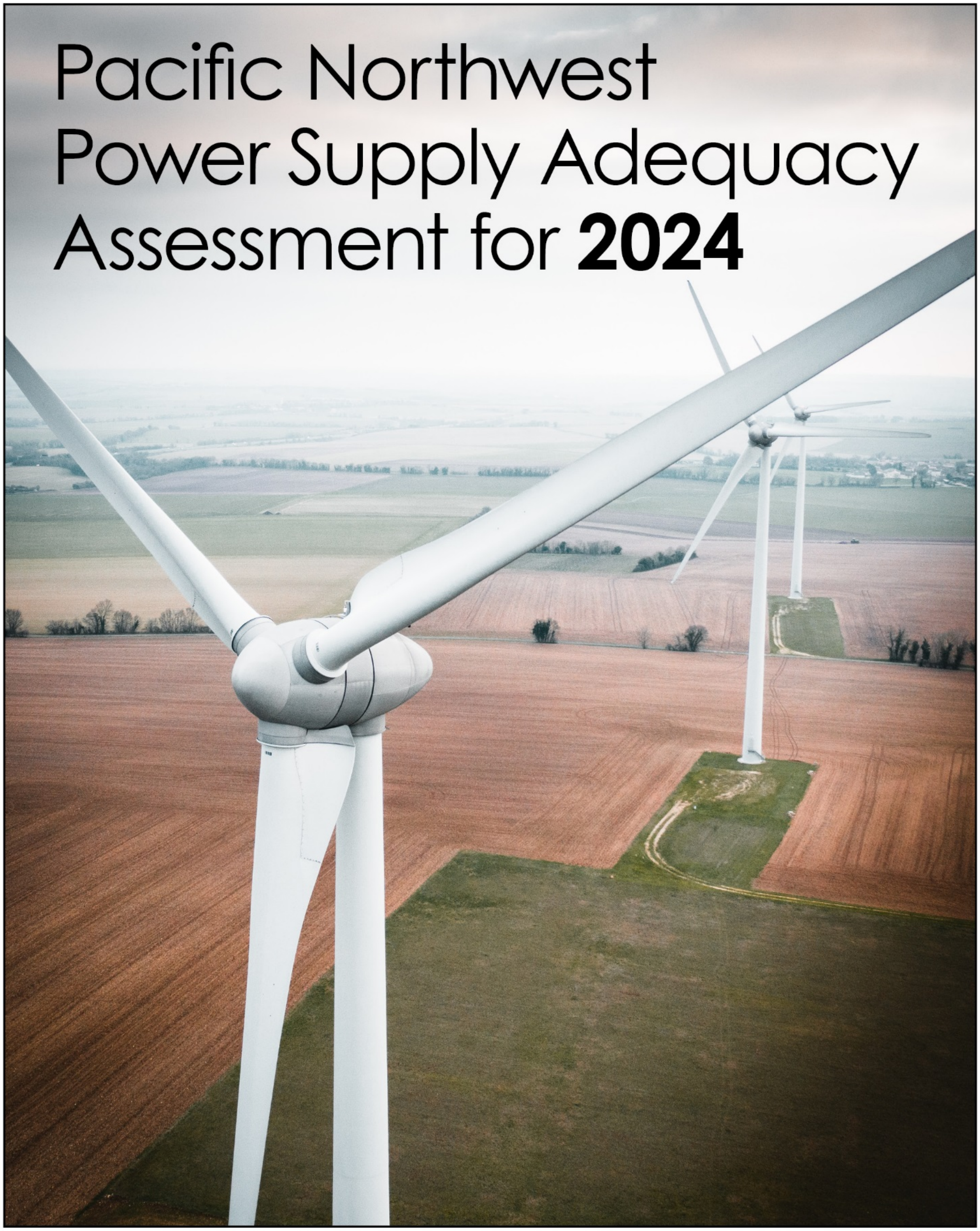
Pacific Northwest Power Supply Adequacy Assessment for **2024**



October 31, 2019
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Northwest **Power** and **Conservation** Council

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This document summarizes the Northwest Power and Conservation Council's assessment of the regional power supply's adequacy for the 2024 operating year (October 2023 through September 2024). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for adequacy and set its maximum threshold at 5 percent. For the power supply to be deemed adequate, the likelihood (LOLP) of a shortfall (not necessarily an outage) occurring anytime in the year being examined cannot exceed 5 percent.

The Council, with aid from the Resource Adequacy Advisory Committee (RAAC), updated its resource and load data, examined all appropriate operating assumptions and ran the Council's adequacy model (GENESYS) to produce the results shown in the charts and tables in this report. Other adequacy metrics that measure the size of potential shortages, how often they occur and how long they last are also reported because they provide valuable information to planners as they consider resource expansion strategies.

In 2018, Power Systems Research, Inc. was contracted to redevelop the GENESYS model to add more granularity to its simulation of the power supply. Since the redeveloped model is still being vetted, its preliminary results are not reported in this assessment. However, the new model will be used for future adequacy assessments and to aid in the development of the Council's 2021 power plan.

In addition, the Council has initiated a process to review its current adequacy standard. Council staff and RAAC members will be reviewing the viability of the current metric (LOLP) and threshold (5 percent). This review will consider similar efforts going on in other parts of the United States, namely the IEEE Resource Adequacy Working Group (RAWG), the North American Electric Reliability Corporation's (NERC) Probabilistic Assessment Working Group (PAWG) and the Northwest Power Pool's (NWPP) resource adequacy review. Once the redeveloped GENESYS model has been fully vetted, the Council will consider options for amending its adequacy standard.

EXECUTIVE SUMMARY

In 2011, the Northwest Power and Conservation Council adopted a resource adequacy standard to provide an early warning should resource development fail to keep pace with demand growth. The standard defines the regional power supply to be adequate when the likelihood of a shortfall or Loss-of-Load Probability (LOLP) is no more than 5 percent. Every year, the Council assesses resource adequacy five years into the future to give utilities time to acquire new resources, if needed.

By 2021, the Northwest power supply becomes inadequate, with an estimated LOLP of 7.5 percent, primarily due to the announced retirement of 1,619 megawatts of coal-fired generating capacity. Besides existing resources, the assessment only includes planned resources that are sited and licensed, and targeted future energy efficiency savings.

By 2024, with the planned retirement of an additional 127 megawatts of coal plant capacity, the LOLP grows to 8.2 percent. Load growth over the next five years is almost entirely met by targeted energy efficiency savings, with a net annual load growth of about 0.3 percent. Potential shortfall events in 2024 are more likely to occur during winter and are expected to last longer and have higher peak-hour shortfalls than summer events.

These results could change significantly if future load growth and/or market conditions change. For example, under a high load growth scenario (3 percent above medium) with a lower market supply (1,000 megawatts less), the 2024 LOLP grows to 21 percent. Under a low growth scenario (3 percent below medium) with a higher market supply (1,000 megawatts more), the LOLP drops to 2 percent. But the likelihood of a very low or very high load growth rate over the next five years is small.

By 2026, with another 804 megawatts of announced coal plant capacity retiring, the LOLP grows to 17 percent. And, with the planned retirement of an additional 1,060 megawatts of coal plant capacity by 2032, the region will be facing a very large resource gap to fill. However, these assessments do not include utilities' replacement plans.

The Council's next power plan is scheduled to be completed by 2021, giving the region time to develop an appropriate replacement strategy that will account for state-level legislation affecting future resource choices, climate change, and increasing renewable generation.

It should be emphasized that these results reflect the adequacy of the aggregate regional power supply. Individual utilities within the Pacific Northwest are facing a wide range of future resource needs and are preparing for those needs in their integrated resource plans.

Addendum

In October of 2019, PacifiCorp proposed moving up the retirement dates for several of its coal plants. The Jim Bridger 1 coal plant (530 megawatts), originally scheduled to be retired by 2028, is now under consideration to be retired by the end of 2023. The Jim Bridger 2 coal plant (530 megawatts), originally scheduled to be retired by 2032, is now under consideration to be retired by the end of 2028. Also, PacifiCorp is proposing divesting from the Colstrip 3 (518 megawatts) and Colstrip 4 (681 megawatts) coal plants by the end of 2027.

The earlier retirement of the Jim Bridger 1 coal plant increases the 2024 reference case LOLP from 8.2 percent to 12.8 percent and increases the 2026 LOLP from 17 percent to 26 percent. Between 2026 and 2028, the region could potentially lose an additional 1,729 megawatts of capacity if the Jim Bridger 2 and the Colstrip 3 and 4 coal plants are retired. The Council will keep abreast of any changes to resource availability or to regional demand and will continue to monitor the adequacy of the regional power supply during the development of its next power plan.

THE COUNCIL'S RESOURCE ADEQUACY STANDARD

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to “provide an early warning should resource development fail to keep pace with demand growth.” The standard defines an adequate power supply to be one in which the likelihood of a power supply shortfall is less than or equal to 5 percent.

The Council assesses adequacy using a stochastic analysis to compute the likelihood of a supply shortfall. It performs a chronological hourly simulation of the region's power supply over many different future combinations of stream flows, temperatures, wind and solar generation patterns and forced generator outages. Besides targeted energy efficiency savings, existing generating resources are included, along with sited and licensed plants that are expected to be operational in the study year. The simulation also assumes a fixed amount of out-of-region market supply and explicitly models the economic dispatch of in-region merchant resources.

