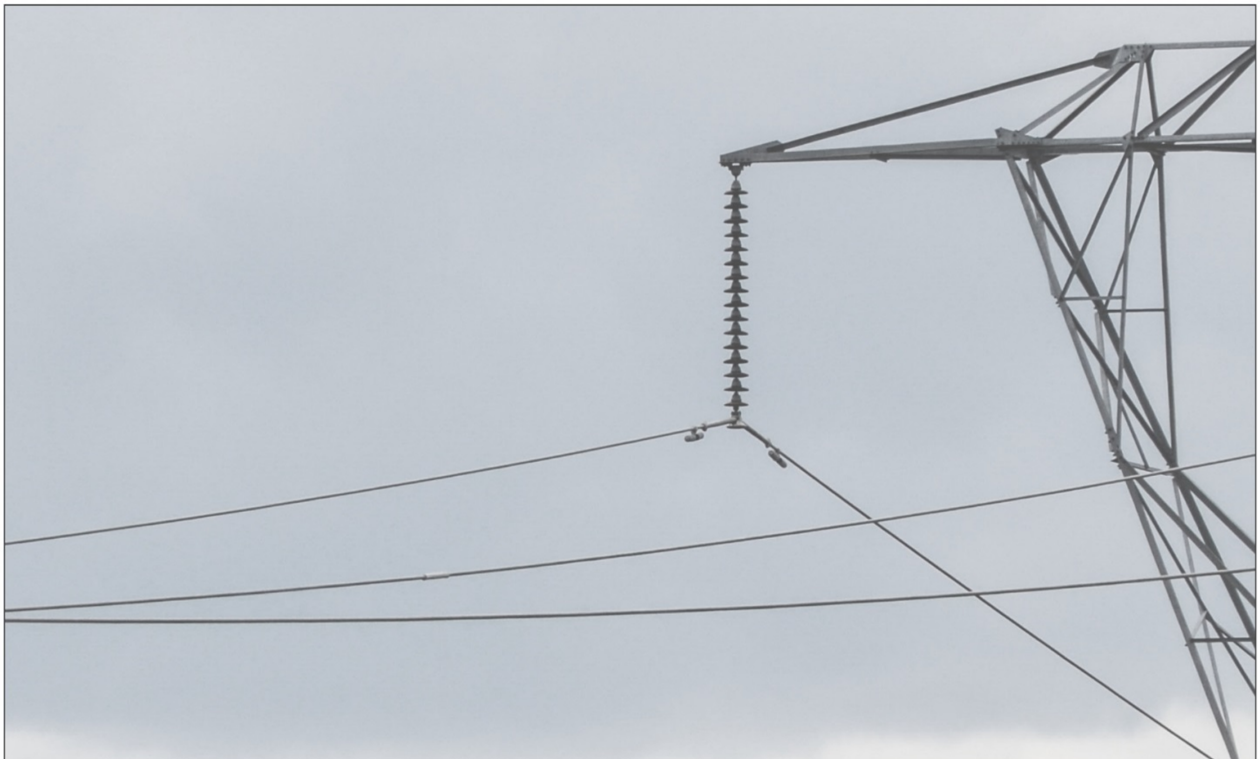
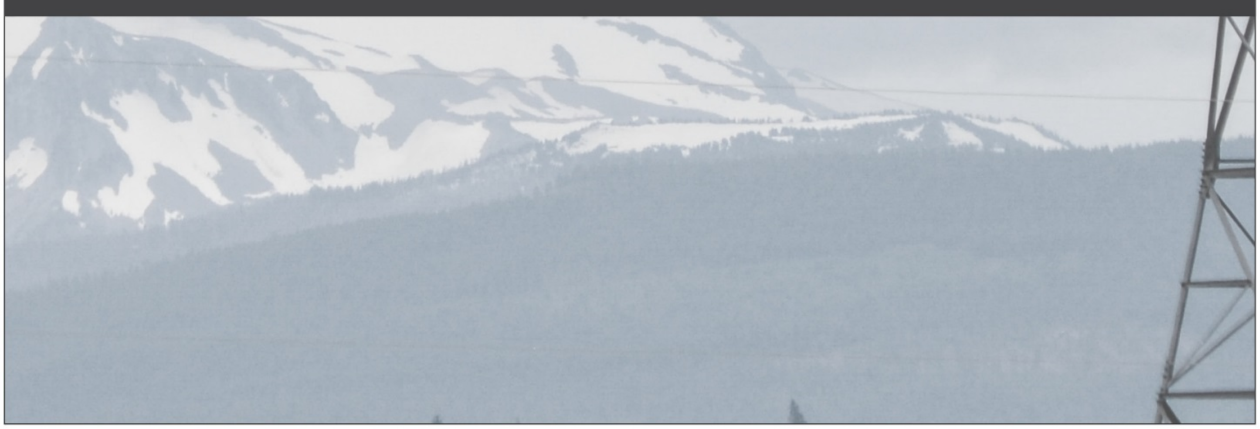


Pacific Northwest Power Supply Adequacy Assessment for 2022



July 11, 2017
Document 2017-5

Northwest **Power** and **Conservation** Council

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This document summarizes the Northwest Power and Conservation Council's assessment of the adequacy of the power supply for the 2021[1] and 2022 operating years (October through September). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for power supply adequacy and set its maximum value at 5 percent. For a 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 help of the Resource Adequacy Advisory Committee, updated its resource and load data, examined all appropriate operating assumptions and ran the GENESYS model 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.

The Council is currently in the process of enhancing its adequacy model (GENESYS), in particular the hourly hydroelectric system dispatch simulation, and expects to complete the work by September of 2018. In addition, the Council will initiate a process in the fall of 2017 to review its current adequacy standard. Council staff and RAAC members will be asked to review the viability of the current metric (LOLP) and threshold (5 percent). This review should consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).

[1] The Council's annual adequacy assessment looks at the status of the power supply five years out, to ensure that sufficient time is available for mitigating actions, if needed. However, because of the retirement of two major coal plants in 2021, the Council wanted that year's adequacy to be reassessed.

EXECUTIVE SUMMARY

Last year, the Council reported[2] that the Northwest power supply would become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 megawatts combined). We estimated the loss-of-load probability (LOLP) in 2021 to be 10 percent, which is above the Council's adopted maximum of 5 percent. However, many changes have occurred to alter that assessment.

The updated assessment for 2021 shows an LOLP of just under 7 percent and the projected LOLP for 2022 is slightly higher at just over 7 percent. These results assume the Council's energy efficiency targets[3] through 2022 will be achieved. To comply with the Council's adequacy standard, the region will need to add an estimated 400 megawatts of new effective capacity[4] by 2021.

LOLP values are very sensitive to both the load forecast and Southwest market supply assumptions. For example:

- Decreasing the Southwest market supply by 500 megawatts increases the 2022 LOLP to about 8.5 percent, whereas increasing the available supply from the market by 500 megawatts decreases the LOLP to about 6 percent.
- Reducing the 2022 load forecast by 0.8 percent[5] brings the LOLP down to the Council's 5 percent standard and has roughly the same effect as adding 400 megawatts of effective capacity.
- Increasing the load forecast by 0.6 percent[6] raises the 2022 LOLP to about 9 percent and doubles the amount of effective capacity needed (from 400 to 800 megawatts) to bring the LOLP down to the Council's 5 percent standard.

