RESOURCE ADEQUACY
APPENDIX L

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction

To perform the resource adequacy analysis used in the 2023 Electric Progress Report (2023 Electric Report), Puget Sound Energy (PSE) contracted with the energy consulting firm Energy and Environmental Economics (E3). The firm used their RECAP model for this analysis. This appendix provides a resource adequacy overview, detailed inputs and updates, the modeling approach, and results.

2. Resource Adequacy Overview

Puget Sound Energy performs resource adequacy planning to ensure we can reliably meet future customers' energy demands. We do this by building generating capacity or acquiring capacity through contracts. Many factors can impact our ability to meet demand reliably, including variations in temperatures, power demand, energy demand, generation of various resources, equipment failures, transmission interruptions, and wholesale power supply curtailment. Resource adequacy planning allows us to consider these many uncertainties when planning our system.

The outputs from our resource adequacy analysis are key inputs to PSE's long-term portfolio analysis presented in this report. The resource adequacy analysis determines the total resource need from future resources to ensure our system remains reliable. The resource adequacy analysis also determines the capacity contributions of different resources so we can appropriately account for each resource's contribution to reliability. This section discusses critical concepts for the resource adequacy analysis, including factors influencing the total resource need and the resources' ability to contribute to satisfying that need.

2.1. Energy Demand

We plan our system to meet customers' future energy demands. Energy demand forms the basis for our plan because generation resources and transmission require years to develop and build, so we must forecast energy demand as part of our plans. Chapter Six: Demand Forecast discusses the load forecast for the 2023 Electric Report in more detail.

In addition to planning to meet expected energy demand, we must also plan our system to respond to variations in energy demand. Energy demand varies significantly throughout the year and between years due to temperature changes, among other factors. For example, demand for heat yields higher energy demand during the winter, and demand for cooling results in higher energy demand in the summer. Extreme temperatures can vary considerably between years. One year could have a week-long cold snap that significantly increases energy demand, and the following year could have a mild winter. We must plan our system to have enough resources to meet energy demands and maintain reliability across various conditions, including extreme events with low probability.

Climate change also impacts PSE's energy demand. Average temperatures have increased in the Pacific Northwest over the past decades, which is predicted to continue to increase in the coming decades. Higher temperatures raise energy demand in the summer. Moreover, climate change can make extreme events more likely, such as the extreme heat dome event the Northwest experienced in 2021. We must account for the effects of climate change on energy demand in our long-term plans to ensure resource adequacy.

2.2. Operating Reserves

In addition to supplying enough generation to satisfy energy demand, we must maintain minimum operating reserves to respond to contingencies and balance short-term, sub-hourly fluctuations in load and generation. Energy demand plus operating reserves determine the total resource requirement in each operating period. We must curtail load if PSE has insufficient resource capacity to meet this requirement and cannot rely on the wider regional energy system to fill the gap.

Load curtailment, also known as a loss of load event, reduces or discontinues energy consumption.

We included two operating reserve requirements: contingency reserves and balancing reserves in the resource adequacy analysis.

2.3. Contingency Reserves

The North American Electric Reliability Corporation (NERC) requires that utilities maintain reserves above end-use demand as a contingency to ensure continuous, reliable operation of the regional electric grid. On October 1, 2014, the Federal Energy Regulatory Commission (FERC) approved rule Bal-002-WECC-1, which requires PSE to carry reserve amounts equal to three percent of load plus three percent of online generating resources. The terms load and generation in the rule refer to the total net load and generation in PSE's Balancing Authority Area (BAA).

Puget Sound Energy participates in the Northwest Power Pool (NWPP) Reserve Sharing Program, which governs our requirement to maintain contingency reserves. In an event that causes PSE to have insufficient resources to satisfy power demand plus operating reserves requirements, we can call on the contingency reserves of other program members to cover the resource loss during the 60 minutes following the event. After the first 60 minutes, we must return to load-resource balance by re-dispatching other generating units, purchasing power, or curtailing load.

2.4. Balancing Reserves

Although we perform resource adequacy analysis hourly, utilities must also have sufficient reserves to maintain system reliability during the operating hour. We must have adequate reserves to meet load or variable resource generation fluctuations on a minute-by-minute and second-by-second basis. The resource adequacy analysis accounts for these sub-hourly fluctuations by requiring balancing reserves be held in addition to serving load and holding contingency reserves. Unlike contingency reserves, which we only utilize when the system meets specific criteria and on a short-term basis, balancing reserves are called upon regularly within an operating hour to balance the system as loads and resources fluctuate.

The consulting firm E3 calculated balancing reserve requirements on behalf of PSE. They estimated the balancing reserves by measuring the amount of intra-hour variability PSE could experience based on anticipated future resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations.

Including balancing reserves in the overall operating reserves requirements ensures that the resource adequacy analysis accounts for the sub-hourly variability we manage and meet hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's system's five-minute load, wind, and solar data. To ensure that the load, wind, and solar profiles correspond to the same underlying weather conditions and incorporate any correlations or relationships between them, E3 first obtained three years of historical weather-matched data from PSE. Then they scaled up load, wind, and solar generation to match PSE's expected future levels. Lastly, E3 subtracted wind and solar generation from the load to obtain a net load profile for subsequent analysis. We ultimately need to manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of five-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

2.5. Reliability Target

No electricity system is perfectly reliable; there is always some chance that generator outages, transmission failures, and extreme weather conditions that impact supply and demand could lead to insufficient resources and loss of load. Therefore, we cannot plan for zero loss of load events and must set an appropriate reliability target for planning.

A reliability target sets a minimum threshold for one or more reliability metrics, ensuring the system can satisfy power and energy demand and maintain reliability across various weather and system operating conditions. There is no single reliability target in the electricity industry. System planners typically set reliability targets based on the probability of a loss of load event in a year or the frequency of loss of load events.

We plan our system to a reliability target of five percent loss of load probability (LOLP). If we maintain sufficient resources to satisfy this standard, we can expect a loss of load one year out of every twenty years. Puget Sound Energy's five percent LOLP reliability target is consistent with the reliability target used by the Northwest Power and Conservation Council (the Council).

2.6. Total Resource Need

We conduct resource adequacy analysis based on the reliability target to determine the system's total resource need. Total resource need is the capacity in megawatts (MW) required to satisfy the reliability target. When considering all existing and new resources, we must ensure enough capacity to meet the total resource need and the reliability target. If our existing resource portfolio falls short of the total resource need, this indicates a capacity shortfall we must meet with additional resources. The portfolio analysis modeling in the 2023 Electric Report determines what resources we should use to meet that capacity shortfall.

2.7. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - \ Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it means there is a 50 percent probability of the actual peak load being higher than this forecast and a 50 percent probability of it being lower than the forecast.

The PRM represents the resource need amount beyond the normal peak load PSE must maintain to satisfy the total resource need and, ultimately, the reliability target of five percent LOLP.

2.8. Capacity Credit of Resources

To determine whether PSE's resource portfolio satisfies the PRM, we must determine the total resource capacity that counts toward the PRM. The capacity credit of a resource is the amount the resource counts toward the PRM in MW.

The peak capacity contribution of natural gas resources is different from other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need occurs at 23 degrees Fahrenheit, we set the capacity of natural gas plants to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. However, we adjust ELCC on new generic thermal resources since the model does not account for them in the forced outages.

This adjustment includes natural gas generators and contracted power from Mid-Columbia (Mid-C) hydroelectric plants. We call out contracted power for hydroelectric plants separately from other hydroelectric generation because the contract has firm delivery, meaning the party is financially and physically obligated to deliver the agreed-upon amount of energy or capacity per the agreement. For resources whose capabilities to supply power are variable or limited — also known as dispatch-limited resources —we set the capacity credit equal to the ELCC of the resource. The dispatch-limited resources include hydroelectric, wind, solar, energy storage, contract, and demand response resources.

The ELCC is the quantity of perfect firm capacity that could be replaced or avoided by a resource while achieving our five percent LOLP. The ELCC can be expressed in MW or as a percentage of a resource's nameplate capacity. For example, a resource with an ELCC of 50 percent would mean the addition of 100 MW of the resource could displace the need for 50 MW of perfect capacity without an impact on reliability. Perfect capacity is a benchmark to quantify the contribution of dispatch-limited resources toward the PRM.

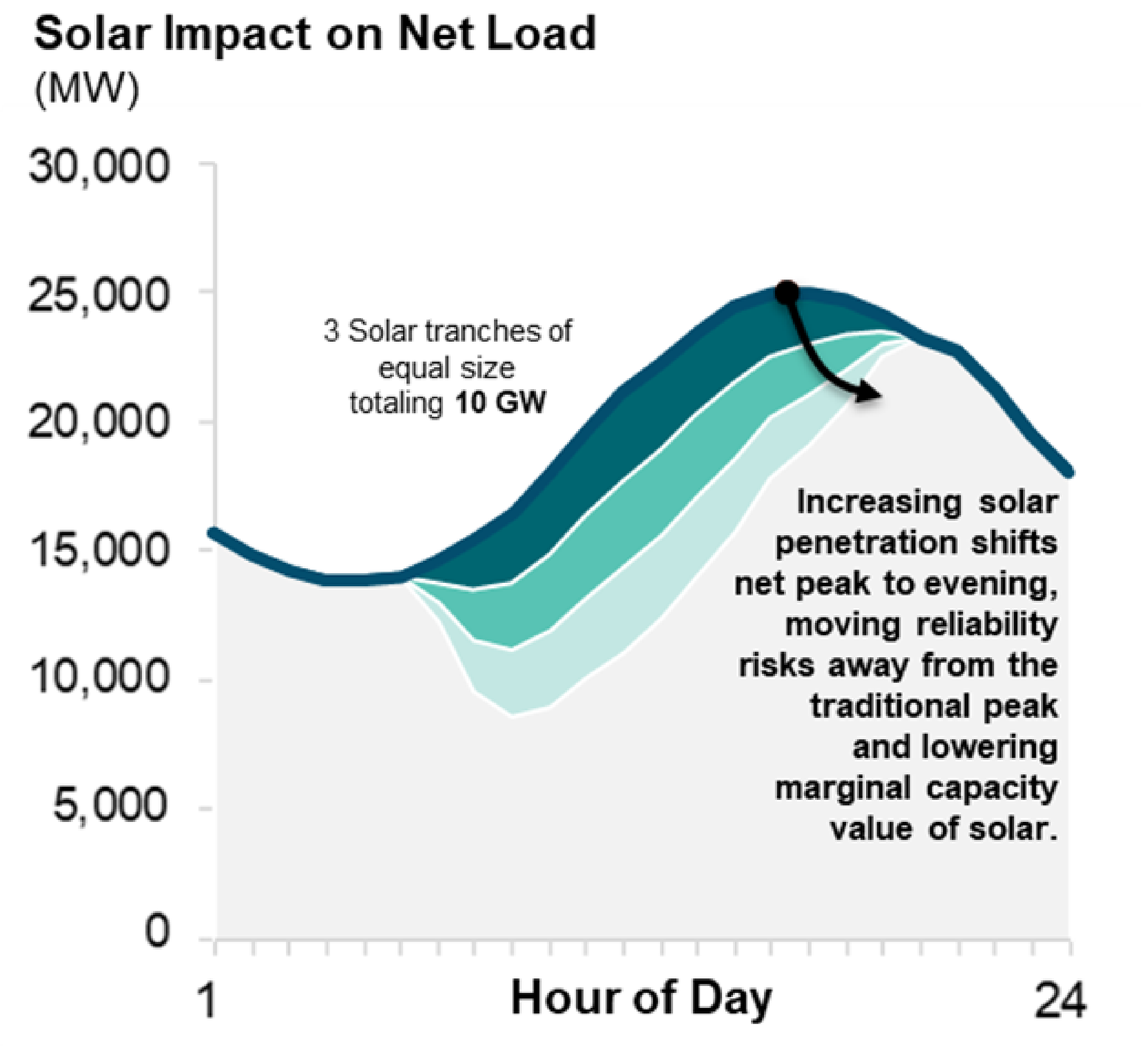
The ELCC for dispatch-limited resources is typically less than 100 percent. Wind and solar resources have an inherently variable output which may not be at maximum levels when the PSE system needs additional capacity. Energy storage resources are limited by the duration of time they can operate at full capacity. Demand response has similar limitations regarding the length and frequency of calls. The ELCC metric ensures we account for the correct contribution of each of these resources toward the PRM, which is increasingly important as we add more dispatch-limited resources to our resource portfolio.

The choice of how to assign capacity credits to resources also impacts the total resource need. Because we count natural gas and Mid-C hydroelectric resources at nameplate capacity despite their limitations — such as forced outages or limited water budget — we must ensure PSE maintains enough capacity to make up for these limitations. We calculate the total resource need to take these limitations into account.

2.9. ELCC Saturation Effect

The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. See Figure L.1 for an example of solar dynamics on a peak summer day. Note this is an illustrative example and does not represent PSE's system. The first tranche of solar produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, adding more solar shifts the net peak demand (load minus renewable generation) into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during daytime but can't contribute to the reliability needs during nighttime hours. Wind resources experience this same saturation effect, except rather than shifting the net load from day to nighttime hours, wind resources shift the net load from when wind generation is high to when wind generation is low.