If the supply is deemed inadequate, the Council estimates how much additional capacity is required to bring the likelihood of a power supply shortfall (commonly referred to as the loss-of-load probability or LOLP) back down to 5 percent. However, this analysis is not intended to provide a resource expansion strategy because it assesses only one of the Council's criteria for developing a power plan. The Council's mandate is to develop a resource strategy that provides an adequate, efficient, economic and reliable power supply. There is no guarantee that a power supply that satisfies the adequacy standard will also be the most economical or efficient. Thus, the adequacy standard should be thought of as simply an early warning to test for sufficient resource development. A comprehensive resource strategy for the region is provided in the Council's power plan.

Because the GENESYS model cannot possibly take into account all contingency actions that utilities have at their disposal to avert an actual loss of service, an LOLP greater than 5 percent should not be interpreted to mean that actual curtailments will occur. Rather, it means that the likelihood of utilities having to take extraordinary and generally costly measures to provide continuous service exceeds the Council's tolerance for such events. Some utility emergency actions are captured in the LOLP assessment through a post-processing program that simulates the use of what the Council has termed "standby resources."

Standby resources are demand-side actions and small generators that are not explicitly modeled in the adequacy analysis. They are mainly composed of demand response measures, load curtailment agreements, small thermal resources and pumped storage at Banks Lake.

Demand response measures are expected to be used to help lower peak-hour demand during extreme conditions (e.g. high summer temperatures or low winter temperatures). These resources primarily provide peaking capacity and have a very limited amount of energy (i.e. once their available energy is used up, they can no longer be dispatched). The effects of demand response measures that <u>have already been implemented in the past</u> are assumed to be reflected in the Council's load forecast. New demand response measures that have <u>no operating history</u> and are, therefore, not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions, which would be contractually available to utilities to help reduce peak hour load, and small generating resources may also provide some energy assistance. However, they are not intended to be used often. High usage of these resources is a good indicator that the underlying supply is inadequate. The energy and capacity capabilities of these non-modeled resources are aggregated along with the demand response measures mentioned above to define the total capability of standby resources. A post-processing program uses these capabilities along with the simulated curtailment record to calculate the resultant LOLP and other adequacy metrics for the year being examined.

Evolution of Adequacy Assessments

The Council recognizes that the power system of today is very different from that of 1980, when the Council was created by Congress. For example, significant increases in variable energy resources, such as solar and wind, have added a greater band of uncertainty surrounding system operation. This and other changes to the power supply have created the need to more precisely simulate hourly operations. Toward this end, the Council has redeveloped its adequacy model (GENESYS) to significantly improve hourly hydroelectric simulation, to add a better representation of unit commitment and balancing reserve allocation and to add other enhancements to more precisely mimic real-life operations. A beta version of the redeveloped GENESYS has been completed and is currently being vetting with the aid of regional stakeholders. However, because the new GENESYS has not yet been fully vetted, preliminary results using the new model are not presented in this report.

In addition, the Council is reviewing work done by the North American Reliability Corporation (NERC) to standardize metrics used to assess power supply adequacy.

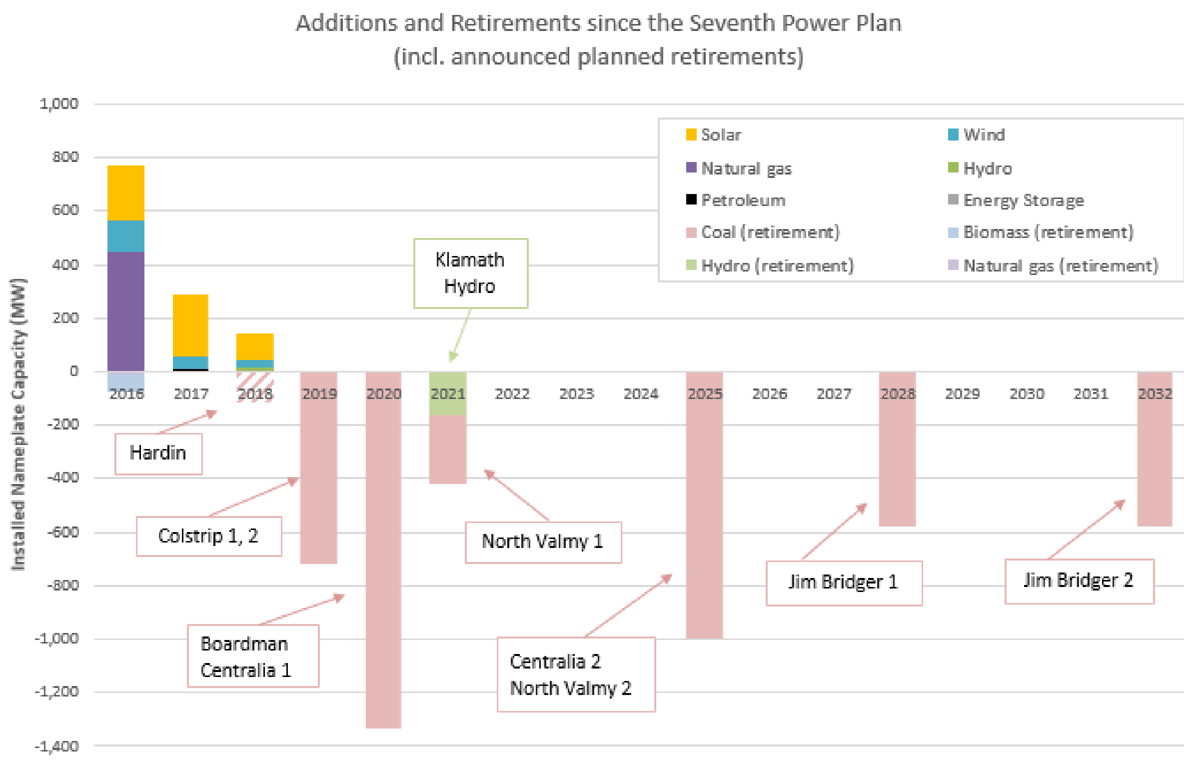
Council staff have participated in these efforts and are staying current with trends around the country and internationally. Once the redeveloped GENESYS model has been fully vetted, the Council will initiate a review its current adequacy standard and, if appropriate, amend the standard to provide a better measure of power supply adequacy.

2024 RESOURCE ADEQUACY ASSESSMENT

To ensure that utilities have enough time to acquire new resources, if needed, the Council assesses the region's power supply adequacy five years out – for this report the 2024 operating year. However, because of announced retirements of additional major generating resources, this assessment also examines adequacy for 2021 and for 2026. Figure 1 identifies the timing and amounts of announced resource additions and retirements through 2032.

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the announced retirements of Hardin, Colstrip 1 and 2, Boardman and Centralia 1 coal plants (1,619 MW of nameplate capacity), the system will no longer meet the Council's adequacy standard in 2021. The loss-of-load probability (LOLP) for that year is estimated to be 7.5 percent. By 2024, with the additional retirement of the North Valmy 1 coal plant (127 megawatts) the LOLP rises to 8.2 percent. By 2026, with an additional loss of 804 megawatts of coal-fired capacity (North Valmy 2 and Centralia 2), the LOLP grows to 17 percent.

Figure 1: Resource Additions and Retirements

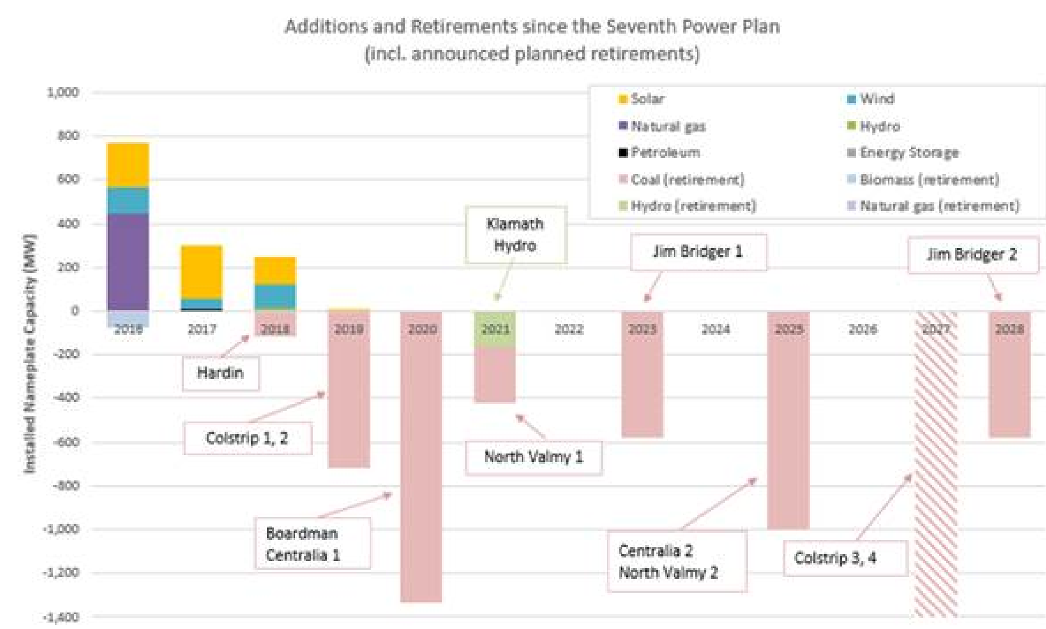


2024 Assessment Update

In October of 2019, PacifiCorp proposed moving up the retirement dates for several of its coal plants. The Jim Bridger 1 coal plant (530 megawatts), originally scheduled to be retired by 2028, is now under consideration to be retired by the end of 2023. The Jim Bridger 2 coal plant (530 megawatts), originally scheduled to be retired by 2032, is now under consideration to be retired by the end of 2028. Also, PacifiCorp is proposing divesting from the Colstrip 3 (518 megawatts) and Colstrip 4 (681 megawatts) coal plants by the end of 2027. These earlier retirement dates are illustrated in Figure 2.