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[2] The Council's 2016 Adequacy Assessment Report can be found at the following link: https://www.nwcouncil.org/media/7150591/2016-10.pdf

[3] See the Council's Seventh Power Plan, Chapter 4 – Action Plan and Chapter 3 – Resource Strategy for energy efficiency targets.

[4] "Effective capacity" in this context is that portion of a resource's nameplate capacity that can be counted on during any shortfall hour in the year. Wind resources, for example, typically have very low effective capacity values.

[5] This means multiplying the load in each hour of the year by 0.992.

[6] This means multiplying the load in each hour of the year by 1.006.

Key updates since last year's assessment include:

- The revised load forecasts for 2021 and 2022 project a greater trend toward lower winter peak loads and higher summer peak loads. This lowers the likelihood of winter shortfalls but increases the likelihood of summer problems. The revised annual weather-normalized load for 2021 shows a slight increase of about 75 average megawatts.

- The Canadian hydroelectric operation for 2021 and 2022 under the Columbia River Treaty shows a shift in the timing and amount of inflows into the United States. The projection is for increased US hydro generation in summer but decreased generation in October. This lowers the likelihood of summer problems but increases the probability of shortfalls in October.

- For past adequacy assessments, the Council assumed that the regional power supply had no access to the Southwest market during October. However, after a review of current data, and with input from the Resource Adequacy Advisory Committee, this assumption has been modified to allow for some market availability. This offsets the effects of the anticipated shifts in hydroelectric generation due to Canadian operations.

- The recently announced retirement of the North Valmy 1 coal plant (127 megawatts dedicated to regional service) in 2019 has the effect of increasing LOLP assessments by about 1 percent, which is reflected in the study results.

- Expected energy savings by 2022 from the Council's energy efficiency targets and from codes and federal standards will not completely offset the loss of generation from the planned retirements of Centralia 1 (688 megawatts), Boardman (642 megawatts), North Valmy 1(127 megawatts), Colstrip 1 and 2 coal plants (308 megawatts) and the Pasco gas-fired plants (44 megawatts).

While we did not analyze the adequacy of today's power supply, planners generally agree that we currently have an adequate system. However, the planned loss of 1,457 megawatts of generating capacity by 2021 and the loss of an additional 352 megawatts by 2022, without any new resource acquisitions, would lead to an inadequate supply by 2021. The good news is that continued implementation of the Council's energy efficiency targets (1,570 average megawatts of cumulative savings from 2017 through 2022) and the energy savings from codes and federal standards go a long way to offset the loss of generating capability.

To ensure the continued adequacy of the power supply, we project that the region will need to acquire about 400 megawatts of new effective capacity by 2021, in addition to the targeted energy efficiency savings. However, as previously noted, this estimated need for new capacity is sensitive to both load and resource assumptions and could vary between zero and 1,000 megawatts. This is why the Council annually updates its adequacy assessment for the power supply five years out.

Demand response plays a big role in the Council's Seventh Power Plan resource strategy and could potentially fill the projected gap in resource need for 2021. In its plan, the Council did not establish a target for demand response acquisition but recommended that 600 megawatts be developed by 2021.

Regional utilities are also aware of this potential capacity need and have identified in their integrated plans over 1,200 megawatts of capacity-providing resources, 200 megawatts of demand response and over 500 megawatts of wind and solar capacity, which could be brought online by 2021, pending regulators' approvals.[7] These resources were not included in this analysis because they are not sited and licensed, but it is important to note that utilities are poised to acquire new capacity, if needed. It should also be noted that this analysis reflects the adequacy of the aggregate power supply. Individual utilities within the Northwest have different resource mixes and different load shapes and, therefore, must evaluate their own need for new resources.

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 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 effective[8] capacity and energy generating capability is required to bring the system's LOLP back down to 5 percent. However, the standard is not intended to provide a resource-planning target 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

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[7] Source: Pacific Northwest Utilities Conference Committee's 2017 Northwest Regional Forecast.

[8] "Effective capacity" in this context is that portion of a resource's nameplate capacity that can be counted on during any shortfall hour in the year. Wind resources, for example, typically have very low effective capacity values.

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.

Because the computer model used to assess adequacy (GENESYS) 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 costly measures to provide continuous service exceeds the 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 or low winter temperatures). These resources primarily provide peaking capacity and have a very limited amount of energy (i.e. once the assigned energy is used up, they are no longer available for dispatch). The effects of demand response measures that have already been implemented are assumed to be reflected in the Council’s load forecast. New demand response measures that have no operating history and are, therefore, not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions, which are 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 final LOLP and other adequacy metrics.

RECENT ADEQUACY ASSESSMENTS

Table 1 below highlights the results of recent adequacy assessments. Since 1998, when the Council began using stochastic methods to assess adequacy, the power supply and, to some extent the methodology, have changed significantly, sometimes making it difficult to compare annual assessments. The evolution of adequacy assessments will continue and the Council has initiate efforts to improve its adequacy model and to revisit the viability of the current adequacy standard.

Table 1: History of Adequacy Assessment

Year Analyzed	Operating Year	LOLP	Observations
2010	2015	5%	Was part of the Council's 6th Power Plan
2012	2017	7%	Imports decreased from 3,200 to 1,700 MW, load growth 150 aMW per year, only 114 MW of new thermal capacity
2014	2019	6%	Load growth 120 aMW per year, over 600 MW new generating capacity, increased imports by 800 MW
2015	2020	5%	Lower load forecast, 350 aMW of additional EE savings
2015	2021	8%	*Early estimate (BPA INC/DEC only)* Loss of Boardman and Centralia 1 (~1,330 MW)
2016	2021	10%	Including regional INC/DEC requirements reduces hydro peaking capability
2017	2021	6.9%	Lower LOLP primarily due to lower load forecast and shift in Canadian hydro operations
2017	2022	7.2%	LOLP increases slightly even with the loss of Colstrip 1 and 2 coal plants because of the 317 aMW of targeted EE savings for this year.

The Council recognizes that the power system of today is very different from that of 1980, when the Council was created by Congress. In particular, the trend for increasing penetration of variable energy resources, such as solar and wind, have added a greater band of uncertainty surrounding the adequacy assessment. This has led to a greater need for the ability to model hourly operations, especially for the hydroelectric system. Toward this end, the Council is currently in the process of redeveloping its adequacy model (GENESYS) to add more precision to the simulation of hydroelectric generation.

The thrust of this effort is to improve the hourly operation simulation by adding a better representation of unit commitment, balancing reserve allocation and plant-specific hourly operations (the current model simulates hourly hydroelectric generation in aggregate for the region). These enhancements, expected to be completed by 2018, could likely change the results in a significant way. It will require an extensive vetting effort to ensure that the results of the redeveloped model are a better representation of expected operations.

2021 RESOURCE ADEQUACY ASSESSMENT

To ensure that sufficient time is available, if needed for resource acquisition, the Council's annual adequacy assessment looks at the status of the power supply five years out. However, because of the retirement of two major coal plants by the end of 2020, the Council is also assessing adequacy for 2021.

