WECC

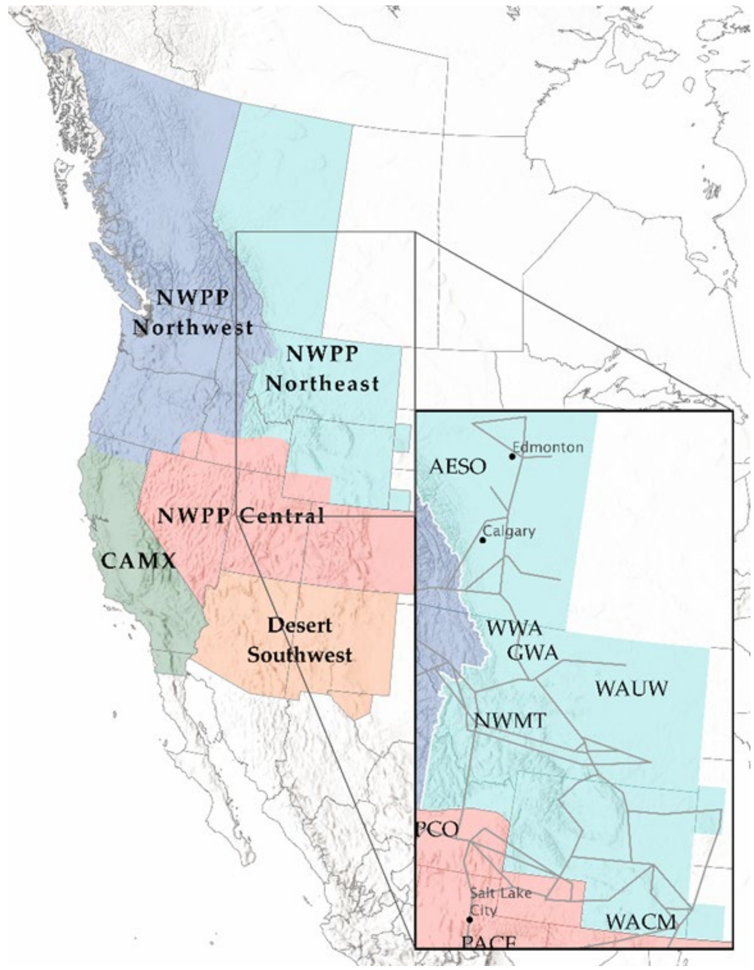
Western Assessment of Resource Adequacy Subregional Spotlight: Northwest Power Pool—Northeast

February 26, 2021

Northwest Power Pool—Northeast

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—Northeast (NWPP-NE) subregion. The NWPP-NE subregion is a winter-peaking area that covers the province of Alberta and parts of Montana, Idaho, Wyoming, South Dakota, and Nebraska.

Figure 1: Northwest Power Pool—Northeast Subregion



This spotlight document covers 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 a 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-NE subregion is expected to peak in early February at about 14,800 MW. However, there is a 5% probability that the subregion could peak as high as 15,600 MW, which is a 5% load forecast uncertainty. Overall, the NWPP-NE subregion should expect a 30% ramp, or 3,400 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 19,600 MW. However, under low availability conditions, the NWPP-NE subregion may have 16,700 MW available to meet the expected 14,800 MW peak, although there is only a 5% probability of this occurring. Baseload resources account for roughly 17,100 MW of the subregion's resource availability and, under low availability conditions (5% probability), baseload resources could supply as little as 15,300 MW. In addition, wind generation availability could range from an expected availability of 900 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-NE subregion. However, in the months in which variability in energy supply and demand is highest, a planning reserve margin around 22% 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-NE subregion needs external assistance to maintain resource adequacy. In 2021, in each of the stand-alone scenarios, the NWPP-NE subregion could experience up to 4,200 hours in which the ODITY threshold of resource adequacy is not maintained.

