WECC

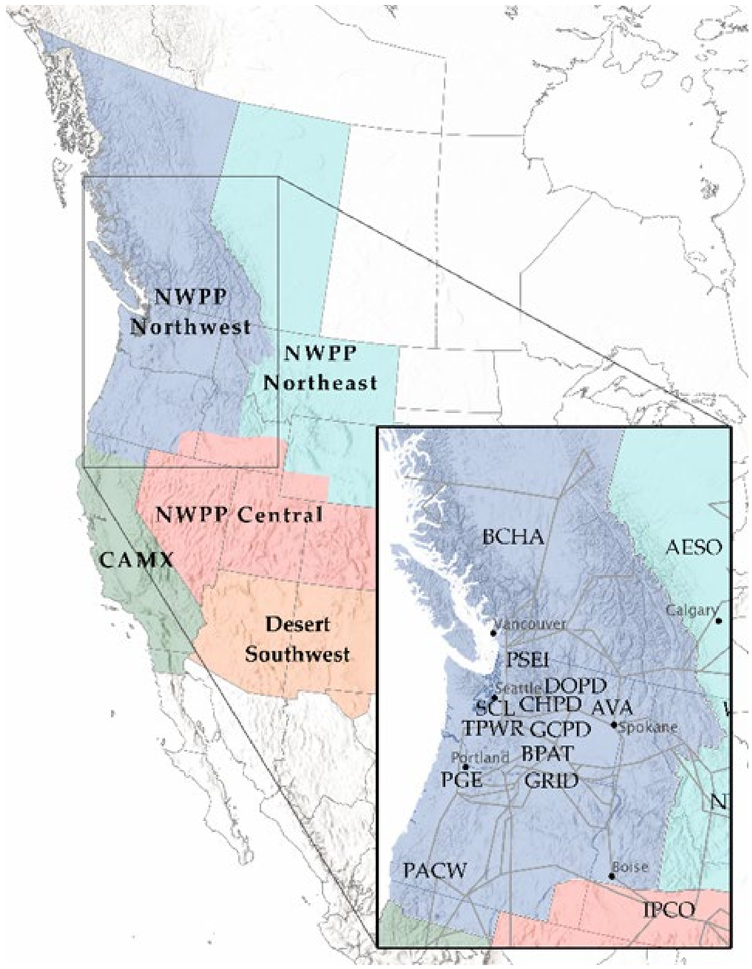
Western Assessment of Resource Adequacy Subregional Spotlight: Northwest Power Pool—Northwest

February 26, 2021

Northwest Power Pool—Northwest Subregion

WECC's Western Assessment of Resource Adequacy (Western Assessment)[1] divides the Western Interconnection into five subregions to account for geographic, operational, and system diversity (See Figure 1). As described in the assessment, each subregion faces unique resource adequacy challenges that require tailored solutions. The Western Assessment, released December 18, 2020, discussed resource adequacy at an interconnection-wide level. This subregional spotlight focuses on the Northwest Power Pool—Northwest (NWPP-NW) subregion. The NWPP-NW subregion is a winter-peaking area that includes British Columbia, Washington, Oregon, and parts of Montana, Idaho, and California.

Figure 1: Northwest Power Pool—Northwest Subregion



The discussions of each subregion are similarly structured and cover six areas:

1. **Key Findings**: Highlighted takeaways specific to the subregion.
2. **Demand Analysis**: Assessment of peak demand and annual demand, as well as the variability in the subregional demand forecast.
3. **Resource Availability Analysis**: Description of the subregion's resource portfolio and expected changes over the 10-year study period, as well as the variability in the expected availability of each type of resource.
4. **Planning Reserve Margin Analysis**: Assessment of the planning reserve margins needed to maintain the one-day-in-ten-year (ODITY) threshold.
5. **External Assistance Analysis**: Assessment of the availability of excess resources in the other subregions, focused on time of need, and a discussion of potentially available assistance.
6. **Demand at Risk**: A study of the annual and peak day demand at risk before external assistance.

[1] The Western Assessment was released on December 18, 2020. The assessment contains an explanation of terms and WECC's methods and tools.

Key Findings

These findings, along with findings from the other subregions, are summarized in the Western Assessment document.

Demand

In 2021, the NWPP-NW subregion is expected to peak in mid-January at about 39,300 MW. However, there is a 5% probability that the subregion could peak as high as 45,300 MW, which equates to a 15% load forecast uncertainty. Overall, the NWPP-NW subregion should expect a 51% ramp, or 13,400 MW, from the lowest to the highest demand hour of the peak demand day.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 44,400 MW. However, under low-availability conditions, the NWPP-NW subregion may only have 29,200 MW of resources available to meet the expected 39,300 MW peak. Although there is only a 5% probability of this occurring, significant imports would be needed to meet demand under low-availability conditions. Baseload resources account for roughly 14,700 MW of the subregion's resource availability and, under low availability conditions (5% probability), baseload resources could supply as little as 12,300 MW. Hydro generation availability could range from an expected availability of 29,400 MW to a low of 17,200 MW; again, a 5% probability. Wind resources show the greatest amount of variation in availability. Wind generation could range from an expected availability of 300 MW to a low of zero MW (5% probability).

Planning Reserve Margin

For 2021, an annual planning reserve margin of 15% is enough to maintain the median resource adequacy ODITY threshold for the NWPP-NW subregion. However, in the spring months when variability in energy supply and demand is highest, a planning reserve margin as high as 42% may be needed to maintain the ODITY threshold. As more variable resources are added to the system, a larger planning reserve margin is needed to compensate for variability in the system and remain resource adequate.