The earlier retirement of the Jim Bridger 1 coal plant increases the 2024 reference case LOLP from 8.2 percent to 12.8 percent and increases the 2026 LOLP from 17 percent to 26 percent. Between 2026 and 2028, the region could lose an additional 1,729 megawatts of capacity with the potential retirements of the Jim Bridger 2 and the Colstrip 3 and 4 coal plants.

Figure 2: Updated Resource Retirements



Planned retirements based on agreements, announcements, IRPs; subject to change

*Colstrip 3, 4 should be considered **very tentative**

Hardin Generating Station was sold to an out of region cryptocurrency company, therefore no longer "counts" towards the region

Regardless of the analytical tool used to assess power supply adequacy, it is safe to say that the region will be facing a huge resource gap over the next decade. Between now and 2028, announced coal plant retirements add up to as much as 4,800 megawatts of generating capacity (see Figure 2) – nearly enough capacity to serve five cities the size of Seattle. In addition, the region's winter peak-hour load is expected to increase by about 1,000 megawatts over the same period (0.3 percent per year after accounting for expected energy efficiency savings). However, even though these numbers are daunting, it should be noted that the adequacy assessment does not include planned utility resources (unless they are sited and licensed) – and utilities are currently developing their integrated resource plans. Also, the power supply is not currently on the cusp of being inadequate – it could lose about 800 megawatts of dispatchable capacity before it crosses the 5 percent LOLP threshold. However, with nearly all western states passing clean-air and/or renewable portfolio standard legislation, choices for future replacement resources are becoming more limited. These are the challenges facing the Council as it works to develop a cost-effective and robust resource strategy for the 2021 power plan.

SENSITIVITY ANALYSIS

Given the late announcement and remaining uncertainty surrounding some of the proposed retirement dates in Figure 2, the analysis and results presented in this adequacy assessment are based on the original retirement dates shown in Figure 1.

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability in the out-of-region market supply.[1] Long-term load uncertainty for this analysis covers a 3-percent range around the mean. The out-of-region market is limited to only include California surplus generation. Thus, variation in the market supply is influenced only by future resource development (and retirements) in California and by the ability to transfer surplus energy from California into the Northwest. For the sensitivity analysis, the range of market availability went from a low of 1,500 megawatts to a high of 3,500 megawatts from October through March.[2]

Table 1 summarizes the results of market variation and load growth uncertainty on the LOLP values for 2024. In the extreme case, with high load growth and low import availability, the loss of load probability is over 21 percent. At the other extreme, with low load growth and higher import availability, the loss of load probability drops to about 2 percent. The cells in Table 1 are color coded to indicate the power supply's adequacy, with red cells indicating an inadequate supply (LOLP values greater than 5 percent) and green cells indicating that the power supply meets the Council's standard. It should be noted that the likelihood of futures with high or low load growth is much lower than the expected growth, in fact, the low and high loads used for this sensitivity analysis fall into the 15th and 85th probability percentiles – meaning that there is a 15 percent chance that loads in 2024 will be equal to or lower than then low case and there is a 15 percent chance that the loads will be equal to or higher than the high case.

[1] Another potential random variable not currently modeled is the availability of transmission (outages and maintenance).

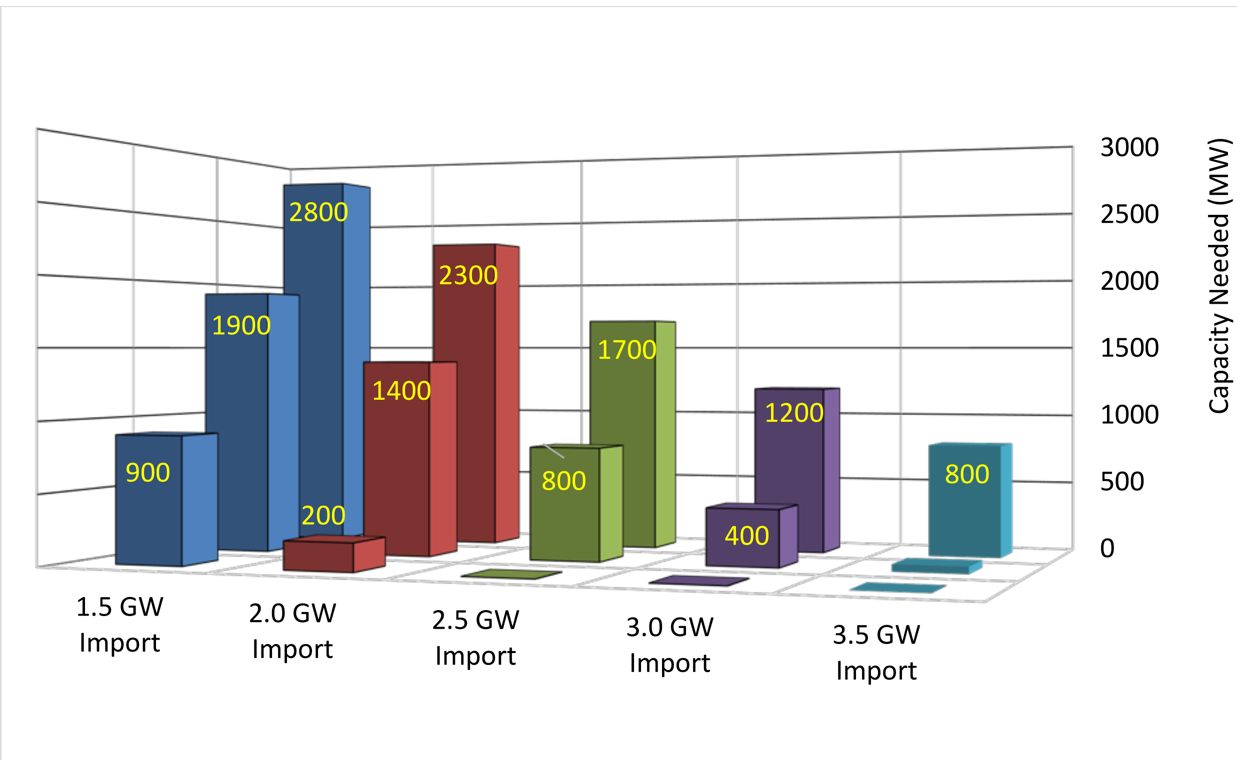
[2] The Council also modeled a separate out-of-region market, namely a purchase-ahead market, which is available all year but allows imports only during non-peak hours and only if a shortfall is expected in the following day or week.

Table 1: 2024 Loss of Load Probability (LOLP in %)

Import (MW)	1500	2000	2500	3000	3500
High Load (3% higher)	21.1	18.0	16.0	14.4	12.0
Medium Load	12.5	10.2	8.2	6.9	5.2
Low Load (3% lower)	7.0	5.2	4.0	3.1	2.0

Figure 3 shows the estimated amount of additional capacity[3] needed to maintain adequacy for each sensitivity case scenario (i.e. to get the LOLP down to the Council's 5 percent standard). In the extreme case, the region would need to acquire about 2,800 megawatts of capacity to maintain an adequate supply. At the other extreme, with low load growth and higher import availability, no additional capacity is required for adequacy needs. It should be noted that the actual amount of new capacity needed to maintain adequacy is highly sensitive to acquired resource type.

Figure 3: 2024 Estimated Capacity Needed to Maintain Adequacy (MW)



[3] Additional capacity needed to maintain adequacy is estimated using combustion turbines as the surrogate acquisition resources.

MONTHLY ANALYSIS

As discovered during the development of the Council's Seventh Power Plan, it is imperative to assess monthly adequacy values in order to better inform resource planners in the Northwest. This is important because some resources such as demand response and certain energy efficiency measures are only seasonally available (e.g. in winter or in summer only). In order to develop the most cost-effective and robust resource strategy, the seasonality of future resource needs must be identified.

Figure 4 below highlights the monthly LOLP values for the 2024 operating year,[4] which indicate that the regional power supply is still mostly a winter needy system. It should be noted that this analysis assumed no out-of-region spot market availability from April through September, 1,250 megawatts in October and 2,500 megawatts from November through March.

But this pattern of seasonal resource needs is expected to change. Future load growth forecasts (e.g. with increasing air conditioning penetration rates), in combination with lower and more constrained hydroelectric summer generation, project futures with greater and greater summer needs. This trend is exacerbated when forecasted changes in future climate are considered. Under all climate change scenarios, regional power needs are expected to lessen in winter (with lower loads due to higher forecasted temperatures and higher hydroelectric generation due to higher expected river flows). On the other hand, power needs are expected to grow in summer (with higher loads due to higher forecasted temperatures and lower hydroelectric generation with expected lower river flows).