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the planned retirements of the Boardman, Centralia 1 and North Valmy coal plants (1,457 MW of nameplate capacity), the system will no longer meet the Council's adequacy standard in 2021.

The projected LOLP for 2021 is 6.9 percent, which is over the Council's 5 percent standard. To ensure that the power supply remains adequate, the region will have to acquire about 400 megawatts of new effective capacity by 2021. This result assumes that the Council's energy efficiency targets, as identified in the Seventh Power Plan, will be achieved.

Last year's assessed LOLP for 2021 was projected to be higher, at 10 percent. The reassessed lower LOLP for the 2021 operating year is primarily due to the factors described below:

- The revised load forecast for 2021 (using one more year of observed loads) shows a 300 MW average decline in winter peak loads and a nearly 900 MW average increase in summer peak loads. Since the Northwest is still primarily a winter peaking region, the decline in winter peak loads has the effect of lowering the overall LOLP. The revised annual load forecast for 2021 increased slightly by 75 average megawatts.
- The projected Canadian hydroelectric operation for 2021 shifts inflows coming into the US system. Average October inflows are reduced substantially, resulting in a reduction of about 550 average megawatts of hydroelectric generation in that month. Late summer inflows are projected to increase, thus helping to ease potential summer shortfalls.
- The reduction in October hydroelectric generation would result in a significant increase in shortfall conditions because past assessments have assumed that no market supplies are available in that month. However, after reviewing data related to SW market availability, RAAC members agreed that some level of market supply should be available in October, thus entirely offsetting the expected reduction in hydroelectric generation.

2022 RESOURCE ADEQUACY ASSESSMENT

The updated adequacy assessment for 2021 shows an LOLP of 6.9 percent, but additional resource retirements are expected by 2022. The Colstrip 1 and 2 coal plants (308 MW nameplate capacity) are planned for retirement and the gas-fired generators at Pasco (44 MW of dedicated regional capacity) are not expected to be operational during that time period.

For the 2022 assessment, 352 megawatts of capacity is removed from the mix. The 2022 load forecast shows a 175 average megawatt decline in annual load (from 2021), with an average 200 megawatt decrease in winter peak loads and an average 90 megawatt decrease in summer peak loads. These results include the effects of the Council's targeted energy efficiency savings for 2022, which amount to 317 average megawatts. They also include the effects of codes and federal standards, which are estimated to save about 100 average megawatts annually.

The projected LOLP for 2022, after accounting for the loss of generation and the new load forecast, is 7.2 percent – just a little higher than the LOLP for 2021. This is because the overall decline in loads (primarily due to energy efficiency savings) nearly offsets the loss of generating capacity in 2022. A regional acquisition of 400 megawatts of effective capacity in 2021 for adequacy is sufficient to maintain adequacy through 2022.

Figure 1 displays the peak-hour unserved energy duration curve (probability of exceedance) and Figure 2 shows the annual average unserved energy duration curve. The point at which these curves cross the horizontal axis provides a good estimate for the LOLP, in this case 7.2 percent.[9] The curve in Figure 1 can also be used to estimate the amount of additional capacity needed to make the power supply adequate (e.g. LOLP of 5 percent). The objective is to determine how much added capacity is needed to shift the entire probability curve to the left so that it crosses the X-axis at the 5 percent point. An easy way to do this is to draw a vertical line from the 5 percent point on the X-axis up to the probability curve. Then draw a horizontal line from that point to the left all the way to the Y-axis. The capacity (megawatts) identified on the Y-axis where the horizontal line crosses provides a good estimate of the required new capacity needed to yield a 5 percent LOLP. From Figure 1, this value is about 400 megawatts. Of course, a more precise analysis of the curtailment record is used to more accurately assess the needed capacity.

The same approach can be used to estimate the amount of needed energy (in combination with the needed capacity) to get to a 5 percent LOLP. However, as evident in Figure 2, this assessed value for needed energy is very small, on the order of a few average megawatts. This is an indication that the 2022 power supply has a greater need for capacity than for energy.

[9] This is a simplification of the actual process, which takes into account monthly results.

Figure 1: Peak-Hour Curtailment Probability

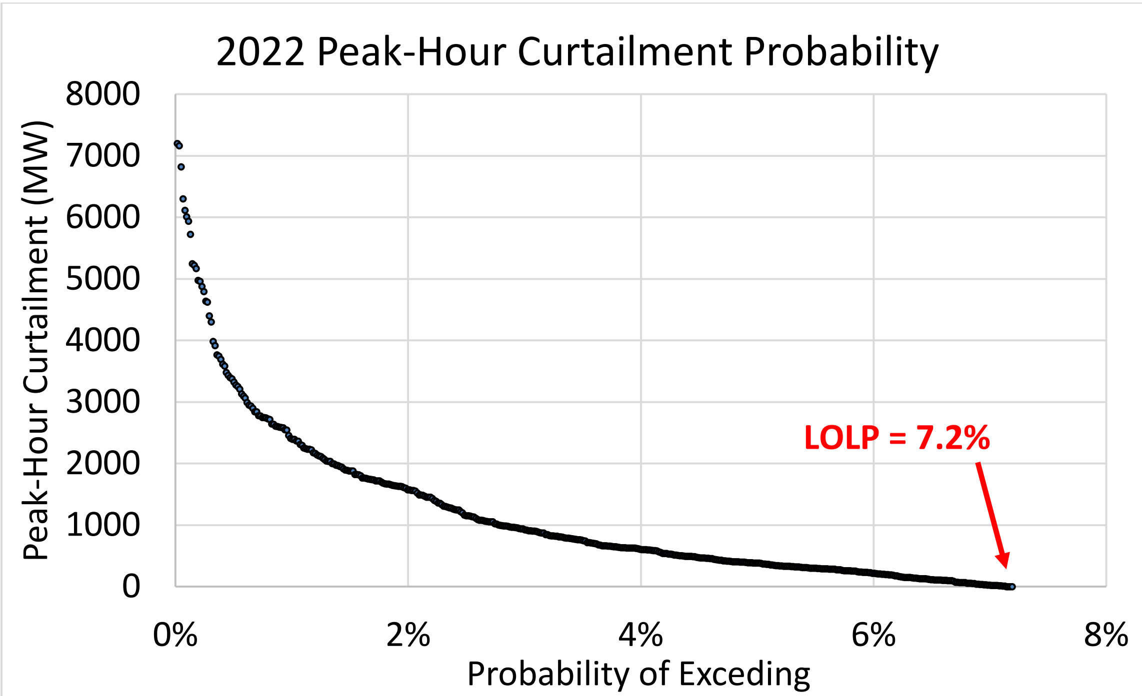
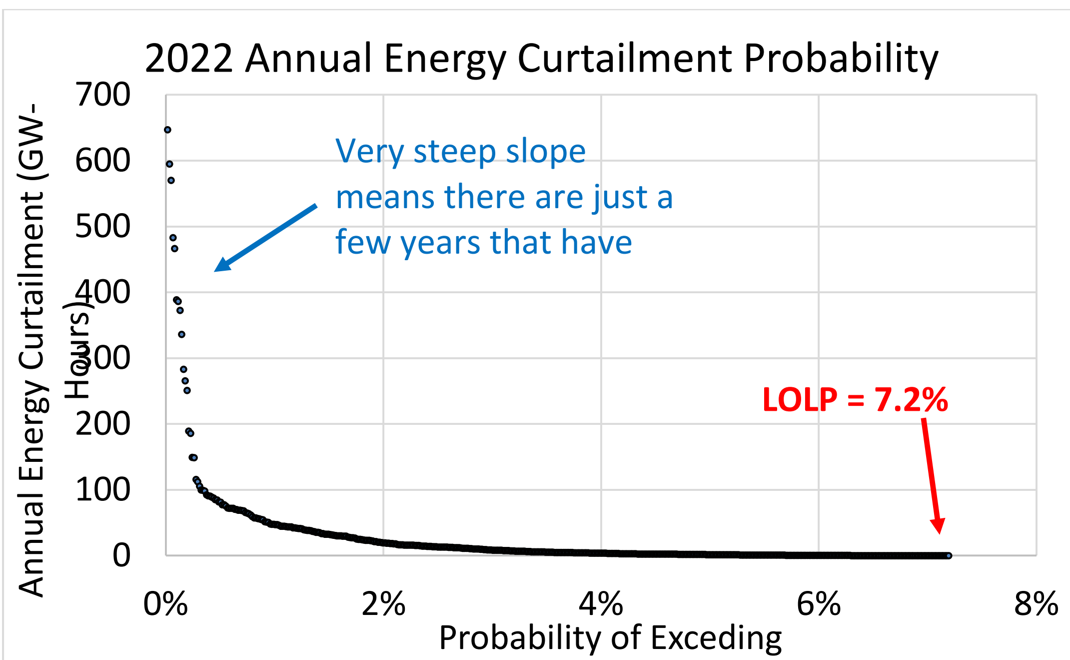