Annual Demand at Risk

Hours at Risk

In 2021 and beyond, even with all planned resource additions, the NWPP-NW subregion needs external assistance to maintain resource adequacy. In 2021, in the Stand-alone EX scenario, the NWPP-NW subregion could experience as many as 208 hours in which the ODITY threshold of resource adequacy is not maintained. Under the Stand-alone T1 scenario, the potential demand at risk is reduced to 195 hours. This is further reduced to 194 hours under the Stand-alone T2 scenario.

In all variations of the import scenario (EX[2], T1[3], and T2[4]), there are no hours that fail to meet the ODITY threshold.

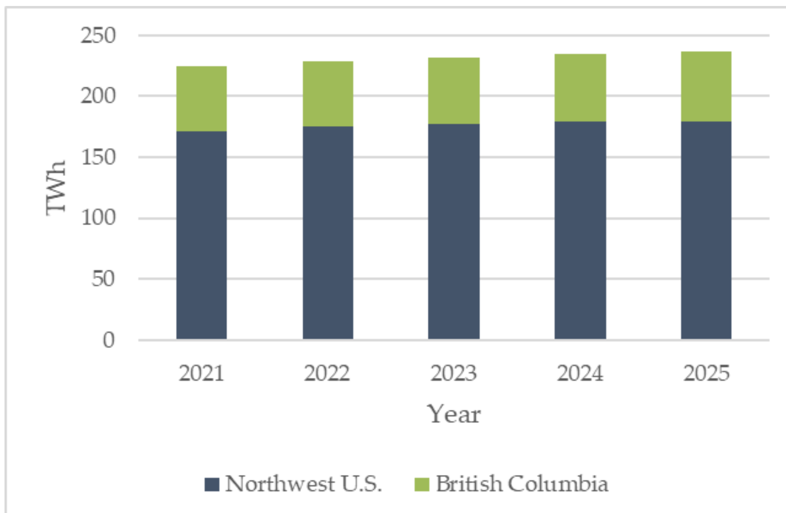
Energy at Risk

Energy at risk is the sum of all the demand at risk over the year. In 2021, the total energy at risk in the stand-alone scenario is about 26 GWh. Spread over the 208 hours at risk in this scenario, this means about 125 MW of unserved demand per at-risk hour. This trend continues through 2024, with increasing levels of demand at risk each year.

Demand Analysis

WECC examines three demand categories in its resource adequacy analysis: annual demand, peak day demand, and peak hour demand.

Figure 2: Annual Demand



Annual Demand

From 2021 to 2025, annual energy demand in the NWPP-NW subregion is expected to increase from 224.5 TWh to 236.3 TWh. The U.S. portion accounts for the largest part of the demand in the subregion (See Figure 2).

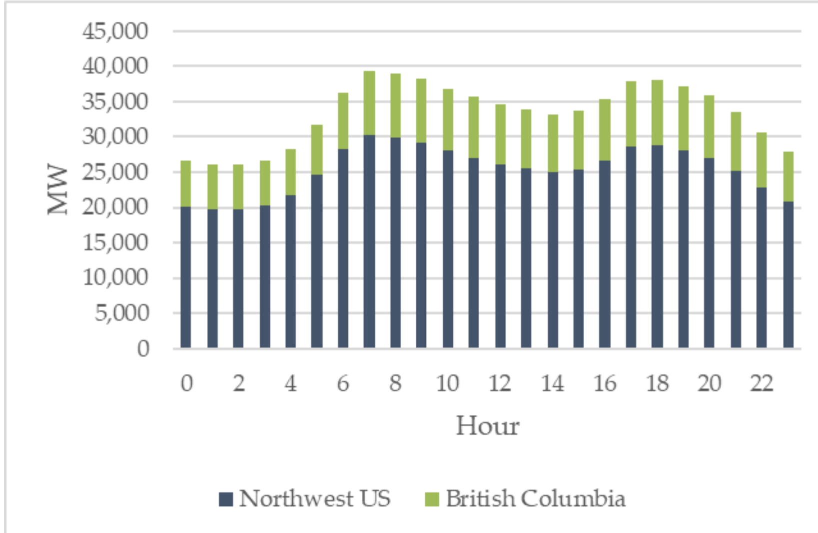
[2] Existing (EX): Resources that are in service and can be expected to run in future forecasts, barring unforeseen circumstances that take them off-line.

[3] Tier-1 (T1): Resources that are under construction and expected to be complete and available for the year being studied.

[4] Tier-2 (T2): Resources that are under contract but have yet to begin construction. These resources may be on-line by the year being studied.

Peak Demand

Figure 3: Peak Day Demand—2021



In 2021 the NWPP-NW subregion's coincident peak demand hour is expected to be at 7:00 a.m. on the peak demand day. The lowest demand that day is expected to be at 2:00 a.m. (See Figure 3). Over the five hours from 2:00 to 7:00 a.m., demand is expected to increase 51% from 26,000 MW to over 39,000 MW across the subregion.

