with flood control rules, and there was limited snowmelt to recharge supply.”⁵⁹ An online book produced by BPA discussing the institution’s history tells a similar story: “Three consecutive low-water years from 1991 to 1994 ate through BPA’s financial reserves, taking them down from \$900 million to \$200 million by 1995.”⁶⁰ One mentions of particularly cold weather in the winter of 1992/1993 came from an Oregon State University blog, which mentioned off-hand that, “whereas many of the drought years, especially 2015, were especially warm, this winter was especially cold. In fact, this winter was the

⁵⁷ Graphs include all four scenarios of the future and all weather years used in the analysis (1950 through 2008).

⁵⁸ Graphs include the entire 2020-2039 study period and all four scenarios of the future.

⁵⁹ <https://www.fs.fed.us/r6/fire/falt/2015-spring/blmdroughtfinal2.pdf>

⁶⁰ <https://www.bpa.gov/news/pubs/GeneralPublications/Book-Power-of-the-River-BPA-History-Book-low-res.pdf>

coldest winter on record in the Pacific Northwest since 1992/1993.”⁶¹ A 2017 NOAA publication on Pacific Northwest winter temperatures in 2017 similarly stated, “The last time December through February average temperatures were this cold was in the winter of 1992-93”.⁶²

The results indicate that the potential adequacy challenges that we could face with the *Slice/Block Only* portfolio are not consistent adequacy issues likely to occur in many years. In fact, we would have enough resources to meet its load in all other weather years. Rather, the occasional failures to meet our adequacy standard are driven entirely by very low probability (nearly a 1 in 60-year event) but potentially high impact events.

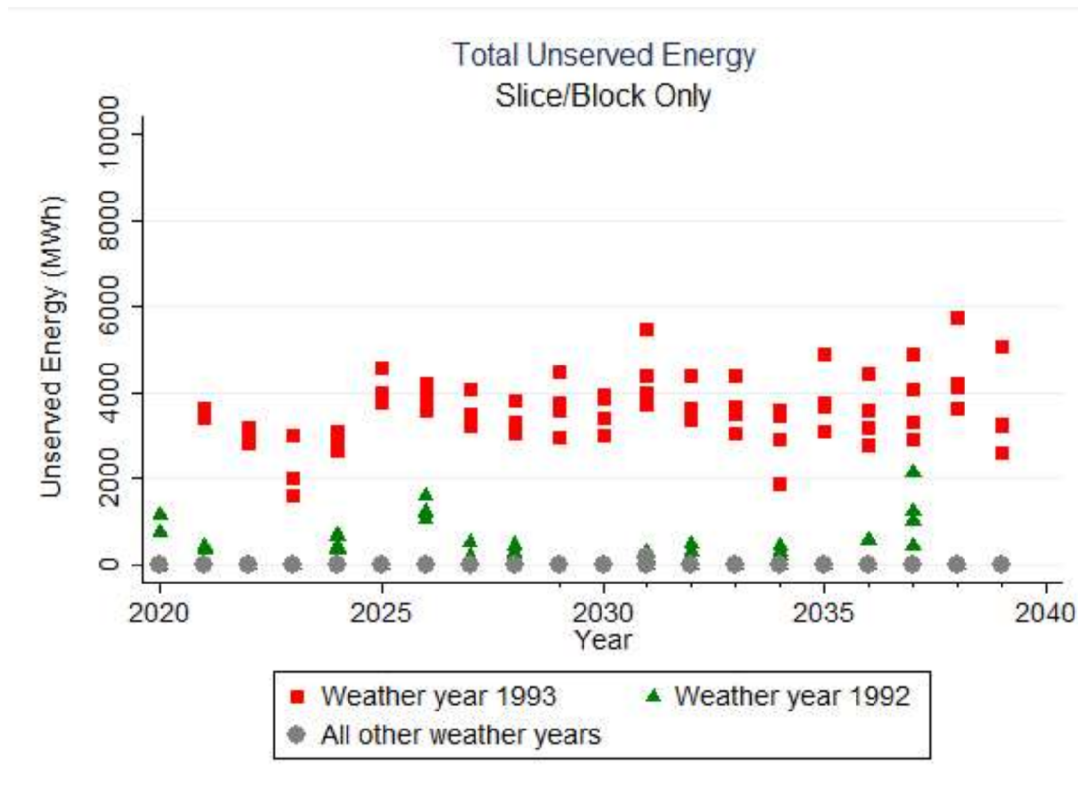


Figure 59: Capacity shortfalls over time by weather year

⁶¹ <http://terra.oregonstate.edu/2017/05/water-years-long-cold-wet-goodbye-kiss-drought/>

⁶² <https://www.weather.gov/media/pdt/Vol20-2017Spring.pdf>

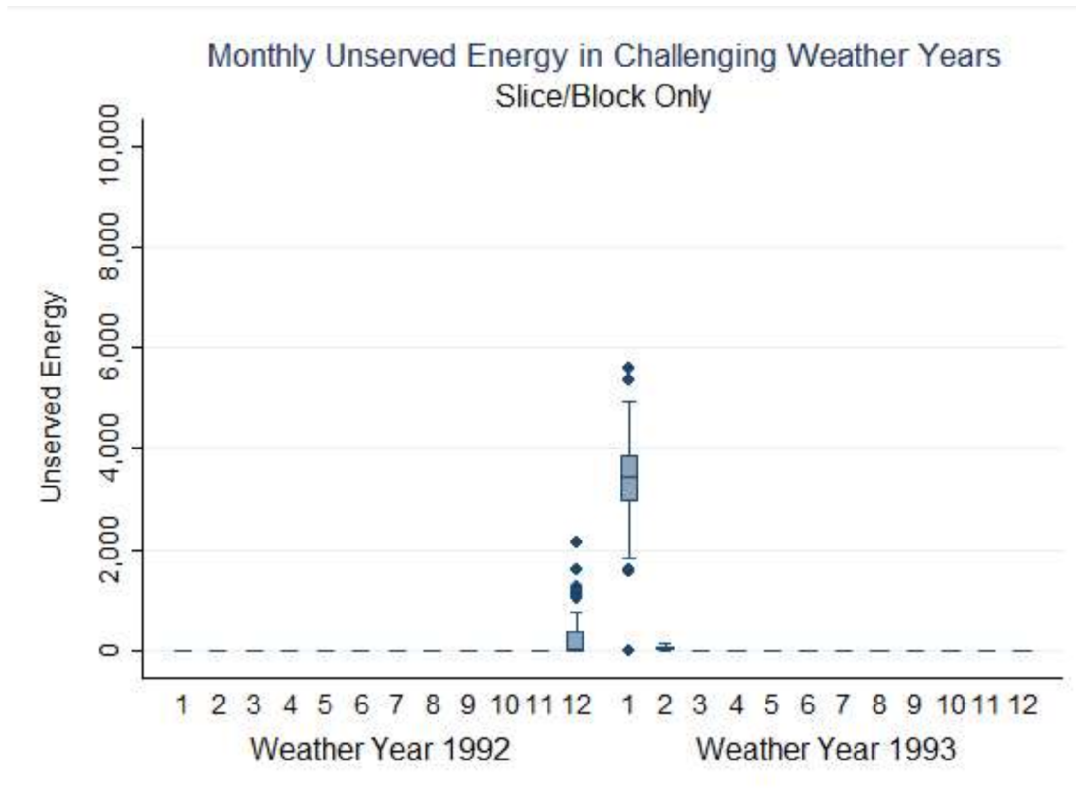


Figure 60: Monthly shortfalls across months (1992 and 1993 weather years only)

12.2.4 Comparison to previous IRP findings

In order to preserve some level of continuity and consistency as the IRP transitions to new models and metrics, the IRP team used the SAM model to re-create two of the resource adequacy metrics evaluated in the 2017 IRP update—annual and monthly load resource balance. This allows us to understand whether differences in findings across the last IRP and the current one were due primarily to updates to IRP modeling tools or updates to IRP metrics.

Using different modeling tools and adequacy metrics, previous IRPs have consistently concluded that our current portfolio is resource adequate. This IRP has slightly different conclusions, which can be attributed primarily to changes in the adequacy metrics used. Figure 61 compares the annual resource adequacy metric for the 2017 IRP (which used the PLEXOS model) and the current IRP (which used the SAM model). Both the 2017 and 2020 IRP conclude that we are resource adequate based on an annual energy adequacy metric. Similarly, Figure 62 compares the monthly resource adequacy metric for the 2017 and current IRPs. Again, both conclude that we are resource adequate based on a monthly energy adequacy metric. Note that the SAM model actually models Slice output from inflows, unlike the PLEXOS model that modeled our resources from inflows and modeled Slice based on conservative average historic generation. This resulted in the SAM model showing more Slice generation than the PLEXOS model and an improvement in our energy adequacy position.

There are several reasons why the *Slice/Block Only* portfolio occasionally fails the 2020 IRP adequacy metrics but consistently passed the old metrics. The first is that, unlike past IRPs, the probabilistic metrics in the 2020 IRP consider all water years. The small adequacy risks presented by the *Slice/Block*

Only portfolio are caused by very low-probability but high-impact events that occur under December 1992/January 1993 water conditions, which are worse than the critical water conditions considered in the last IRP’s annual adequacy metric or the 5th percentile conditions considered in the monthly adequacy metrics presented in Figure 61 and Figure 62.

Second, the 2020 IRP adequacy metrics consider our capacity position (i.e. how much could we generate in a given hour given the amount of water available behind the dams) rather than the energy positions (i.e. how much would we generate over a certain period of time). Assessing adequacy based on capacity vs. energy can yield different results, as the 2020 IRP analysis demonstrates.

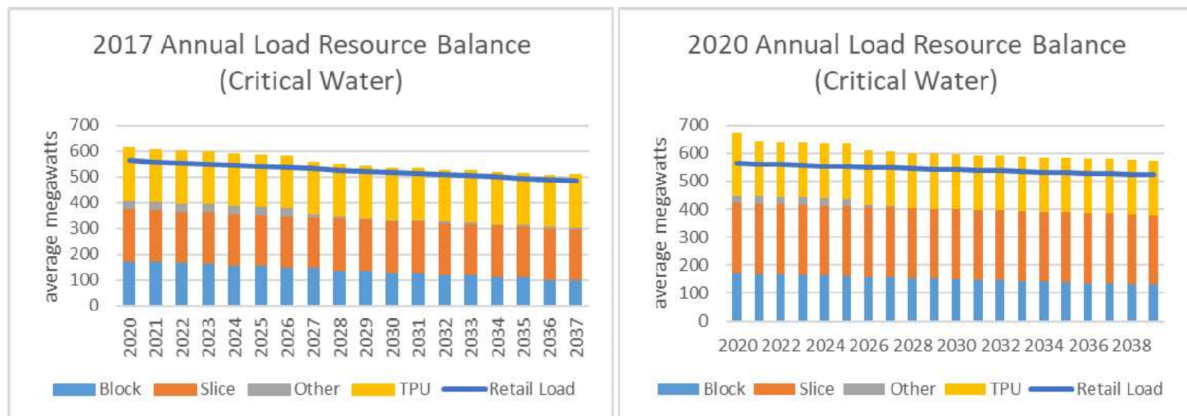


Figure 61: Comparison of 2017 and 2020 annual load resource balance (annual energy adequacy metric)

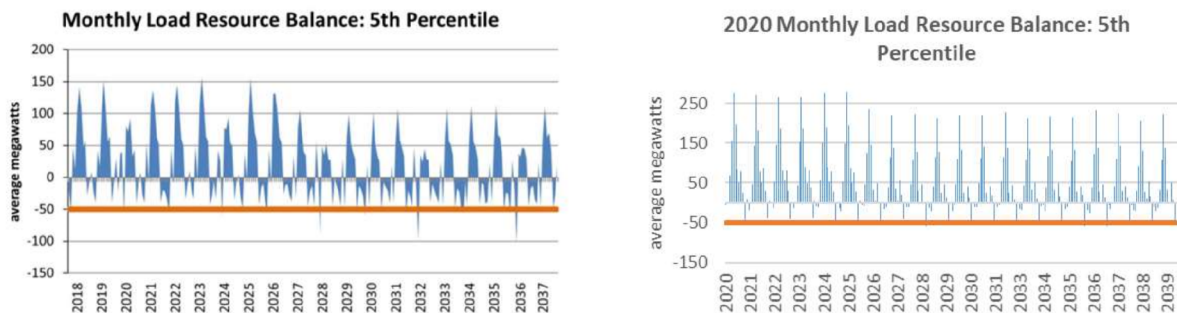


Figure 62: Comparison of 2017 and 2020 monthly load resource balance (monthly energy adequacy metric)