Figure 2: Annual Energy Curtailment Probability



Sensitivity Analysis

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability in the out-of-region market supply.[10] Long-term load uncertainty for this analysis covers 2 standard deviations from the mean (approximately 3 percent higher and lower). 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, market availability was allowed to range from a low of 2,000 megawatts to a high of 3,400 megawatts during October through March only.[11]

Table 2 summarizes the results of the market and load growth sensitivity analysis for 2022. In the extreme case, with high load growth and low import, the loss of load probability is nearly 24 percent. Fortunately, this scenario is not very likely. At the other extreme, with low load growth and maximum import availability, the loss of load probability drops to under 2 percent. The cells in Table 2 are color coded to better highlight conditions that lead to inadequate supplies. Reddish cells indicate an inadequate power supply with LOLP values greater than 5 percent and greenish cells indicate the power supply meets the Council's standard.

Table 2: 2022 Loss of Load Probability (LOLP in %)

Import (MW)	**3400**	**3000**	**2500**	**2000**
High Load	18.1	19.0	21.0	23.6
Med Load	5.8	6.2	7.2	8.6
Low Load	1.8	2.1	2.7	3.4

Some members of the advisory committee pointed out that the ratio of peak-hour load to annual-average load appears to be too high in the hybrid load forecast used in this analysis. To test the sensitivity of the LOLP to this parameter, a case with lower peak-to-average load ratios was examined. The 2022 hybrid load forecast was replaced by the short-term model forecast, which has a lower peak-to-average load ratio. The resulting LOLP dropped from 7.2 percent (hybrid loads) to 6.9 percent (STM loads) – not a significant change.

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

[11] The Council also modeled a separate out-of-region market, namely a purchase-ahead market, which allows imports only during non-peak hours and only if a shortfall is expected.

Table 3 shows how much additional capacity is required for each scenario to maintain adequacy (i.e. to get the LOLP down to the Council's 5 percent standard). Included in this table are two additional sets of load sensitivity studies; 1) a set with a load increase of 0.6 percent and 2) a set with a load decrease of 0.8 percent. The percentage of load increase was chosen so that, relative to the reference case, the needed capacity is about double (from a need of 385 to 785 megawatts). The percentage of load decrease was chosen so that, relative to the reference case, the needed capacity goes to zero. (See the highlighted cells in Table 3).

Table 3: 2022 Estimated Effective Capacity Need to Maintain Adequacy (MW)

Import (MW)	3400	3000	2500	2000
Load + 3%	1500	1600	1830	2100
Load + 0.6%	515	600	785	1050
Med Load	115	200	385	650
Load – 0.8%	0	0	0	250
Load – 3%	0	0	0	0

Monthly Analysis

As discovered during the development of the Council's Seventh Power Plan, it is also important to assess monthly adequacy values in order to better inform the Council's resource acquisition methodology. For example, some resources such as demand response are only available in winter or in summer.

Figure 3 below shows the monthly LOLP values for both the 2021 and 2022 operating years.[12] It is clear from this figure that the region has both winter and summer adequacy issues. And, although the annual LOLP values for both years are nearly the same, the 2022 results show improvement in December but higher likelihood of shortfalls in August. This is consistent with the general observation that summer peaks are growing while winter peaks are decreasing.

[12] 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, say one in January and one in August, would count the same toward the annual LOLP value as a simulation with only a January event or only an August event.