Demand Variability

Variability in demand occurs every hour. Understanding how demand variability can affect resource adequacy allows planners to plan for the variability. Many factors drive demand variability, including weather, technology, policy, energy efficiency, and shifting demographics. Demand forecasts represented as a single number do not capture demand variability adequately. Instead, demand forecasts that provide a range of possible demand values allow resource adequacy analyses to account for demand variability across a probability distribution. As more demand or consumer-side programs, like home batteries, electric vehicles, rooftop solar, or demand response programs are added to the interconnection, variability in demand will continue to grow. Increased variability means more uncertainty in demand forecasts, which may affect resource adequacy for the entire Western Interconnection.

Figure 4: Peak Hour Demand Distribution Curve—2021

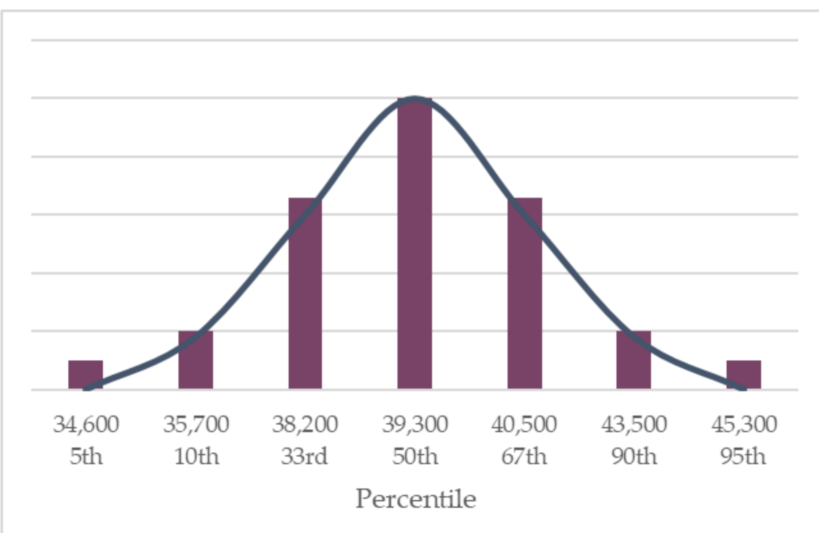
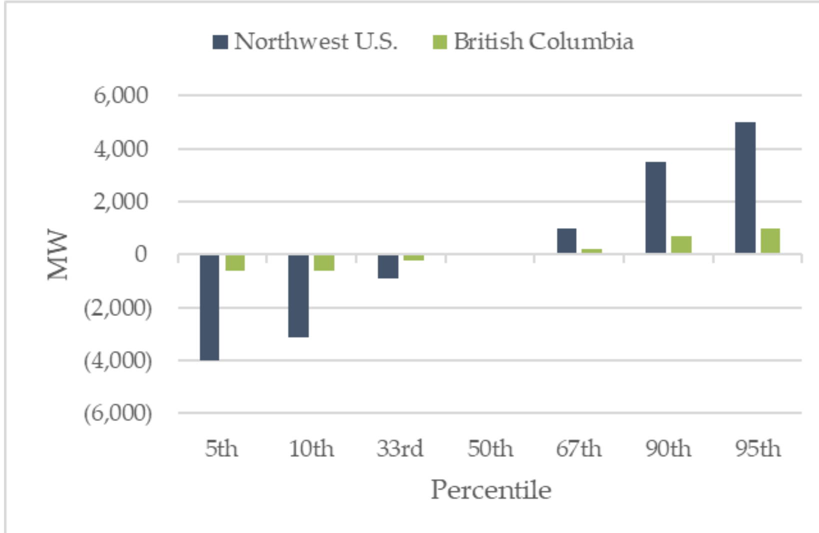


Figure 4 shows the degree of demand variability in the NWPP-NW subregion. On the peak hour of 2021, there is an equal probability that demand could be higher or lower than 39,300 MW. In an extreme scenario (a 5% probability of occurring), demand could increase from the forecast demand of 39,300 to 45,300 MW, which is 6,000 MW or 15% higher than expected. Likewise, there is a 10% possibility that demand could be 43,500 MW, or 4,200 MW higher than expected.

While all areas within the subregion have some degree of demand variability, the variability is not the same for all areas because of factors like weather. Figure 5 shows the variability within the NWPP-NW subregion, reported by the U.S. and British Columbia areas. The NWPP-NW U.S. part of the subregion has the largest and most variable demand in the subregion. The U.S. demand ranges from 4,000 MW below the expected demand to 5,000 MW above it. The British Columbia area's variability can range from 600 MW less than expected to 1,000 MW more than expected.

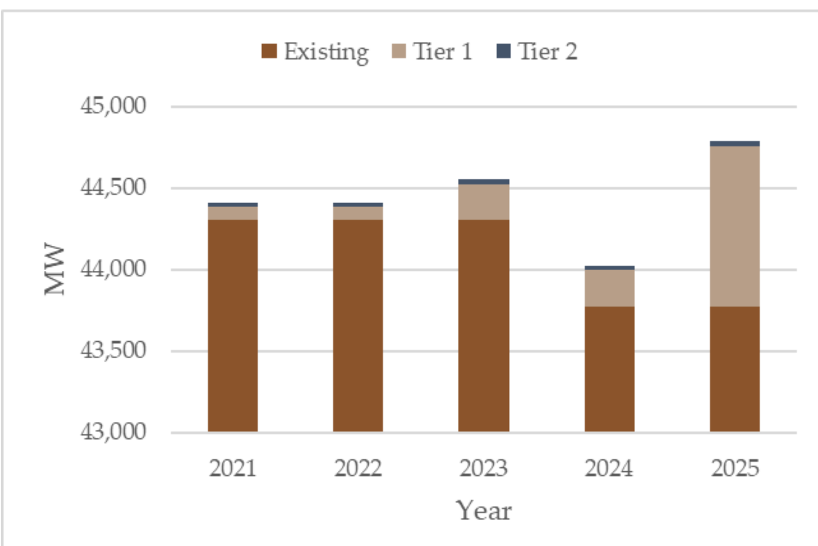
Figure 5: Demand Variance by Area—2021



Resource Availability Analysis

WECC analyzes resource availability for both the peak hour and peak day. This assessment analyzes the amount of generation that is expected to be available from a resource, which varies greatly by resource type.