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 575 GWh. Spread over the 4,200 hours at risk in this scenario, this is about 137 MW of unserved demand per at-risk hour. This trend continues through 2024, with increasing levels of demand at risk each year.

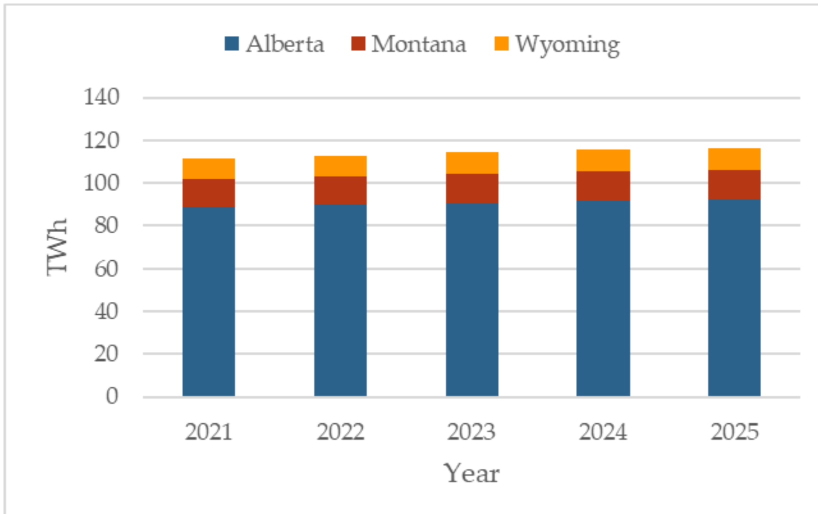
Demand Analysis

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

Annual Demand

From 2021 to 2025, annual energy demand in the NWPP-NE subregion is expected to increase from 111.5 TWh to 116.3 TWh. The Alberta area accounts for the largest part of the demand in the subregion (See Figure 2).

Figure 2: Annual Demand



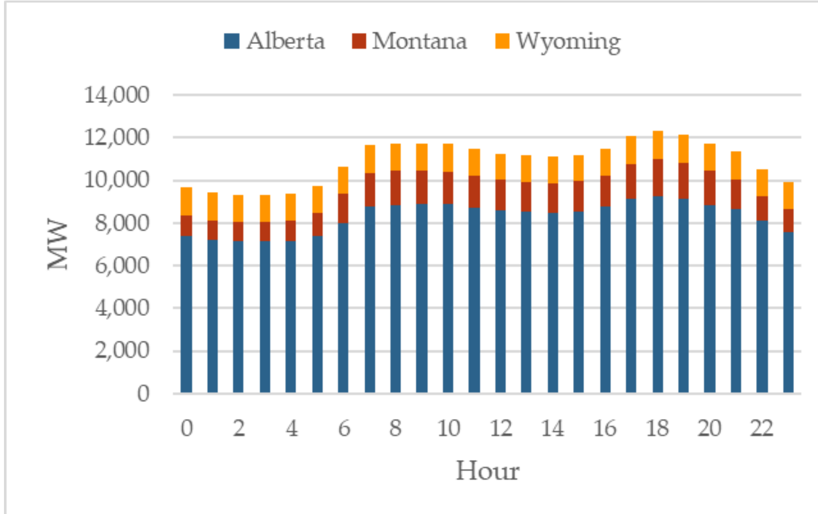
[2] Existing (EX): Resources that are in service and can be expected to run in future forecasts, barring unforeseen circumstances that take them off-line.

[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-NE subregion's coincident peak demand hour is expected to be at 6:00 p.m. on the peak demand day. The lowest demand that day is expected be at 3:00 a.m. (See Figure 3). Over the 15 hours from 3:00 a.m. to 6:00 p.m., demand is expected to increase more than 32%—from 9,300 MW to about 12,300 MW. The Alberta area is expected to see a 2,100 MW (30%) ramp on the peak day, while the Wyoming part expects to see a ramp of about 80 MW (7%). The Montana area has the largest ramp at almost 900 MW or about 96%.