Figure 3: 2021-22 LOLP by Month

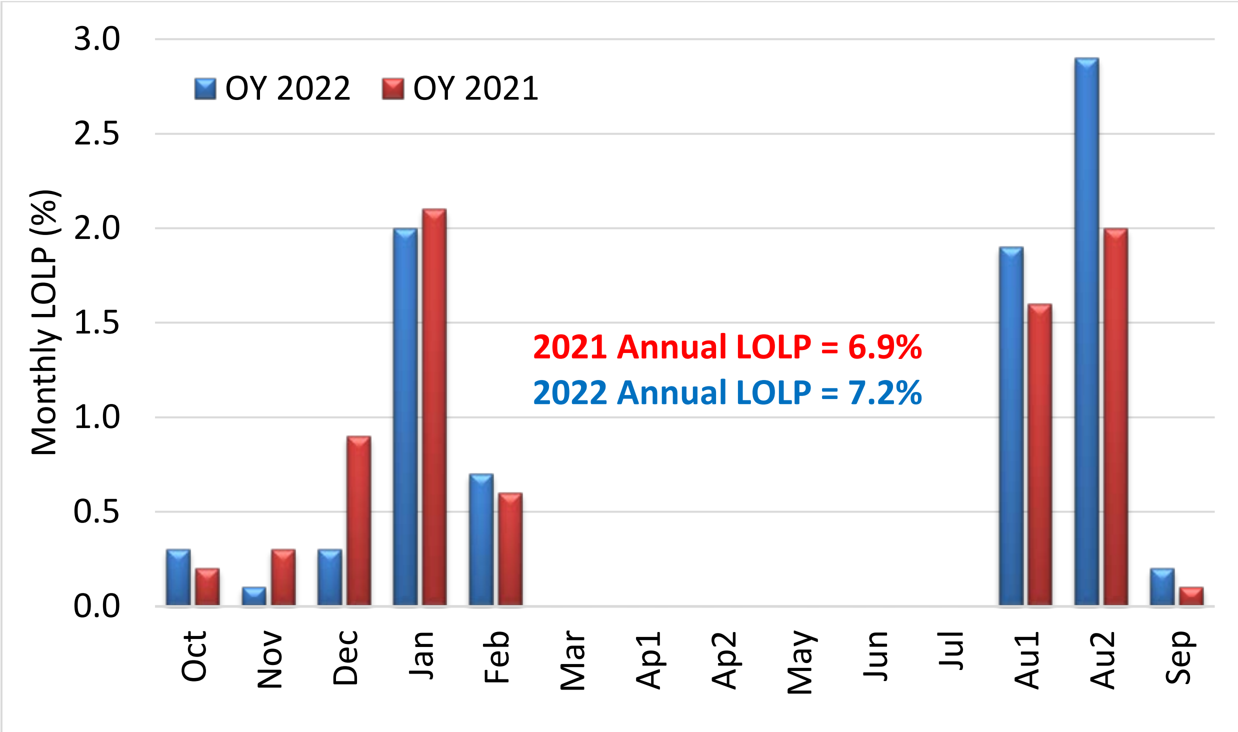

Table 4 summarizes the 2022 operating-year average monthly dispatch for blocks of resources, namely wind, coal, gas, nuclear and the market.

Table 4: Expected Resource Dispatch (aMW) for 2022

Base Case	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	1206	1250	1204	1314	1299	1563	1770	1866	1755	1707	1575	1457	1345	1152
Coal	3006	2572	2471	1950	1613	1399	1294	704	386	678	1568	2560	2852	3025
Gas	3239	1413	1346	1439	1062	803	888	599	493	577	869	1756	2316	2409
Nuclear	1034	1039	1070	1075	1128	1077	1071	1066	1076	1054	1077	1067	1110	1055
Market	661	666	622	654	358	219	90	26	3	27	82	283	394	397

Curtailment Statistics

Curtailment statistics can sometimes provide valuable insight into the behavior of the power system. Table 5 below summarizes several statistics from the curtailment record for 2022. All adequacy studies were run with 6,160 simulations (all combinations of 80 water conditions and 77 temperature conditions).

Table 5: 2022 Simulated Curtailment Statistics

Statistic		Units
Number of simulations	6,160	Number
Simulations with a curtailment	444	Number
Loss of load probability (LOLP)	7.2	Percent
Pre-standby resource LOLP	11.3	Percent
Number of curtailment events	844	Number
Loss of Load Events (LOLEV)	0.14	Events/year
Average event peak curtailment	1,043	MW
CVaR Peak	1,625	MW
Pre-standby resource Average Event Magnitude	12,917	MW-hours
Expected un-served energy (EUE)	2,038	MW-hours
Pre-standby resource Average Event Duration	11.1	Hours
Expected curtailed hours per year (LOLH)	1.6	Hours

An interesting result from Table 5 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-in-10 year standard. If the "1-in-10" refers to 1-event-in-10 years, then the implied adequacy threshold for LOLEV is 0.1 events/year. Because the reference case LOLEV of 0.14 events/year exceeds this threshold, we conclude that the reference case does not comply with the 1-in-10 year standard. Adding sufficient capacity to bring the 2022 LOLP down to the 5 percent level yields an LOLEV of 0.093 events/year, which is very close to the 0.1 threshold. In other words, when the regional power supply just meets the 5 percent LOLP standard, its corresponding LOLEV value is consistent with a 1-event-in-10 year threshold (at least for this one example).

Besides looking at curtailment statistics, it may also be of great value to examine the conditions under which curtailments occurred. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis will be provided in a separate spreadsheet (available on the Council's website). The four random variables are;

- Water supply, as a percentage of monthly runoff volume
- Temperature, as a percentage of that day's historical temperature range
- Wind generation, based on historical wind capacity factors from BPA's wind fleet
- Forced outage conditions

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 4a illustrates the event duration histogram, which shows the number of events observed for each duration. Figure 4b shows cumulative event duration, which gives the percent of events with a specified duration or less. In Figure 4a, the x-axis represents event duration and the y-axis represents number of events. What stands out in this figure is that the most likely event duration is 16 hours. This is not unexpected because, by design, the hydroelectric system's output is adjusted, whenever possible, to spread any anticipated unserved energy across all peak hours of the day. This produces a flat amount of hourly unserved energy, which is easier to satisfy than a shorter duration, higher magnitude and non-uniform shortfall.

From Figure 4b, the fact that almost 40 percent of events have a duration less than 8 hours bodes well for demand response as an adequacy-providing resource. For example, the pre-standby resource LOLP is 11.3 percent but adjusting for the effects of standby resources (661 megawatts of capacity in winter and 1,079 megawatts in summer) drops the LOLP to 7.2 percent. Thus, although demand response 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).

Figure 5 shows the number of shortfall events per month and Figure 6 shows the average peak-hour shortfall by month. The interesting result here is that the frequency of summer events is higher (three times more likely) than winter events but the magnitude of the shortfalls is much smaller (less than half). This is consistent with results from previous adequacy assessments. A possible explanation is that the range of hydroelectric generation for summer months is much narrower than for winter months. Thus, we are more likely to see a shortfall in the summer but the size of the problem is smaller and easier to solve. In winter months, certain combinations of poor water conditions and extreme temperatures can lead to very large shortfalls, even though they are not as likely to occur.