Figure 5 shows the seasonality of shortfall events, with the bulk of events (73 percent) occurring during winter (November through February) and the remainder during summer (July through September). The seasonal pattern of shortfall events in Figure 5 is very similar to the seasonal pattern for monthly LOLP values shown in Figure 4. However, the patterns in these two figures are not an exact match because of the way that monthly LOLP is calculated. A month with multiple events counts the same as a month with a single event for the LOLP calculation, whereas the pattern in Figure 5 counts every event for every month.

[4] It should be noted that the sum of monthly LOLP values will always be equal to or greater than the annual LOLP value because of the way in which the Council has defined its standard. The annual LOLP counts simulations with at least one curtailment event regardless of when it occurs. A simulation with multiple events in the same year, say one in January and one in August, would be counted the same as a simulation with only a January event or only an August event.

Figure 4: 2024 LOLP by Month

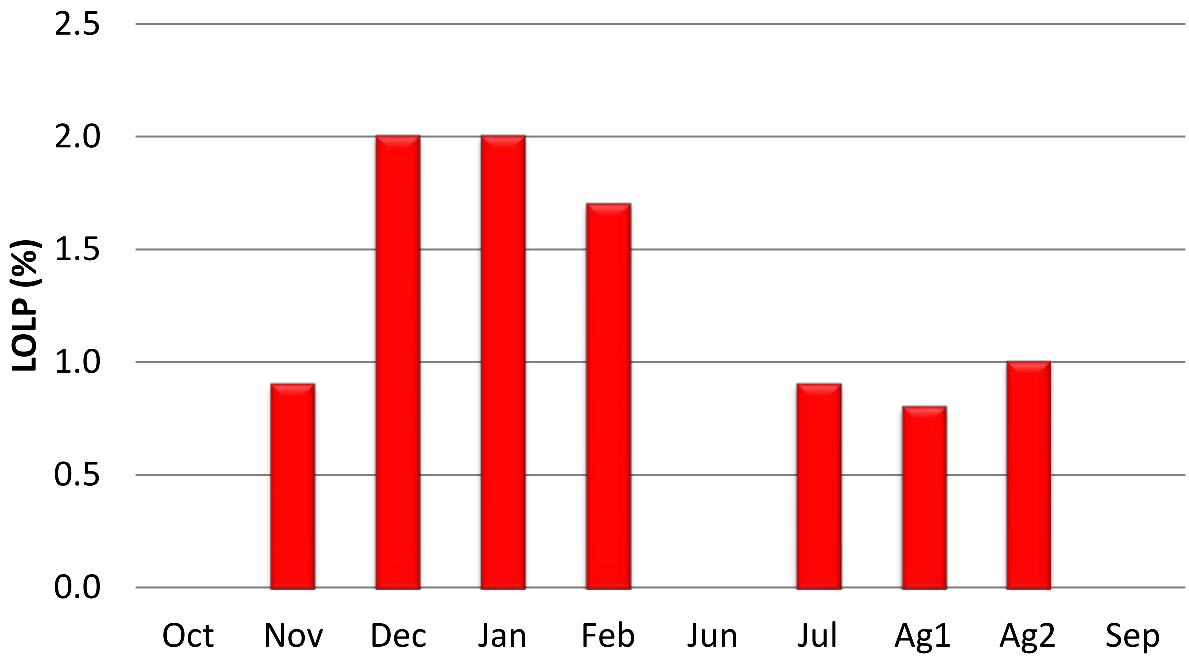
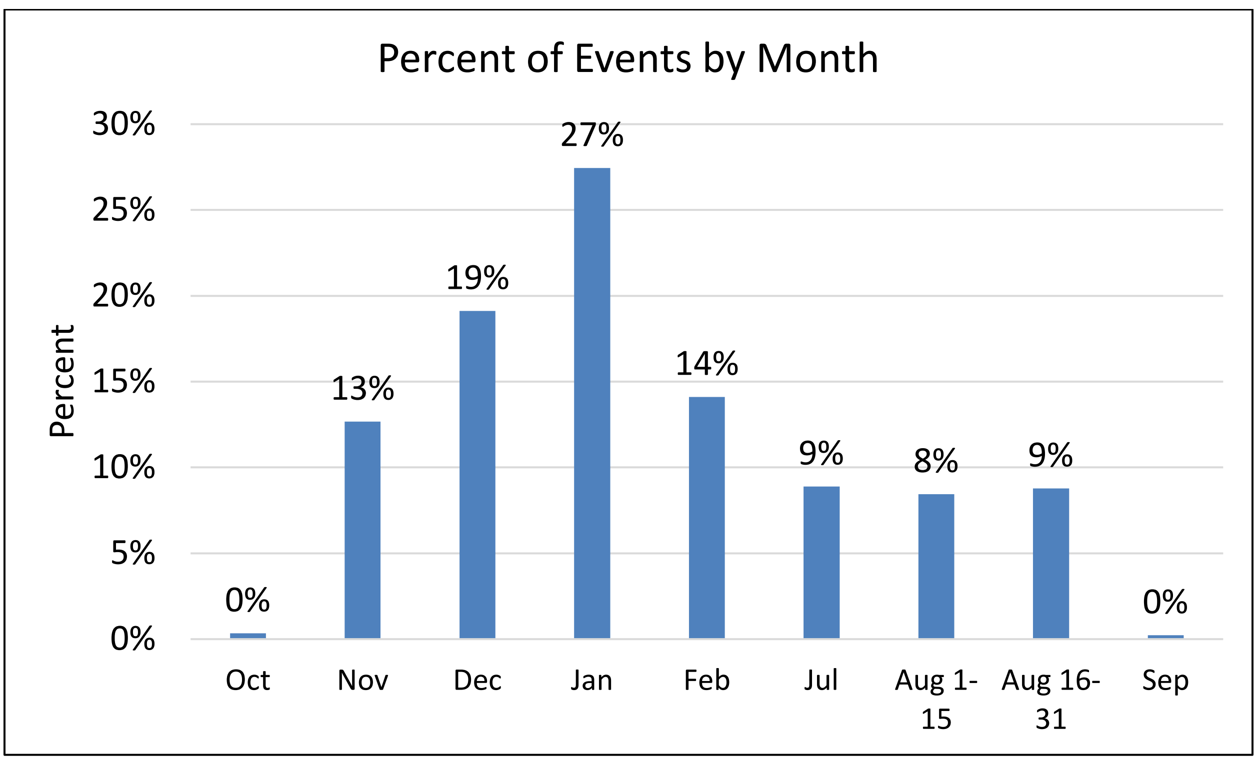


Figure 5: Percent of Events per Month



All shortfall events are not the same. Figure 6 shows average event duration by month. As evident in that figure, winter events tend to last much longer than summer events, with an average duration of about 23 hours (not counting October). The average summer event duration is about 6 hours (not counting September). One reason for the longer duration events in winter is that winter shortfalls tend to be driven by longer periods of extremely cold temperatures. Summer heat waves generally do not last as long as severe arctic winter cold snaps. Another reason for the longer duration winter events is that (at least for the time being) peak winter loads are much higher than summer peak loads. As presented later, the average winter peak-hour load for 2024 is about 34,500 megawatts compared to 28,800 megawatts for the average summer peak-hour load.