Figure 6: Peak Demand Hour Availability by Tier



Peak Hour Availability

In 2021, available generation in the NWPP-NW subregion is expected to be about 44,300 MW (See Figure 6). The planned retirement of coal-fired and other baseload resources reduces this number by 500 MW by the end of 2025; however, Tier 1 and Tier 2 resource additions that are expected to be on-line by 2025 increase the peak hour generation availability to 44,800 MW.

Table 1 below shows the total MW each resource type is expected to contribute to resource availability during the peak hour over the next five years. Baseload resources account for about 33% of available generation in 2021 and remain relatively stable through 2025. The amount of available generation for the peak demand hour is expected to remain relatively stable over the next five years for baseload, hydro, and wind generation, taking planned retirements and additions into account.

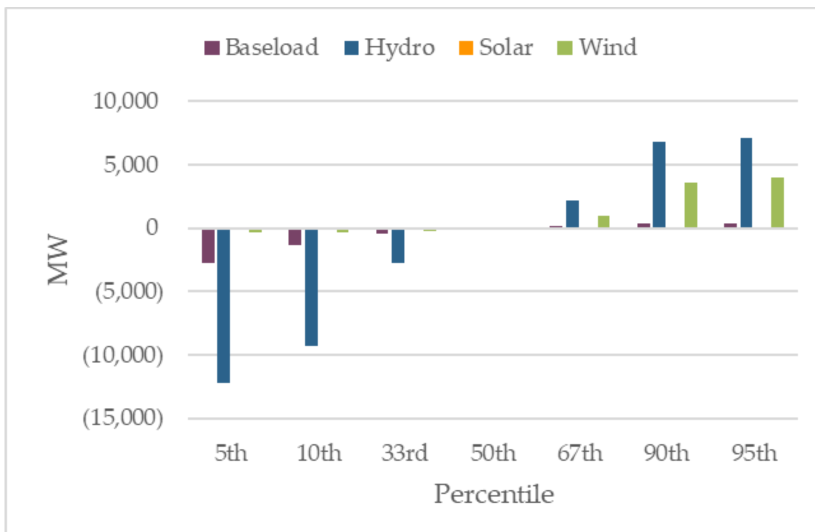
Table 1: Peak Demand Hour Availability by Type (MW)

	2021	2022	2023	2024	2025
Baseload	14,687	14,654	14,687	14,159	14,159
Hydro	29,376	29,376	29,516	29,516	30,276
Solar	5	4	5	5	5
Wind	344	344	344	344	344

Variability by Resource Type

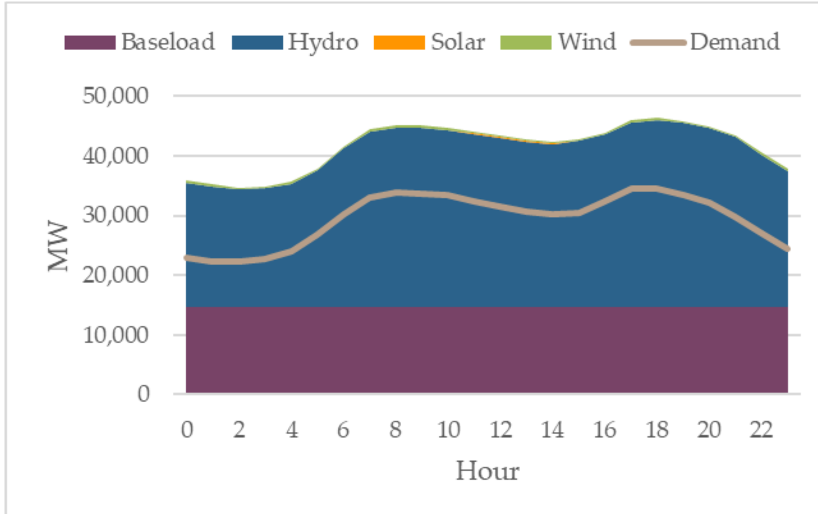
Figure 7 shows how resource availability varies by resource type across the NWPP-NW subregion. Under expected conditions, baseload resources can provide about 14,700 MW; under low availability conditions, baseload resources could supply 2,400 MW less than expected, reducing availability to 12,300 MW. There is a 5% probability of the low availability conditions occurring. Hydro generation has an expected availability of about 29,400 MW, but under low availability conditions, a 5% probability, hydro could supply 12,200 MW less than expected. This would reduce availability to 17,200 MW. Likewise, there are conditions in which hydro generation could produce over 36,000 MW, an increase of over 7,000 MW, also a 5% probability of happening. Wind resources also have a wide range of availability. Although wind is expected to produce around 300 MW, that value can vary from a low availability of 0 MW to a high of over 4,000 MW, both with a 5% probability.