12.2.5 Understanding differences between diversification with wind vs. solar

One important finding from this resource adequacy analysis is that resource adequacy would deteriorate more so if we were to partially replace its BPA take with wind than it would if we were to instead do the same thing with solar. This may seem counterintuitive at first because wind is more suited to Tacoma’s load needs because it generates more in the wintertime. However, the current BPA contract works such that our net requirement is calculated based on the difference between our need (i.e. our load) and our resources in each month of the year. Because wind produces more in the wintertime, it also reduces our net requirement (and so the amount of Block power that we get from BPA) by more in the wintertime. The result is that we end up replacing stable, guaranteed BPA Block power with less predictable wind power at the time of year when we are most at risk of having an adequacy problem. In most years, this would probably not present a problem for us. However, it does

create a problem when we experience particularly poor winter water conditions. Solar, on the other hand, produces very little in the wintertime and so has almost no impact on our net requirement calculation in the winter, leaving us with essentially the same amount of winter Block power as we would have if we did not diversify at all. Diversifying with wind yields particularly poor resource adequacy outcomes with Slice/Block because the wind replaces only the firm Block component of our BPA take rather than the Slice component. Because the Slice component is correlated with our own generation (i.e. when we have poor water conditions, BPA typically does as well) and already presents some minor adequacy risk in extreme low winter water conditions, further reducing the Block component compromises adequacy considerably.

12.3 COST AND FINANCIAL RISK

The subset of portfolios that passed the initial resource adequacy screen often enough to be considered further are identified in Table 22. Each of these portfolios is next evaluated on total cost and financial risk.

12.3.1 Results for all portfolios that are adequate or nearly adequate

Expected portfolio costs and financial risk are calculated as an average across all weather years, gas price risks runs and scenarios, and financial risk is measured by the average cost across the 10% highest-cost outcomes across all weather years, gas price risks runs and scenarios. Table 46 presents the net present value of expected costs and financial risk outcomes across the whole study period (2020 through 2039), and Table 47 presents average annual cost and financial risk outcomes in the post-2028 period (2029-2039). Portfolios are ordered from lowest to highest expected cost, and all values are reported in 2020 dollars. In each table, the second set of columns on the right report the difference between the expected cost and the financial risk metric for a given portfolio versus the same two values for the lowest cost, least risk portfolio.

- 1) **Lowest cost portfolio:** The portfolio in which Slice/Block is renewed and no other resources besides conservation are acquired (*Slice/Block Only* portfolio) is the lowest cost option. It also presents the lowest financial risk.⁶³
- 2) **Lowest cost portfolio with improved adequacy:** Adding 10MW of demand response to the *Slice/Block Only* portfolio is just a little more costly and improves adequacy considerably. Adding 10MW of demand response increases expected lifetime costs by about \$3.6 million and adds the least amount of financial risk by far.
- 3) **Other options for improving adequacy:** Adding other types of capacity (whether additional hydrogenation or wind generation) to Slice/Block generally results in lower expected cost than changing to Shapeable Block product but tends to be higher risk financially than switching to Shapeable Block. Adding pumped storage is especially high risk financially.
- 4) **BPA diversification:** Partially replacing BPA Slice/Block with a 60MW solar resource adds around \$30 million to lifetime costs (\$4.8 million per year) and does not improve resource adequacy (Section 12.2.2). Renewing with Shapeable Block and partially replacing it with wind resulted in a lower-cost and lower-financial risk portfolio than just renewing Shapeable Block, but doing so does worsen adequacy. This suggests that partially replacing Slice/Block with wind would also be

⁶³ It is important to note that cost estimates for BPA do not contemplate a major change to BPA resources (such as removal of hydrogenation projects) in the high-cost case.

lower cost than *Slice/Block Only*, but this was not considered because it compromised resource adequacy significantly (Section 12.2.2). Simply adding 80MW of wind to *Slice/Block* improves adequacy considerably and results in lower expected lifetime costs than partially replacing *Slice/Block* with 60MW of solar but also increases financial risk. However, adding 10MW of demand response improves adequacy as much as adding 80MW of wind and does so at a lower cost and financial risk.

- 5) **What it would take to replace BPA:** Portfolios that replace BPA with wind, demand response and additional generation capacity add substantially to expected costs. These portfolios add around \$200 million to lifetime portfolio costs (\$24 to \$30 million per year) and add \$420 to \$450 million in potential risk (\$53 to \$58 million per year) compared to the lowest cost *Slice/Block* options. Thus, even if these portfolios were feasible, they would add substantially to costs.

Table 46: NPV portfolio cost and financial risk

Portfolio	NPV Cost (2020-2039)		Comparison to Lowest-Cost, Lowest-Risk Portfolio	
	Expected Cost	Financial Risk	Additional Lifetime Cost	Additional Financial Risk
Slice/Block Only	\$ 2,501,065,464	\$ 3,383,879,528	\$ -	\$ -
Slice/Block + 10MW DR	\$ 2,504,627,896	\$ 3,391,660,344	\$ 3,562,432	\$ 7,780,816
Slice/Block + Add Generator	\$ 2,511,085,328	\$ 3,460,964,256	\$ 10,019,864	\$ 77,084,728
Slice/Block + 50MW DR	\$ 2,519,613,104	\$ 3,412,889,808	\$ 18,547,640	\$ 29,010,280
Slice/Block + 60MW Wind +10MW DR	\$ 2,528,355,744	\$ 3,451,145,856	\$ 27,290,280	\$ 67,266,328
Slice/Block + 80MW Wind	\$ 2,532,915,488	\$ 3,463,878,144	\$ 31,850,024	\$ 79,998,616
Reduce Slice/Block with Solar	\$ 2,536,293,488	\$ 3,422,866,080	\$ 35,228,024	\$ 38,986,552
Slice/Block + Pumped Storage	\$ 2,547,463,008	\$ 3,489,219,712	\$ 46,397,544	\$ 105,340,184
Slice/Block + CBH	\$ 2,556,587,832	\$ 3,463,559,440	\$ 55,522,368	\$ 79,679,912
Reduce Block with E. WA Wind	\$ 2,572,632,616	\$ 3,434,153,808	\$ 71,567,152	\$ 50,274,280
Shapeable Block Only	\$ 2,579,229,352	\$ 3,456,522,848	\$ 78,163,888	\$ 72,643,320
Shapeable Block + Add Generator	\$ 2,589,838,800	\$ 3,533,643,600	\$ 88,773,336	\$ 149,764,072
Shapeable Block + 50MW DR	\$ 2,597,778,040	\$ 3,485,532,848	\$ 96,712,576	\$ 101,653,320
Reduce Block with Solar	\$ 2,612,326,856	\$ 3,495,707,872	\$ 111,261,392	\$ 111,828,344
Shapeable Block + Pumped Storage	\$ 2,630,224,032	\$ 3,562,003,968	\$ 129,158,568	\$ 178,124,440
Wind + Add Gen + DR (no BPA)	\$ 2,690,067,592	\$ 3,800,396,352	\$ 189,002,128	\$ 416,516,824
Wind + PSH + DR (no BPA)	\$ 2,738,817,144	\$ 3,836,953,616	\$ 237,751,680	\$ 453,074,088

Table 47: Annual portfolio cost and financial risk (2029-2039)

Portfolio	Annual Average (2029-2039)		Comparison to Lowest-Cost, Lowest-Risk Portfolio	
	Expected Cost	Financial Risk	Additional Annual Cost	Additional Financial Risk
Slice/Block Only	\$ 155,409,299	\$ 227,809,479	\$ -	\$ -
Slice/Block + 10MW DR	\$ 155,714,497	\$ 228,524,241	\$ 305,199	\$ 714,762
Slice/Block + Add Generator	\$ 156,269,052	\$ 237,197,501	\$ 859,753	\$ 9,388,022
Slice/Block + 50MW DR	\$ 157,882,442	\$ 231,678,044	\$ 2,473,143	\$ 3,868,564
Slice/Block + 60MW Wind +10MW DR	\$ 157,817,085	\$ 232,953,866	\$ 2,407,786	\$ 5,144,387
Slice/Block + 80MW Wind	\$ 158,225,942	\$ 233,783,578	\$ 2,816,643	\$ 5,974,099
Reduce Slice/Block with Solar	\$ 160,180,225	\$ 232,965,873	\$ 4,770,927	\$ 5,156,394
Slice/Block + Pumped Storage	\$ 160,243,500	\$ 240,583,046	\$ 4,834,201	\$ 12,773,567
Slice/Block + CBH	\$ 162,135,039	\$ 236,562,284	\$ 6,725,740	\$ 8,752,804
Reduce Block with E. WA Wind	\$ 164,001,718	\$ 233,887,567	\$ 8,592,419	\$ 6,078,087
Shapeable Block Only	\$ 165,203,955	\$ 237,401,814	\$ 9,794,656	\$ 9,592,335
Shapeable Block + Add Generator	\$ 166,114,986	\$ 246,795,913	\$ 10,705,687	\$ 18,986,433
Shapeable Block + 50MW DR	\$ 167,677,159	\$ 241,270,704	\$ 12,267,860	\$ 13,461,225
Reduce Block with Solar	\$ 169,788,544	\$ 242,584,625	\$ 14,379,245	\$ 14,775,146
Shapeable Block + Pumped Storage	\$ 170,454,420	\$ 250,195,718	\$ 15,045,121	\$ 22,386,239
Wind + Add Gen + DR (no BPA)	\$ 179,447,073	\$ 281,255,599	\$ 24,037,775	\$ 53,446,119
Wind + PSH + DR (no BPA)	\$ 185,264,541	\$ 285,704,934	\$ 29,855,242	\$ 57,895,455

12.3.2 Understanding cost differences between Slice/Block and Shapeable Block

A key finding in this IRP and the 2015 IRP is that, for Tacoma Power, the Slice/Block product has a lower net cost than the Shapeable Block product. Table 48 summarizes key cost elements of each product. Values represent average expected costs across the years 2029-2039.

- **Composite charge:** The composite charge is the biggest piece of the BPA charge and is same across both products. For both products, it is calculated based on our net requirement (i.e. the difference between our expected load and our resources under critical water conditions).
- **Credit for surplus energy sales:** 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 contract, we take output from the federal system in-kind and then we 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. We also must pay the transmission costs associated with marketing surplus energy. However, this cost is also a wash, since BPA also deducts transmission costs from the credit it would give us for marketing surplus power.
- **Capacity and risk-related charges:** Block products like Shapeable Block come with additional capacity and risk-related charges (load shaping charges, demand charges and risk and balancing charges) that are the major source of difference in cost between the Slice/Block and the Shapeable Block products. With the Slice/Block product, we take on most or all of the responsibility for managing the variability and peakiness of its load itself as well as the financial

risk of marketing surplus power. With Shapeable Block, BPA would take these on instead and charge us for the costs of taking them on.

- **Tacoma Power costs of managing Slice:** The Slice product is complex and requires a considerable investment of staff time to manage it. We estimate that the FTE cost of managing Slice is approximately \$500,000. The costs of managing Slice are not large enough to offset the extra costs incurred in the Shapeable Block product.

The net result is that the Slice/Block product is lower cost by approximately \$9 million per year on average for Tacoma Power.