Figure 6: Average Event Duration by Month

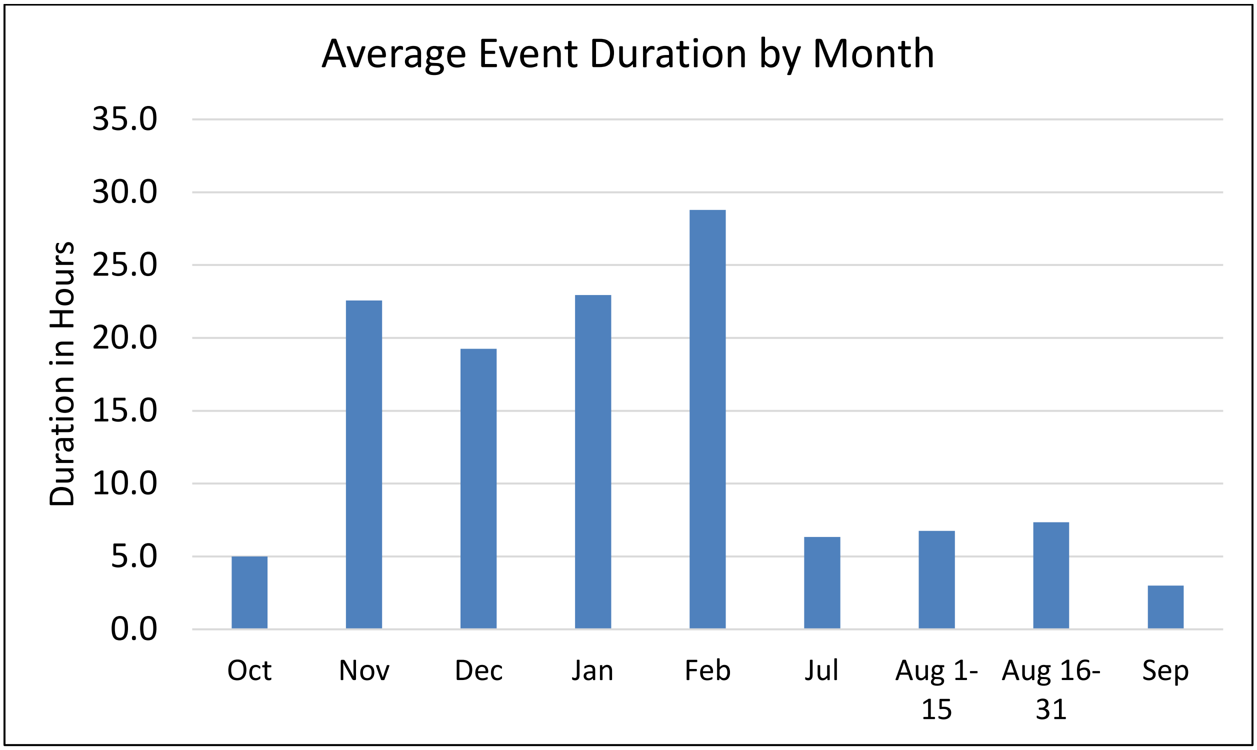


Figure 7 shows the average event magnitude (total megawatt-hours of unserved energy) by month. This figure shows a very sharp distinction between winter and summer events. The average winter event magnitude is about 43,300 megawatt-hours compared to the 3,300 megawatt-hour average summer event magnitude. One reason for this is that winter events last longer but also, as illustrated in Figure 8, winter shortfalls miss peak-hour loads by a wider margin. The average winter peak-hour shortfall is about 1,750 megawatt-hours compared to about 500 megawatt-hours for the average summer peak-hour shortfall.

Figure 7: Average Event Magnitude by Month

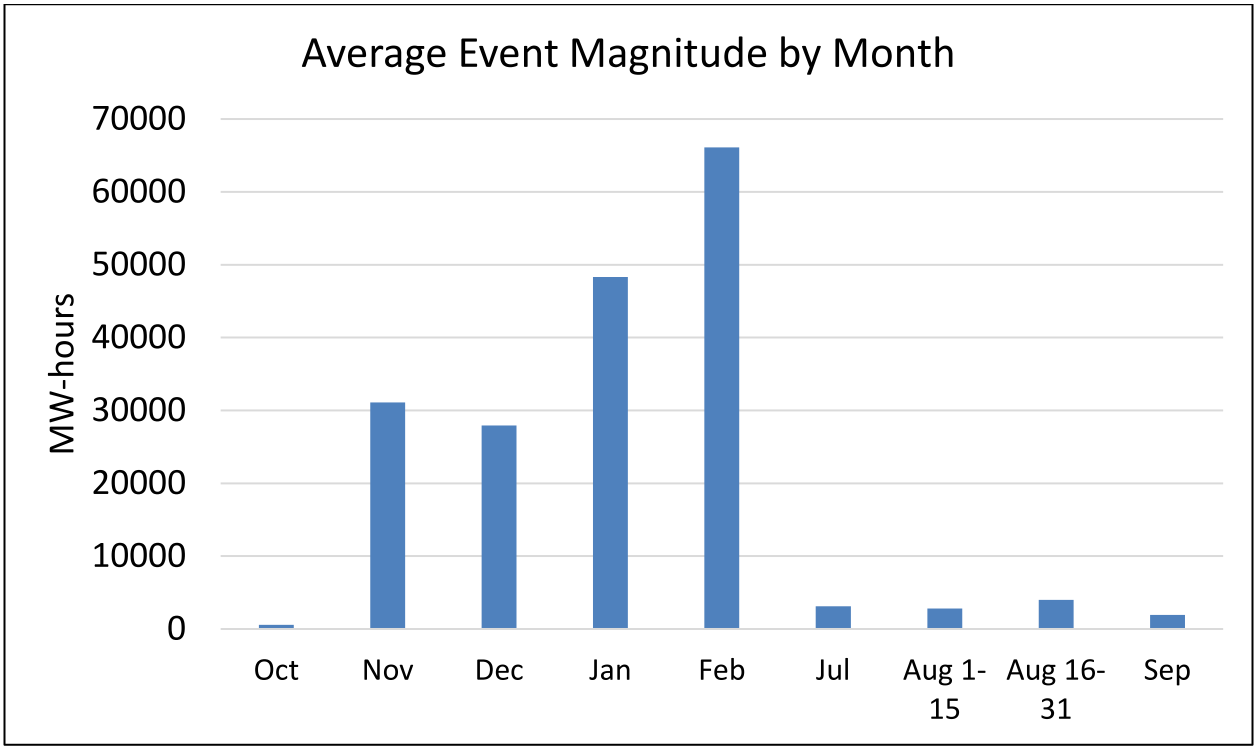
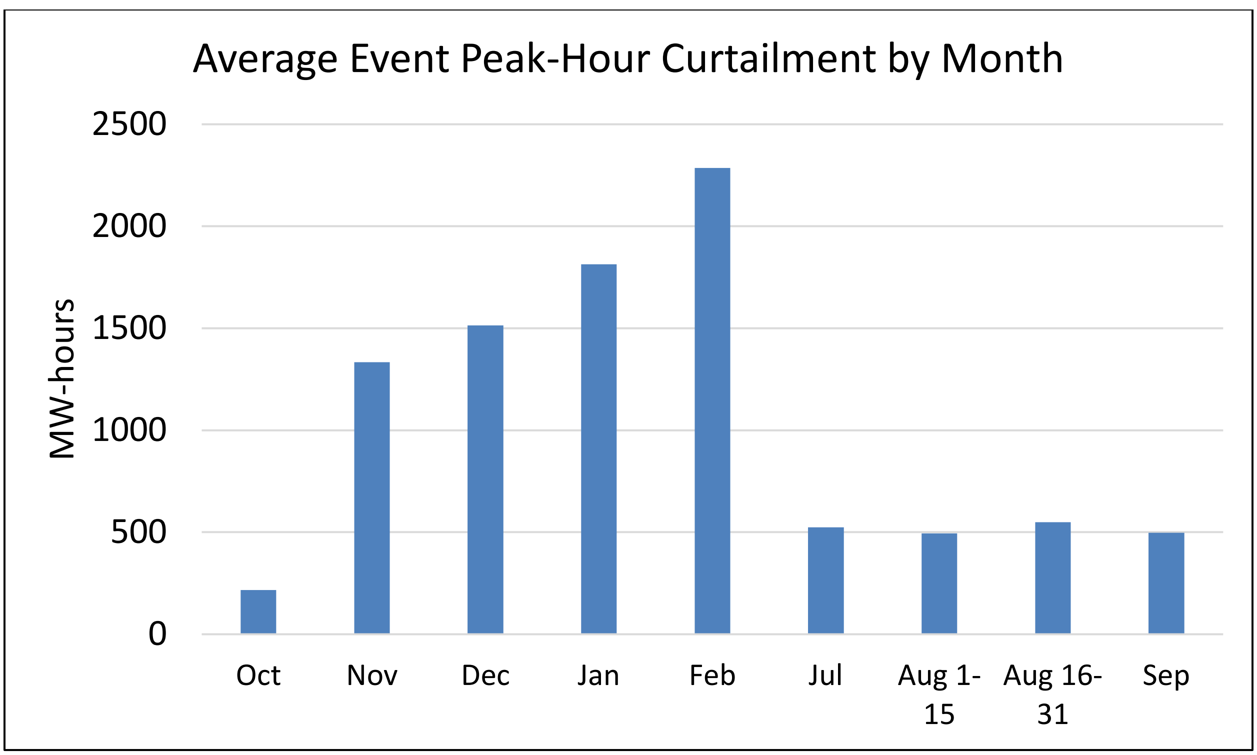


Figure 8: Average Peak-Hour Curtailment per Month



CURTAILMENT STATISTICS

Curtailment statistics can often provide valuable insight into the behavior of the power system. Table 2 below summarizes several key statistics from the simulated curtailment record for 2024. All adequacy studies were run with 5,520 simulations (which include all combinations of the historical 80-year water record with the historical hourly 69-year temperature record). The red-colored row in Table 2 highlights the Council's current measure for adequacy, namely a 5-percent maximum for annual LOLP. The green-colored rows highlight metrics currently proposed by the North American Reliability Corporation (NERC) for reporting. However, NERC does not specify a threshold for its proposed metrics (i.e. an adequacy standard). A more detailed description of the proposed NERC metrics is provided later in this report.

Out of the 5,520 simulated years, 425 years had at least one shortfall event, thus the annual LOLP is 452 divided by 5,520 or 8.2 percent. Based on this statistic, the region is expected to face a shortfall year once every 12 years or so. There was a total of 900 separate shortfall events. A shortfall event is a set of contiguous hours when resources fail to serve all loads. There are twice as many shortfall events as there are shortfall years, which means that, on average, when the region faces a shortfall year, it will typically experience two separate shortfall events during that year. This is not unreasonable because, as will be shown later, conditions that typically lead to shortfalls are low river runoff and/or extreme temperature events. Low river runoff conditions tend to lead to multiple periods of shortfall, especially when paired with extremely low or high temperatures (e.g. cold snaps or heat waves).