Figure 7: Resource Variance by Type—2021



Peak Day Availability

Figure 8: Peak Day Resource Type Availability—2021



In addition to analyzing generation availability on the peak hour, WECC looks at generation availability on the peak day. Figure 8 shows the peak demand day for 2021 in the NWPP-NW subregion along with the expected resource availability by resource type. The NWPP-NW subregion depends largely on hydro (with storage) and baseload resources, which creates less variability throughout the day and decreases uncertainty in resource adequacy planning.

Resource Availability Variability

The NWPP-NW subregion's resource portfolio is less variable than other subregions; though, it is still subject to a range of availability based on the probability distribution across the subregion.

Figure 9: Peak Hour Availability Distribution Curve—2021

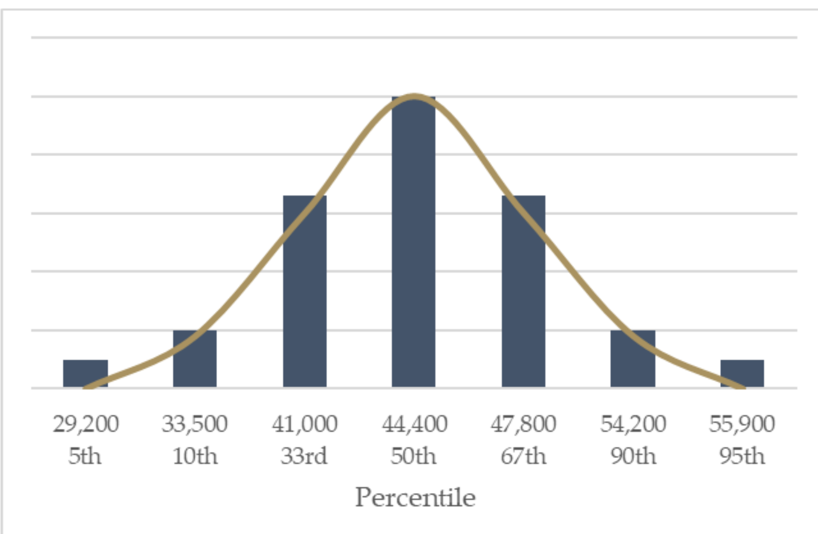
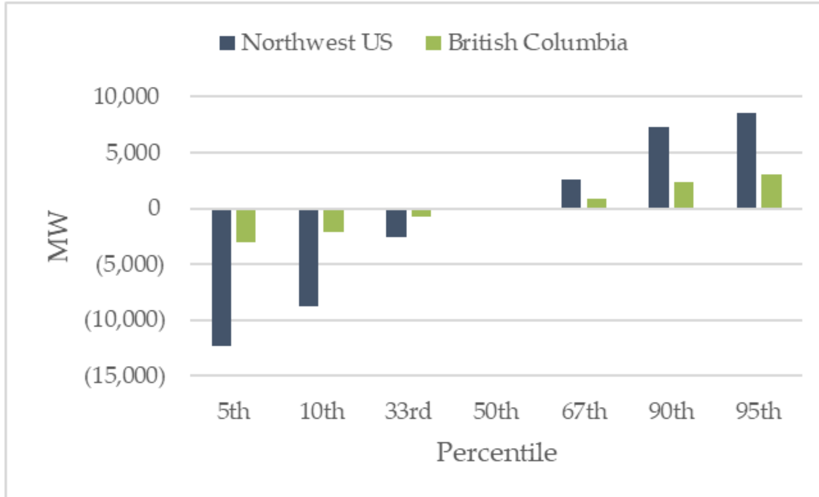


Figure 9 shows the expected variability of generation availability in the NWPP-NW subregion. The figure highlights the NWPP-NW subregion's total generation availability at different levels of probability. In 2021, at least 44,400 MW of generation is expected to be available 50% of the time, while 50% of the time availability is expected to be less than 44,400 MW. Likewise, the chart shows that 33% of the time generation availability could be lower than 41,000 MW, 10% of the time the availability could be lower than 33,500 MW, and in extreme cases, 5% of the time the availability could be lower than 29,200 MW.

In rare cases where generation availability could be extremely low, meeting demand while maintaining operating reserves may be difficult. Because resource availability differs across resource types, WECC analyzes the types of resources in a portfolio in addition to the generation capacity.

Figure 10 shows the differences in resource variability within the NWPP-NW subregion. The Northwest U.S. part of the subregion has the greatest amount of variability in resource availability, ranging from 12,300 MW less to about 8,600 MW more than expected, both cases with 5% probability. The British Columbia part has mostly hydro generation coupled with storage capability, which results in narrower variability, ranging from 3,000 MW below to 3,000 MW above expected.