Table 48: Average net costs for Slice/Block vs. Shapeable Block

	Slice/Block	Shapeable Block	Difference (Shapeable Block- Slice/Block)
Base Charge	\$117,542,812	\$117,542,812	\$0
Composite charge	\$117,542,812	\$117,542,812	\$0
Capacity and Risk-Related Charges	\$4,531,869	\$15,109,296	\$10,577,427
Risk and Balancing Costs	\$4,195,906	\$10,483,702	\$6,287,796
Load Shaping Charges	\$335,963	\$1,378,997	\$1,043,034
Demand Charges	\$0	\$3,246,597	\$3,246,597
Credit for Suplus Energy Sales	\$16,871,247	\$17,679,012	\$807,765
BPA Wholesale Rev Credit	\$7,658,821	\$17,679,012	\$10,020,191
Value of Energy received in-kind	\$9,962,426	\$0	\$9,962,426
Transmission costs	\$750,000	\$0	\$750,000
Other Costs	\$500,000	\$0	\$500,000
Slice FTE Costs	\$500,000	\$0	\$500,000
Net Cost	\$105,703,434	\$114,973,096	\$9,269,662

12.3.3 Scenario-specific results for most promising portfolio options

This section takes a closer scenario-specific look at a few key portfolios that address central questions identified for analysis in the 2020 IRP. Figure 63 presents expected costs within each future scenario of the world in order to understand whether certain future outcomes would result in a different recommendation than what the pooled results indicate. Portfolio costs generally tend to be highest in the Technology Solves Everything scenario, when prices are low and stable. This is primarily because we are not able to generate as much revenue from surplus power sales in the wholesale market to offset portfolio costs under these price conditions. Costs tend to be lowest under the Cruise Control (base case) scenario, when prices are also low but also the most volatile. Cost differences across portfolios tend to be most pronounced in the Technology Solves Everything scenario and least pronounced in the Carbon Policy Accelerates scenario, when prices tend to be high and volatile (though not nearly as volatile as in the Cruise Control scenario).

- CBH renewal:** The *Slice/Block Only* portfolio and the *Slice/Block + CBH* portfolios are compared in order to understand the cost implications of CBH renewal. Figure 63 demonstrates that renewing CBH would result in a more costly portfolio regardless of which future unfolds. On average across scenarios, renewing the CBH contract costs the utility approximately \$7 million per year. The cost of renewing CBH is greatest in the Technology Solves Everything scenario (around \$10 million per year) and smallest in the Carbon Policy Accelerates scenario (around \$4 million per year).
- BPA product choice:** The *Slice/Block Only* and the *Shapeable Block Only* portfolios are compared in order to understand the cost implications of choosing either Slice/Block or the Shapeable Block product. Again, Figure 63 demonstrates that comparing average portfolio costs across scenarios provides the same answer directionally as does looking at outcomes scenario by scenario. In all cases, the Slice/Block portfolio costs the utility approximately \$10 million less than the Shapeable Block portfolio. However, the Shapeable Block portfolios eliminates all adequacy concerns, even in extreme low water conditions. The premium for that additional adequacy is around \$10 million per year.
- Shoring up minor adequacy risks of Slice/Block portfolio:** On average across scenarios, adding 10MW of demand response is the least-cost way to improve the adequacy of our Slice/Block portfolio and eliminate most of the potential adequacy risks even under extreme low water conditions. Adding 10MW of demand response adds approximately \$300,000 in annual costs on average across all scenarios, versus approximately \$3 million to add 80MW of wind or a combination of wind and demand response. The cost differences are most pronounced in the Technology Solves Everything scenario (when adding 80MW of wind is around \$8 million more costly than adding demand response) and least pronounced in the Carbon Policy Accelerates scenario (when adding the wind is actually lower cost by around \$100,000). This variability in outcomes is primarily due to the fact that the net portfolio costs associated with the wind portfolio depend on how much the market will pay for surplus wind that we would generate with that portfolio.

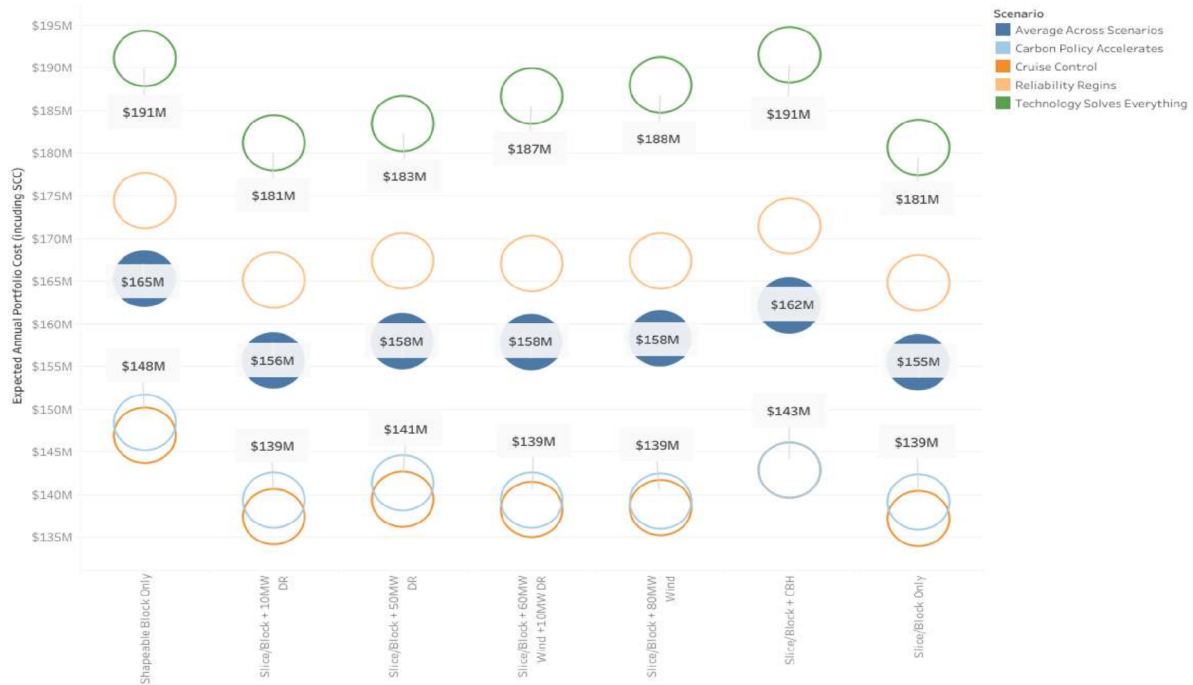


Figure 63: Scenario-specific expected annual costs for key portfolios

12.4 CARBON EMISSIONS

Because all of the portfolios that passed the resource adequacy screening include only non-emitting generating resources, carbon entering our portfolio comes exclusively from market purchases we would make or, in the case of portfolios in which the BPA contract is renewed, from market purchases made by BPA that pass through to Tacoma Power. Figure 64 presents expected reported emissions across portfolios and Figure 65 reports expected emissions intensity. In both figures, scenario-specific averages are reported in addition to the average across scenarios. Generally, the results show that all portfolios examined are very low-carbon. The emissions intensity of the portfolios ranges from a low of 0.002 MT/MWh for certain portfolios under certain future scenarios and a high of 0.008 MT/MWh, with most portfolios falling in the 0.002 to 0.005 MT/MWh range. This is substantially lower than a thermal portfolio’s emissions intensity. A natural gas plant, for example, tends to emit around 0.4 MT/MWh.

There are small differences across portfolios, however. Portfolios in which we renew the Slice/Block product tend to result in lower reported emissions and emissions intensity than those with the Shapeable Block product. Portfolios in which BPA is renewed (with Slice/Block or Shapeable Block) tend to result in lower reported emissions than those in which BPA is replaced with wind and other non-emitting generation, but the emissions intensity of non-BPA portfolios is similar to that of the Shapeable Block portfolios because more energy is generated with those non-BPA portfolios. Differences across portfolios are driven primarily by differences in our market purchases associated with a given portfolio rather than difference in emissions coming from BPA.

One important caveat to the emissions results presented in this section is that these results may both underestimate the amount of reported carbon associated with a given portfolio and misestimate the relative performance of different portfolios in terms of reported carbon. The current IRP model

represents all of our market activities as buying and selling on the real-time market. In reality, the utility often sells power ahead of time to hedge its financial risk. This is likely to lead to more market purchases with certain portfolios than what is captured in the modeled results above. It is likely that we would engage in more forward selling and more buying back when prices are low with the Slice/Block product relative to Shapeable Block because, under many water conditions, Slice leaves us with surplus power. Our current portfolio was last certified by the California Air Resources Board to have an emissions rate of between 0.0168 MT/MWh⁶⁴ whereas modeled emissions for 2020 are around 0.002 MT/MWh. While all of the portfolios considered would still result in very little reported carbon even if reported emissions were all ten times higher than modeled emissions, the ordering of which portfolio results in the lowest emissions might be different.