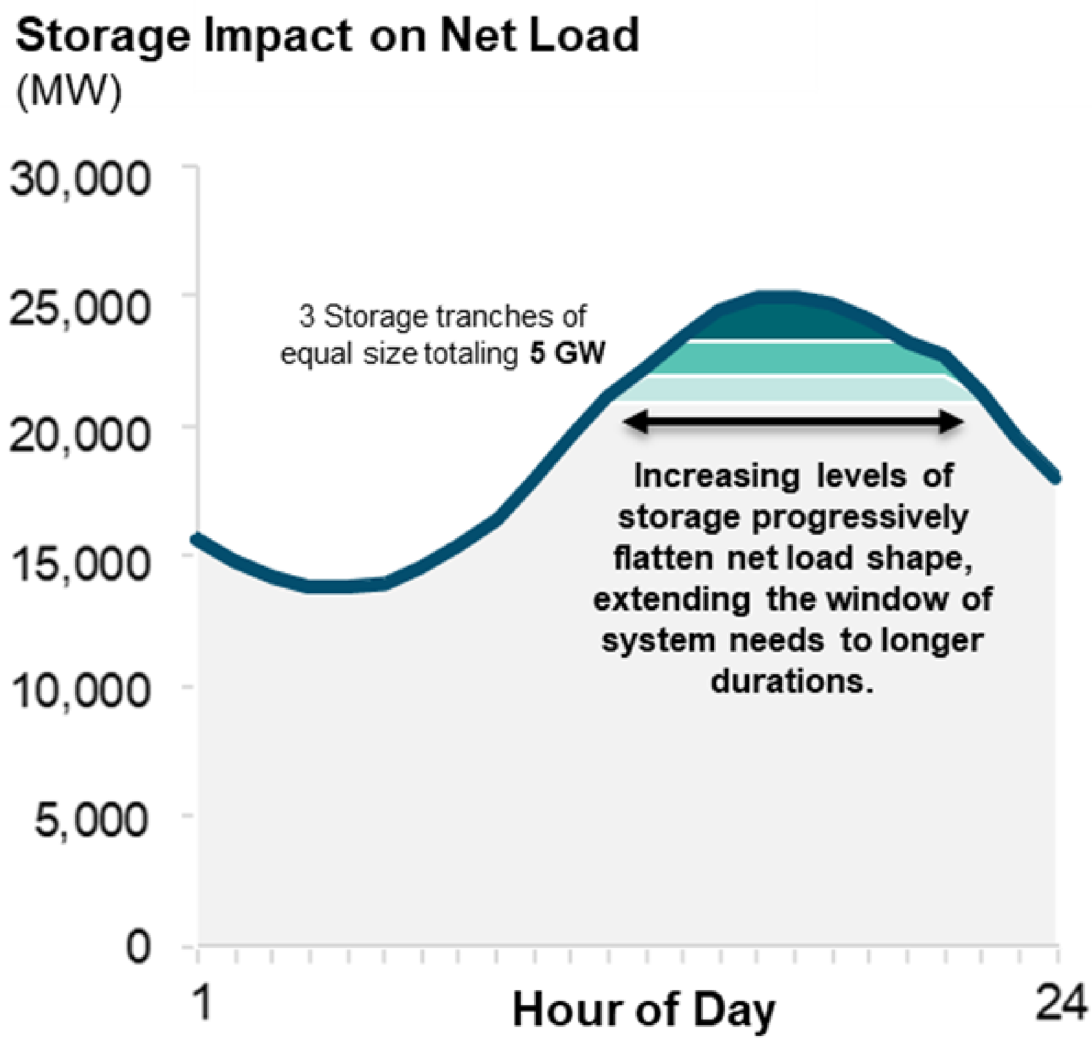
Figure L.1: Example of ELCC Saturation Effect for Solar (Does not represent PSE's system)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure L.2 for an example showing the dynamics for storage on the same peak day. Note that this illustrative example does not represent PSE's system.

The first tranche of energy storage produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as we add more energy storage, the net peak demand (load minus energy storage generation) flattens and spans longer. As a result, the ELCC for these later tranches is lower because the storage is mitigated during the highest peak demand hours but can't contribute the same reliability value over longer hours due to limitations in energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, and the length of calls but without a need of charging.

Figure L.2: Example of ELCC Saturation Effect for Energy Storage (Does not represent PSE's system)



2.10. Loss of Load Probability Modeling

To quantify the total resource need, the PRM, and the ELCC of resources, we rely on loss of load probability (LOLP) modeling. We use LOLP modeling to simulate the availability of resources to meet power demand and operating reserve requirements across a broad range of conditions. The model accounts for factors such as weather-driven load variability, forced outages of power plants, capacity derating at higher temperatures of thermal units, the natural variability of resources like wind and solar, operating constraints for hydroelectric and storage, and the availability of wholesale market purchases. To appropriately capture the risk of rare extreme events, we use LOLP modeling to simulate potential operating conditions on an annual basis hundreds of times using stochastic simulation techniques. By simulating many years, this analysis can generate the LOLP metric by comparing the number of simulations years with loss of load to the total number of simulated years, which we then compare to PSE's reliability target.

Calculating the ELCC of a resource using a LOLP model is a three-step process.

1. First, the LOLP model calibrates the system to the reliability target by adding enough perfect capacity to the existing resource portfolio, so the system exactly satisfies PSE's reliability target.

2. Then, the LOLP model adds the resource of interest to the system. Because this resource will add more resource capacity to the system, the LOLP metric will fall relative to the target: the system becomes more reliable than the reliability target.

3. Lastly, the LOLP model removes enough perfect capacity, so the system returns to PSE's reliability target. The amount of perfect capacity the model removed is the resource's ELCC in MW.

Calculating the total resource need of the system follows a different three-step process.

1. First, we estimate the ELCC of all dispatch-limited resources in the system and wholesale power purchases.

2. Next, we determine the capacity shortfall for the system: the amount of perfect capacity PSE needs in addition to the existing system to satisfy the reliability target.

3. Lastly, we sum the capacity contribution of all resources and the capacity shortfall to get the total resource need. The PRM is a simple derivation from the total resource need.

3. Resource Adequacy Inputs and Updates

We improved the inputs and methodology for the resource adequacy analysis in this report. These improvements relate to future impacts of climate change, seasonal resource needs, better representation of resource capabilities, and other factors. This section details these improvements and how they relate to assumptions in PSE's 2021 Integrated Resource Plan (IRP).

3.1. Background

Puget Sound Energy filed a draft all-source request for proposal (RFP) on April 1, 2021, to meet our capacity and clean energy resource needs established in the 2021 IRP. We received comments from interested parties and Washington Utilities and Transportation Commission (Commission) staff on that draft during a 45-day comment period. As a result of those comments, we filed revisions to the RFP in June 2021 and added a technical workshop for interested parties to discuss our ELCC methodology and assumptions.

On August 31, 2021, we held a public ELCC workshop[1] and presented the modeling approach and assumptions we used to derive the generic and resource-specific ELCC assumptions used in our planning and acquisition analyses. We gave ELCC estimates and solicited feedback from interested parties to guide and inform the 2021 all-source RFP. In response to public feedback, our Independent Evaluator, Bates White, retained consulting firm E3 to review PSE's

[1] https://www.pse.com/pages/energy-supply/acquiring-energy

methodology for calculating ELCC values. E3 issued a report[2] on October 8, 2021. Based on their review, E3 found our approach to calculating ELCCs was reasonable but recommended several areas for improvement.

On August 31, 2021, the Commission issued a public notice of opportunity to file written comments in WUTC docket UE-210220 related to PSE's ELCC estimates and use in the company's all-source request for proposals. Comments were initially due by the end of September; however, due to the timing of E3s final report, the Commission extended the comment deadline to October 22, 2021. The Commission received public comments[3] from 13 individuals and organizations regarding PSE's ELCC results and the E3 methodology and assumptions report.

➔ The full Commission docket and public comments are available on the UTC website.

In response[4] to this feedback and E3 recommendations, we made several updates to the 2023 Electric Progress Report and phase two of the 2021 RFP, described in the following sections.

Puget Sound Energy hosted a follow-up informational webinar to discuss resource adequacy on August 24, 2022. In this meeting, PSE presented the summary of E3's resource adequacy modeling results, an overview of the Western Resource Adequacy Program (WRAP), and an overview of the Northwest Regional Forecast by the Pacific Northwest Utilities Conference Committee (PNUCC).

➔ You can find all the materials from the resource adequacy webinar on the PSE website.

3.2. Overview of Updates

E3 proposed six recommendations for improvements to PSE's resource adequacy methodology. In PSE's December 2021 response comments, PSE indicated that it would attempt to incorporate these recommendations for the RFP and the 2023 Electric Report but might not be able to complete all changes due to time requirements to gather data, develop processes, update models, and benchmark results. We worked closely with E3 to implement E3's recommended updates for RFP and the 2023 Electric Report. In summary, we incorporated four of E3's six recommendations and made many other improvements to the resource adequacy analysis. Following is a description of E3's six recommendations and other changes to the analysis compared to the 2021 IRP.

3.3. Years Modeled

E3 performed a five- and 10-year resource adequacy assessment to determine the PRM. The 2023 Electric Report time horizon starts in 2024, so the five-year assessment is for October 2029–September 2030, and the 10-year

[2] Review of Puget Sound Energy Effective Load Carrying Capability Methodology, https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/PSE--ELCC-StudySept-202110072021FINAL.pdf

[3] https://www.utc.wa.gov/casedocket/2021/210220/docsets

[4] https://apiproxy.utc.wa.gov/cases/GetDocument?docID=159&year=2021&docketNumber=210220

assessment is for October 2034–September 2035. These years are two years later than those we modeled in the 2021 IRP.

The modeled years follow the hydroelectric year (October–September) to capture the entire winter and summer seasons, consistent with the Council's GENESYS model. If we had modeled the calendar year instead, it would break up the winter season (November–March).

3.4. Climate Change Impacts

We incorporated future climate change impacts in the resource adequacy analysis for this report and relied on climate change data from the Council. Anticipated future climate change impacted four critical inputs to the resource adequacy analysis:

1. Energy demand
2. Hydroelectric generation
3. Market purchases
4. Duration and frequency of outage events

➔ For a detailed description of the load forecasts development process and inputs, see Chapter Six: Demand Forecast of the 2023 Electric Report.

These load forecasts show that PSE's system would experience much higher energy demand in summer than the load forecast we used in the 2021 IRP. Winter energy demand, however, would be at similar levels because the load data include a 30-year temperature warming trend (2020–2049), and the energy demand in summer increases meaningfully over the 30 years. However, the resource adequacy analysis applies to a single future year (2029 or 2034) and represents the amount of climate change for that year.

E3 detrended the load forecasts to correspond to a single model year (2029 or 2034) to ensure that the climate impacts for the modeled 30 years correspond to the appropriate model year while capturing the range of potential load levels for that model year. In this report, we modeled future load data that include climate change's impacts. In the 2021 IRP, we used historical load data that did not capture the future effects of climate change.

The Council also developed hydroelectric generation forecasts for each climate scenario and the two model years. The climate change forecasts influence the amount and timing of rainfall, snowmelt, and water inflows. The University of Washington Climate Impacts Group (CIG) provided water inflows for the Columbia River and coastal drainages in Washington, covering the Mid-C and Baker hydroelectric plants. The daily inflows are also for the same three climate change scenarios: A, C, and G. We then used this water inflow data to determine the total generation at each hydroelectric plant. The hydroelectric generation varies across 30 weather years, the same future weather years we used for the load forecast. In the 2021 IRP, we utilized 80 years of historical hydroelectric generation to characterize hydroelectric variability.

Lastly, we assessed the availability of market purchases from neighboring utilities and markets. Just as the climate impacts load and hydrological conditions for our system, it also impacts these conditions for the greater Pacific Northwest and the West. We used the Council's Classic GENESYS model to characterize the region's curtailments and California imports. During a Pacific Northwest-wide load-curtailment event, there is not enough physical power supply available in the area (including available imports from California) for the region's utilities to fully meet their firm loads plus operating reserve obligations.

We used the Wholesale Purchase Curtailment model (WPCM) to determine PSE's share of curtailments in the Northwest region and capture how the Pacific Northwest wholesale markets would likely operate in such a situation. To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years. This report used modeled load and hydroelectric generation data for the future to capture the impacts of climate change and performed 900 simulations. In the 2021 IRP, we used the classic GENESYS model but relied on historical load and hydroelectric generation data to perform 7,040 simulations.

These updates to our methodologies ensured we captured the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems.

3.5. Seasonal Analysis

In the 2023 Electric Report, we performed resource adequacy analysis on a seasonal rather than an annual basis. This more detailed approach allowed us to determine the resource need and assess the contribution of resources to the PRM by season. We modeled two seasons: winter, November–March, and summer, June–September.

E3's seasonal resource adequacy analysis calculated separate PRM and ELCC values for winter and summer. The seasonal PRM sets the total amount of resources needed in that season. The seasonal ELCC is a resource's contribution to the PRM by season. We calculated the PRMs for winter and summer to ensure PSE adds enough resources to satisfy them and meet our annual five percent LOLP target. We calculated the ELCCs for winter and summer, so they only consider how a resource contributes to winter and summer reliability, respectively.

3.6. Wholesale Purchase Curtailments

We updated the wholesale purchase curtailments for this report with the Classic GENESYS and WPCM. Table L.1 shows the wholesale purchase curtailment results for the 2021 IRP and the 2023 Electric Report. We based the results for the 2021 IRP on 7,040 simulations and the results for the 2023 Electric Report on 900 simulations for each climate model — 2,700 total simulations.

In winter, wholesale purchase curtailments are similar between the 2021 IRP and climate model G in the 2023 Electric Report. The average number of curtailment events, length of curtailment events, and the overall amount of curtailment are similar. However, climate models A and C in the 2023 Electric Report show less overall curtailment in winter. These two climate models exhibit more overall warming than climate model G, resulting in lower average winter temperatures and fewer wholesale purchase curtailments.

In summer, wholesale purchase curtailments significantly differ between the 2021 IRP and the 2023 Electric Report. The frequency and magnitude of curtailment events are much larger in the 2023 Electric Report. Climate model G has more curtailment events and overall curtailment than the 2021 IRP. This difference is even more pronounced for climate models A and C, which have more overall warming than climate model G.

The results in this report show wholesale purchase curtailments are less common in winter and much more common in summer. These results mean wholesale purchases will be less limited in winter and more limited in summer relative to the 2021 IRP. One caveat to this assumption is that electrification of heating demands in the future could again make winter a more constrained period for wholesale purchases. The 2023 Electric Report does not consider widespread building electrification in the future.

Table L.1: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Winter Modeling

Metric	2021 IRP[1] Winter	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.22	0.10	0.00	0.18
Average curtailment duration (hours)	37.7	8.8	2.5	28.3
Average amount of curtailment (MWh/year)	5,792	445	2	5,991

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

Table L.2: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Summer Modeling

Metric	2021 IRP[1] Summer	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.79	22.10	18.93	10.43
Average curtailment duration (hours)	9.4	10.6	9.6	10.4
Average amount of curtailment (MWh/year)	3,234	189,140	143,927	84,398

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

3.7. Energy Storage Modeling

We made several changes to the assumptions we used to calculate the ELCC of energy storage resources in this report:

- Storage can discharge at its rated capacity for its rated duration. A minimum state of charge does not apply to the modeled energy capacity. For example, a fully charged 100 MW four-hour lithium-ion battery resource can discharge to the grid at 100 MW for four consecutive hours.

- Storage can have forced outages. The modeled forced outage rate for lithium-ion storage is two percent, and for pumped storage is one percent.
- Storage can help meet PSE's operating reserve requirements. When providing operating reserves, storage resources are on standby and do not discharge to the grid.
- The NWPP Reserve Sharing Program can be called when an energy storage resource is added to the system.