Figure 10: Resource Variance by Area—2021



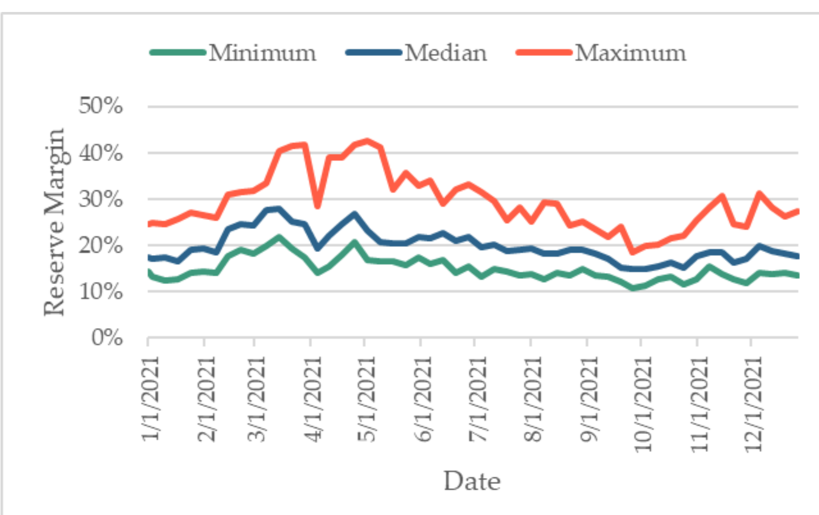
Planning Reserve Margin Analysis

The expected variability in both demand and resource availability emphasizes the importance of maintaining a planning reserve margin that accounts for variations in seasonal and hourly supply and demand. The planning reserve margins are calculated based on the stand-alone scenario and variances.

Reserve Margin—Percentage

Under different supply and demand scenarios, the planning reserve margin changes. When demand and resource variability are lower, a lower planning reserve margin is required to meet the ODITY threshold. Conversely, when demand and resource variability are greater, a higher planning reserve margin is required to meet the ODITY threshold. The difference in conditions leads to a range of planning reserve margins. Figure 11 highlights the range of potential reserve margins necessary to cover demand and resource variability across the NWPP-NW subregion in 2021.

Figure 11: Planning Reserve Margin Plot—Percent



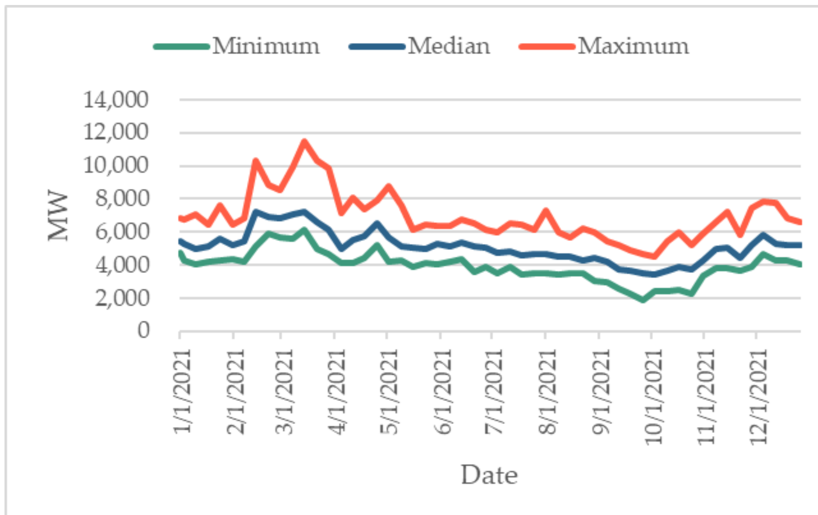
The planning reserve margin is calculated for every hour of the year. The figure shows the minimum, median, and maximum planning reserve margin for each week of 2021. For example, the minimum planning reserve margin for the first week of January 2021 is 14%, while the median planning reserve margin for that week is 17%, and the maximum planning reserve margin for that week is 24%.

The planning reserve margin in 2021 ranges from 10% to 42% with the lowest value occurring in September and the highest value occurring in March and May. There are 7,932 hours in which the planning reserve margin is at or above 15%. This means, if a flat 15% reserve margin were applied to all hours of the year, almost 91% of the hours would not meet the ODITY threshold.

Reserve Margin as Megawatts

Figure 12 shows the planning reserve margin ranges for the NWPP-NW subregion. For the entire subregion, the minimum planning reserve margin needed to maintain the ODITY threshold is as high as 6,000 MW in the spring to as low as about 2,000 MW in the fall. The median planning reserve margin ranges from about 3,400 MW in the fall to almost 7,200 MW in the spring. The maximum planning reserve margin needed to meet the ODITY threshold ranges from 4,600 MW in early October to 11,400 MW in mid-March.

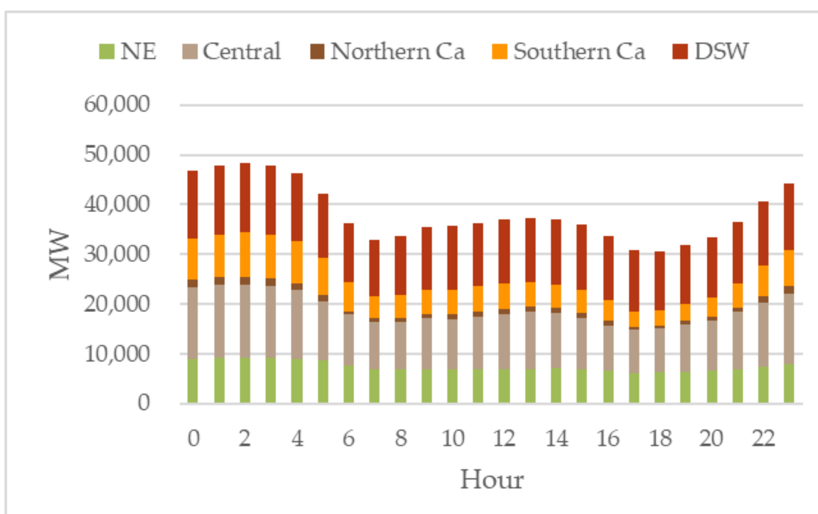
Figure 12: Planning Reserve Margin Plot—MW