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

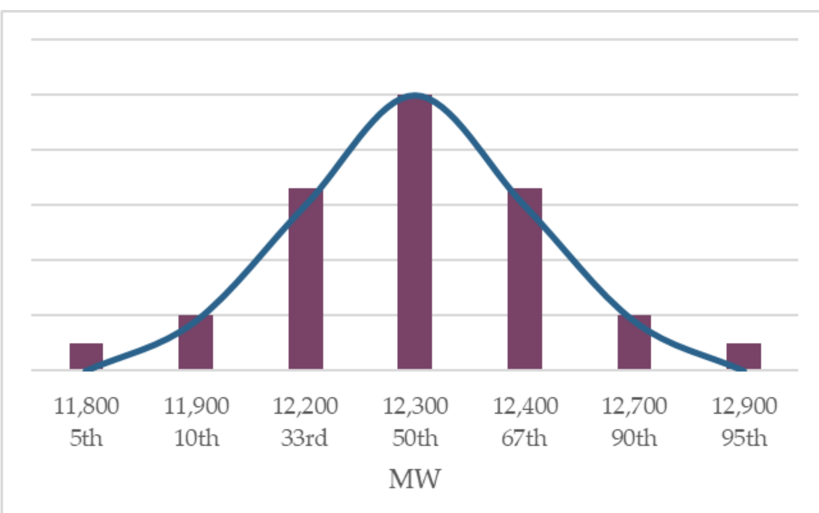
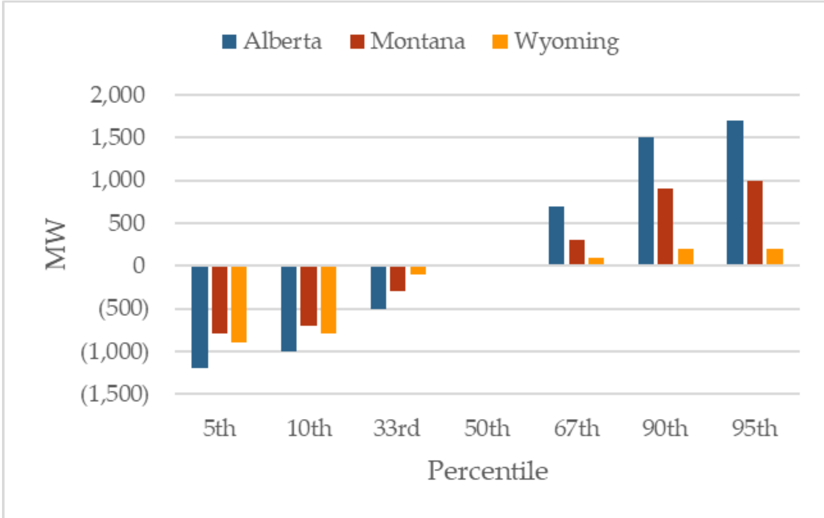


Figure 4 shows the degree of demand variability in the NWPP-NE subregion. On the peak hour of 2021, there is an equal probability that demand could be higher or lower than 12,300 MW. In an extreme scenario (a 5% probability of occurring) demand could increase from the forecast demand of 12,300 MW to 12,900 MW, which is 600 MW (5%) higher than expected. Likewise, there is a 10% possibility that demand could be 12,700 MW, which is 400 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-NE subregion, reported by area.

Figure 5: Demand Variance by Area—2021



The Alberta part of the subregion has the largest and most variable demand in the subregion. Alberta demand ranges from 300 MW below expected to 300 MW above it.

Resource Availability Analysis

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

Peak Hour Availability

In 2021, available generation in the NWPP-NE subregion is expected to be about 19,400 MW (See Figure 6). The planned retirement of coal-fired and other baseload resources reduces this number by 3,600 MW by the end of 2025. However, the addition of Tier 1 and Tier 2 resources expected to be on-line by 2025 increase the peak hour available generation to 20,200 MW. These Tier 1 and Tier 2 resources are primarily composed of baseload resources.