3.8. Hydroelectric Generation Flexibility

In the 2023 Electric Report model, we allowed specific hydroelectric resources to dispatch flexibly. These resources included PSE's five contracted Mid-C hydroelectric plants, PSE's Upper Baker plant, and PSE's Lower Baker plant. PSE's Snoqualmie plant was not modeled with a climate change model and dispatch flexibility and instead had a fixed generation profile because detailed climate change data was not available from the University of Washington Climate Impacts Group for this resource. In the 2021 IRP, PSE modeled all hydroelectric resources with fixed generation profiles.

E3 modeled daily flexibility at each hydroelectric plant, meaning each can shift hydroelectric generation across hours within a single day. E3 determined the hydroelectric generation available at each plant daily based on PSE's modeling across climate models. The daily hydroelectric generation available, or daily energy budget, varies by model year (2029, 2034), climate model (A, C, G), hydroelectric plant, and day (across 30 years).

E3 also characterized the flexibility for each hydroelectric plant to shift generation within a day. E3 analyzed historical hydroelectric generation (2014 through 2021, subject to data availability) to develop relationships between the daily energy budget and the minimum and maximum hourly generation for each hydroelectric plant. E3 calculated the minimum hourly power output and maximum hourly power output for different daily energy budget ranges at each plant based on this historical data. E3 then programmed RECAP to dispatch hydroelectric plants flexibly, subject to the daily energy budget and minimum and maximum power output constraints.

3.9. Wind and Solar Generation Profiles

In the 2023 Electric Report, PSE switched to new renewable energy profiles. PSE contracted with DNV to obtain renewable profiles for each existing wind and solar resource and each candidate generic wind and solar resource. Each profile spans 250 years at an hourly resolution. These profiles capture the variability that PSE can expect from these resources on an annual, seasonal, and hourly basis. The underlying weather conditions are the same for each resource's profile, so the profiles capture correlations between resources. The 2021 IRP used profiles developed with data from the National Renewable Energy Laboratory (NREL).

3.10. Balancing Reserves

In the 2023 Electric Report, we updated the hourly balancing reserve requirements that PSE must meet. These balancing reserve requirements ensure that we have sufficient reserves to meet sub-hourly fluctuations in load or variable resource generation on a minute-by-minute basis.

E3 calculated the balancing reserve requirements on our behalf. They estimated the balancing reserves by measuring the intra-hour variability PSE could expect to experience based on expected resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations. Balancing reserves as part of the overall operating reserves requirements ensures the resource adequacy analysis accounts for the sub-hourly variability, we must manage in addition to meeting hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's five-minute load, wind, and solar data from the three years of historical weather-matched data we provided. This ensured the load, wind, and solar profiles corresponded to the same underlying weather conditions and incorporated any correlations or relationships. E3 then scaled up load, wind generation, and solar generation to match the expected future levels on PSE's system. Lastly, E3 subtracted wind and solar generation from load to obtain a net load profile for subsequent analysis. We would manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average levels for the net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of 5-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

Table L.3: shows the balancing reserve requirements in MW for the 2021 IRP and the 2023 Electric Report. The upward balancing reserves — reserves on standby to increase generation on demand — for the 2023 Electric Report fall within the range in the 2021 IRP.

Table L.3: Balancing Reserves Requirements (MW)

Type	2021 IRP 2025	2021 IRP 2030	2023 Electric Report 2029	2023 Electric Report 2034
Wind Capacity Balanced by PSE	875	2,375	1,215	2,915
Solar Capacity Balanced by PSE	-	1,400	-	719
Average Upward Balancing Reserves	141	492	143	210

The balancing reserves in the 2021 IRP and the 2023 Electric Report differ for two reasons:

- The PSE forecast integrated a different amount of wind and solar resources in the 2023 Electric Report.
- E3 utilized a methodology for the 2023 Electric Report that is different from the one we used in the 2021 IRP.

The 2021 IRP analysis compared the difference between the hour-ahead forecast and actual real-time values for the net load. In contrast, for the 2023 Electric Report, E3 compared the difference between the actual hourly and real-time values. E3 made this change because the balancing reserves should capture sub-hourly net load variability but should exclude any hourly forecast error that would be incorporated if using the hour-ahead forecast. Although it is important to consider hourly forecast error in the system, it does not factor into the resource adequacy analysis.

3.11. Reserve Sharing Program

We did not consistently model the NWPP Reserve Sharing Program in the ELCC of energy storage resources in the 2021 IRP. When E3 calculated this report's ELCC of energy storage resources, they maintained the same reserving sharing program assumptions across all cases.

The NWPP Reserve Sharing Program allows PSE to rely on neighboring systems to compensate for insufficient resources for the first 60 minutes following a qualifying event so we do not have to curtail load during this operating hour. E3 incorporated this assumption in their model but allowed PSE to rely on the Reserve Sharing Program only when the rest of the region has sufficient energy supplies. If PSE does not have enough resources and the wider region lacks sufficient resources, then the Reserve Sharing Program is unavailable as a last resort.

3.12. Other Updates Not Incorporated

Due to the limited time to gather data, develop processes, update models, and benchmark results, we could not incorporate two of E3's recommendations for the resource adequacy analysis. Based on the resource adequacy analysis results, E3 changed their guidance for the Classic GENESYS sensitivity and recommended not pursuing one of these recommendations. We will continue to explore the recommendation on correlations between load demand and renewable resources in future resource adequacy analyses. We described these two items in more detail in the next section.

In our December 2021 response comment filing, we said PSE would "run an additional sensitivity of a Classic GENESYS model run assuming regional capacity additions such that the region meets a 5 percent LOLP standard." We did not run this additional sensitivity. E3 initially recommended we perform this sensitivity to see if it would increase the ELCC of storage resources. However, after E3's modeling showed the ELCC of energy storage is very high (>95 percent for a four-hour lithium-ion battery), and there is sufficient energy to charge the energy storage to meet reliability needs, they recommended we not run this sensitivity as it would not add significant value considering the new results.

In our December 2021 response comment filing, we stated PSE would "follow up with E3 to explore different ways to approach correlations between wind/load and solar/load." We also indicated we might need to consider this recommendation for future IRP cycles to allow adequate time for model preparation and quality review.

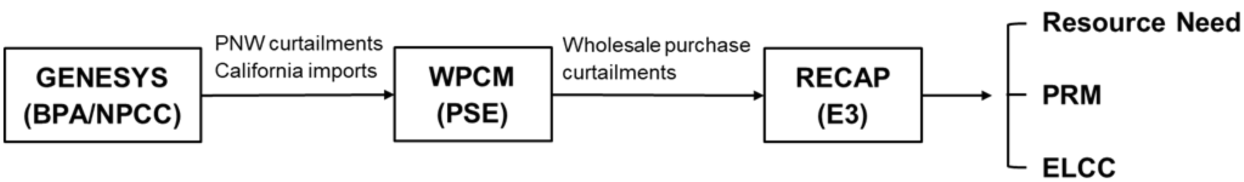
In addition to updating the load profiles based on climate change impacts, we also updated the renewable energy profiles. With changes to load profiles, renewable profiles, and many other assumptions for Phase 2 of the 2021 All-Source RFP and the 2023 Electric Report, we did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future analysis, as they could impact resource adequacy for PSE's system. For example, a cold snap in winter could result in high energy demand and low renewable output simultaneously, resulting in more extreme conditions for maintaining resource adequacy.

4. Resource Adequacy Modeling Approach

In this report, we relied on a similar set of models to those we used in the 2021 IRP. We used the Classic GENESYS model developed by the Council and Bonneville Power Administration (BPA) to analyze load and resource conditions for the Pacific Northwest region. We used PSE's wholesale purchase curtailment model (WPCM) to investigate the impacts of regional load curtailments on our system. Rather than use our resource adequacy model (RAM) to analyze load and resource conditions for PSE's system, we asked E3 to perform LOLP modeling using their proprietary RECAP model[5].

Figure L.3 shows how the three models work together. Because PSE has historically relied on significant wholesale power purchases to maintain reliability, the analysis includes an evaluation of potential curtailments to regional power supplies. The Classic GENESYS model characterizes when the region is short (i.e., insufficient resources to meet energy demand plus operating reserves). The WPCM characterizes how PSE would curtail wholesale power purchases when the region is short on energy. Lastly, RECAP simulates PSE's resource need and availability across hundreds of simulation years to determine the resource need and calculate other reliability metrics. The rest of this section describes each of the three models and the types of inputs for this analysis.

Figure L.3: Models in the Resource Adequacy Analysis



4.1. The Classic GENESYS Model

The Council and the Bonneville Power Administration (BPA) developed the Classic GENESYS model for regional-level load and resource studies. Classic GENESYS is a multi-scenario model that incorporates 30 years of hydroelectric conditions and, as of the 2023 assessment, 30 years of temperature conditions. For the 2023 Electric Report, we started with the Classic GENESYS model from the Council power supply adequacy assessment for 2023.

When the model combines thermal plant forced outages and the mean expected time to repair those units, variable wind plant generation, and available power imports from outside the region, it determines the PNW's overall hourly capacity surplus or deficit in 900 multi-scenario simulations. Since the Classic GENESYS model includes all potentially available supplies of energy and capacity an operator could use to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[6]

5 Due to staffing constraints, PSE engaged E3 to perform this analysis.

6 We included operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) in the Classic GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, Classic GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydroelectric resources to the maximum extent possible within a defined set of operational constraints. Classic GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) with forward and short-term purchases.

Since we set the Classic GENESYS model for a 2023 assessment, we made some updates to capture regional load and resource changes to run the model for 2029 and 2034. The updates to the GENESYS model include the following:

- Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW)
- The Council used climate data developed by the River Management Joint Operating Committee (RMJOC) in the Classic GENESYS load model for the 2021 power plan. We used three climate change models, A, C, and G, representing CanESM, CCSM, and CNRM in the GENESYS model[7]. For details regarding the various climate change models, please refer to Chapter Six: Demand Forecast.
- Updated coal plant retirements with retirement years are in Table L.4.

Table L.4: Modeled Coal Plant Retirements

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3 & 4	2025

We did not include any other adjustments to Classic GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from the Council already built into the model.

4.2. The Wholesale Purchase Curtailment Model

During a PNW-wide load-curtailment event, the region lacks enough physical power supply (including available imports from California) for the area's utilities to meet their firm loads plus operating reserve obligations fully. To mimic how the PNW wholesale markets would likely work in such a situation, PSE developed the wholesale purchase

[7] For more details about the climate change model, refer to the NWPCC Climate Change Scenario Selection Process and the River Management Joint Operating Committee (RMJOC) report.

curtailment model (WPCM) as part of the 2015 IRP. The WPCM links regional events to their impacts on PSE's system and our ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace directly impacts how much capacity PSE can purchase. Therefore, the WPCM first assembles load and resource data for the region and many utilities in the region, especially those expected to buy relatively large amounts of energy and capacity during winter peaking events.

We used the capacity data in BPA's 2018 Pacific Northwest Loads and Resources Study for this analysis. The BPA published the 2019 Pacific Northwest Loads and Resources Study[8] in October 2020. Commonly referred to as the White Book, the 2019 report presents the region's load obligations, contracts, and resources for operating years 2021 through 2030. Under critical water conditions, the BPA study forecasts unbalanced energy from a deficit of 194 MW to a surplus of 354 MW. The annual energy deficits and surplus forecasts are similar to the forecasts in the 2018 White Book. We used the same forecasts in the 2021 IRP in this report and will incorporate the updated forecasts for future IRP cycles.

4.2.1. Allocation Methodology

The WPCM then uses a multi-step approach to allocate the regional capacity deficiency among the region's utilities. We reflected these individual capacity shortages via a reduction in each utility's forecasted level of wholesale market purchases. The WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a decrease in PSE's wholesale market purchases hourly. In some cases, PSE's initial desired wholesale market purchase volume reductions could trigger a load-curtailment event in the LOLP portion of RECAP.

To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years.

In the study, we used the three climate change models to capture the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems. We also updated the model's contracts, third-party generation, and loads.

It is worth noting that no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

4.2.2. Forward Market Allocations

The model assumes each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility can purchase its target capacity in these markets, reducing the remaining capacity available in the spot markets. If the wholesale market does not have enough capacity to satisfy all

8 BPA's 2019 Pacific Northwest Loads and Resources Study is at https://www.bpa.gov/-/media/Aep/power/white-book/2019-wbk-summary.pdf.

the forward purchase targets, the model reduces those purchases on a pro-rata basis based on each utility's initial target purchase amount.

Besides the market purchase, the WPCM model uses the Mid-C transmission line to transmit the PSE Mid-C project and the Wild Horse site power to PSE. The model also uses transmission capacity to get balancing and spinning reserves, which is 50 percent of the operating reserve. We use the remaining capacity for market purchases.

4.2.3. Spot Market Allocations

For spot market capacity allocation, we assumed each of the five large utility purchasers to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation is not based on a straight pro-rata allocation because, in actual operations, the largest purchaser (usually PSE) is not guaranteed automatic access to a fixed percentage of its capacity need. Instead, all the large purchasers aggressively attempt to locate and purchase scarce capacity from the same sources. Under deficit conditions, the largest purchasers tend to experience the biggest MW shortfalls between what they need and can buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs, but the larger purchasers cannot.

4.2.4. WPCM Outputs

For each simulation and hour in which the Council's Classic GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- Puget Sound Energy's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions
- Puget Sound Energy's initial wholesale market purchase amount (in MW) limited only by PSE's overall Mid-C transmission rights
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage

Figure L.4, Figure L.5, Figure L.6, Figure L.7, Figure L.8, and Figure L.9 show the results of the WPCM. The charts illustrate the PSE's average share of the regional deficiency. The results show the deficiency in each of the 900 simulations (gray lines) and the mean of the simulations (red line). The mean deficiency is close to zero, but in some simulations, the market purchases may be limited by 1000 MW (in August 2029 Model A) and 1200 MW (in August 2034 Model A). This means that of the 1,500 MW of available Mid-C transmission, we could only fill 500 MW in August 2029 Model A and 300 MW in August 2034 Modal A.