External Assistance Analysis

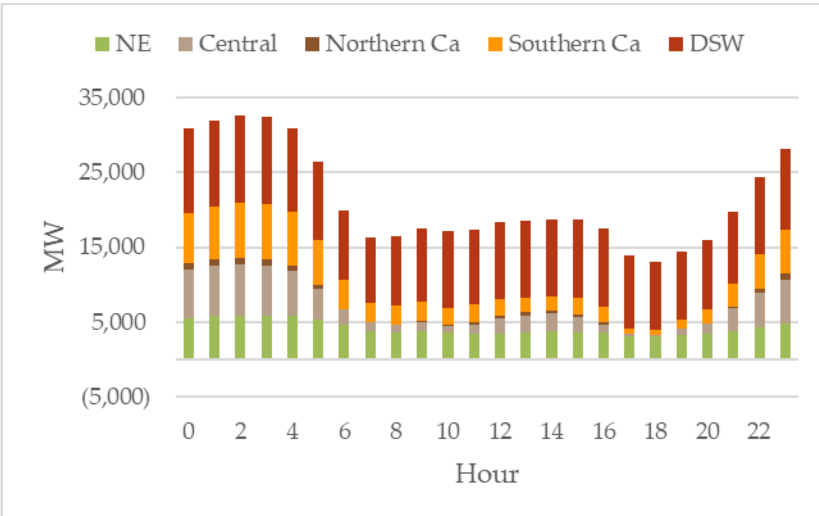
External assistance, or energy that is available to import from other subregions, can only be counted on when the energy and transmission are available. Figure 13 shows the potential imports available for the NWPP–NW subregion's peak demand day in mid-January, assuming expected demand and resource availability and Tier 2 resources are built. Under this scenario, all regions outside NWPP-NW have resources available and

Figure 13: Peak Day Expected Import Availability—2021



could provide imports during the NWPP-NW's peak hour, which occurs at 7:00 a.m. However, if all the subregions experience low resource availability at the same time, the potential for them to provide imports is reduced by about 50% from over 30,000 MW to about 15,000 MW (Figure 14). If all the other subregions experience high demand and low resource availability at the same time, imports into the NWPP-NW subregion may not be available. This was the case in the California-Mexico (CAMX) subregion during the August 2020 Heatwave Event, in which coincident high demand and low availability occurred across the Western Interconnection, vastly reducing available imports into the CAMX subregion. The probabilities of all subregions experiencing high demand and low availability at the same time is very low. However, as weather patterns and the resource mix continues to change, the likelihood of extreme demand and supply events stressing resource adequacy also increases.

Figure 14: Peak Day Low Import Availability—2021



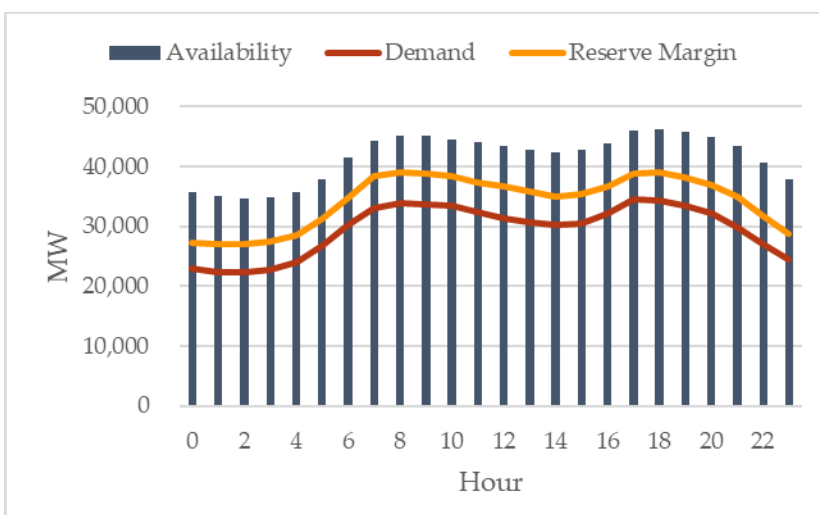
Demand at Risk

Demand at risk is the amount of end-customer demand that may not be served, or is at risk of not being served, due to a deficiency of generation. WECC analyzes demand at risk on both the peak demand day and annually.

Peak Day Demand at Risk

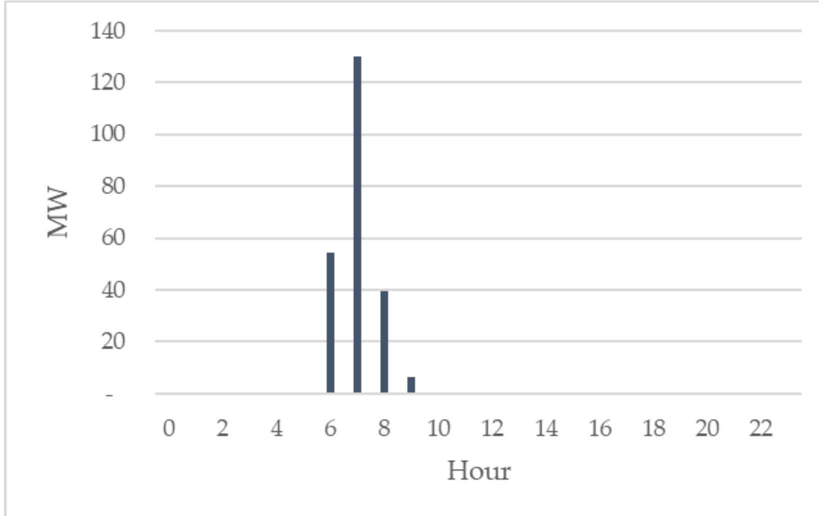
Figure 15 shows expected supply, demand, and planning reserve margin for the NWPP-NW subregion's peak demand day in mid-January 2021. Under expected demand and expected availability of resources on the peak day, the NWPP-NW subregion may experience some hours in the U.S. part of the subregion in which demand is at risk of not being served