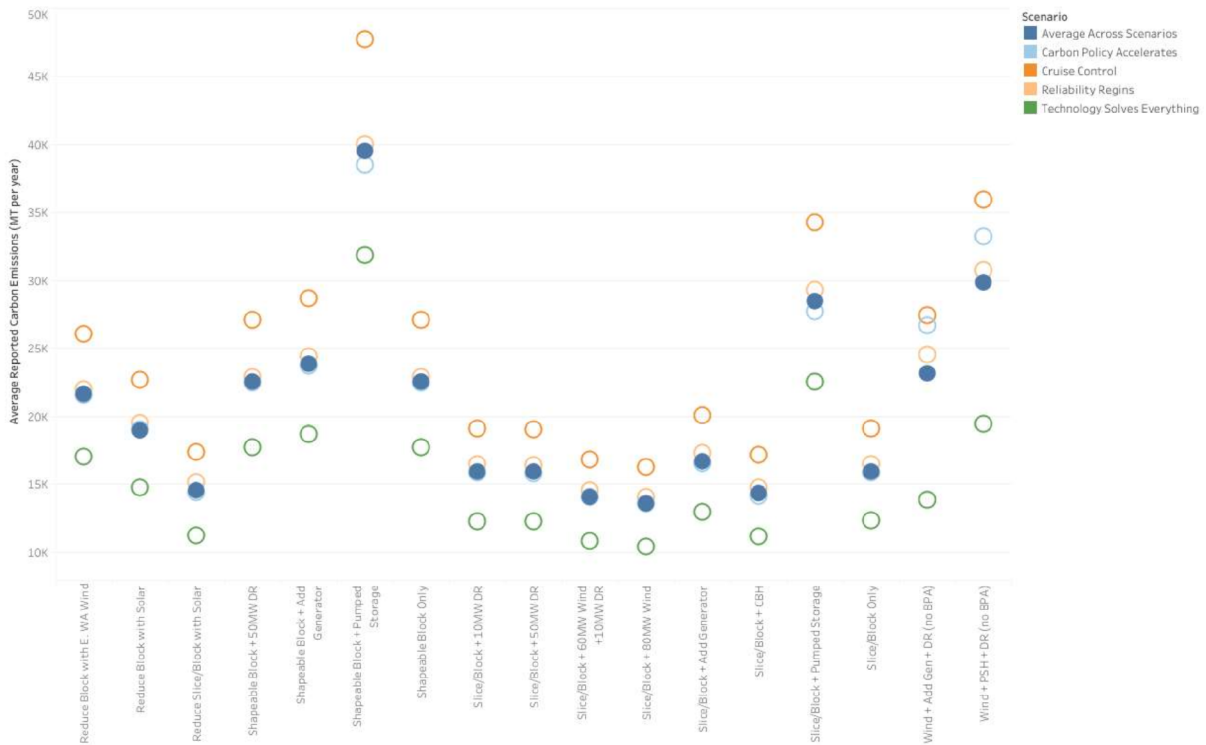


Figure 64: Expected reported emissions

⁶⁴ <https://ww2.arb.ca.gov/mrr-acs>

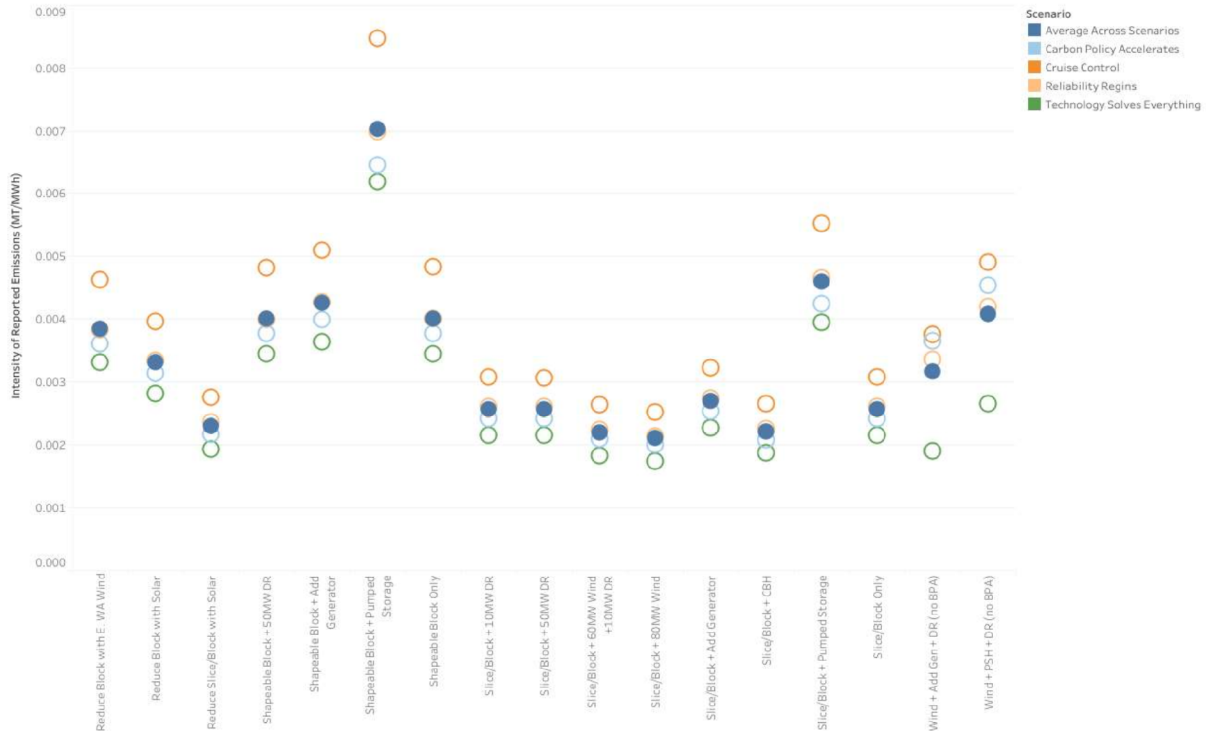


Figure 65: Expected intensity of reported emissions

12.5 SUMMARY OF PORTFOLIO PERFORMANCE

Table 49 summarizes portfolio performance along all dimensions considered, and Figure 66 provides a visual look at where portfolios fall in terms of cost, financial risk and resource adequacy. Figure 66 displays expected costs on the x-axis, financial risk along the y-axis and color codes portfolios according to their resource adequacy results (green meaning that a portfolio always passes our adequacy standard, blue meaning that a portfolio very occasionally fails the standard and yellow meaning a portfolio fails the standard more often but not often enough to be removed from consideration). Summary findings from the analysis of portfolio performance are:

- **CETA Compliance:** All portfolios modeled were CETA-compliant through 2044.
- **Cost and Financial Risk:** The *Slice/Block Only* portfolio was found to be the lowest cost option and presented the lowest financial risk. However, it does sometimes fail our resource adequacy standard due to the challenge it can present in extreme low water conditions. Adding 10MW of demand response was found to be the lowest cost and least- risk way to improve adequacy of *Slice/Block* in extreme low water conditions.
- **Carbon Emissions:** All portfolios examined are very low-carbon, but our model suggests that renewing the *Slice/Block* product tends to result in the lowest reported emissions (all coming from market purchases made by Tacoma Power or BPA). However, the IRP may be missing important features of operations that could impact whether *Slice/Block* would truly result in the lowest reported emissions compared to other options.

Table 49: Portfolio performance summary table

Portfolio	Feasibility	Resource Adequacy	Additional PV Cost Relative to Slice/Block	Additional Financial Risk Relative to Slice/Block	Reported Annual Emissions (MT)
Slice/Block Only	Feasible	Small inadequacies	\$ -	\$ -	15,918
Slice/Block + 10MW DR	Feasible	Minimal inadequacies	\$ 3,562,432	\$ 7,780,816	15,913
Slice/Block + Add Generator	Unsure	Always adequate	\$ 10,019,864	\$ 77,084,728	16,711
Slice/Block + 50MW DR	Unsure	Always adequate	\$ 18,547,640	\$ 29,010,280	15,903
Slice/Block + 60MW Wind +10MW DR	Feasible	Always adequate	\$ 27,290,280	\$ 67,266,328	14,064
Slice/Block + 80MW Wind	Feasible	Minimal inadequacies	\$ 31,850,024	\$ 79,998,616	13,592
Reduce Slice/Block with Solar	Feasible	Small inadequacies	\$ 35,228,024	\$ 38,986,552	14,547
Slice/Block + Pumped Storage	Unsure	Always adequate	\$ 46,397,544	\$ 105,340,184	28,466
Slice/Block + CBH	Feasible	Small inadequacies	\$ 55,522,368	\$ 79,679,912	14,319
Reduce Block with E. WA Wind	Feasible	Minimal inadequacies	\$ 71,567,152	\$ 50,274,280	21,668
Shapeable Block Only	Feasible	Always adequate	\$ 78,163,888	\$ 72,643,320	22,537
Shapeable Block + Add Generator	Unsure	Always adequate	\$ 88,773,336	\$ 149,764,072	23,875
Shapeable Block + 50MW DR	Unsure	Always adequate	\$ 96,712,576	\$ 101,653,320	22,523
Reduce Block with Solar	Feasible	Always adequate	\$ 111,261,392	\$ 111,828,344	18,987
Shapeable Block + Pumped Storage	Unsure	Always adequate	\$ 129,158,568	\$ 178,124,440	39,495
Wind + Add Gen + DR (no BPA)	Not feasible	Minimal inadequacies	\$ 189,002,128	\$ 416,516,824	23,130
Wind + PSH + DR (no BPA)	Not feasible	Minimal inadequacies	\$ 237,751,680	\$ 453,074,088	29,830

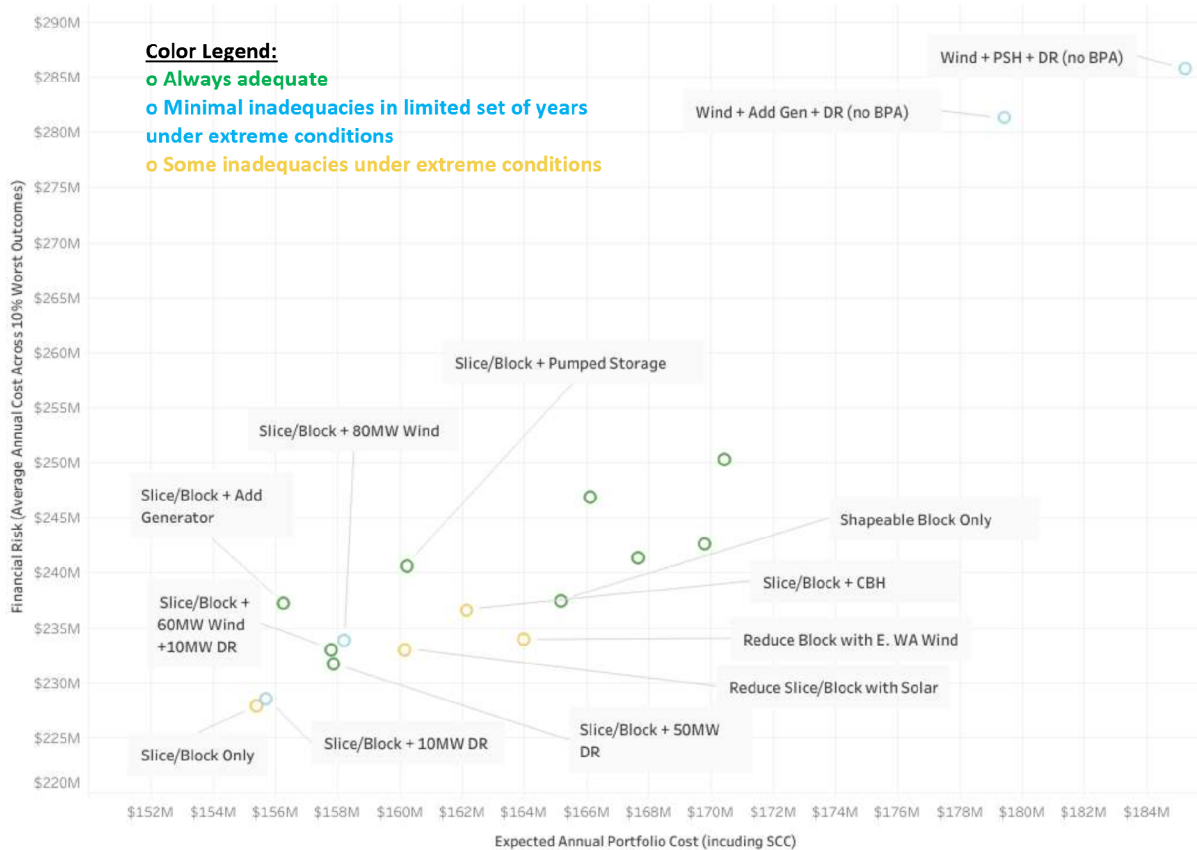


Figure 66: Portfolio performance summary graph

13 PREFERRED PORTFOLIO

The 2020 IRP set out to answer five key questions in order to determine our preferred portfolio. Answers to the questions are below. Based on this analysis, our preferred portfolio is the *Slice/Block + 10MW DR* portfolio. The resource plan is summarized in Table 50.

1) Should we renew our CBH contracts, which begin to expire in 2022?

Renewing the CBH contracts does not improve resource adequacy and adds around \$55.5 million in expected costs over the study period. As a result, it is not in the interest of our customers to renew the CBH contracts.

2) Should we renew our BPA contract in 2028?

Based on this analysis, it is unlikely to be in the interest of customers for us to forego our access to a contract for BPA preference power and replace it with the other non-emitting resources. Replacing BPA with sufficient quantities of wind, demand response, and other non-emitting generation to maintain resource adequacy is very difficult and would cost between \$13 and \$30 million more on average than BPA options. However, we will continue to explore this question and other options available as 2028 draws nearer.

3) If we were to renew our BPA contract in 2028, which BPA product looks most promising?

Current analyses suggest that renewing the BPA contract with Slice/Block is the lowest cost option and presents the lowest financial risk. However, it does sometimes fail our resource adequacy standard due to the adequacy challenges it can present in extreme low water conditions. Adding 10MW of demand response is likely to be the lowest cost and least risk way to improve adequacy of Slice/Block in extreme low water conditions. Although flexibility to change course in the future was not directly evaluated as a performance metric in this IRP, demand response also presents lower risk because, unlike most supply-side resources, it does not require a 20-year (or longer) commitment. It can be discontinued if the utility later finds that an extra resource is no longer needed.

4) If we were to renew our BPA contract in 2028, could there be value in diversifying our portfolio by replacing part of our BPA contract with another source of non-emitting generation, like wind or solar?

Replacing BPA partially with wind or solar worsens adequacy. If there is a desire to diversify with wind or solar, adding 80MW of wind without replacing BPA would be lowest cost way to include wind or solar in the portfolio. Doing so would also improve adequacy but would do so at a much higher cost and financial risk than adding 10MW of demand response. It is thus not in the interest of our customers to acquire a wind or solar resource immediately, but future IRPs will continue to evaluate this question.

5) What (if any) other resources should we acquire?

For years conservation has been the only resource that we have acquired, and we remain committed to helping customers reduce their energy use and defer the need to invest in costly

generation. The IRP resource plan includes acquisition of the 10 and 20-year conservation potentials identified in our 2020 Conservation Potential Assessment (CPA).

The 2020 IRP also finds a new and promising role for a moderate demand response acquisition. Adding 10MW of demand response is the least-cost way to improve the adequacy of Slice/Block and eliminate most of its potential adequacy risks even under extreme low water conditions.