Figure 4a: Event Duration Histogram

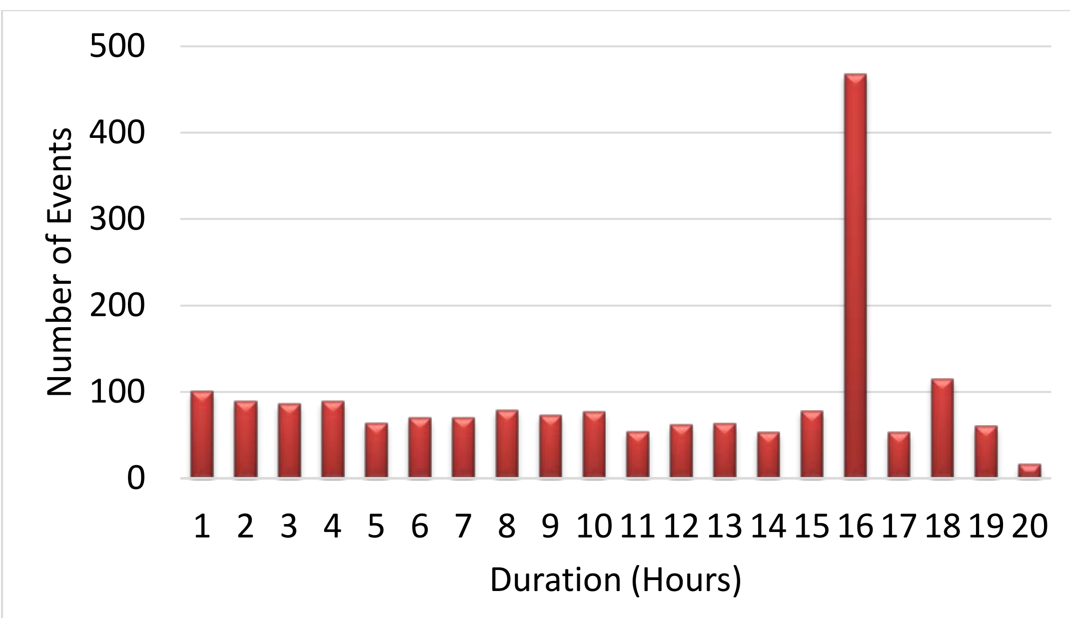

Figure 4b: Cumulative Event Duration

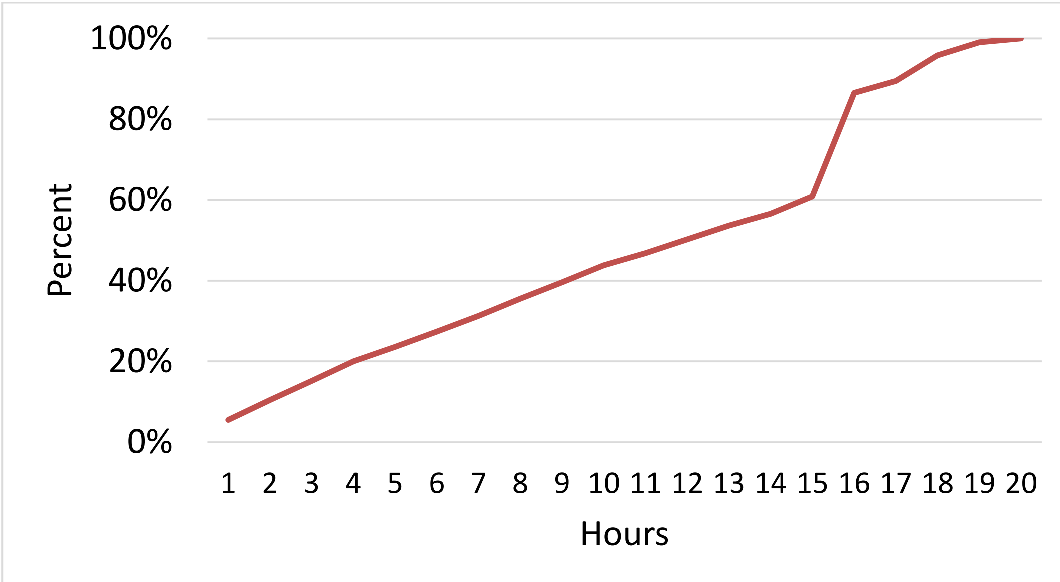

Figure 5: Number of Events per Month

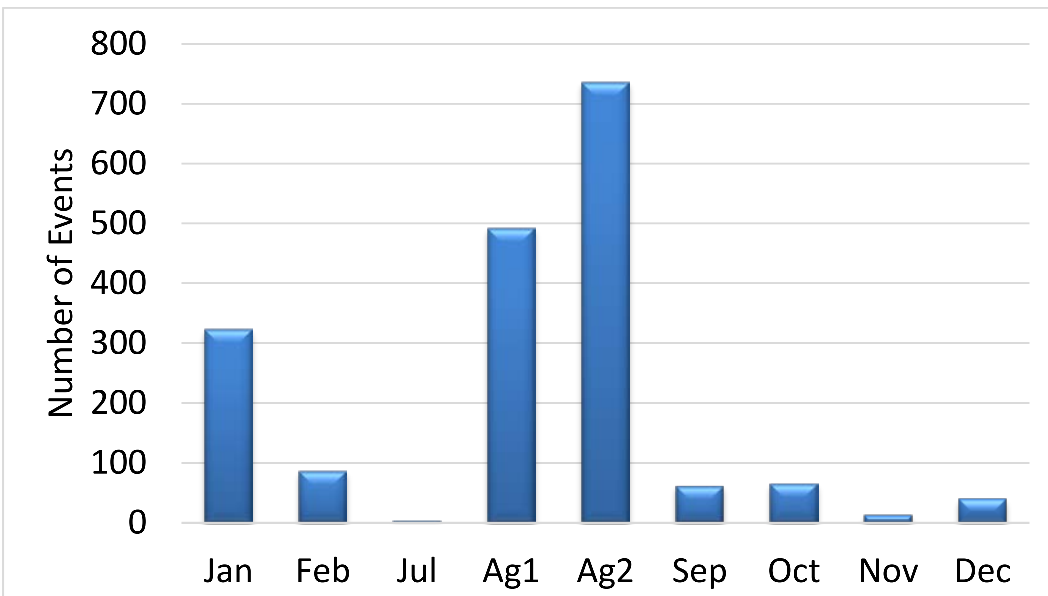

Figure 6: Average Peak-Hour Curtailment per Month

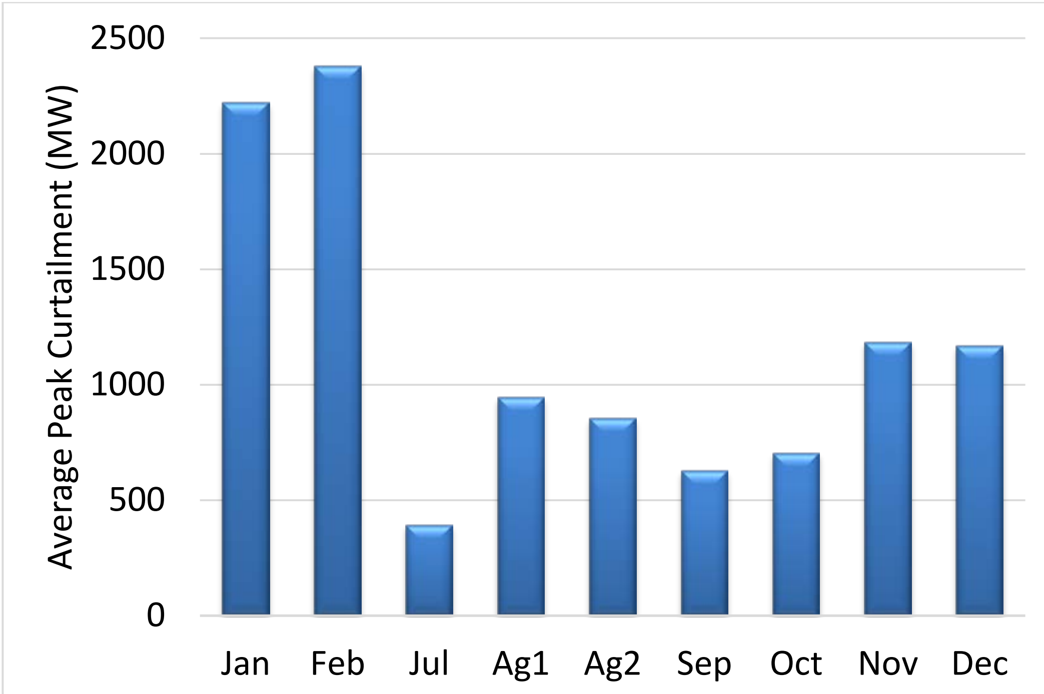

Figure 7 shows the number of events by water year and Figure 8 shows the number of events by temperature year. It appears, from Figure 7, that regardless of temperature there are seven water years that have particularly high frequency of shortfall events. Similarly, in Figure 8, there appears to be three temperature years that, regardless of water conditions, show a high frequency of events. Finally, Table 6 shows the combinations of water and temperature years that yield the highest likelihood of shortfalls.