Figure 6: Peak Demand Hour Availability by Tier

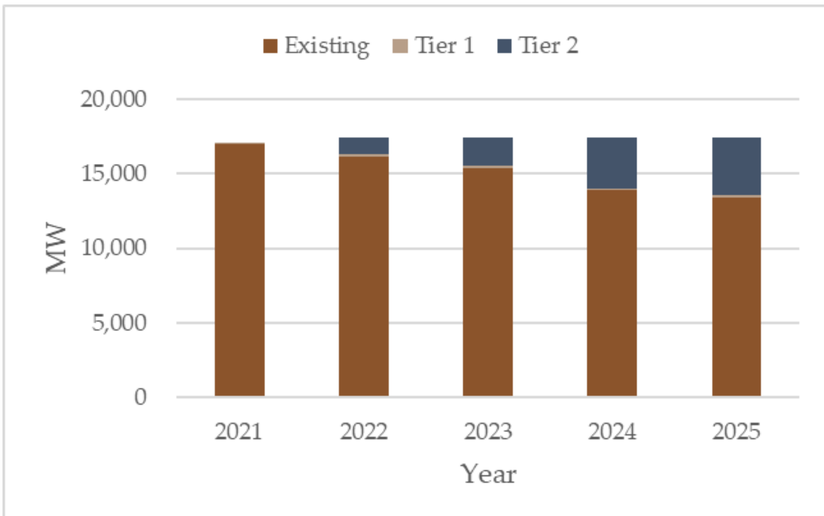


Table 1 shows the total megawatts each resource type is expected to contribute to resource availability during the peak hour over the next five years. Baseload resources account for about 17,100 MW, or 87% of the available generation in 2021, and increase through 2025 to almost 17,500 MW. Resource availability in the NWPP-NE is expected to remain quite stable with a good mix of baseload, hydro, and wind generation, taking planned retirements and additions into account.

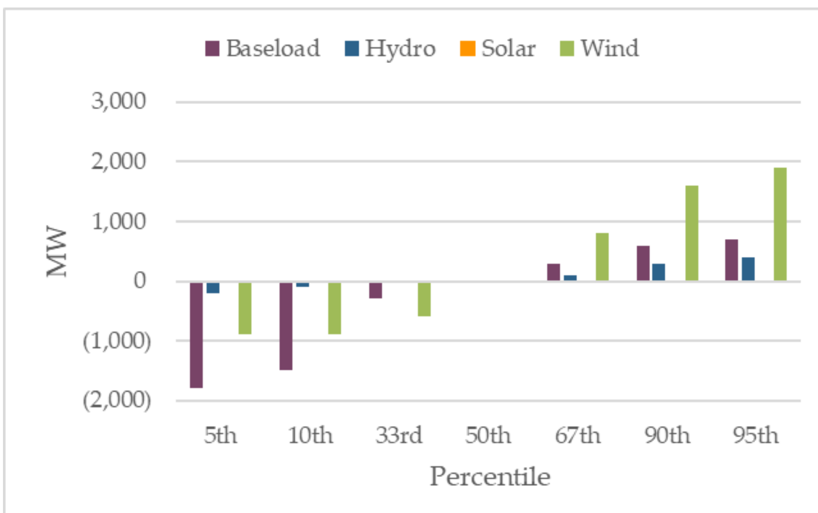
Table 1: Peak Demand Hour Availability by Type

	2021	2022	2023	2024	2025
Baseload	17,110	17,469	17,465	17,465	17,465
Hydro	1,628	1,628	1,628	1,628	1,628
Solar	0	0	0	0	0
Wind	863	1,082	1,082	1,082	1,082