Table 50: Summary of Tacoma Power resource plan

Resource	Resource Plan
Tacoma Power hydro generation	Assume continued operation at current levels.
Conservation	Acquire CPA economic potential: 26.7 aMW by 2029
BPA contract	Renewing Slice/Block at current resource levels in 2028 looks most promising.
Columbia Basin Hydro (CBH) contract	Allow contracts to expire without renewal between 2022 and 2026
Demand Response	Add 10MW of DR by 2024

14 SENSITIVITY ANALYSES ON PREFERRED PORTFOLIO

Not all uncertainties can be addressed even with the 1,000+ simulations run in the IRP. To address some of the key factors that were excluded from the core analysis in the preceding sections, we investigated how the preferred portfolio’s resource adequacy might be affected by (1) climate change, (2) a different assumption about the availability of market purchases and (3) large changes to industrial loads.

14.1 CLIMATE CHANGE

Currently climate change is modeled 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. That study projected that we were likely to experience slightly reduced winter heating load and a negligible increase in summer cooling and the timing of inflows was likely to change, with more precipitation falling as rain in the winter and less coming in as runoff in the spring and summer. The net effect was expected to coincide better with our power needs but also present an increased risk of river flooding.⁶⁵ The 2020 IRP took the next step and made a first attempt at including climate change projections directly into our system model. We plan to conduct additional work to (a) determine which climate projections to include in our modeling, (b) determine how climate change can be incorporated into our WECC model, and (c) refine how temperatures and inflows are translated into loads and generation, respectively, when projected values fall outside the range of what our current models are tuned to consider.

⁶⁵ 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

14.1.1 Climate change projections

Some of the best and most complete projections on the impacts of climate change on Northwest streamflows were produced by a team of climate and hydrology researchers from Oregon State University and the University of Washington for a 2018 Columbia River Climate Change (CRCC) study funded primarily by BPA with additional funding to the University of Washington from the United States Bureau of Reclamation and the United States Army Corps of Engineers.⁶⁶

While we commissioned our own climate change study in 2015 using the same climate models at the CRCC study, we opted to use this regional dataset rather than our own 2015 study for two key reasons:

- 1) **Consistency across BPA inflows and Tacoma Power inflows:** For portfolios that include BPA's Slice/Block product, BPA Slice generation needs to be adjusted to account for climate change in addition to our generation. However, the 2015 Tacoma Power study projected streamflow outputs only for our sites, and downscaling methods used for the study were not identical to those used in the CRCC study. As a result, streamflow projections are not always consistent across the two studies. Because it is important to correctly correlate Slice generation and our generation in a given water year to accurately reflect the risk associated with the *Slice/Block Only* portfolio, the IRP team opted to use CRCC study data for all streamflow projections.
- 2) **Consistency with Tacoma Power load models:** Tacoma Power's current load models use temperatures from the SeaTac weather station. The regional CRCC study includes temperature projections for SeaTac, whereas our 2015 study used McChord AFB weather station temperatures, which can differ considerably from SeaTac.

Climate change modeling for hydro conditions involves several modeling steps.⁶⁷ The first is selecting an emissions scenario, referred to in the literature as a Representative Concentration Pathway (RCP). The CRCC study selected two common scenarios to include: RCP 4.5 and RCP 8.5. RCP4.5 is consistent with relatively low emissions and RCP8.5 is consistent with a very high GHG emissions. The second step is selecting a Global Climate Model (GCM), which use the RCPs to project global climate outputs. Ten GCMs were selected for inclusion in the CRCC study. The third step is to select a downscaling method, which turns outputs from the GCMs into localized climate projections. Three different approaches were selected for inclusion in the CRCC study. The fourth and final step is selecting a hydrologic model that produces streamflow data based on climate conditions. Two different hydrologic models were selected—the VIC model and the PRMS model—and the VIC model was implemented in three different ways, yielding a total of 4 streamflow outputs for each localized climate model. Altogether, the CRCC study produced 43 separate projections of outdoor air temperature and 172 separate projections of streamflows through the year 2099 for 172 sites in the Northwest, including Tacoma Power's project sites.

Currently we cannot reasonably incorporate 172 separate sets of streamflow projections due to computational time. The NW Power and Conservation Council faces a similar challenge and conducted an analysis to determine which of the 172 models to incorporate into its modeling for the 2021 Power Plan. They opted to use three different sets of projections, all of which assume high emissions (RCP8.5): *CanESM2_RCP85_BCSD_VIC_P1*, *CCSM4_RCP85_BCSD_VIC_P1*, and *CNRM-CM5_RCP85_MACA_VIC_P3*.

⁶⁶ <https://www.hydro.washington.edu/CRCC/>

⁶⁷ The CRCC study website provides a more detailed discussion of the modeling efforts at <https://www.hydro.washington.edu/CRCC/documentation/methods/>

For this first attempt at incorporating climate change into our IRP modeling, we opted to use the same models as those selected preliminarily by the Power Council. However, we will re-evaluate this choice for the next IRP.

14.1.2 Temperature and load impacts

When comparing the distribution of the yearly peak load, we find that peak loads observed with *CNRM-CM5* temperatures were comparable to peak loads using our historical model. This is most likely a direct result of the current load simulation method. Because the load simulation is comprised of linear regression models based solely on weather from 2013-2018, it is sensitive to extreme weather temperature conditions. The *CNRM-CM5* model contains more volatile temperatures, and contains instances of extreme cold temperatures, which translate to extreme peak loads. Compared to the historical model, *CCSM4* peak loads decreased by 4.5%, and *CanESM2* peak loads decreased by 4.9%.

When exploring average energy under climate change, all three models show a decrease in average energy compared to the historical model because we experience our largest loads in the wintertime and average daily temperatures rise under climate change conditions. Annual load decreases by 2.1%, 2.5% and 2.8% for the *CNRM-CM5*, *CCSM4* and *CanESM2* models, respectively.

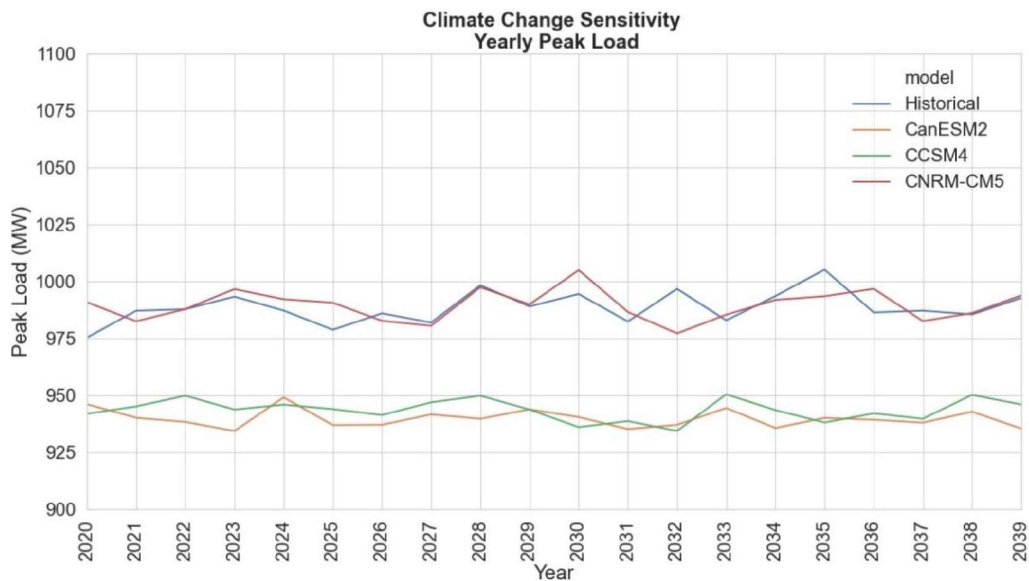


Figure 67: Average of annual peak under climate change models vs. historical weather conditions

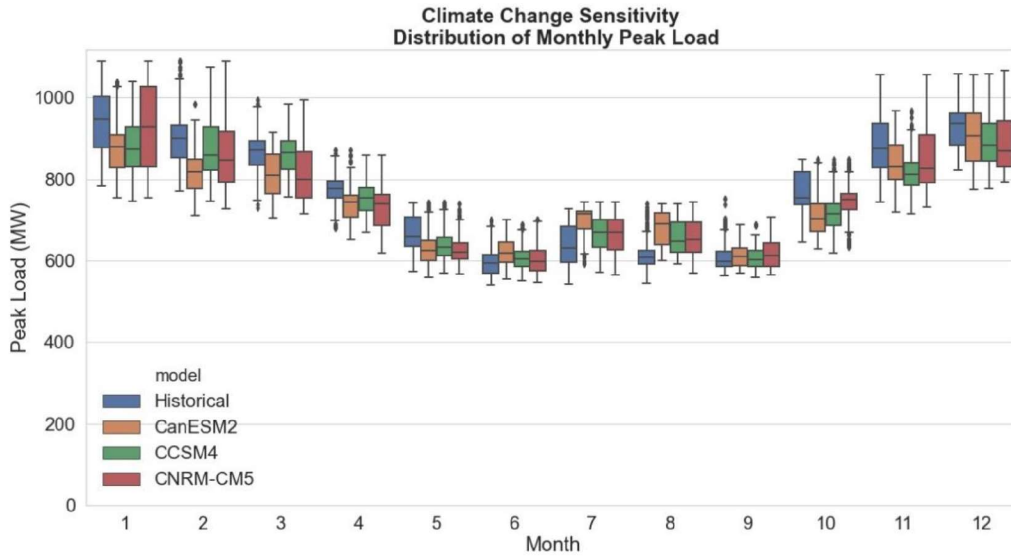


Figure 68: Distribution of monthly peak load under climate change models vs. historical weather conditions

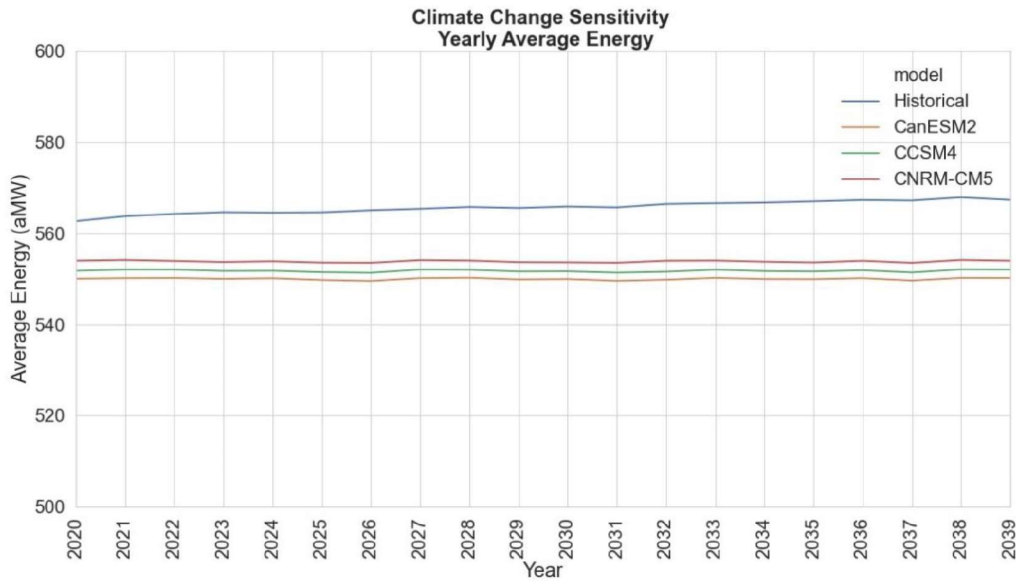


Figure 69: Average of annual energy under climate change vs. historical weather conditions