Figure 7: Number of Events by Water Year

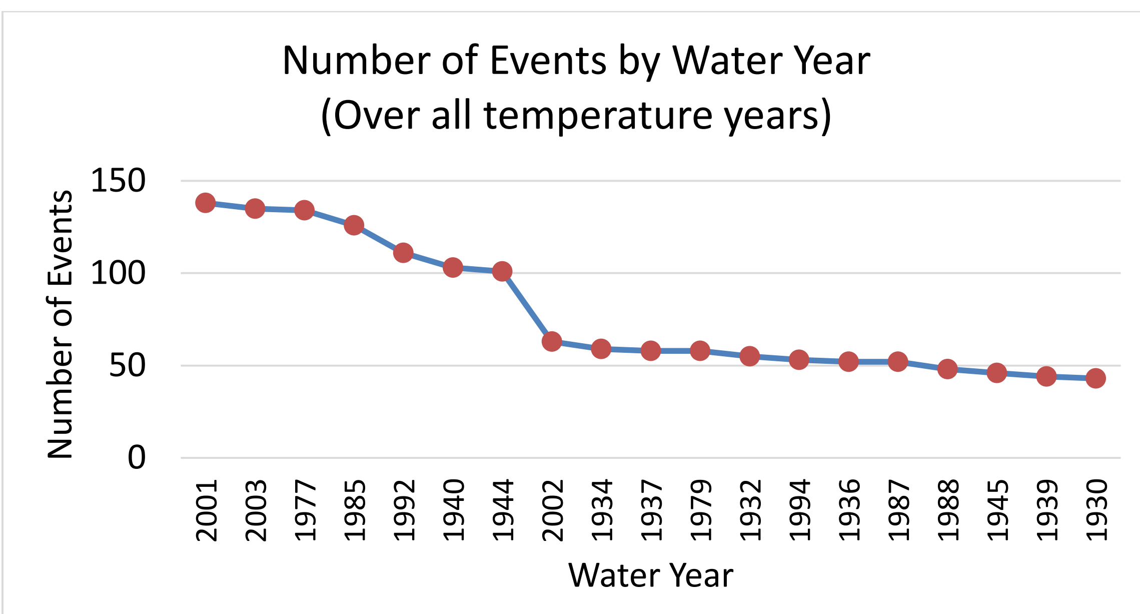

Figure 8: Number of Events by Temperature Year

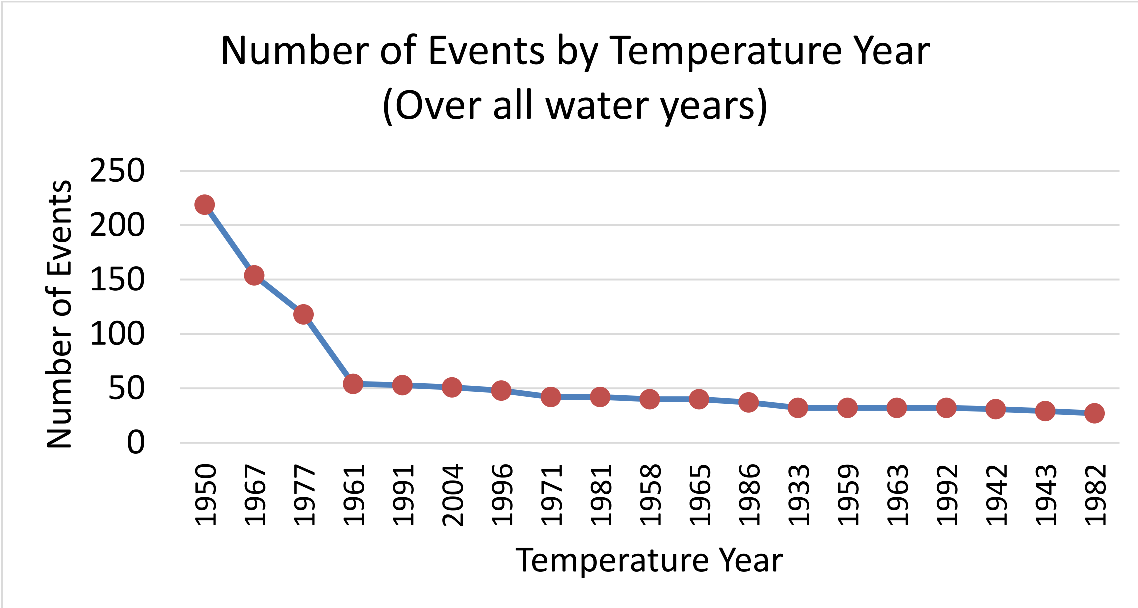

Table 6: Water Year/Temperature Year Combinations with the most Shortfalls

Water Year	Temp Year	Number of Events
1985	1967	15
1937	1950	14
2003	1950	13
1988	1950	13
1977	1967	13
1977	1977	12
1932	1950	12
1936	1950	12
1930	1950	12
1944	1950	11
1985	1977	11
1931	1950	11
2001	1967	11
1944	1967	11
1992	1950	11

Other Adequacy Metrics

Adequacy metrics help planners better understand the magnitude, frequency and duration of curtailments. These metrics provide valuable information to planners as they consider resource expansion strategies. Table 7 below defines some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 8 provides the regional assessments of these metrics for 2022 and past years.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It asked that each of its sub-regions in the United States provide 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. In fact, it may be impossible to do so because power supplies vary drastically across regions.

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 will be necessary to develop future power plans. The Council's Regional Portfolio Model uses quarterly reserve margin targets 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 that we end up with a power supply that has 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 amend its existing adequacy standard to include quarterly targets.

Table 7: 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 8: Annual Adequacy Metrics (Base Case)

Metric	2017	2019	2020	2021	2022	Units
LOLP	6.6	5.9	4.7	6.9	7.2	Percent
CVaR - Energy	99.0	59.2	50.6	34.7	40.5	GW-hours
CVaR - Peak	4,000	3,337	2,949	1,563	1,625	MW
EUE	5,000	3,000	2,536	1,743	2,038	MW-hours
Normalized EUE	N/A	N/A	N/A	N/A	11.55	PPM
LOLH	2.7	1.7	1.5	1.4	1.6	Hours/year
LOLEV	N/A	N/A	N/A	N/A	0.14	Events/year

Table 9: Monthly Adequacy Metrics (Reference Case)

Month	LOLP %	CVaR Energy GW-Hours	CVaR Peak MW	EUE MW-hours	NEUE ppm	LOLH hours
Oct	0.3	0.3	42	17	0.10	0.0
Nov	0.1	0.2	22	9	0.05	0.0
Dec	0.3	0.6	60	29	0.15	0.0
Jan	2.0	22.9	938	1,144	5.78	0.7
Feb	0.7	8.7	389	437	2.43	0.2
Mar	0	0	0	0	0	0
Apr 1-15	0	0	0	0	0	0
Apr 16-30	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug 1-15	1.9	2.8	210	139	0.77	0.3
Aug 16-31	2.9	5.2	362	258	1.47	0.4
Sep	0.2	0.1	21	6	0.04	0.0

Tables 10-13 show how these other adequacy metrics change as load and import assumptions vary.