Figure 15: Peak Day Condition Expectations—2021



with internally available resources (See Figure 16). During these hours, the Northwest U.S. area may need imports from British Columbia or another subregion to maintain the ODITY threshold. On the peak hour of 2021, the U.S. portion of the NWPP-NW subregion has just over 130 MW of demand at risk of not being served with Tier 1 and 2 resources, without imports from external areas. If resources fall short of expected availability, or if demand is higher than expected, demand may be at risk of not being served.

Figure 16: Peak Day Potential Demand at Risk—2021



Annual Demand at Risk

Figure 17 shows the number of expected hours in 2021 through 2024 in which the ODITY threshold of resource adequacy is not met for each of the six scenarios studied. In 2021, in the Stand-alone EX scenario, the NWPP-NW subregion could experience 208 hours in which the ODITY threshold of resource adequacy is not maintained. Under the Stand-alone T1 scenario, the potential demand at risk is reduced to 195 hours. This is further reduced to 194 hours under the Stand-alone T2 scenario. The assessment indicates that, even with all planned resource additions, the NWPP-NW subregion will still rely on external assistance to maintain the ODITY threshold as early as 2021.

Figure 17: Potential Demand at Risk Hours

In all variations of the import scenario (EX, T1, and T2), there are no hours that fail to meet the ODITY threshold.

Energy at Risk

Figure 18: Potential Demand at Risk GWh

In 2021, nearly 26 GWh of energy are at risk of not being served in the Stand-alone EX scenario (See Figure 18). Spread over the 208 hours at risk in this scenario, this means there will be about 125 MW of demand at risk per hour. This trend continues through 2024, with increasing levels of demand at risk each year for each of the stand-alone scenarios.

The assessment indicates that, for the stand-alone scenarios, under all variations, additional or different types of resources (above those planned to be added over the next four years) are needed for the NWPP-NW subregion to remain resource adequate and avoid unserved demand.

Conclusion

As early as 2021, under expected conditions, the NWPP-NW subregion may experience 208 hours in which demand is at risk of not being served with internally available resources. When including imports from other subregions across the Western Interconnection, the NWPP-NW subregion can eliminate all hours in which the ODITY threshold is unmet. The assessment indicates that entities in the NWPP-NW subregion need to build the resources currently included in the construction queue as part of the solution to maintain the ODITY threshold. At times, the subregion will depend on imports from other subregions to maintain resource adequacy. The growing variability in both supply and demand across the Western Interconnection increases the risk that imports may not be available to maintain the resource adequacy threshold. Therefore, the subregion should consider the degree to which it plans to rely on imports from other subregions and consider supplementing its own resources to remain resource adequate.

Appendix A

Announced and Expected Generation Retirements Used in the MAVRIC Model

Announced and Expected Generation Retirements (2020-2030)							
Subregion	State / Province	Unit Name	Unit Number	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date
NWPP - NW	WA	TransAlta Centralia Gen LLC	ST1	729.88	Bituminous Coal	12/1/1972	12/1/2020
NWPP - NW	CA	Fall Creek	1	0.50	Water	9/1/1903	12/31/2020
NWPP - NW	OR	West Side	1	0.60	Water	3/22/1905	12/31/2020
NWPP - NW	CA	Fall Creek	2	0.45	Water	8/1/1907	12/31/2020
NWPP - NW	CA	Fall Creek	3	1.25	Water	1/1/1910	12/31/2020
NWPP - NW	CA	Copco 1	1	10.00	Water	1/1/1918	12/31/2020
NWPP - NW	CA	Copco 1	2	10.00	Water	11/1/1922	12/31/2020
NWPP - NW	OR	East Side	1	3.20	Water	8/1/1924	12/31/2020
NWPP - NW	CA	Copco 2	1	13.50	Water	7/1/1925	12/31/2020
NWPP - NW	CA	Copco 2	2	15.50	Water	8/1/1925	12/31/2020
NWPP - NW	OR	John C Boyle	1	50.35	Water	10/1/1958	12/31/2020
NWPP - NW	OR	John C Boyle	2	47.63	Water	10/1/1958	12/31/2020
NWPP - NW	OR	Boardman	1	63.22	Bituminous Coal	8/1/1980	12/31/2020
NWPP - NW	OR	Boardman	1	642.20	Subbituminous Coal	8/1/1980	12/31/2020
NWPP - NW	WA	TransAlta Centralia Gen LLC	ST2	729.88	Bituminous Coal	7/1/1973	12/1/2025
NWPP - NW	BC	Silversmith Power & Light	1	0.35	Water	10/1/2016	10/1/2026