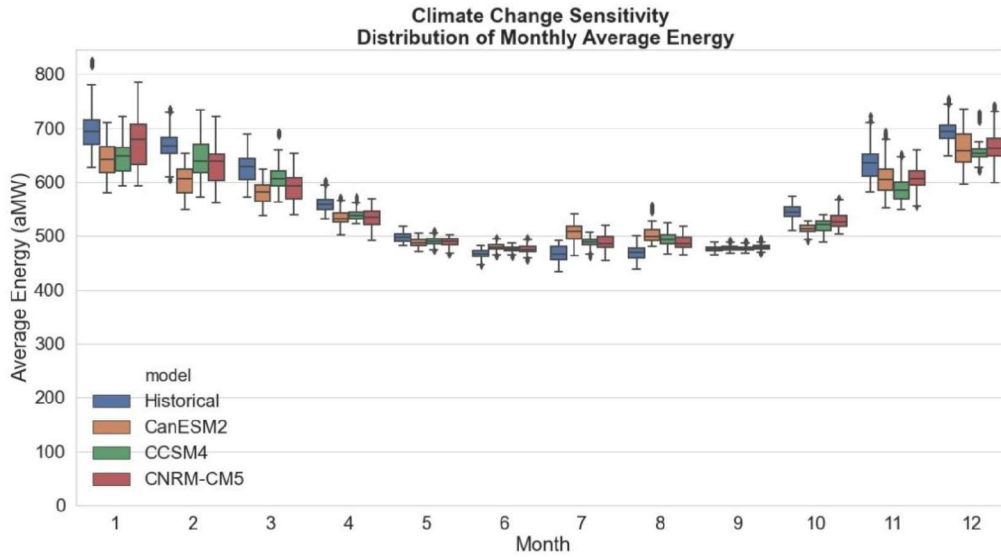


Figure 70: Distribution of monthly average energy under climate change vs. historical weather conditions

14.1.3 Inflow & generation/capacity impacts

The timing of inflows into both our system and BPA’s system directly impacts the timing of power generation. Under the three climate change models, we observe significant changes in the shape of average inflows into our projects, as well as into Grand Coulee Dam and Ice Harbor Dam. Inflows under climate change conditions tend to increase in the wintertime compared to historical weather conditions at our projects (Figure 71 and Figure 73) and BPA’s projects (Figure 75 and Figure 77), though winter inflows still vary quite a bit in all the three climate models (Figure 72, Figure 74, Figure 76, Figure 78). The most significant differences between historical and projected inflows are extreme increases in inflows into Ice Harbor Dam (Figure 77 and Figure 78). This directly affects the Slice portion of our current Slice/Block model.

Changes in the timing of inflows require our system to adjust how much power we generate at different times of the year. All of the climate models result in more generation in the spring and less generation in the fall through October. Changes in winter and summer generation vary across models (Figure 79).

14.1.3.1 Tacoma Power projects

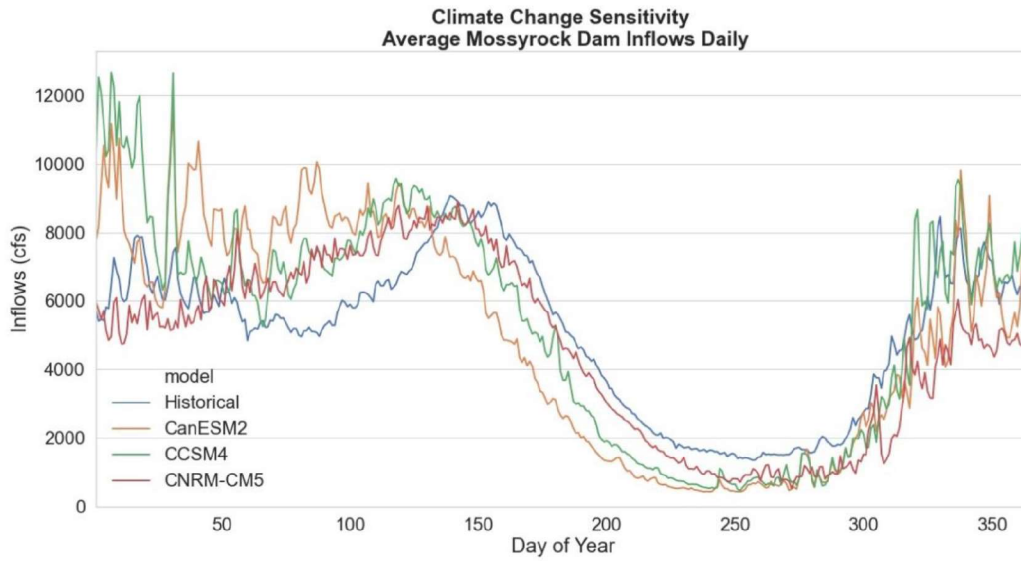


Figure 71: Average daily inflows into Cowlitz River Project under climate change models vs. historical weather conditions

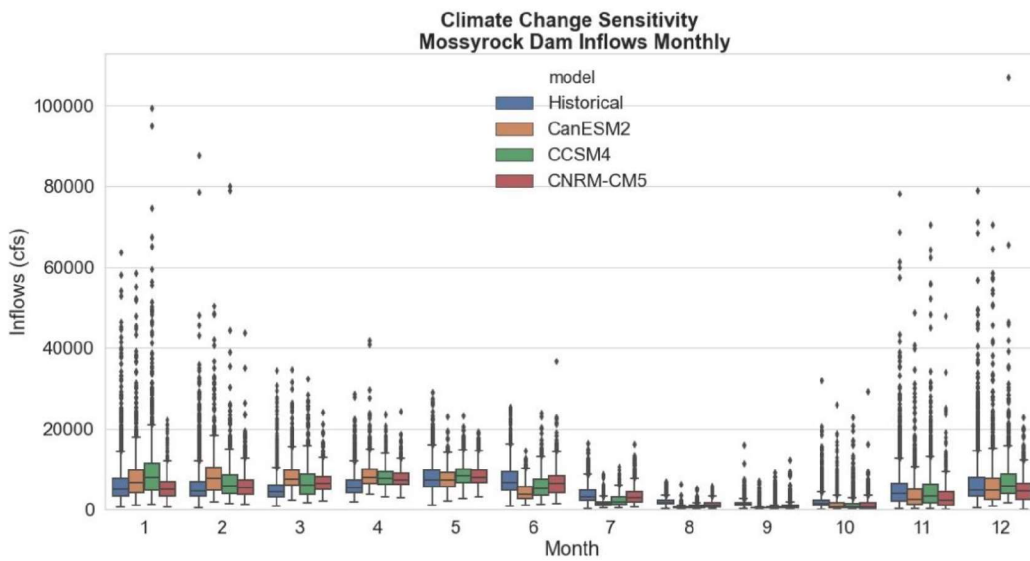


Figure 72: Monthly distribution of daily inflows into Cowlitz River Project under climate change models vs. historical weather conditions

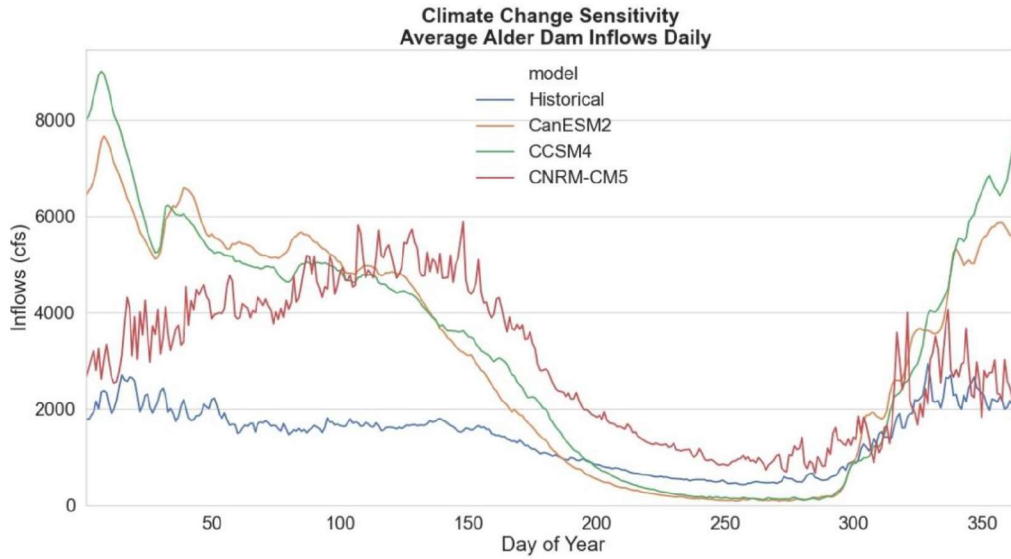


Figure 73: Average daily inflows into Nisqually River Project under climate change models vs. historical weather conditions

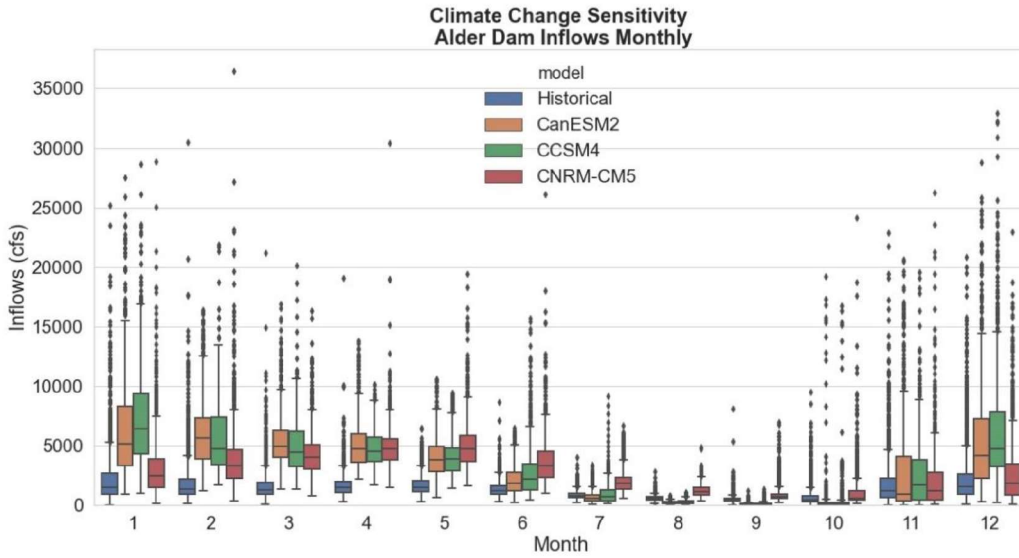


Figure 74: Monthly distribution of daily inflows into Nisqually River Project under climate change models vs. historical weather conditions

14.1.3.2 BPA system

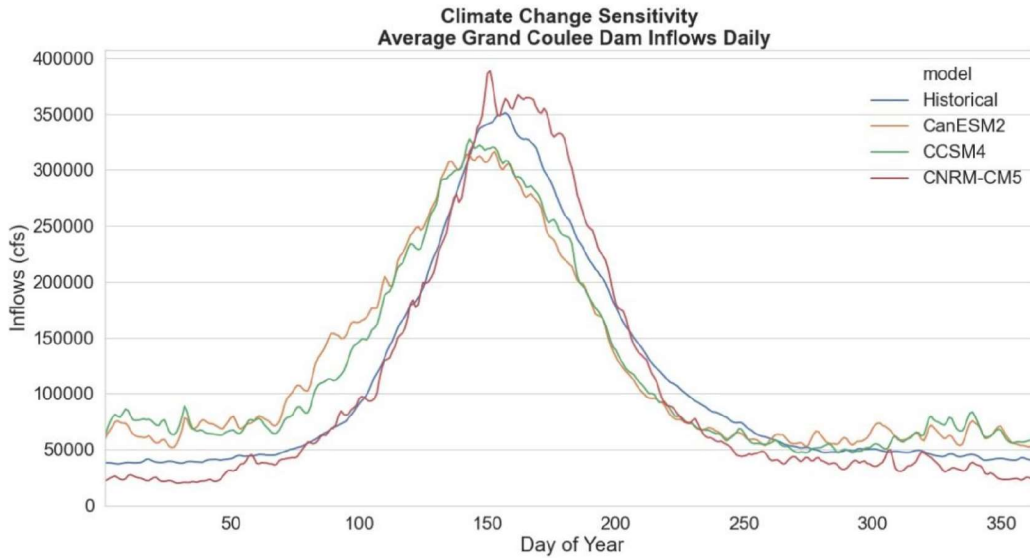


Figure 75: Average daily inflows into Grand Coulee Dam under climate change models vs. historical weather conditions