Figure L.4: Average Curtailment by Month, 2029 Model A

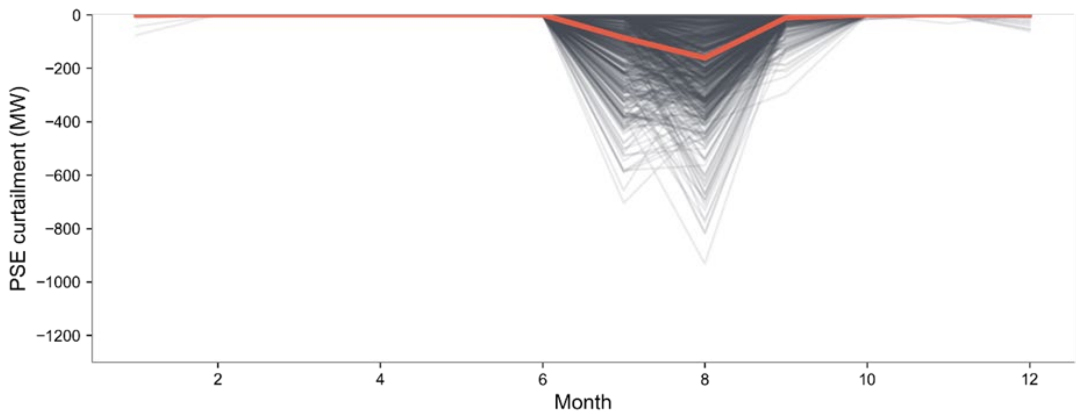


Figure L.5: Average Curtailment by Month, 2029 Model C

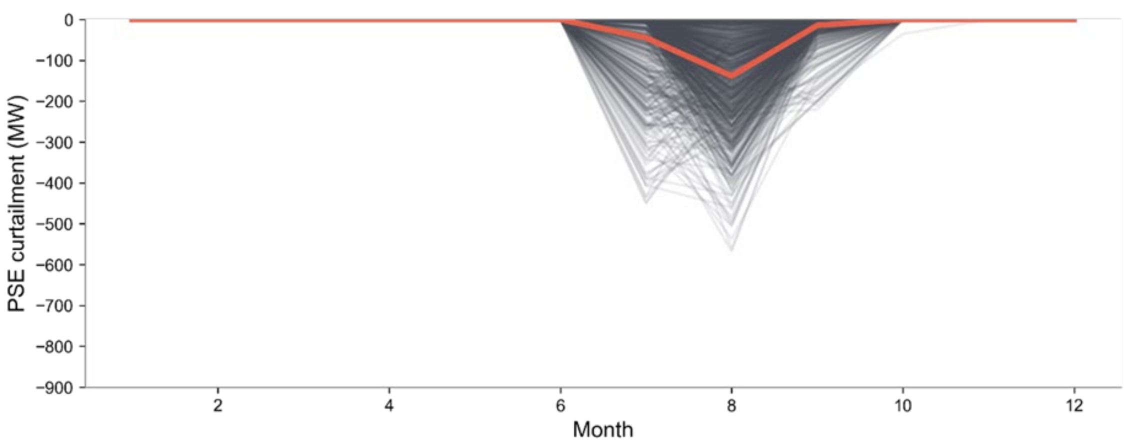


Figure L.6: Average Curtailment by Month, 2029 Model G

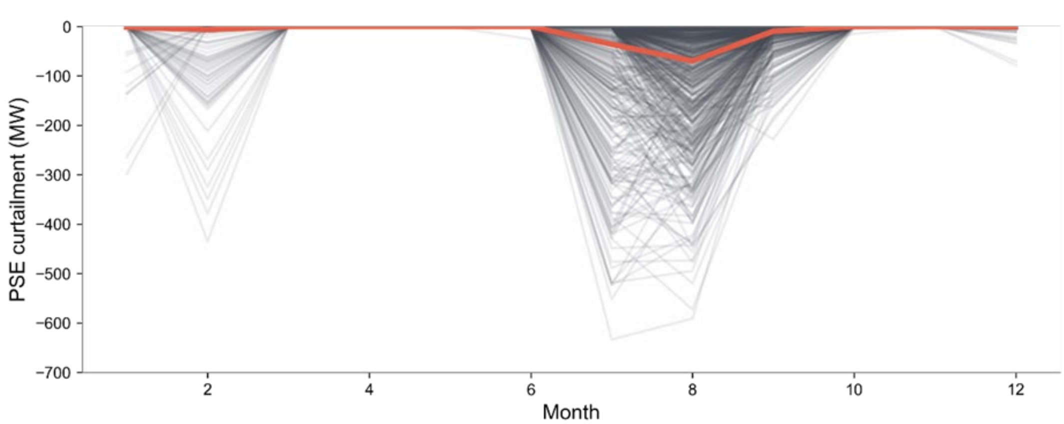


Figure L.7: Average Curtailment by Month, 2034 Model A

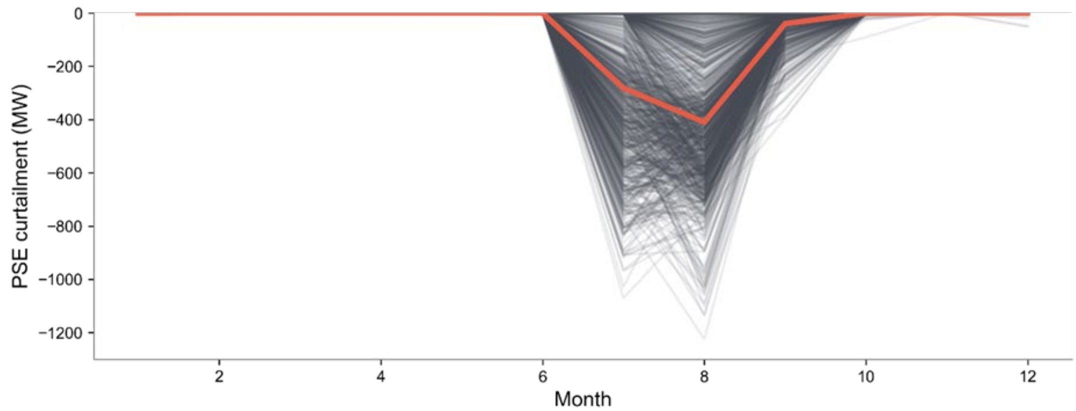


Figure L.8: Average Curtailment by Month, 2034 Model C

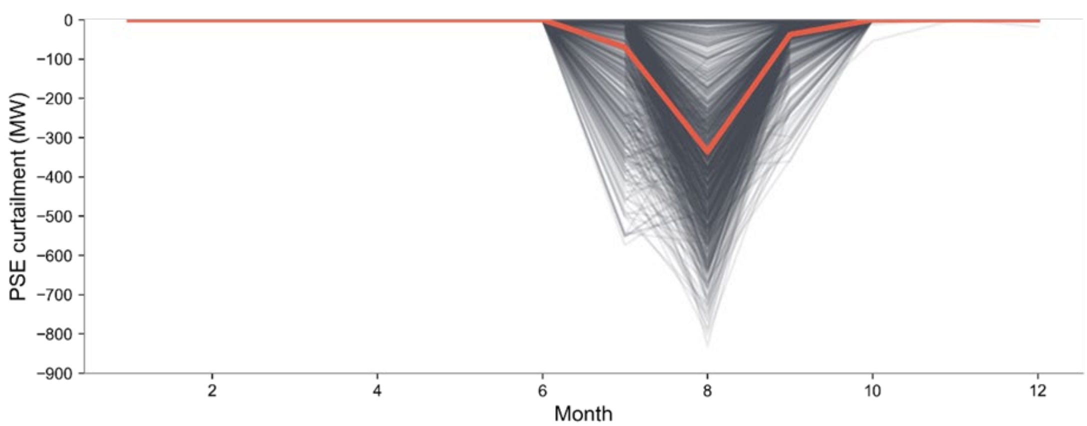
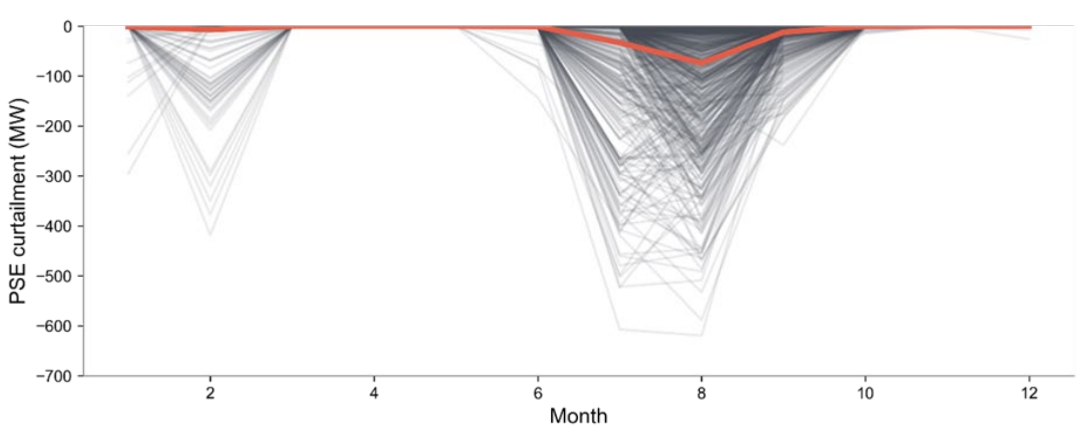


Figure L.9: Average Curtailment by Month, 2034 Model G



In addition to the WPCM results included in PSE's resource adequacy analysis, we also conducted a separate market risk assessment. That assessment is described later in this chapter.

4.3. The RECAP Model

E3 used its RECAP model to determine the PSE system's resource need, PRM, and ELCC metrics. E3 has used RECAP extensively to assess the resource adequacy of electric systems across North America. In the Western United States, E3 used RECAP in the following states: Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, and Washington.

RECAP is a LOLP model that simulates the availability of resources to meet energy demand across a broad range of conditions. RECAP accounts for factors such as weather-driven variability of electric demand, the natural variability of resources such as wind and solar, availability of wholesale purchases, forced outages of thermal power plants, and operating constraints for resources like hydroelectric, storage, and demand response. These simulations determine the likelihood and magnitude of loss of load — energy demand that PSE cannot serve — and provide the basis for assessing resource adequacy for PSE's system.

RECAP simulates system conditions over hundreds of simulation years using stochastic techniques to capture the risk of rare tail events that can significantly impact PSE's system. RECAP simulates the system each hour of a year and repeats this process hundreds of times with different system conditions, which ensures that RECAP captures a wide distribution of potential outcomes, including low-probability but high-risk tail events.

RECAP conducts a Monte-Carlo time-sequential simulation of loads, resources, and power purchases for each simulation year. RECAP first determines the load based on the simulation year and calculates the operating reserve requirements hourly. RECAP then simulates renewable generation and forced outages for thermal generators. After this, RECAP determines the number of wholesale power purchases available based on the simulation year. RECAP then dispatches hydroelectric resources that have the flexibility to shift generation throughout the day to maximize generation during the times when the PSE system has the greatest need. Lastly, RECAP dispatches storage and demand response resources.

Energy storage devices charge when sufficient capacity is available and discharge to meet energy demand not met by other resources. RECAP tracks energy storage resources' state of charge (SoC) to ensure their operations respect physical limitations. Demand response resources serve as a last resort and are constrained by limits on the number and duration of calls. If there is a period when the supply of resources is inadequate to meet the load requirement, there is a loss of load event.

RECAP determines the frequency, duration, and magnitude of the loss of load events across all simulation years. RECAP then uses these outputs to calculate PSE's system's resource need, PRM, and ELCC metrics.

Detailed documentation of E3's RECAP model is on E3's website[9].

[9] https://www.ethree.com/wp-content/uploads/2022/10/RECAP-Documentation.pdf

4.4. Key Inputs to Capture Uncertainty

To perform the resource adequacy analysis, we must appropriately characterize the range of operating conditions PSE can expect over a long time, including low-probability tail events. This analysis must capture the uncertainties in power and energy demand and resource supply that could ultimately lead to load loss. These factors include energy demand, availability of thermal generators, availability of hydroelectric, wind, and solar generation, and availability of market purchases. The resource adequacy analysis for the 2023 Electric Report captures each of these factors, described further in the following and the Resource Adequacy Inputs and Updates sections.

4.4.1. Energy Demand

We modeled hourly system loads as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 30 temperature years. These demand draws created with stochastic outputs from PSE's economic and demographic model and two consecutive historical weather years predict future weather. Each coming weather year from 2020 to 2049 is represented in the 30 weather draws. Since the resource adequacy model examines a hydroelectric year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. The model also examines adequacy in each hour of a given future year; therefore, we scaled the model inputs to hourly demand using the hourly demand model.

4.4.2. Forced Outages

A forced outage is when a generator fails unexpectedly and cannot generate at maximum output for some amount of time until repaired. We accounted for forced outages for natural gas and storage units by modeling forced outage rates (FOR) and mean time to repair (MTTR) for each resource. The method for modeling forced outage rates in the resource adequacy analysis is consistent with our frequency duration outage method in AURORA, which allows units to fail and return to service at any timestep within the simulation.

4.4.3. Hydroelectric Generation

We use the same 30 hydroelectric years, simulation for simulation, as the GENESYS model. Based on PSE's modeling of daily We hydroelectric availability for each hydroelectric year, E3 models PSE's Mid-Columbia and Baker River plants flexibly in RECAP, so each plant can shift hydroelectric generation across hours within a single day, subject to daily energy budget and power output constraints. The 900 combinations of hydroelectric and temperature simulations are consistent with the Classic GENESYS model.

4.4.4. Wind and Solar Generation

We modeled 250 unique 8,760 hourly profiles exhibiting typical wind and solar generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that we preserved this intermittency. The other goal is to ensure that we reflect correlations across wind farms and the seasonality of wind and solar generation. DNV, an energy and atmospheric science consultant, provided wind speed and solar irradiance data to PSE. Wind and solar data were selected for specific sites representing locations of generic resources and processed to give wind and solar production data. DNV utilized its stochastic engine to generate 1,000 unique 21-year production profiles for each site. From the 1,000 unique profiles, we selected 250 to use in the resource adequacy model. Statistical analysis of these 250 randomly selected profiles ensured that they represented the entire population of wind and solar profiles.

➔ Details of the profiles provided by DNV and DNV's methodology are available in Appendix C: Existing Resource Inventory and Appendix D: Generic Resource Alternatives.

4.4.5. Wholesale Market Purchases

These inputs to RECAP are determined in the WPCM, as explained. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same classic GENESYS model simulations as E3's RECAP. We computed the initial set of hourly wholesale market purchases that we import into our system using our long-term Mid-C transmission rights as the difference between PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind farm and PSE's contracted shares of the Mid-C hydroelectric plants.

To reflect regional deficit conditions, we reduced this initial set of hourly wholesale market imports on the hours when we identified a PNW load-curtailment event in the WPCM. We then used the final set of hourly PSE wholesale imports from the WPCM as data input into RECAP and determined PSE's loss of load probability, expected unserved energy, and loss of load expectation. In this fashion, the LOLP, EUE, and LOLH metrics determined in RECAP incorporate PSE's wholesale market reliance risk.

5. Detailed Results for Generic Resources

The following section shows the detailed results regarding the generic resources we modeled in the 2023 Electric Progress Report.