Table 2: 2024 Curtailment Statistics

Statistic	Value	Units
Number of simulations	5,520	Number
Simulations with a curtailment	452	Number
Loss of load probability (LOLP)	8.2	Percent
Number of curtailment events	900	Number
Loss of load events (LOLEV)	0.16	Events/year
Average time between shortfall years	12	years
Average event peak-hour curtailment	1,400	MW
Average event magnitude	32,700	MW-hours
Average event duration	19	hours
Conditional value at risk (CVaR) peak	2,623	MW
Conditional value at risk (CVaR) energy	104,470	MW-hours
Expected un-served energy (EUE)	5,338	MW-hours
Expected curtailed hours per year (LOLH)	3.0	Hours

The average duration for a shortfall event is 19 hours, which is a little longer than the 16 WECC-defined on-peak hours of the day. In fact, as will be shown later, most shortfall events last exactly 16 hours. This is because the regional hydroelectric system is operated, as much as is allowed under non-power constraints, to even out projected shorter-term shortfalls that might occur over the 2 to 6-hour period of highest load. It is much easier to resolve a 16-hour relatively small resource shortfall than a 2 to 6-hour extremely large resource gap. The average peak-hour shortfall is about 1,400 megawatts, which for perspective is a little less than Seattle City Light's average winter peak-hour load (about 1,800 megawatts).

An interesting result from Table 2 is the value for the Loss-of-Load-Events (LOLEV) metric. This metric measures the frequency of shortfall events and is the most relevant metric to compare to the historic 1-day-in-10-year loss-of-load-expectation "standard" that has been utilized for over 70 years. If the "1-in-10" refers to 1-event-in-10 years, then the implied adequacy threshold for LOLEV should be no more than 0.1 events/year. Not surprisingly, the 2024 reference case LOLEV of 0.16 events/year exceeds the implied 0.1 events/per year standard. With an LOLEV of 0.16, the region is expected to face, on average, a shortfall event once every 6 years. But, by adding enough capacity to bring the 2024 LOLP down to the 5 percent level, the LOLEV drops to 0.1 events/year. This means that when the regional power supply meets the 5 percent LOLP standard, its corresponding LOLEV value is consistent with a 1-event-in-10-year threshold. <u>However, statistics can often lead to misleading results</u>. A more accurate interpretation of these statistics is that when the LOLP is exactly 5 percent, on average, the region is expected to face a shortfall year once every 20 years and will expect to see 2 shortfall events during that year.

Figure 9 below shows the likelihood of having multiple shortfall events in a single year. Of the 452 simulations (out of 5,520) that had at least one shortfall, a little more than half only had one event and a quarter of them had two events. Simulations with more events are rare – only six percent had five or more events. Years with such a high number of shortfall events are typically those with very low runoff volume and extremely cold or hot temperature days. For example, simulating the 2024 power supply under 1929 runoff conditions (one of the driest years on record) and 1950 winter temperatures (coldest on record) yielded eight shortfall events during January and February.

Figure 10 displays the event duration histogram, which shows the number of events per specified duration. The x-axis represents event duration and the y-axis shows the number of events with that duration. What stands out is that the most common event duration is 16 hours. This is not unexpected because, by design, the hydroelectric system is operated (i.e. filled or drafted), whenever possible, to spread the anticipated unserved energy across all 16 peak hours of the day. This produces a relatively flat amount of hourly unserved energy, which is easier to rectify than a shorter duration, higher magnitude and non-uniform shortfall.

Figure 9: Probability of Multiple Events per Year

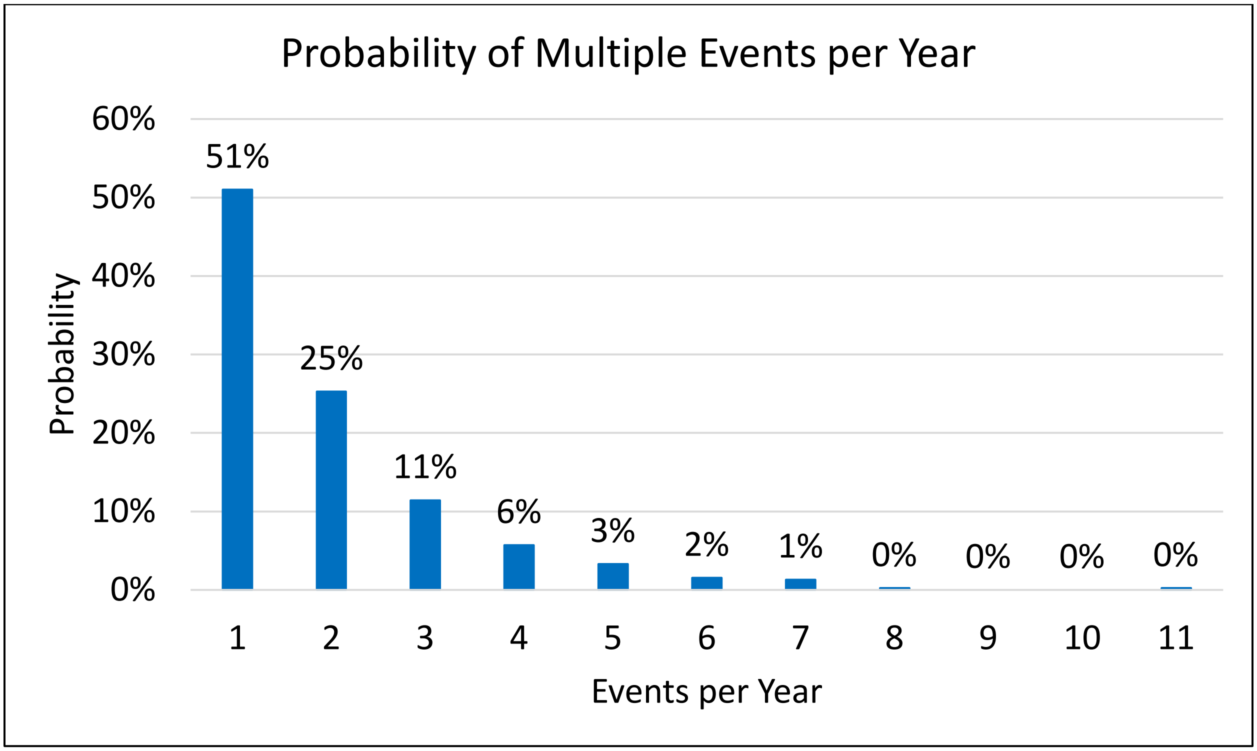
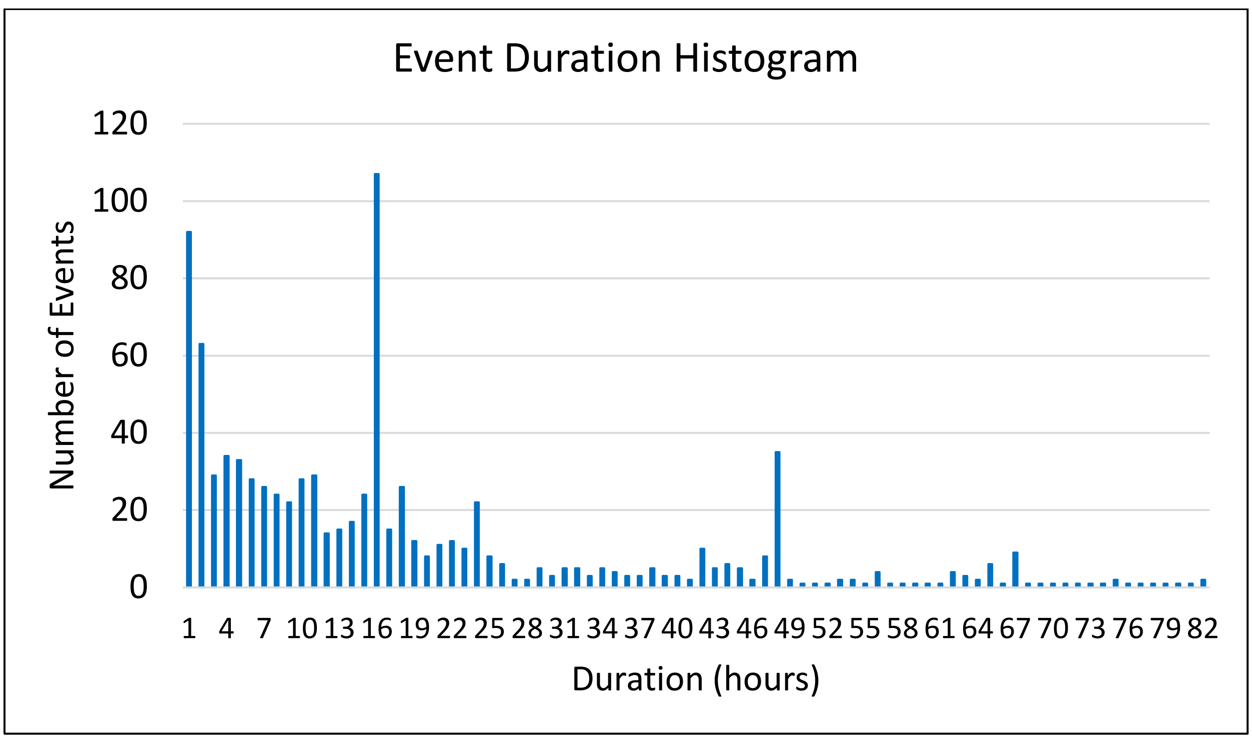
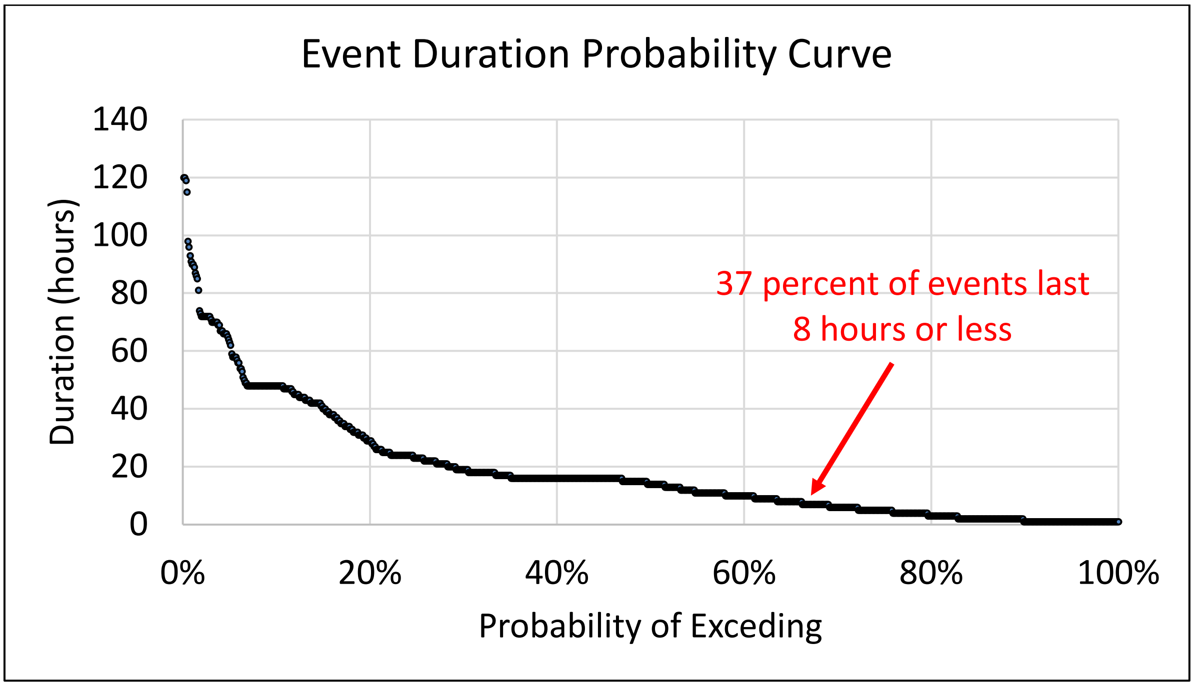