Table 10: Expected Unserved Energy (EUE in MW-hours)

Import (MW)	3400	3000	2500	2000
High Load	6113	6801	8159	10434
Med Load	1085	1448	2038	2942
Low Load	358	533	844	1305

Table 11: Loss of Load Hours (LOLH in Hours)

Import (MW)	3400	3000	2500	2000
High Load	7.0	7.3	8.1	9.6
Med Load	1.2	1.3	1.6	2.1
Low Load	0.3	0.4	0.6	0.8

Table 12: Conditional Value at Risk for Peak (CVaR Peak in MW)

Import (MW)	3400	3000	2500	2000
High Load	2362	2551	2921	3436
Med Load	1053	1247	1625	2120
Low Load	397	519	730	1054

Table13: Conditional Value at Risk for Energy (CVaR Energy in MW-hours)

Import (MW)	3400	3000	2500	2000
High Load	104,000	113,000	131,000	158,000
Med Load	22,000	29,000	40,000	58,000
Low Load	7,000	11,000	17,000	26,000

Assumptions

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on non-utility supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,653 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.

Table 14: Assumptions used for the 2022 Adequacy Assessment

Item	Oct-Mar	Apr-Sep
Average Load (aMW)	19,686	
Avg. Peak Load (MW)	34,707	28,710
DSI Load (aMW)	421	421
Mean EE (aMW)	1,924	1,530
Peak EE (MW)	3,280	2,070
Spot Imports (MW)	2,500[13]	0
Purchase Ahead (MW)	3,000	3,000

Other assumptions used for the 2022 adequacy assessment are shown in Tables 14-20. Table 14 summarizes assumptions for load, energy efficiency savings and out-of-region market availability. Tables 15-17 provide the energy and capacity contributions for generating and standby resources. Table 18 shows the monthly breakdown of firm contracts, both into and out of the region. Tables 19 and 20 provide the monthly incremental and decremental balancing reserves. To the extent possible, the hydroelectric system was used to carry these reserves. Using the Council's hourly hydroelectric optimization program (TRAP model), a portion of the peaking capability and an amount of minimum generation at specific hydroelectric projects was reserved to support the within-hour balancing needs. Unfortunately, not all balancing reserves could be assigned to the hydroelectric system. The remaining reserves should be assigned to other resources but the current adequacy model does not have that capability. This is one of the major enhancements targeted in the GENESYS redevelopment process.

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

Table 15: Generating Resources

Annual Values	2021	2022	Difference
Nuclear (MW)	1,144	1,144	0
Coal (MW)	3,758	3,323	(308)
Gas and Misc (MW)	7,541	7,497	(44)
IPP (MW)	2,653	2,653	0
Total Thermal Resource	**15,096**	**14,661**	**(352)**
Wind Nameplate (MW)	4,896	4,906	10
Solar Nameplate (MW)	396	407	11

Table 16: Standby Resource Assumptions – Peak (MW)

Item	Oct-Mar	Apr-Sep
Exist DR	373	791
Emergency Generation	288	288
Total Existing	**661**	**1079**

Table 17: Standby Resource Assumptions – Energy (MW-hours)

Item	Oct-Mar	Apr-Sep
Monsanto Curtailment	35,000	35,000
Emergency Generation	6,900	6,900
Total Existing	**41,900**	**41,900**

Table 18: Firm Contracts

2022	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep	Ann
Canada/PNW West	22	40	51	65	71	63	30	30	30	39	28	21	21	16	39
PNW West/Canada	455	456	455	455	455	455	455	455	455	455	479	568	572	455	467
PNW West/S Cal	21	18	14	7	12	14	25	29	30	30	30	19	25	24	21
Net Out of Region	454	434	418	397	396	406	450	454	455	446	481	566	576	463	449

2021	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep	Ann
Canada/PNW West	9	17	21	27	30	26	13	13	12	16	11	9	9	7	16
PNW West/Canada	454	454	454	454	454	454	454	454	454	454	463	470	509	450	458
PNW West/S Cal	32	18	16	14	13	22	27	30	29	92	203	23	31	29	44
Net Out of Region	477	455	449	441	437	450	468	471	471	530	655	484	531	472	486

Difference 2022 - 2021	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep	Ann
Canada/PNW West	13	23	30	38	41	37	17	17	18	23	17	12	12	9	23
PNW West/Canada	1	2	1	1	1	1	1	1	1	1	16	98	63	5	9
PNW West/S Cal	-11	0	-2	-7	-1	-8	-2	-1	1	-62	-173	-4	-6	-5	-23
Net Out of Region	-23	-21	-31	-44	-41	-44	-18	-17	-16	-84	-174	82	45	-9	-37

Table 19: BPA Within-hour Balancing Reserves – Incremental (MW)

Period	2021	2022
October	900	524
November	900	524
December	900	524
January	900	524
February	900	524
March	900	524
April 1-15	400	524
April 16-30	400	524
May	400	524
June	400	524
July	900[14]	524
August 1-15	900	524
August 16-31	900	524
September	900	524

[14] BPA's DEC reserve requirements of 400 megawatts extend through the end of July but the analysis in this report incorrectly assumed that the July reserve requirement was 900 megawatts. It was determined that rerunning all of the studies to include this correction was not warranted.

Table 20: Within-hour Balancing Reserves – Decremental (MW)

Period	2021	2022
October	900	638
November	900	638
December	900	638
January	900	638
February	900	638
March	900	638
April 1-15	900	638
April 16-30	900	638
May	900	638
June	900	638
July	900	638
August 1-15	900	638
August 16-31	900	638
September	900	638

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply annually as a check for power supply adequacy. This task is becoming more challenging because planners must now focus on satisfying not only winter energy needs but also summer energy needs and capacity needs year round. Continued development of variable generation resources combined with changing load patterns has added complexity to this task. 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[15] 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

Issues identified in 2017 by the Council's Resource Adequacy Advisory Committee to consider for future assessments include:

Action-1	Review and update the availability of California market supplies for all months and all hours.
Action-2	Incorporate the effects of energy efficiency savings and of codes and standards directly into the Council's load forecasting model for adequacy assessments.
Action-3	Investigate ways to incorporate uncertainty in EE savings into adequacy assessments.

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

Action-4 Investigate the availability of the interties that connect the NW with regions that may provide market supplies. Consider adding maintenance schedules and forced outages.

Action-5 Explore ways to incorporate the effects of climate change into the adequacy assessments.

Action-6 Develop a method to explicitly model the use of standby resources for adequacy assessments, in particular demand response and storage.

Not all of the action items and recommendations listed above will be addressed and resolved before the next adequacy assessment, which is tentatively scheduled for release in May of 2018. However, any enhancements that can be made and tested in time for the next assessment will be implemented.