5.1. Generic Wind and Solar Resource Groups

E3 calculated the ELCC for eight wind resources, two distributed solar resources, and five utility-scale solar resources (see the results section of Chapter Seven: Resource Adequacy). These ELCC values represent the capacity contribution for the first 100 MW of incremental capacity we added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in the next section.

As discussed in section 6.3 of this appendix, the ELCC for a dispatch-limited resource declines as its penetration increases. We modeled an ELCC saturation curve for each wind and solar resource to capture this relationship between ELCC and penetration.

E3 first categorized the generic wind and solar resources into resource groups (see Table L.5). Each resource group includes resources that have highly correlated generation profiles. When one resource in a group has a high generation, additional resources in the group likely have a high generation. Just as higher penetration of a single resource results in a lower ELCC for that resource, higher penetration of highly correlated resources also results in a lower ELCC. Highly correlated resources make similar contributions towards meeting load during critical periods, so adding one of these resources will cause the reliability value — or ELCC — of the other resources to decline or saturate.

Table L.5: Resource Groups for ELCC Saturation

Resource Group	Resources in Group
Pacific Northwest Wind	British Columbia; Washington
Rockies Wind	Wyoming East; Wyoming West; Montana Central; Montana East
Idaho Wind	Idaho Wind
Offshore Wind	Offshore Wind
Solar	Idaho Solar; Washington East; Washington West; Wyoming East; Wyoming West; Distributed Ground Mount; Distributed Rooftop

Note that there can be interactions between all resources, not just those in the same resource group. However, due to the large number of potential resource combinations, it was not feasible for E3 to model the interactive and saturation effects between all resources. Moreover, PSE's capacity expansion model cannot incorporate a multi-dimensional ELCC surface. The more straightforward resource group approach still provides a way to capture the strongest and most important interactions between highly correlated resources, as it allows us to calculate the capacity contribution of an individual resource based on the overall penetration of resources in its corresponding resource group.

5.2. Generic Wind and Solar ELCC Saturation Curves

Figure L.10 shows the winter and summer ELCC saturation curves for the Pacific Northwest wind (including the British Columbia wind and Washington wind). E3 calculated the ELCC for three tranches of Pacific Northwest wind: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. The ELCC declines with each successive tranche due to the ELCC saturation effect. For example, the first tranche of Washington wind has an ELCC of 13 percent in winter, the second has an ELCC of 11 percent, and the third has an ELCC of 6 percent.

The ELCC saturation curve determines how much a resource contributes toward the PRM. For example, assume that PSE adds 1,500 MW of Washington wind. The total capacity contribution of this incremental capacity would be 13 MW for the first tranche (100 MW x 13 percent), plus 99 MW for the second tranche (900 MW x 11 percent), and 30 MW for the third tranche (500 MW x 6 percent), for a total of 142 MW.

The total capacity additions within the resource group determine the overall penetration for all resources in the resource group. For example, assume that PSE adds 1,000 MW of Washington Wind in an earlier year and then adds 500 MW of British Columbia Wind in a later year. The ELCC for the 500 MW of British Columbia Wind would be 16 percent because the penetration for the resource group is already at 500 MW, putting the incremental British Columbia Wind in the third tranche.

Figure L.10: ELCC Saturation Curves for Pacific Northwest Wind

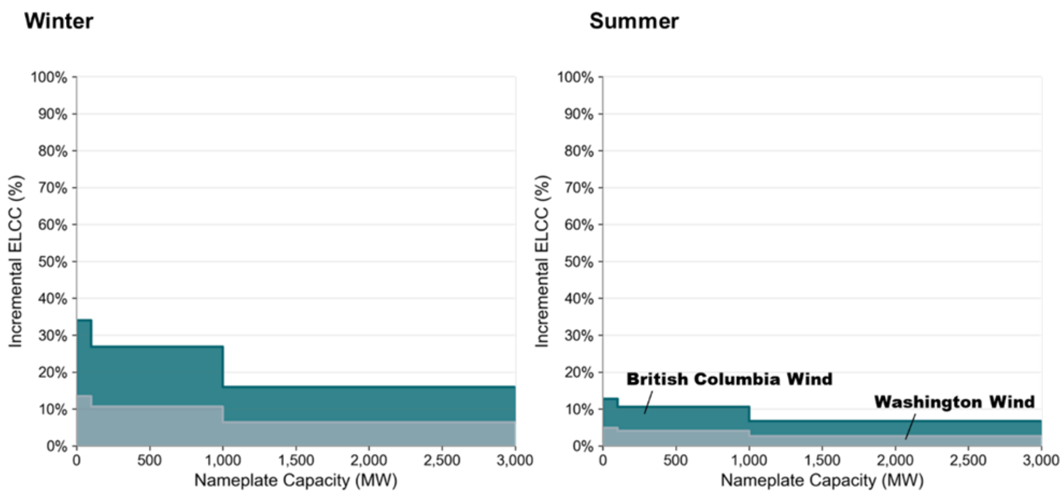


Figure L.11 shows the winter and summer ELCC saturation curves for the Rockies Wind (including Montana Central Wind, Montana East Wind, Wyoming East Wind, and Wyoming West Wind). E3 calculated the ELCC for three tranches for Pacific Rockies Wind: 0–100 MW, 100–1,000 MW, and 1,000–2,000 MW. The Montana East Wind ELCC is lower than the ELCC of the other resources because we already have 350 MW of wind in eastern Montana in its resource portfolio (Clearwater Wind). Note that the ELCC of Montana Central Wind and Wyoming West Wind are very similar in winter, so the figure does not differentiate between these resources. The ELCC of Wyoming East Wind and Wyoming West Wind are similar in summer, so the figure does not distinguish between these two resources.

Figure L.11: ELCC Saturation Curves for Rockies Wind

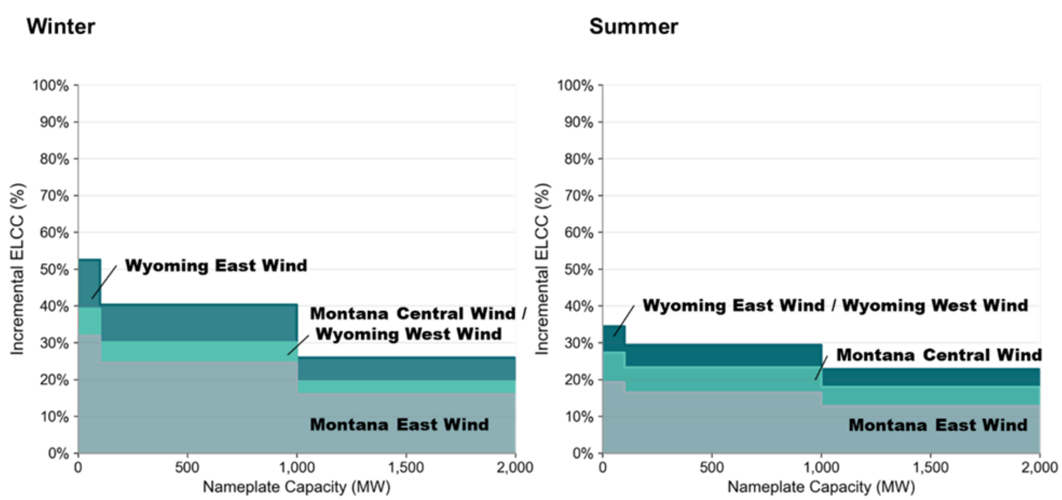


Figure L.12 shows the winter and summer ELCC saturation curves for Idaho and Offshore Wind. E3 calculated two tranches for Idaho Wind: 0–100 MW and 100–800 MW. E3 calculated the ELCC for two tranches of Offshore Wind: 0–100 MW and 100–300 MW. Note that Idaho Wind and Offshore Wind are not in the same resource grouping, so the penetration of one does not impact the penetration of the other when determining ELCC saturation.

Figure L.12: ELCC Saturation Curves for Idaho Wind and Offshore Wind

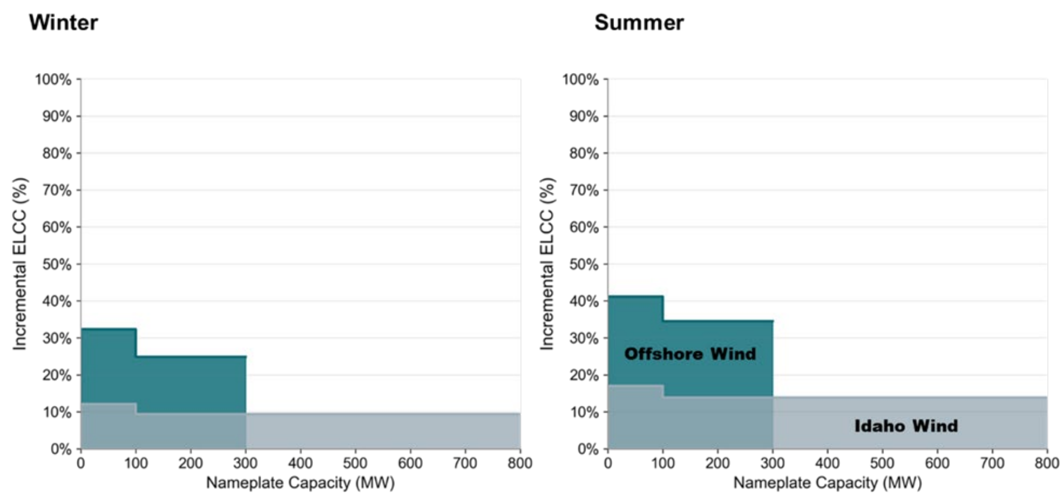
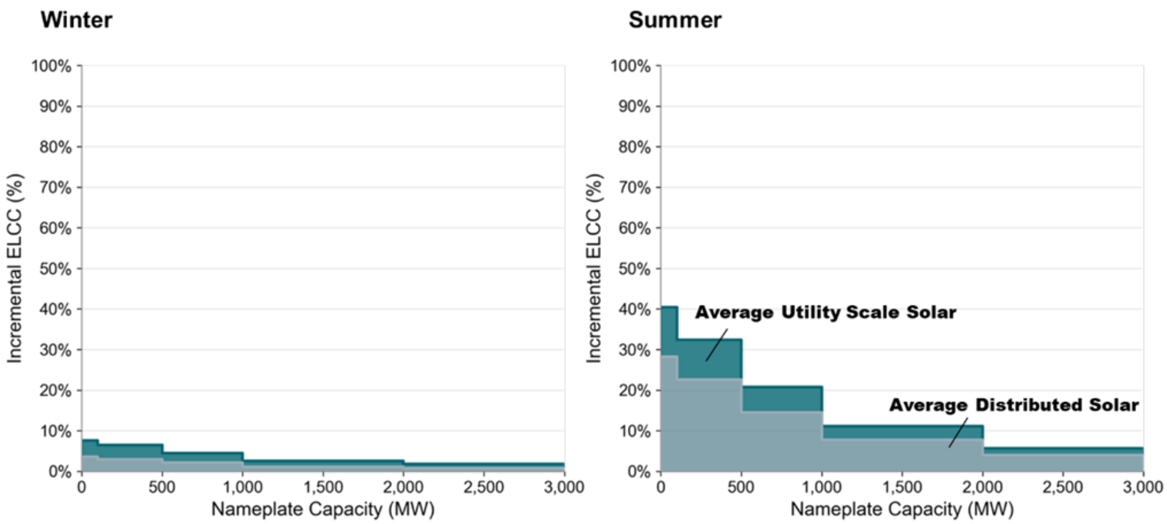


Figure L.13 shows the average winter and summer ELCC saturation curves for utility-scale solar (comprised of Idaho Solar, Washington East Solar, Washington West Solar, Wyoming East Solar, and Wyoming West Solar) and distributed solar (comprised of Distributed Ground Mount Solar and Distributed Rooftop Solar). Utility-scale and distributed solar are in the same resource group, so the overall penetration of solar resources determines the ELCC saturation for each solar resource. E3 calculated the ELCC for five tranches for Solar: 0–100 MW, 100–500 MW, 500–1,000 MW, 1,000–2,000 MW, and 2,000–3,000 MW.

The ELCC for solar is already very low in winter, so the ELCC saturation effect does not have as much impact in winter. On the other hand, the ELCC for solar in summer starts relatively high and then declines rapidly at higher penetration levels. The ELCC begins high because solar generation generally coincides nicely with periods of high energy demand in summer — when air conditioning loads are high — and because PSE's resource portfolio does not have high solar penetration.

At higher penetration levels, the ELCC for incremental solar is much lower. For example, the ELCC for the first tranche of utility-scale solar is 40 percent in summer, but the ELCC for the 2,000–3,000 MW tranche is only six percent in summer. If PSE had 2,000 MW of additional solar in its resource portfolio, this solar would largely mitigate reliability concerns during daytime hours in summer but would not do anything to alleviate reliability concerns during nighttime hours. As a result of the reliability need being low during solar generation hours, the ELCC for additional solar beyond 2,000 MW is low.

Figure L.13: ELCC Saturation Curves for Solar Resources



Tables that list the ELCC for each resource as a function of penetration are in the next section. The values in these tables correspond to the values in the saturation curves earlier in this appendix. Each table contains the ELCC values for all resources within a resource group.

To understand how to interpret these tables, take Table L.6 as an example. E3 calculated the ELCC for three tranches: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. For the 0–100 MW tranche, the ELCC of British Columbia Wind in winter is 34 percent. If we added 100 MW of this resource, the capacity contribution would be 34 percent x 100 MW = 34 MW. For the 100–1,000 MW tranche, the ELCC of British Columbia Wind in winter is 27 percent. If we added 1,000 MW of this resource, the capacity contribution of the 900 MW added beyond the first tranche would be 27 percent x 900 MW = 243 MW. The same logic applies to the 1,000–3,000 MW tranche.