Figure 10: Event Duration Histogram



From Figure11 below, which shows the event duration exceedance probability curve, the fact that about 37 percent of events have a duration less than 8 hours bodes well for demand response and other short-term standby measures. For example, the LOLP of the 2024 power supply prior to applying the effects of standby resources is 9.3 percent but accounting for standby resources (460 megawatts of capacity and 41,750 megawatt-hours of energy) drops the LOLP to 8.2 percent. Thus, although demand response and other short-term measures can only be applied over several hours, they are nonetheless very effective in eliminating short-duration events (e.g. picking the low hanging fruit, in colloquial terms) and lowering the overall LOLP. What is also obvious in Figure 11 is that some events can last up to 120 hours or nearly an entire week. However, these very long duration events are extremely rare – the 120-hour event shown to the left of the chart below has a 1 in 5,520 chance of occurring.

Figure 11: Event Duration Probability Curve



Besides looking at curtailment statistics, it may also be of great value to examine the conditions under which curtailments occur. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis is provided on the Council's Resource Adequacy website. The four random variables are monthly river flow volume at the Dalles Dam, daily average regional temperature, wind and solar generation and thermal resource forced outages. Some attempts have been made to correlate shortfall events with the occurrence of certain temperatures, water conditions, wind generation patterns and forced outages, but unfortunately without much success. This is an area of study that is being explored further and may produce better results once the GENESYS model has been enhanced to model plant-specific hourly hydroelectric operations.

Figure 12 below shows the number of shortfall events by historic water year and Figure 13 shows the number of events by historic temperature year. From Figure 12, regardless of temperature, the 2003 and 1937 historic river flows provide the worst conditions for adequacy and produce over 12 percent of all simulated shortfall events. In fact, the lowest 10 historic runoff years (as shown in Figure 12) produce nearly 50 percent of all shortfall events (425 out of 900). From Figure 13, regardless of river flows, 1950 and 1956 historic temperatures provide the worst conditions for adequacy and produce 29 percent of all shortfall events (260 out of 900).

Figure 12: Number of Events by Water Year

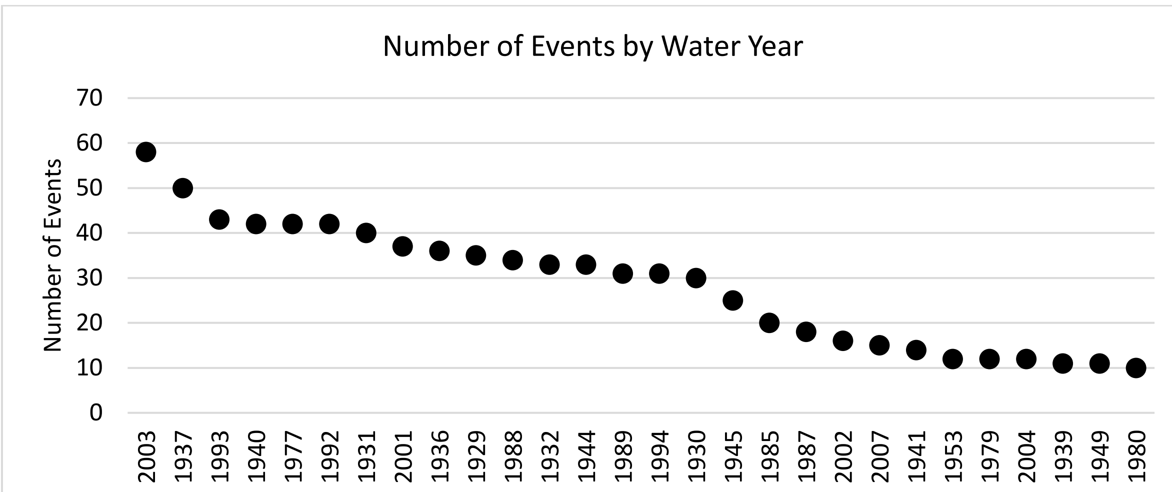
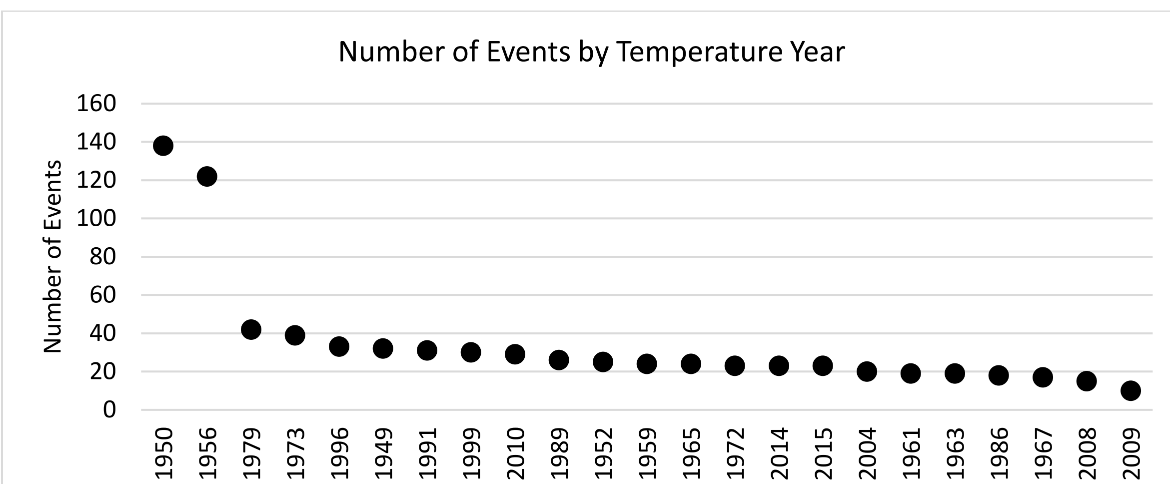


Figure 13: Number of Events by Temperature Year



Finally, Table 3 shows combinations of water and temperature years with the worst conditions for adequacy. From this table, the 1977 runoff year combined with 1950 temperatures is the worst combination, generating 11 shortfall evens in that simulation. As mentioned earlier, the 1929 runoff year paired with 1950 temperatures generated 8 events. In fact, it is clear from the table below that 1950 temperatures are by far the most relevant factor contributing to multiple event simulations, being a part of 10 of the top 15 cases. And, while low wind and solar generation and thermal forces outages can add to shortfalls, they rarely, if ever, are the sole cause. In other words, having an extremely high number of thermal outages can easily be overcome if river flow volumes are near average or above.