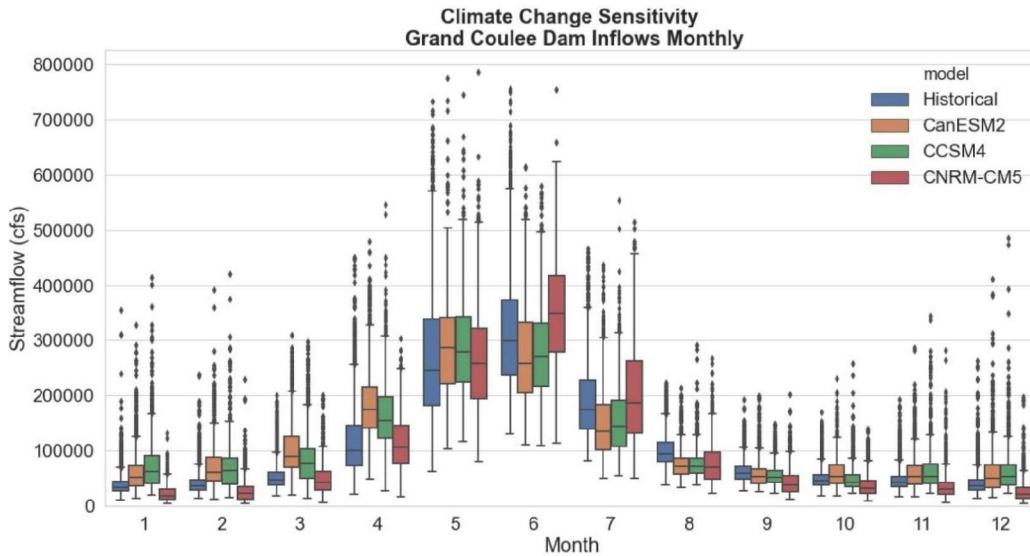


Figure 76: Monthly distribution of daily inflows into Grand Coulee Dam under climate change models vs. historical weather conditions

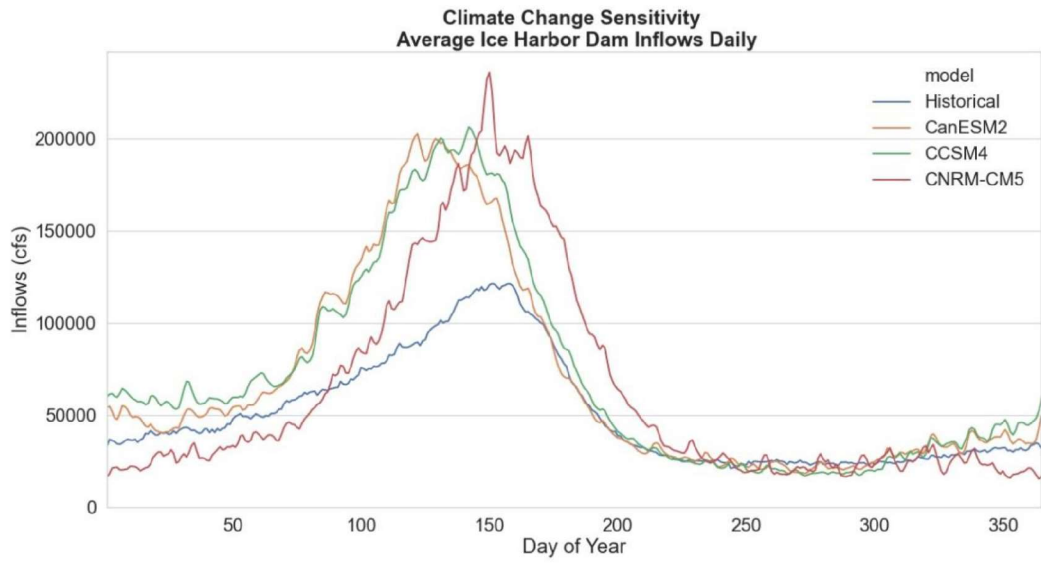


Figure 77: Average daily inflows into Ice Harbor Dam under climate change models vs. historical weather conditions

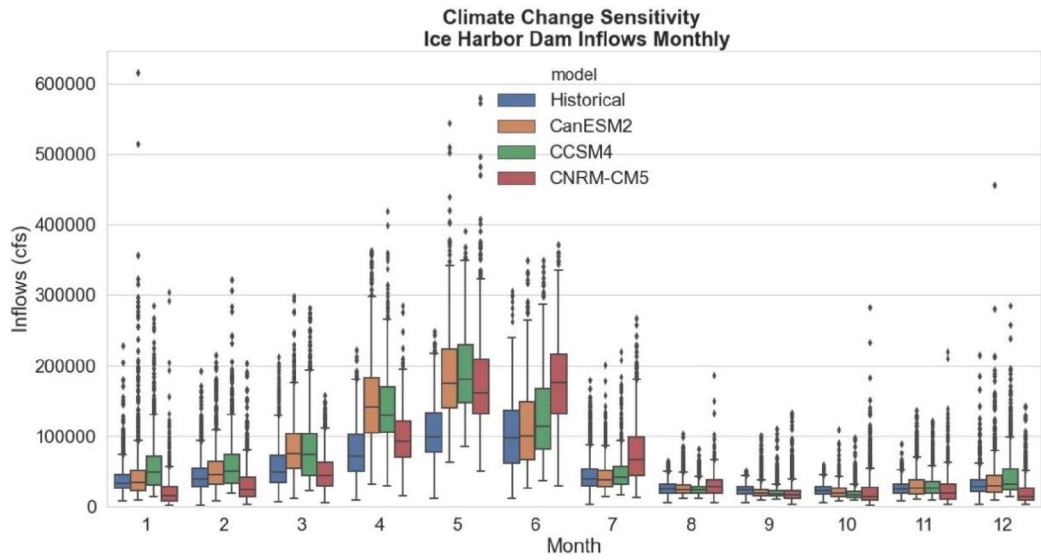


Figure 78: Monthly distribution of daily inflows into Ice Harbor Dam under climate change models vs. historical weather conditions

14.1.3.3 Generation

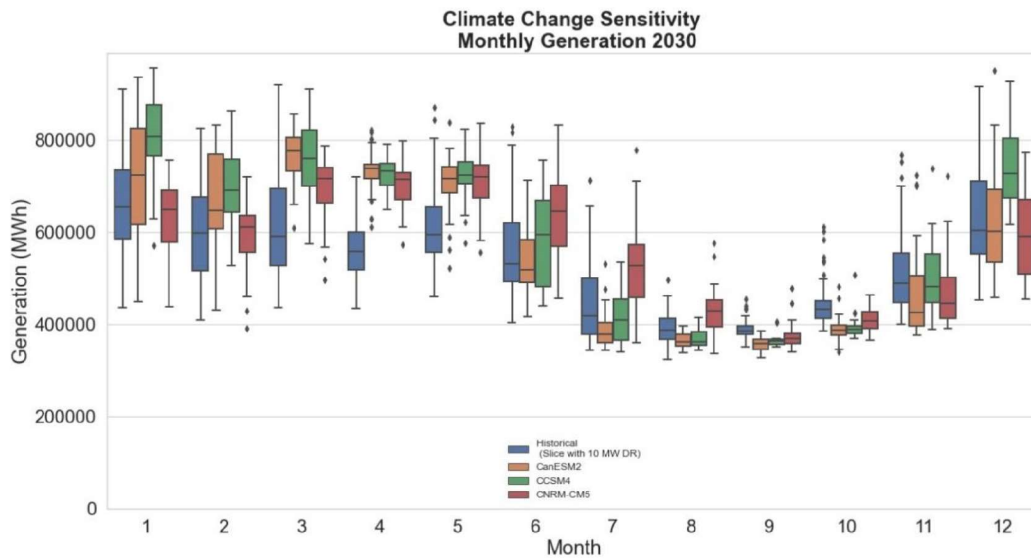


Figure 79: Distribution of average monthly generation in 2030 under climate change models vs historical weather conditions for the Slice with 10 MW of DR portfolio in the base case scenario

14.1.4 Impacts on resource adequacy of the preferred portfolio

Resource adequacy results for both the preferred portfolio (*Slice/Block + 10MW DR*) and its close cousin (*Slice/Block Only*) are presented in Figure 80 through Figure 83. The first three figures examine the impact of climate change on our resource adequacy metrics. In the relatively rare cases when these portfolios did fail our adequacy standard, they did so exclusively in the wintertime. Reductions in winter load combined with more winter inflows into the dams serve to improve the performance of both portfolios by our adequacy standard. Only the Cruise Control (Base Case) scenario was considered for this sensitivity analysis, but results are likely to be directionally similar for other scenarios. For all of the climate scenarios, NEUE (which measures the magnitude of shortfalls) falls essentially to 0.000% for both portfolios (Figure 80).⁶⁸ LOLH (which measures the duration of shortfalls) and LOLE (which measures the frequency of shortfalls) also fall to 0.0 in two of the climate models and improve considerably for the third climate model (Figure 81 and Figure 82).

The fourth figure below (Figure 83) examines how another the metric used by the NW Power and Conservation Council—Loss of Load Probability (LOLP)—is impacted by climate change. LOLP measures the probability of having a shortfall event at some point over the course of a year (or any other time period of interest). This metric measures the likelihood of an event without consideration of its size, duration or magnitude. The NWPCC sets a 5% LOLP standard, meaning that there should be no more than a 5% chance of having a shortfall event in any given year. For two of the climate models, the LOLP goes down to zero, just as our adequacy metrics did. Results for the third climate model (*CNRM-CM5_RCP85_MACA_VIC_P3*) are different, however. While our adequacy metrics improved for that climate model as well, the LOLP increases for both portfolios and occasionally exceeds the 5% threshold.

⁶⁸ This does not necessarily mean that no energy goes unserved. Rather, it means that the magnitude of shortfalls is so small that it is equivalent to zero when rounded to three decimal places.

This discrepancy indicates a potential change in the type of adequacy risk these portfolios present. Rather than the low-probability, high-impact events seen with historical weather conditions, this particular climate model results in higher-probability but lower-impact events (i.e. very small, short duration events that don't occur often throughout the year but occur in more years). For all of the climate models, the minor shortfall events that do occur continue to occur exclusively in the wintertime.

Findings from this analysis are similar in some ways to early NWPC findings for the region as a whole and different in others. Like our results, their early findings indicate that regional adequacy events with climate change are generally becoming more likely (higher LOLP) but smaller in magnitude and shorter in duration (lower EUE and LOLH). Unlike our results, however, their results indicate that the region as a whole may see summer issues increase and winter shortfall events disappear completely.⁶⁹

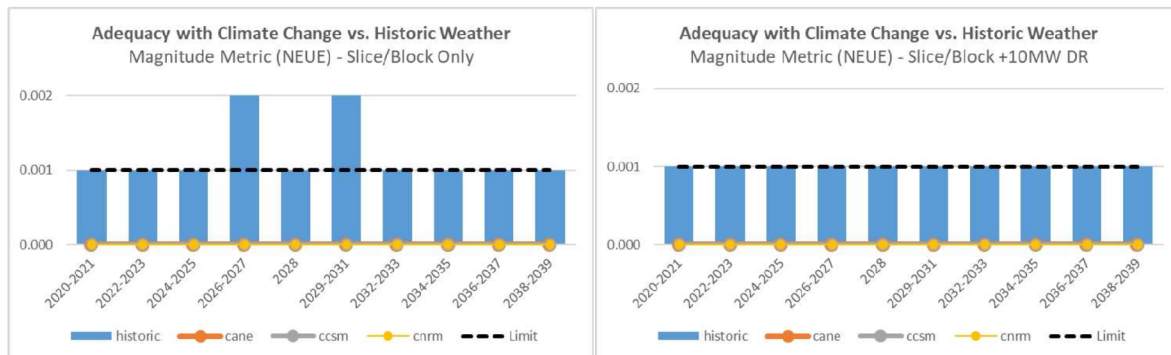


Figure 80: Climate change impacts on Normalized Expected Unserved Energy (NEUE)