Table L.6: ELCC by Tranche for Pacific Northwest Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	3,000
Winter	British Columbia Wind	34%	27%	16%
	Washington Wind	13%	11%	6%
Summer	British Columbia Wind	13%	11%	7%
	Washington Wind	5%	4%	3%

Table L.7: ELCC by Tranche for Rockies Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
Winter	Montana Central Wind	39%	30%	19%
	Montana East Wind	32%	25%	16%
	Wyoming East Wind	52%	40%	26%
	Wyoming West Wind	39%	29%	19%
Summer	Montana Central Wind	27%	23%	18%

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
	Montana East Wind	19%	16%	13%
	Wyoming East Wind	34%	29%	23%
	Wyoming West Wind	34%	29%	23%

Table L.8: ELCC by Tranche for Idaho Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	800
Winter	12%	9%
Summer	17%	14%

Table L.9: ELCC by Tranche for Offshore Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	300
Winter	32%	25%
Summer	41%	34%

Table L.10: ELCC by Tranche for Solar Resources

Season	Resource	Cumulative Capacity by Tranche (MW)				
		100	500	1,000	2,000	3,000
Winter	Idaho Solar	8%	7%	5%	3%	2%
	Washington East Solar	4%	4%	3%	1%	1%
	Washington West Solar	4%	3%	2%	1%	1%
	Wyoming East Solar	11%	10%	7%	4%	3%
	Wyoming West Solar	10%	8%	6%	3%	2%
	DER Ground Mount Solar	4%	3%	2%	1%	1%
	DER Rooftop Solar	4%	3%	2%	1%	1%
Summer	Idaho Solar	38%	30%	19%	10%	5%
	Washington East Solar	55%	44%	28%	15%	8%
	Washington West Solar	53%	42%	27%	15%	7%
	Wyoming East Solar	29%	23%	15%	8%	4%
	Wyoming West Solar	28%	22%	14%	8%	4%
	DER Ground Mount Solar	28%	23%	14%	8%	4%
	DER Rooftop Solar	28%	23%	15%	8%	4%

Table L.11: ELCC by Tranche for Storage Resources

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
Winter	Li-ion Battery (2-hour)	89%	80%	46%	30%	18%	17%	13%	13%	10%	10%
	Li-ion Battery (4-hour)	96%	96%	76%	42%	23%	19%	15%	15%	12%	12%
	Li-ion Battery (6-hour)	98%	98%	82%	68%	31%	21%	16%	16%	12%	12%
	Pumped Storage (8-hour)	99%	99%	94%	76%	43%	23%	17%	17%	14%	14%
Summer	Li-ion Battery (2-hour)	97%	80%	57%	42%	33%	30%	23%	23%	20%	20%

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
	Li-ion Battery (4-hour)	97%	93%	93%	93%	59%	45%	31%	31%	17%	17%
	Li-ion Battery (6-hour)	98%	98%	98%	98%	89%	82%	32%	21%	15%	15%
	Pumped Storage (8-hour)	99%	99%	99%	99%	98%	92%	47%	24%	15%	15%

Table L.12: ELCC by Tranche for Storage Resources (Continue)

Season	Resource	Cumulative Capacity by Tranche (MW)									
		2750	3000	3250	3500	3750	4000	4250	4500	4750	5000
Winter	Li-ion Battery (2-hour)	10%	10%	8%	8%	8%	8%	6%	6%	6%	6%
	Li-ion Battery (4-hour)	12%	12%	9%	9%	9%	9%	7%	7%	7%	7%
	Li-ion Battery (6-hour)	12%	12%	10%	10%	10%	10%	8%	8%	8%	8%
	Pumped Storage (8-hour)	14%	14%	11%	11%	11%	11%	9%	9%	9%	9%
Summer	Li-ion Battery (2-hour)	20%	20%	16%	16%	16%	16%	10%	10%	10%	10%
	Li-ion Battery (4-hour)	17%	17%	10%	10%	10%	10%	8%	8%	8%	8%
	Li-ion Battery (6-hour)	15%	15%	11%	11%	11%	11%	9%	9%	9%	9%
	Pumped Storage (8-hour)	15%	15%	12%	12%	12%	12%	9%	9%	9%	9%

Table L.13: ELCC by Tranche for Demand Response Resources

Season	Resource	Cumulative Capacity by Tranche (MW)	
		100	**300**
Winter	Demand Response (3-hour)	69%	67%
	Demand Response (4-hour)	73%	72%
Summer	Demand Response (3-hour)	95%	87%
	Demand Response (4-hour)	99%	90%

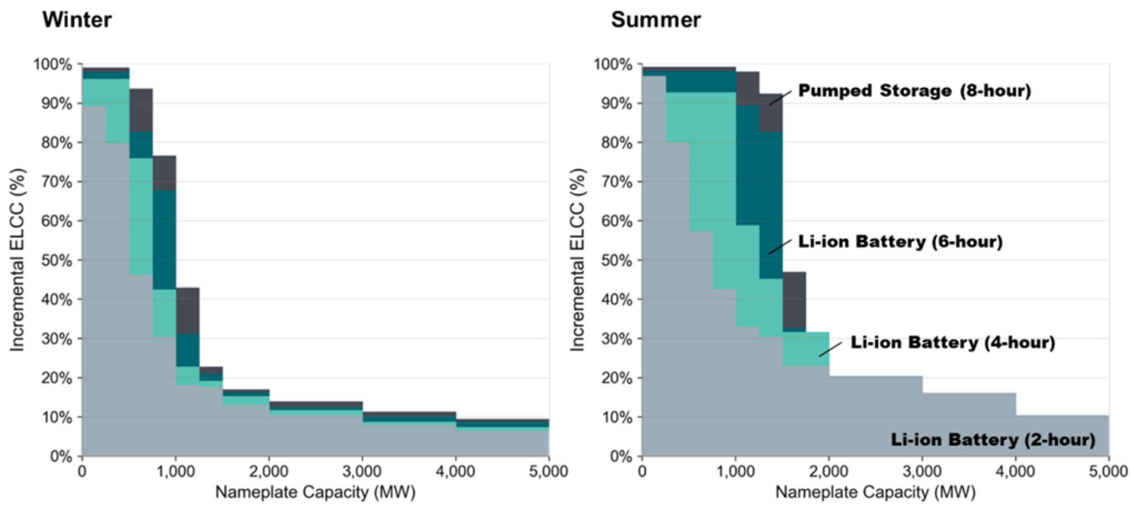
5.3. Generic Energy Storage ELCC Saturation Curves

E3 calculated ELCC saturation curves for each energy storage resource (see Figure L.14). Like other dispatch-limited resources, the ELCC of energy storage declines with increasing penetration levels. E3 calculated the ELCC for ten tranches for energy storage resources: 250–1,500 MW, 1,500–2,000 MW, and 1,000–5,000 MW. E3 calculated separate ELCC saturation curves for each individual energy storage resource.

The ELCC starts high and then declines at increasing penetration levels. The ELCC starts very high because energy storage is effective at supplying energy during a relatively short loss of load event. However, as we added more storage to the system, the net peak load (load minus renewable and storage generation) flattened, and the next tranche of storage must discharge over a longer period to help satisfy the new net peak lead. The ELCC declines more rapidly in winter than in summer. The ELCC starts falling rapidly after approximately 500 MW in winter and 1,000 MW in summer because the net peak load in summer is narrower than in winter. Limited duration energy storage can provide more reliability value in summer because power demand is high for shorter periods relative to winter.

The ELCC saturation curve declines more slowly for longer-duration energy storage. For example, in summer, Pumped Storage (8-hour) has an ELCC greater than 90 percent for the 1,250–1,500 MW tranche, while Lithium-ion Battery (2-hour) has an ELCC of 30 percent for the same tranche. The ELCC for longer-duration storage declines slower because it can discharge longer. As the net peak load flattens and storage must discharge over longer periods, a storage resource with eight hours can discharge at a higher level than a storage resource with only two hours. This does not necessarily mean shorter-duration energy storage is only valid up to a certain penetration level. The selection of different energy storage resources ultimately depends on their relative economics, which depends on the ELCC and other factors, such as resource costs and value from balancing system generation. The portfolio analysis assesses all of these factors together.

Figure L.14: ELCC Saturation Curves for Storage Resources



5.4. Generic Hybrid Resources

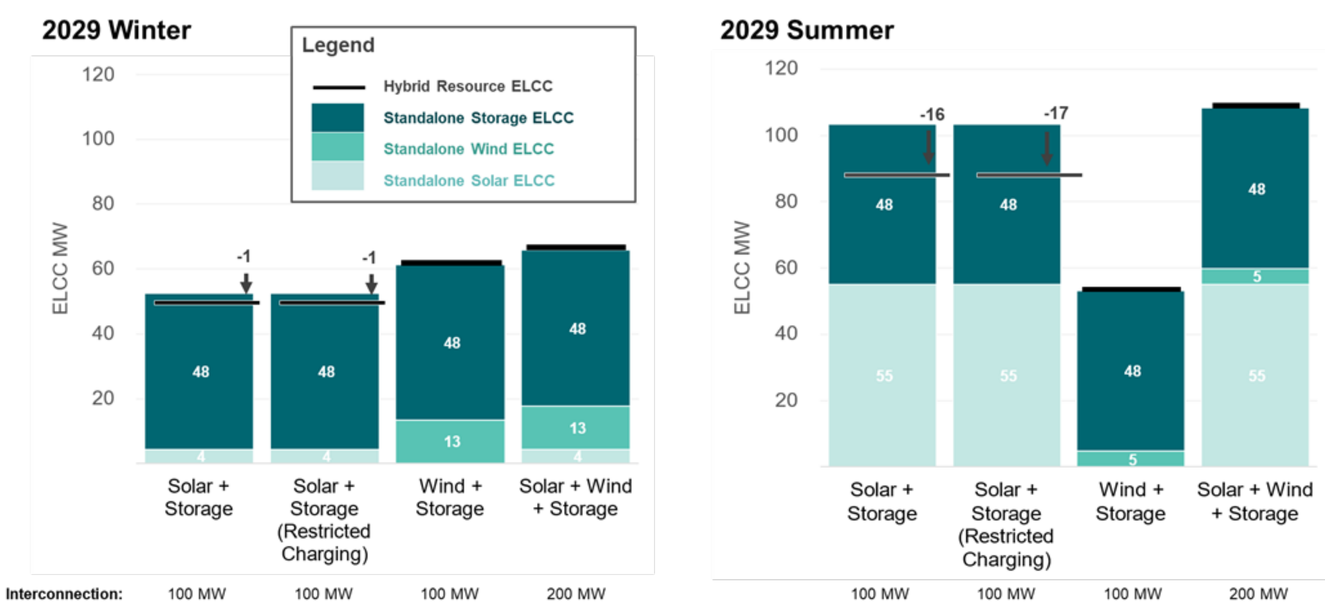
E3 modeled the ELCC of four types of hybrid resources (see Table 7.13 in Chapter Seven: Resource Adequacy Analysis) on behalf of PSE. We assumed we would site these hybrid resources in Washington. The solar resource corresponds to Washington East Solar, the wind resource corresponds to Washington Wind, and the storage resource corresponds to Lithium-ion Battery Storage (4-hour). For each hybrid resource, we assumed the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the storage capacity, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Figure L.15 shows the ELCC results for the hybrid resources. The figure provides the ELCC for each hybrid resource (black line) and compares this to the sum of the ELCCs for the individual resources that make up the hybrid resource (stacked bars).

Figure L.15 notes three major findings. First, the Wind + Storage and Solar + Wind + Storage resources have the same ELCCs as the sum of the ELCCs for the individual resources. This similarity indicates that the interconnection limits for these resources are not binding during times of reliability need. Second, as opposed to the hybrid wind resources, the two Solar + Storage resources have lower ELCCs than the sum of the ELCCs for the individual resources, especially in summer.

The lower ELCCs for Solar + Storage indicates that the interconnection limits for these resources are binding during times of reliability need. During summer peak loads, the solar output is relatively high. When this is the case, it limits the amount of storage that can be discharged to serve reliability needs, as the interconnection is only 100 MW. Lastly, the charging restriction for the Solar + Storage resource does not significantly impact the ELCC for the resource because, most of the time, there is sufficient energy from the solar project to charge the battery between reliability events.

Figure L.15: ELCC for Hybrid Resources



5.5. Generic Natural Gas Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic natural gas resources (see Table 7.14 in Chapter 7: Resource Adequacy Analysis). Three factors influence the capacity contribution of these resources: ambient temperature derates, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing natural gas plants. The summer rating is lower than the winter rating for combined cycle and frame turbine units. There is no derate in summer for reciprocating engines.

The ELCC for these natural gas resources is less than 100 percent because of forced outages. There is a chance that a unit is on forced outage when the PSE system needs the resource to ensure reliability. The assumed forced outage rates are 3.88 percent for combined cycle units, 2.38 percent for frame turbine units, and 3.30 percent for reciprocating engines.

The forced outage rates and the unit sizes influence the ELCC results. The higher the forced outage rate, the greater the chance the unit is on outage when needed and the lower the ELCC. If the unit is large, then this will result in a lower ELCC because, when a larger unit is on forced outage (e.g., 367 MW combined cycle plant), this has a greater chance of causing reliability problems for PSE's system than if a smaller unit is on forced outage (e.g., 18 MW reciprocating engine).

The ELCC for the combined cycle is lower because it has the highest forced outage rate and the largest unit size. The ELCC for a frame turbine unit is similar to the ELCC of a reciprocating engine. Although the forced outage rate for a frame turbine unit is smaller, the unit size is larger. These factors largely offset each other. The ELCC percent values are higher in summer for combined cycle and frame turbine units because the rated capacities are lower than in winter; in other words, the unit size is smaller.

6. Compared: the 2023 Electric Report and the 2021 Integrated Resource Plan

This section compares the results of the 2023 Electric Report with the results from the 2021 IRP. Because we made many updates to the inputs and methodology in the 2023 Electric Report, there are meaningful changes to several key outputs of the resource adequacy analysis.

6.1. Planning Reserve Margin

See Table L.14 for a comparison between the PRM in the 2021 IRP and the 2023 Electric Report.

Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, we can think of the results for the 2021 IRP as akin to the winter results for the 2023 Electric Report. Comparing the results from the 2021 IRP to the 2029 winter results from the 2023 Electric Report shows that the capacity contributions of resources are similar (5,062–5,072 MW in the 2021 IRP and 5,047 MW in the 2023 Electric Report). The median peak load is also similar (4,949–5,199 MW in the 2021 IRP and 5,004 MW in the 2023 Electric Report. The additional perfect capacity need for 2029 in the 2023 Electric Report falls between 2027 and 2031 in the 2021 IRP.

The PRM for the 2023 Electric Report (26 percent) is higher than that of the 2021 IRP (20–24 percent). One of the main reasons for this discrepancy is that the 2023 Electric Report shows an increased risk of loss of load in the summer, whereas the 2021 IRP shows little to no risk of loss of load in the summer. Because the 2023 Electric Report shows a much greater risk of loss of load in the summer, we must ensure the risk of loss of load in winter is meaningfully less than five percent to ensure an annual LOLP of five percent. To achieve this, we need more resource capacity in winter. Because the 2021 IRP shows little to no risk of loss of load in summer, we do not need this additional buffer in winter.