Table 3: Water Year/Temperature Year Combinations with the most Shortfalls

Water Year	Temp Year	Number of Events
1977	1950	11
1929	1950	8
1931	1950	7
1937	1973	7
1988	1950	7
1993	1950	7
1994	1950	7
2002	1950	7
1936	1950	6
1937	1950	6
1993	1949	6
2001	1996	6
2003	1950	6
2006	1956	6
2007	1956	6

OTHER ADEQUACY METRICS

Adequacy metrics help planners better understand the magnitude, frequency and duration of potential future power supply shortfalls. These metrics provide valuable information to planners as they consider resource expansion strategies. Table 4 below provides the definitions for some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 5 shows the value of these metrics for the region for 2024 and 2026. Finally, Table 6 shows the monthly values for these metrics for the 2024 reference case.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It required each of its sub-regions in the United States to report three adequacy measures; 1) expected loss-of-load hours, 2) expected unserved energy and 3) normalized expected unserved energy (EUE divided by load). This effort is a good first step toward standardizing how adequacy is measured across the United States. However, NERC is not tasked with setting nationwide thresholds for these metrics (i.e. setting a national adequacy standard). In fact, it may be impossible to do so because power supplies vary drastically across regions.

Table 4: Adequacy Metric Definitions

Metric	Description
LOLP (%)	Loss of load probability = number of games with a problem divided by the total number of games
CVaR – Energy (GW-hours)	Conditional value at risk, energy = average annual curtailment for 5% worst games
CVaR – Peak (MW)	Conditional value at risk, peak = average single-hour curtailment for worst 5% of games
EUE (MW-hours)	Expected unserved energy = total curtailment divided by the total number of games
Normalized EUE (ppm)	Normalized expected unserved energy = EUE divided by average load (in MW-hours) multiplied by 1,000,000 in units of parts per million
LOLH (Hours)	Loss of load hours = total number of hours of curtailment divided by total number of games
LOLEV (Events/year)	Loss of load events = total number of curtailment events divided by the total number of simulations

Table 5: Annual Adequacy Metrics (Base Case)

Metric	2024	2026	Units
LOLP	8.2	16.9	Percent
CVaR - Energy	104	195	GW-hours
CVaR - Peak	2623	3811	MW
EUE	5338	11,317	MW-hours
Normalized EUE	28	59	PPM
LOLH	3.1	6.6	Hours/year
LOLEV	0.16	0.38	Events/year

Table 6: 2024 Monthly Adequacy Metrics (Reference Case)

Month	LOLP (%)	CVaR Energy (GW-hours)	CVaR Peak (MW)	EUE (MW-ours)	NEUE (ppm)	LOLH (hours)
Oct	0	0.0	1	0	0	0.0
Nov	0.9	12.9	406	642	40	0.5
Dec	2	17.4	785	870	47	0.6
Jan	2	43.3	1043	2162	117	1.0
Feb	1.7	30.4	941	1520	96	0.7
Jul	0.9	0.9	115	45	3	0.1
Ag1	0.8	0.8	92	39	5	0.1
Ag2	1	1.1	120	57	7	0.1
Sep	0	0.0	4	1	0	0.0

While the Council has successfully used the annual LOLP metric to assess adequacy for over a decade, it became evident during the development of the Seventh Power Plan that seasonal adequacy targets are necessary to develop future power plans. The Council's Regional Portfolio Model uses quarterly reserve margin targets, derived from quarterly LOLP thresholds, to test for adequacy. Using a flat 5 percent annual LOLP to set quarterly reserve margins could result in power supplies that are not adequate. In other words, if the adequacy test in the RPM is a quarterly 5 percent LOLP, it is possible for a power supply that meets the 5 percent quarterly threshold to have an annual LOLP of nearly 20 percent. This can happen if curtailments in each quarter occur in different years. Thus, the calculation of quarterly adequacy reserve margins requires quarterly adequacy targets. Recognizing this, the Council added an action item to its Seventh Power Plan to review and amend its current adequacy standard, as necessary, to more accurately calculate seasonal planning reserve margins.

RESOURCE AND LOAD DATA

Tables 7 and 8 summarize the resources and load forecasts used for the 2024 adequacy assessment. Table 10 displays the annual average load and the winter and summer peak loads along with the assumed out-of-region market availability.

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on market supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,151 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with California utilities, the Northwest market availability is limited to 1,000 megawatts. Along with import availability, the Council's analysis includes 460 megawatts of standby resources, which can be used during times of resource scarcity. These resources can only provide 41,750 megawatt-month energy, limiting their operation to 90 hours (at maximum capacity).

Also, this year's load forecast was modified to incorporate the effects of historic hourly temperatures (1949-2017) as opposed to previous short-term load forecasts that used historic daily temperatures. The use of hourly regressions in the Council's short-term econometric load forecasting model produced a significantly better representation of potential hourly loads for the 2024 operating year. Members of the Council's Resource Adequacy Advisory Committee unanimously approved of this method.

Table 7: Loads and Import Availability for 2024

Item	Oct-Mar	Apr-Sep
Average Load (aMW)	21,776	
Avg. Peak Load (MW)	34,535	28,835
DSI Load (aMW)	421	421
Spot Imports (MW)	2,500[5]	0
Purchase Ahead (MW)	3,000	3,000

[5] For October, the spot market availability is set to 1,250 megawatts.

Table 8: Generating Resources

Annual Values	2024	2026	Difference
Nuclear (MW)	1,150	1,150	0
Coal (MW)	3,844	3,330	-514
Bio Mass	490	490	0
Gas and Misc (MW)	7,020	7,020	0
IPP (MW)	2,151	1,861	-290
Total Thermal Resource	**14,774**	**13,970**	**-804**
Wind Nameplate (MW)	5,151	5,151	0
Solar Nameplate (MW)	589	589	0

Updated Resource Data

As mentioned previously, after the analyses for this assessment were completed, PacifiCorp proposed earlier retirement dates for several of its major coal plants. Because of the timing of the announcement and because a certain amount of uncertainty still surrounds the newly announced dates, the results of the 2024 adequacy assessment are based on the original coal retirement dates. Table 9 below provides the original set of retirement dates (used for this analysis) along with the updated retirement dates.

Table 10 shows the cumulative amount of coal plant capacity that is expected to be retired from 2018 through 2032. As can be seen in that table, up to 4,809 megawatts of coal plant capacity might be retired by 2028 (under the updated retirement dates). This represents nearly the capacity of five Columbia Generating Station nuclear plants and is almost enough power to serve five cities the size of Seattle. As mentioned earlier, it doesn’t take a computer model to see that 4,809 megawatts represents a significant part of the Pacific Northwest power supply. If all the updated coal retirement dates are upheld, that loss of coal plant capacity is 22 percent of the region’s average annual load, 14 percent of its average winter peak-hour load and 17 percent of its average summer peak-hour load. The Council is currently in the process of developing its next power plan that will account for these retirements, state clean air legislation and other factors affecting the regional power supply.

Table 9: Major Coal Plant Projected Retirement Dates

Major Coal Plants Serving the PNW	Nameplate Capacity (MW) Serving PNW	Reference Case Retirement Dates (EOY)	Updated Retirement Dates (EOY)
Hardin	119	2018	
Colstrip 1	154	2019	
Colstrip 2	154	2019	
Boardman	522	2020	
Centralia 1	670	2020	
N Valmy 1	127	2021	
N Valmy 2	134	2025	
Centralia 2	670	2025	
Bridger 1	530	2028	2023
Bridger 2	530	2032	2028
Colstrip 3	518	TBD	2027
Colstrip 4	681	TBD	2027
Total	**4,809**		

Table 10: Planned Cumulative Coal Capacity Retirement

By End of This Year	Original Dates Cumulative (MW)	Updated Dates Cumulative (MW)
2018	119	119
2019	427	427
2020	1619	1619
2021	1,746	1,746
2023	1,746	2,276
2025	2,550	3,080
2027	2,550	4,279
2028	3,080	4,809
2032	3,610	4,809

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply annually as a check to ensure that resource acquisition does not lag behind demand growth. This task is becoming more challenging because of continued development of variable generation resources and changing load patterns. For example, regional planners have had to reevaluate methods to quantify and plan for balancing reserve needs. In light of these changes, the Council is in the process of enhancing its adequacy model to represent operations at a more granular level and to address capacity issues.

Another emerging concern is accounting for transmission access to market supplies. For the current adequacy assessment, the Northwest region is split into two sub-regions[6] in which only the major east-to-west transmission lines are modeled along with the major out-of-region interties. The Council is exploring how to address these issues for future adequacy assessments.

The Council's Seventh Power Plan identifies the following action items related to adequacy assessments:

RES-8	Adaptive Management – Annual Resource Adequacy Assessments
COUN-3	Review the regional resource adequacy standard
COUN-4	Review the RAAC assumptions regarding availability of imports
COUN-5	Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model
COUN-6	Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model
COUN-8	Participate in and track WECC [adequacy] activities
COUN-11	Participate in efforts to update and model climate change data
ANLYS-4	Review and enhancement of peak load forecasting
ANLYS-22	GENESYS Model Redevelopment
ANLYS-23	Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations

[6] The dividing line between the east and west areas of the region (for modeling purposes) is roughly the Cascade mountain range.

Issues identified in 2019 by the Council's Resource Adequacy Advisory Committee to consider for future assessments include:

- Review and update the availability of California and other west-wide market supplies for all months and all hours.
- Investigate the availability of interties that connect the Northwest with regions that may be able to provide market supplies. Consider adding transmission intertie maintenance schedules and forced outages to the analyses.