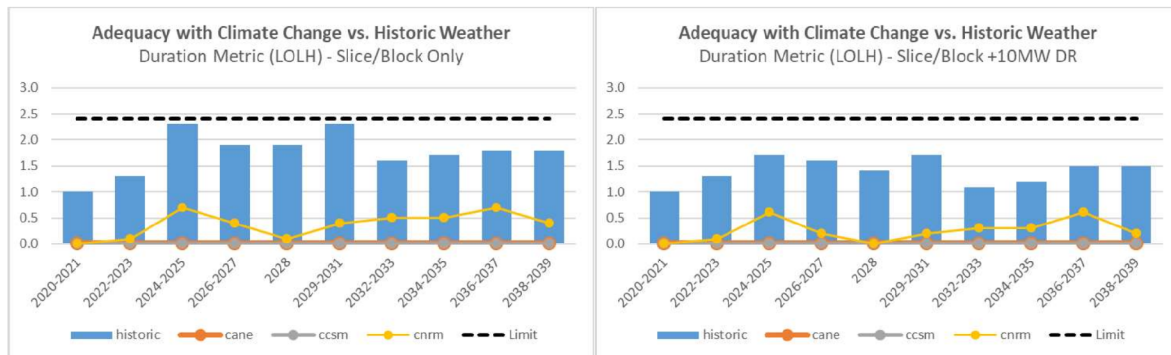


Figure 81: Climate change impacts on Loss of Load Hours (LOLH)

⁶⁹ NWPC findings were still preliminary as of the completion of Tacoma Power's 2020 IRP. A summary of the findings as of July 2020 can be found at: <https://nwcouncil.app.box.com/s/nla2zip91dx9efw5swwnxzg2ckxmdh6b>

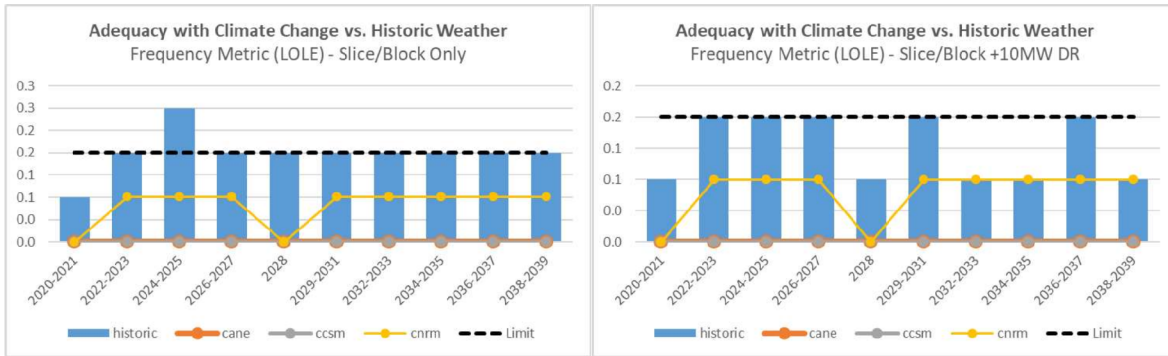


Figure 82: Climate change impacts on Loss of Load Expectation (LOLE)

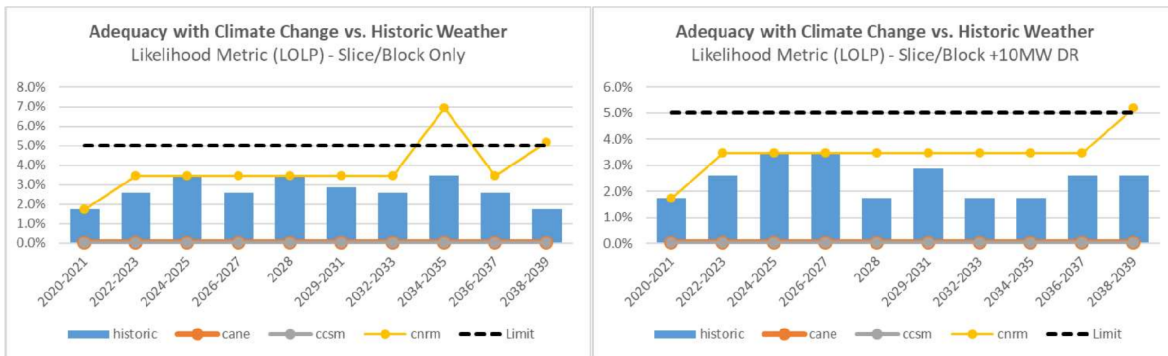


Figure 83: Climate change impacts on Loss of Load Probability (LOLP)

14.2 MARKET AVAILABILITY ASSUMPTION

A critical assumption for resource adequacy is the extent to which a utility can rely on the wholesale market to buffer potential inadequacy events. For the 2020 IRP, we assume that up to 50MW of power could be purchased from the market at any time (the same assumption that it used in the 2015 IRP and 2017 IRP update). Because this 50MW assumption is both (a) a potentially important determinant of resource adequacy results and (b) is difficult to determine with confidence, this section examines how small (10MW) changes in this market availability assumption affect resource adequacy results for the preferred portfolio and its close cousin, the *Slice/Block Only* portfolio.

Figure 84 through Figure 86 compare our three resource adequacy metrics under three different market availability assumptions—40MW, 50MW and 60MW—for the Cruise Control scenario (Base Case) and demonstrate that our *Slice/Block* adequacy results are particularly sensitive to our assumption of 50MW of availability. When we *reduce* market availability by just 10MW, the *Slice/Block Only* portfolio goes from occasionally failing the NEUE standard and never failing the LOLH or LOLE standards in the Base Case to consistently failing the NEUE standard and failing the LOLE standard often. When we instead *increase* market availability by 10MW, the *Slice/Block Only* portfolio passes all three standards in the Base Case. The *Slice/Block +10MW DR* portfolios, on the other hand, almost always passes our adequacy standard in the Base Case, regardless of whether we adjust our market availability assumption up or down slightly.



Figure 84: NEUE Results under different market availability assumptions



Figure 85: LOLH Results under different market availability assumptions



Figure 86: LOLE Results under different market availability assumptions

14.3 LARGE CHANGES TO INDUSTRIAL LOADS

Another source of uncertainty that we always face is the potential for a relatively large and sudden change in load—typically from the introduction of a new industrial load or the loss of an existing industrial load. Although the IRP analyzes outcomes across different load scenarios, these load scenarios are modeled as gradual changes in the trajectory of load over time rather than as sudden increases or drops in load. This section examines how resource adequacy is impacted by a flat 50MW increase or decrease in industrial load.

Figure 87 presents resource adequacy results for the Cruise Control (Base Case) scenario under three different situations: (1) our preferred portfolio (*Slice/Block + 10MW of DR*) with the same loads used in the core IRP analysis, (2) our preferred portfolio with the addition of a flat 50MW industrial load and (3) the *Slice/Block + 50MW DR* portfolio with the same additional 50MW of industrial load. Due to differences in the timing of when 10MW versus 50MW of DR are added to each portfolios, results are presented only for the post-2028 period. The results show that resource adequacy suffers considerably when a 50MW industrial load is added to the preferred portfolio. Without the addition, we always pass our resource adequacy standards in all years under the Cruise Control scenario. Once an additional 50MW of load is added, we instead fail our adequacy standard in every year by all three metrics. While the largest shortfalls continue to be in the winter of 1992/1993, we also find small shortfalls in four other weather years (1952, 1977, 1987 and 2001). The shortfalls are still concentrated in December and January. However, we start to see some additional smaller shortfalls in February, October and November, as well as some very small shortfalls in March (in weather year 1977 only). This suggests that, while our portfolio would typically have enough surplus power to serve a large new industrial load, we could find it very challenging to do so in low water conditions. It is important to note that adding a single large load has a different impact on resource adequacy than adding other types of loads. In general, our BPA net requirement (which is a key determinant of the amount of power we get from BPA) is updated annually based on our load forecast and increases when our load increases. However, new industrial loads that consume 10 aMW or more are excluded from this policy and do not increase our net requirement. As a result, we would need to identify another resource to ensure a new large load would not compromise our adequacy. Adding another 40MW of demand response (50MW of DR total) improves adequacy and eliminates nearly all resource adequacy issues, suggesting that a capacity addition that is approximately commensurate with the size of the load would be needed unless that new load were highly flexible and able to serve as a source of at least 40MW of demand response.

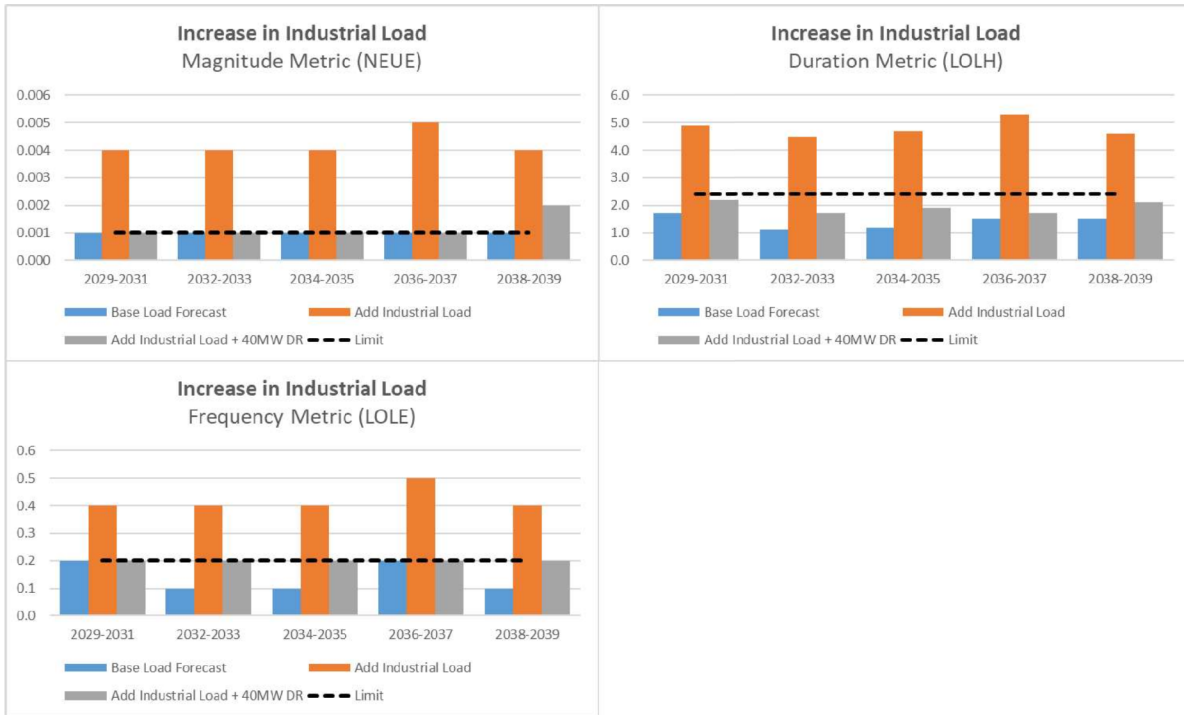


Figure 87: Resource adequacy metrics with the addition of a new large load

Figure 88 examines what happens when we instead lose a large industrial load. We find that losing a large industrial load worsens our adequacy a little in some cases. While this may seem surprising, it is a direct result of the way our BPA net requirement changes as our load changes. Unlike new large loads, much of our existing industrial load is included in our BPA net requirement calculation, and we assume that is the case in this analysis. As a result, when we lose that industrial load, we also reduce our net requirement. This keeps us from having to pay for substantially more power than we need from BPA once this load goes away. However, there is a slight mismatch between how much our BPA Block power is reduced in each month and how much our industrial load is reduced in each month. Because our net requirement is shaped to our historical load, which is higher in the winter than in the summer, we see a larger reduction in our BPA take in the winter when we reduce our net requirement. However, the industrial load in question is assumed to have a flat profile across months in the year. The net result is that our BPA resources are reduced by more than our industrial load goes down in the wintertime and vice versa in the summertime (see Table 51). Since our potential adequacy challenges are in the wintertime, this mismatch causes our adequacy metrics to worsen in some years. However, with a few exceptions, the mismatch is not large enough to cause us to fail our standard.