Because of the preceding reasons, the 2021 IRP results are not directly comparable to the 2023 Electric Report results for the summer. The differences between the 2021 IRP results and the 2023 Electric Report results for summer are similar to the reasons for the differences between the 2023 Electric Report results for winter and 2023 Electric Report results for summer, which we discussed in the Resource Adequacy Inputs and Updates Section.

Table L.14: Compared: PRM in the 2021 IRP and the 2023 Electric Report (MW)

Resource	2027[1]	2031[1]	2029 Winter[2]	2034 Winter[2]	2029 Summer[2]	2034 Summer[2]
Natural Gas	2,050	2,050	2,050	2,050	1,688	1,688
Mid-C Hydroelectric	560	560	560	560	560	560
Wind, Solar, Baker, Other Contracts	981	989	997	981	244	252
Market Purchases	1,471	1,473	1,440	1,434	961	751
Additional Perfect Capacity Need	907	1,381	1,272	1,746	1,875	2,856
Total Resource Need	5,969	6,453	6,319	6,771	5,329	6,107
Normal Peak Load	4,949	5,199	5,004	5,382	4,171	4,831
Planning reserve margin	20%	24%	26%	26%	28%	26%

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report

6.2. Generic Wind and Solar Resources

See Table L.15 for a comparison between the renewable resource ELCC values in the 2021 IRP and the 2023 Electric Report. The 2021 IRP did not model British Columbia wind. The ELCC for Idaho wind is lower in the 2023 Electric Report because the profile from DNV indicates a significantly lower generation than the profile used for the 2021 IRP. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC results from the 2021 IRP are akin to the winter ELCC from this report. The ELCCs differ due to changes in the resource profiles and the timing of the loss of load events.

For solar resources, the ELCC results in the 2021 IRP are generally lower than the winter ELCC results in this report. In the 2021 IRP, loss of load events were usually longer and, in some cases, spanned multiple days. As a result, many loss of load events spanned nighttime hours when solar generation is lower or nonexistent. In this report, by contrast, loss of load events do not span the entire day or multiple days. Most loss of load hours are during daytime hours when solar output would be higher. As a result, the winter ELCC results in this report are higher than the ELCC results in the 2021 IRP.

Table L.15: Compared: Wind and Solar ELCCs in 2021 IRP and 2023 Report (First Tranche: 100 MW)

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	46	32	41
Washington	Wind	18	15	13	5

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
DER Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report

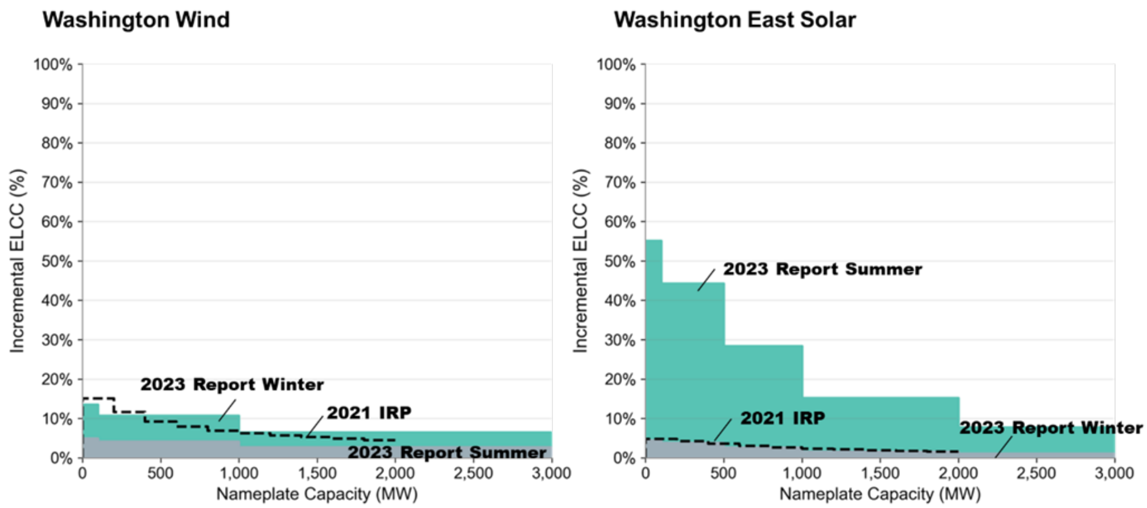
6.3. Generic Wind and Solar ELCC Saturation Curves

Figure L.16 compares the ELCC saturation curves in the 2021 IRP and the corresponding ELCC saturation curves in the 2023 Electric Report. The 2021 IRP included saturation curves for Washington wind and Washington East Solar through 2,000 MW, while the 2023 Electric Report E3 calculated saturation curves through 3,000 MW. The 2021 IRP calculated annual saturation curves, while the 2023 Electric Report E3 calculated separate saturation curves for winter and summer.

The results for Washington wind are similar. The ELCC in the 2021 IRP is similar to the winter ELCC in the report at lower penetration levels. At higher penetration levels, the ELCC in the 2021 IRP is between the winter ELCC and summer ELCC values.

The results for Washington East Solar are similar for winter but not summer. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC from the 2021 IRP can be considered akin to the winter ELCC from the 2023 Electric Report. The two are very similar. As discussed earlier in this section, the summer ELCC in the 2023 Electric Report is much higher than the winter ELCC.

Figure L.16: Compared: ELCC Saturation Curves in 2021 IRP and 2023 Electric Report



6.4. Generic Storage and Demand Response Resources

Table L.16 shows the storage and demand response ELCC results for the 2021 IRP and the 2023 Electric Report. Overall, the ELCC results in the 2023 Electric Report are much higher than those in the 2021 IRP. For example, the range of ELCC values for the 2023 Electric Report is 69-99 percent across resources and seasons, while the range of ELCC values for the 2021 IRP is 12-44 percent across resources.

There are two main reasons why the 2023 Electric Report sees higher ELCCs than the 2021 IRP: First, while PSE remains a winter-peaking system, the magnitude, frequency, and duration of critical reliability periods have changed substantially. Specifically, the duration of critical reliability periods has shortened relative to the 2021 IRP. As a result, energy-limited resources such as energy storage and demand response can perform more similarly to a perfect capacity resource to ensure reliability, the biggest driver for higher ELCC values, as even short-duration resources now have relatively high ELCC values.

Second, we changed how we modeled energy storage resources in the 2023 Electric Report. Allowing energy storage resources to discharge at maximum capacity for their rated duration increases their capabilities relative to the 2021 IRP. Allowing energy storage resources to provide operating reserves without discharging also increases their capabilities relative to the 2021 IRP. Lastly, the 2023 Electric Report ensures that the NWPP Reserve Sharing Program provides the same value to PSE's system when modeling the ELCC of energy storage.

Table L.16: Compared: Storage and Demand Response ELCCs in 2021 IRP and 2023 2023 Electric Report (First Tranche)

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report
3. Demand response first tranche is 100 MW. Storage first tranche is 250 MW.

6.5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs, modeled in the AURORA database to perform long-term expansion planning and hourly dispatch to optimize new builds and mimic the hourly operation of existing and new resources. Multiple tranches on resource ELCC add model complexity and increase run-time significantly. To manage the large-scale optimization problem run-time and meet the ERP study needs, we adjusted the planning reserve margin and resource ELCCs.

6.6. Planning Reserve Margin

We modeled three climate change load forecasts in the resource adequacy analysis to calculate the seasonal generation capacity needed to meet five percent LOLP. To calculate the planning reserve margin in percentage, we used the normal peak forecast in summer and winter and formulated the following equations:

$$\text{Planning Reserve Margin in Summer } \% = (\text{Generation Capacity Needs in Summer} - \text{Normal Peak Loads in Summer}) \,/\, \text{Normal Peak Loads in Summer X } 100\%$$

$$\text{Planning Reserve Margin in Winter } \% = (\text{Generation Capacity Needs in Winter} - \text{Normal Peak Loads in Winter}) \,/\, \text{Normal Peak Loads in Winter X } 100\%$$

The normal peak loads in summer and winter and the P50 load forecast of the average of the three climate change load forecasts are in Table L.17.

Table L.17: Peak Load

Load	Winter 2029	Winter 2034	Summer 2029	Summer 2034
Normal Peak Forecast (MW)	5,104	5,588	4,300	4,845
P50 Peak Load (MW)	5,004	5,382	4,171	4,831

6.7. Storage ELCC Tranches

In the resource adequacy analysis, we defined ten tranches to capture the storage ELCC saturation up to 5000 MW storage build, as shown in Figure L.14. The AURORA simulation shows a significant run-time requirement to dispatch storage with the ten tranches implemented in the model. Ten tranches are consolidated into three tranches to balance the complexity and accuracy of the storage saturation modeling, as shown in Table L.18.

Figure L.17: ELCC Saturation Curves for Storage Resources

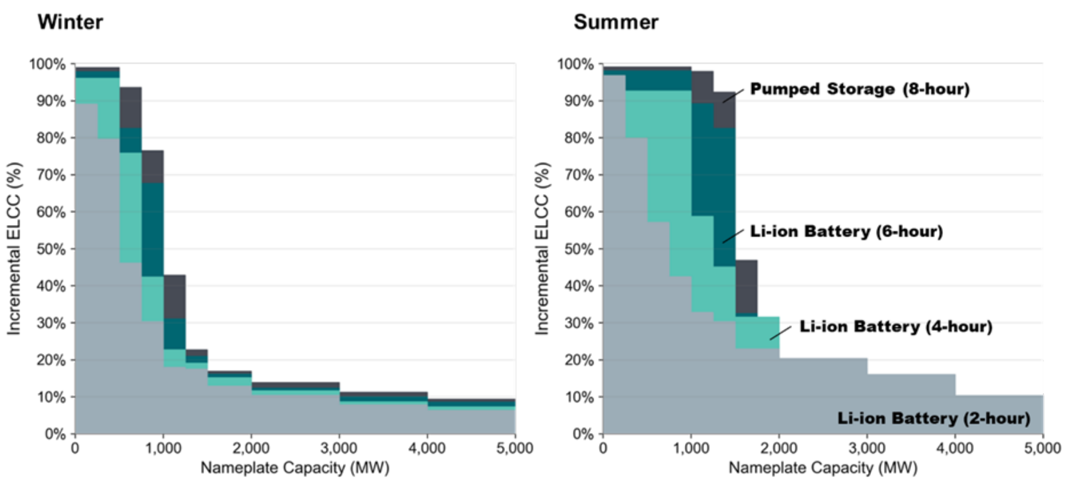
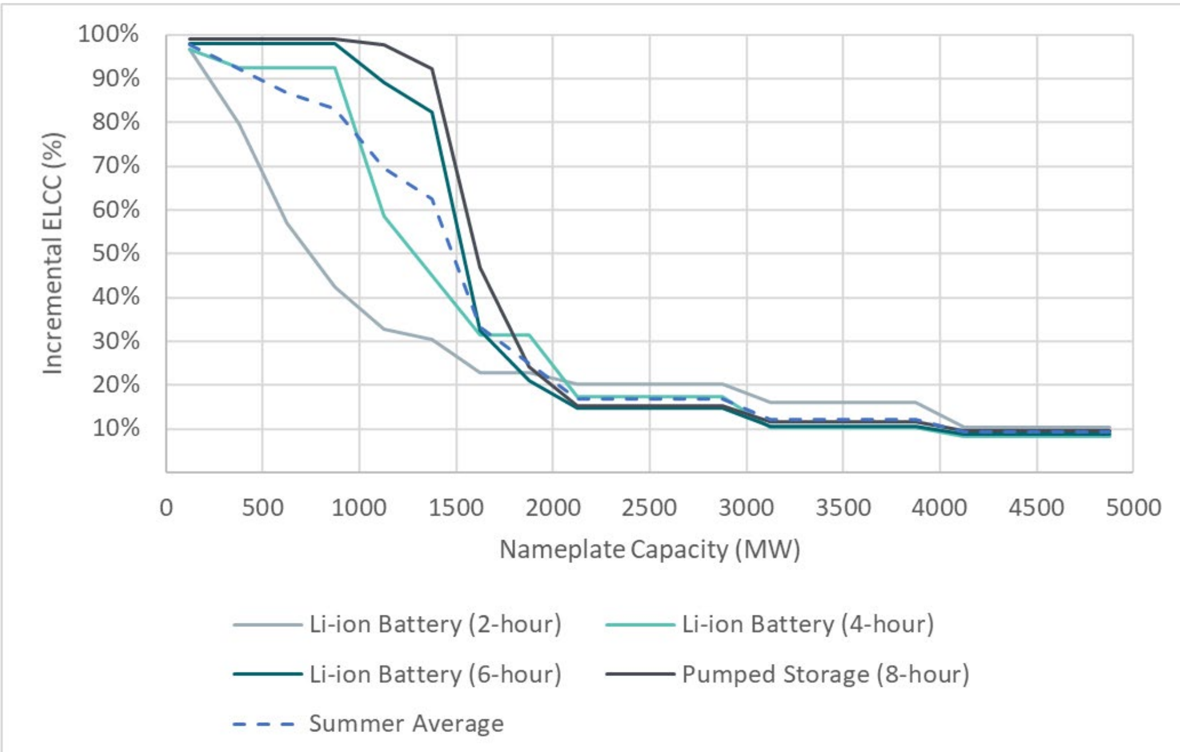


Table L.18: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 (%)	ELCC 2 (%)	ELCC 3 (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15
Cumulative Capacity by Tranche (MW)	Winter	1,000 MW	1,500 MW	5,000 MW
Cumulative Capacity by Tranche (MW)	Summer	1,000 MW	1,500 MW	5,000 MW

In the new tranches, 1000 MW and 1500 MW capacity are selected as points to break tranches to accommodate the saturation effects' trends and degree of accuracy. We used the summer curves to choose breakpoints since summer peak needs are more likely constrained.

Figure L.18: Storage ELCC Saturation Curves in Summer



6.8. Demand Response Tranches Consolidation

In the 2023 Electric Report, we estimate we could add up to 300 MW demand response to the portfolio. We defined two tranches in the resource adequacy analysis to catch the range of the potential builds, as shown in Figure L.19. The ELCCs in the second tranche do not reduce significantly from the ELCCs in the first tranches for winter and summer. The two tranches are consolidated into a single tranche to save the run-time of the AURORA simulation, as shown in Table L.19.

Figure L.19: ELCC Saturation Curves for Demand Response Resources

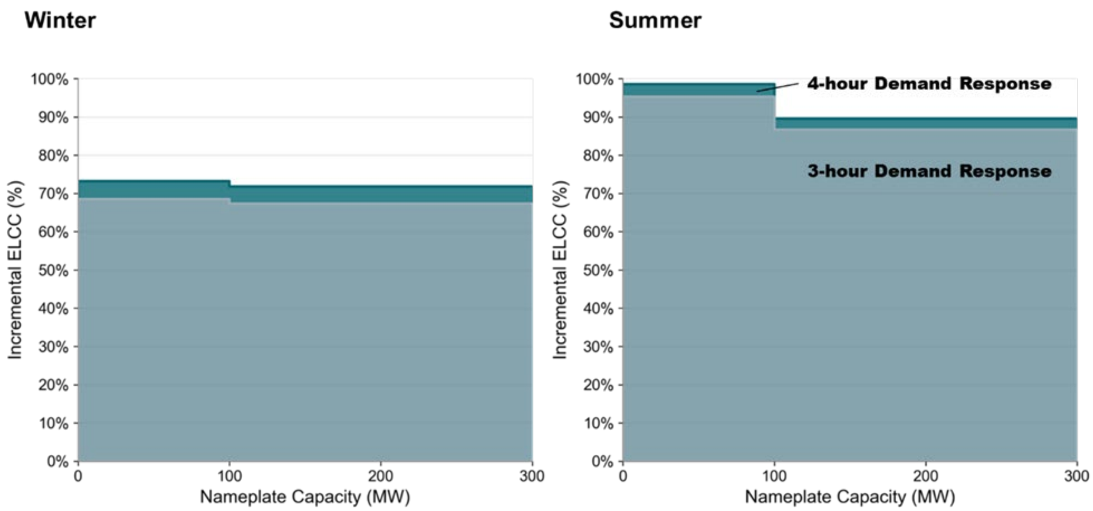


Table L.19: DR ELCC Tranches Consolidation — Incremental ELCC by Tranche in 2029

Resource	Season	1
Demand Response (3-hour)	Winter	68%
Demand Response (4-hour)	Winter	72%
Demand Response (3-hour)	Summer	90%
Demand Response (4-hour)	Summer	93%
Cumulative Demand Response	Winter	300 MW
Cumulative Demand Response	Summer	300 MW

6.9. Solar Tranches

The resource plan will build many renewable energy resources to meet the CETA needs. We calculated five-tranche ELCCs for wind and solar resources to capture the saturation effects in Figure L.10, Figure L.11, Figure L.12, and Figure L.13. The first three tranches cover the maximum builds for each wind resource group. Solar ELCCs go up to five tranches. We consolidated the five to three tranches to reconcile the run-time of the AURORA simulation and preserve the renewable resource ELCC saturation, as shown below in Table L.20.

Table L.20: Solar ELCC Tranches — Incremental ELCC by Tranche in 2029

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
DER Ground Mount Solar	Winter	4	3	1
DER Rooftop Solar	Winter	4	3	1
Idaho Solar	Winter	8	7	3
Washington East Solar	Winter	4	4	2
Washington West Solar	Winter	4	3	1
Wyoming East Solar	Winter	11	10	4

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
Wyoming West Solar	Winter	10	8	3
DER Ground Mount Solar	Summer	28	23	8
DER Rooftop Solar	Summer	28	23	8
Idaho Solar	Summer	38	30	10
Washington East Solar	Summer	55	44	15
Washington West Solar	Summer	53	42	14
Wyoming East Solar	Summer	29	23	8
Wyoming West Solar	Summer	28	22	7
Cumulative Resource	Winter	100 MW	500 MW	6,000 MW
Cumulative Resource	Summer	100 MW	500 MW	6,000 MW

6.10. Hybrid System ELCC Saturation

In the 2023 Electric Report, we modeled the following four hybrid systems as generic resources we could build:

- 100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 100 MW Washington Solar East Solar +50 MW 4-hour Li-ion Battery
- 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 200 MW Montana Wind Central + 100 MW 8-hour PHES

The hybrid ELCC and the sum of the standalone ELCC of each hybrid system are in Table L.21 and Table L.22.

Table L.21: Hybrid ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	51	87
Solar + Storage (Restricted Charging)	51	87
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

Table L.22: Sum of Standalone ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	52	103
Solar + Storage (Restricted Charging)	52	103
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

We calculated the saturation curves of each standalone renewable resource and storage resource in the RA study. We estimated the hybrid system ELCC saturation curves using the standalone resource ELCC saturations, as shown in Table L.23.

Table L.23: Hybrid Systems ELCC Tranches (MW) in 2029

Resource	Season	Tranche 1	Tranche 2	Tranche 3
Solar + Storage	Winter	40	11	5
Wind + Storage	Winter	49	15	5
Solar + Wind + Storage	Winter	51	16	5
Wind + PHSE Storage	Winter	142	33	12
Solar + Storage	Summer	61	28	6
Wind + Storage	Summer	51	28	7
Solar + Wind + Storage	Summer	77	36	7
Wind + PHSE Storage	Summer	141	95	15
Cumulative ELCC	Winter	1,000	1,500	5,000
Cumulative ELCC	Summer	1,000	1,500	5,000

7. Western Resource Adequacy Program Methodology

The Western Power Pool produced the methodology for the WRAP metrics.

➔ For details regarding their approach, please refer to this document on the WPP website.

7.1. Planning Reserve Margin

The planning reserve margin (PRM) measures the quantity of capacity needed above the median year peak load to meet the loss of load expectation (LOLE) standard, which serves as a simple and intuitive metric that can be utilized broadly in power system planning. The PRM is primarily determined on a system-wide basis.

We based the WRAP metrics on modeling completed with data from current Phase 3A participants. These metrics are only representative if the WRAP exists, has participants, and can share the load and resource diversity among participants as anticipated, if current participants move forward with the WRAP in the future, and if participants are subject to binding obligations to share diversity. Until this threshold is reached, participants will continue to assess circumstances and determine how to interpret modeling results and what reserve margins to keep.

We obtained the methodology for the PRM from the Western Power Pool in Section 2, Appendix C of the WRAP methodology document (2021-08-30_NWPP_RA_2B_Design_v4_final.pdf). We modeled the WRAP PRM footprint in two main subregions: Northwest (NW) and Desert Southwest / East (DSW/E).

The calculation for the allocation of the capacity requirement of the PRM follows:

$$Allocated\ capcity\ requirement = \left(\frac{Participant's\ P50\ Load}{\sum All\ Participant's\ P50\ Load}\right) \times regional\ capacity\ need$$

7.2. Qualifying Capacity Contributions

Table L.24, which can be found in the August 24, 2022, Resource Adequacy webinar, shows the methodology for resource capacity accreditation.

Table L.24: WRAP Qualifying Capacity Contributions

Resource Type	Accreditation Methodology
Wind and Solar Resources	Effective Load-Carrying Capability (ELCC) analysis
Run-of-river Hydroelectric	Average monthly output on capacity critical hours (CCHs)
Storage Hydroelectric	The WPP-developed hydroelectric model that considers the past 10 years of generation, potential energy storage, and current operational constraints
Thermal	Unforced capacity (UCAP) method
Short Term Storage	ELCC analysis (recent update — to be completed next model run)
Hybrid Resource	Sum-of-parts method where energy storage will use ELCC, and the generator will use the appropriate method as outlined
Customer-side Resources	Can register as a load modifier or as a capacity resource

7.3. WRAP Solar ELCC Zones

The WRAP footprint is comprised of two zones for solar resource ELCC modeling. Zone 1 contains the Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Zone 2 includes the Southern states in the West, such as California, Nevada, Utah, and Arizona. The allocation of ELCCs within each zone is based on the average monthly output of CCHs, which is anticipated to capture the time zone and geographic (East/West) diversity of resources. For solar ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. We can adjust the allocation of zonal ELCC to individual resources as the actual production data is accumulated.

Figure L.20 depicts the solar zones which can be found in the August 24, 2022, Resource Adequacy webinar.

Figure L.20: WRAP Area and Solar Zones

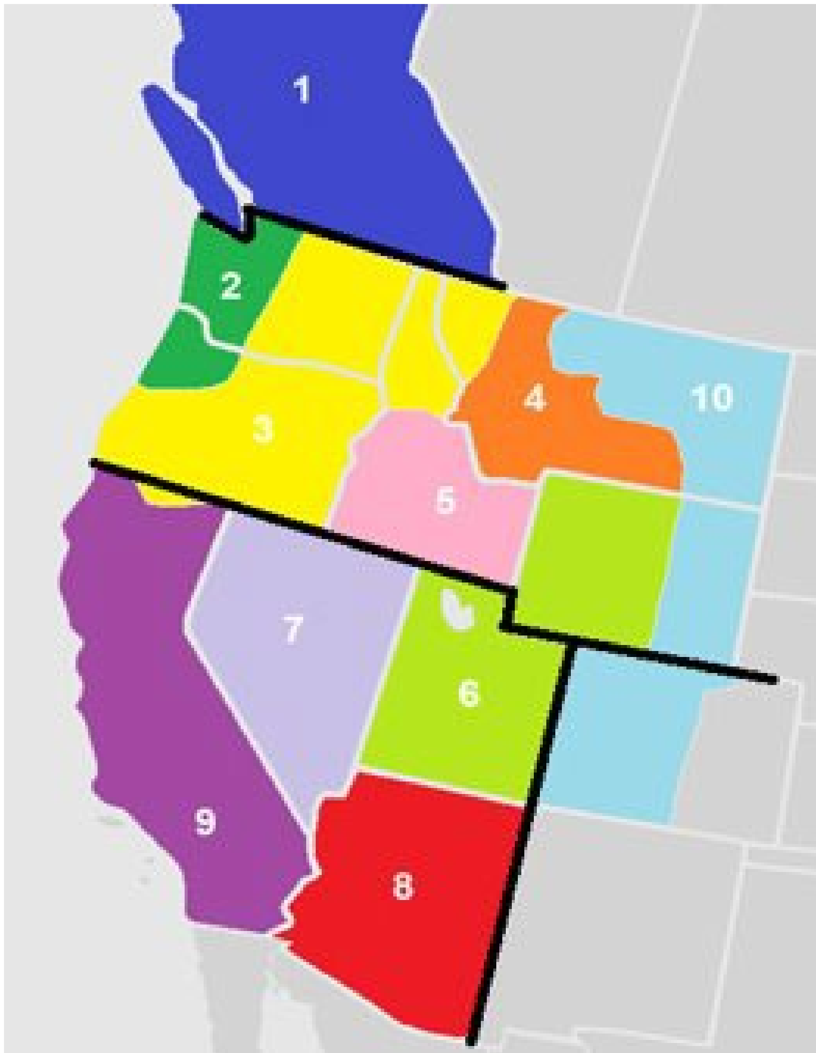


Table L.25: WRAP Solar ELCCs

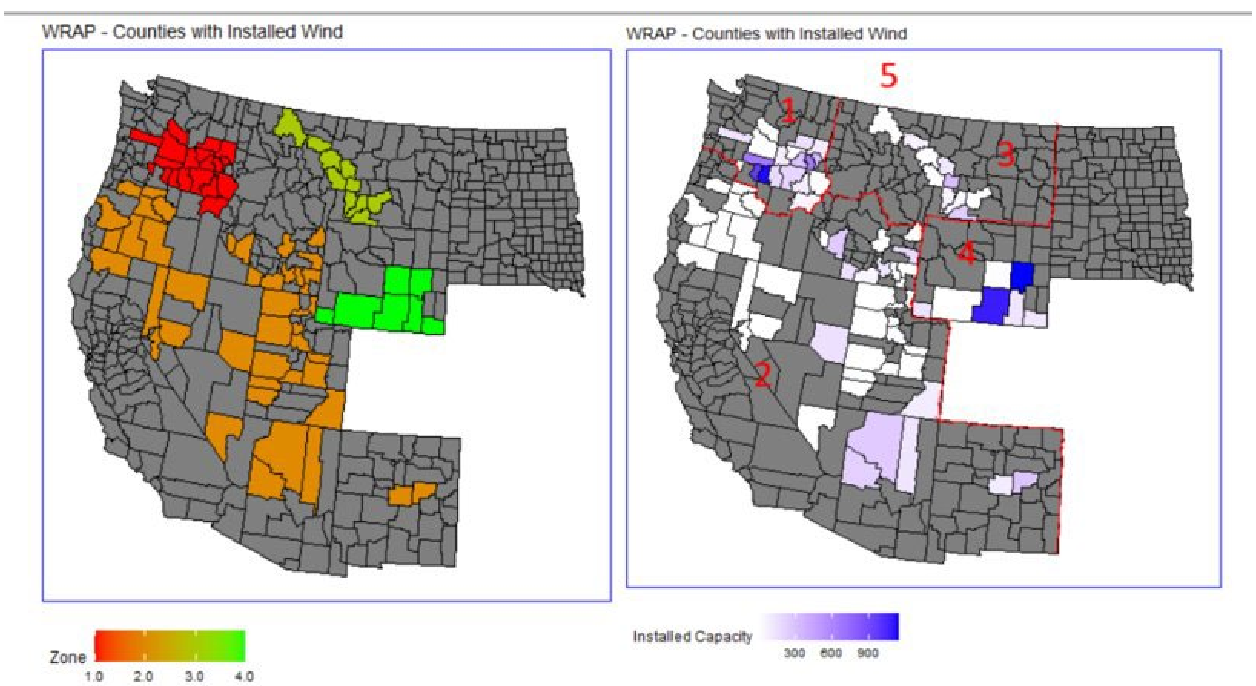
Zone	Nameplate (MW)	Winter 2023-2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (North)	2,138	2	3	3	4	5	23	30	24	13
2 (South)	9,024	3	5	7	7	5	16	24	23	11

7.4. WRAP Wind ELCC Zones

The WRAP footprint includes five wind ELCC zones. Zone 1 models the Columbia Gorge, spanning Southern Washington and Northern Oregon. Zone 2 comprises all other U.S. installed wind, including everything but the Columbia Gorge, Montana, and Wyoming. Zone 3 includes Montana, Zone 4 is Wyoming, and Zone 5 models British Columbia. For wind ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. The allocation of zonal ELCC to individual resources may be adjusted as the production data is accumulated.

Figure L.21 shows the WRAP counties with installed wind and their associated zone and capacity from the August 24, 2022, Resource Adequacy webinar.

Figure L.21: WRAP Counties with Installed Wind[10]



[10] https://www.westernpowerpool.org/private-media/documents/2021-12-21_RAPC_Minutes.pdf

Table L.26: WRAP Wind ELCCs

Zone	Nameplate (MW)	Winter 2023–2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (WA+)	5,734	10	9	8	11	13	19	22	18	13
2	2,400	32	30	28	32	34	18	18	16	16
3 (MT)	1,378	30	29	28	23	25	13	12	13	14
4 (WY)	2,429	36	32	30	27	31	15	16	14	14
5 (BC)	747	29	28	23	24	22	18	17	21	22