Variability by Resource Type

Figure 7 shows how resource availability varies by resource type across the NWPP-NE subregion. Under expected conditions, baseload resources can provide about 17,100 MW; under low availability conditions, baseload resources could supply 1,800 MW less than expected, reducing availability to 15,300 MW. There is a 5% probability of the low availability conditions occurring. Likewise, there are conditions under which baseload generation could produce 700 MW more than expected, increasing availability to 17,800 MW. Hydro generation has an expected availability of 1,600 MW, but under low availability conditions, a 5% probability, hydro could supply 200 MW less than expected, which will reduce availability to 1,400 MW. Although wind is expected to produce around 900 MW, that value can vary from a low availability of zero MW to a high of over 2,800 MW, both in the 5% probability level.

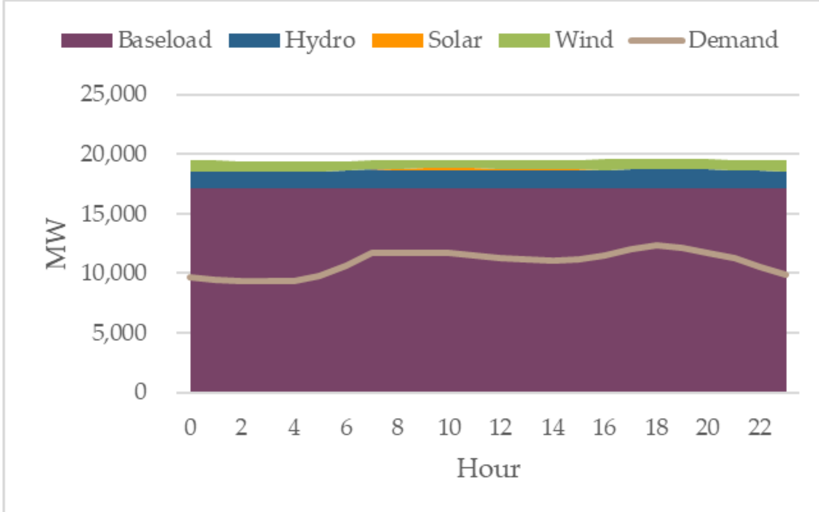
Figure 7: Resource Variance by Type—2021



Peak Day Availability

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-NE subregion along with the expected availability by resource type. The NWPP-NE subregion depends largely on baseload resources, which create less variability throughout the day and decrease uncertainty in resource adequacy planning.

Figure 8: Peak Hour Availability Distribution Curve—2021



Resource Availability Variability

The NWPP-NE 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

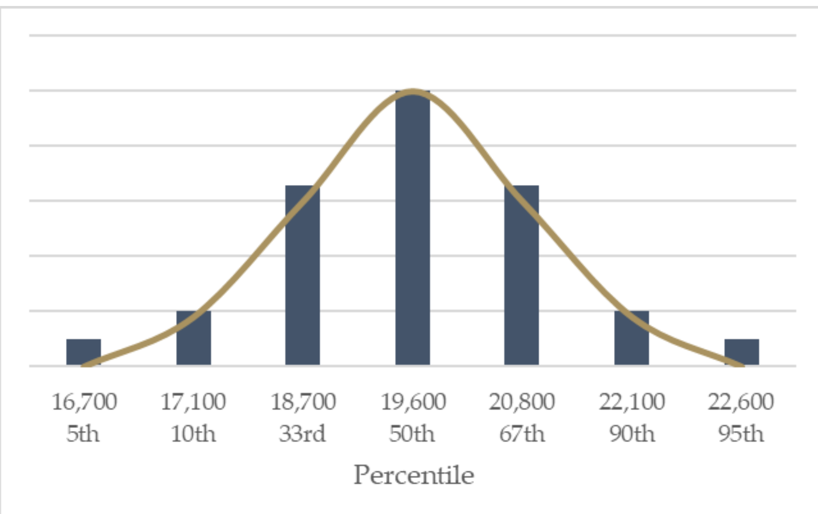
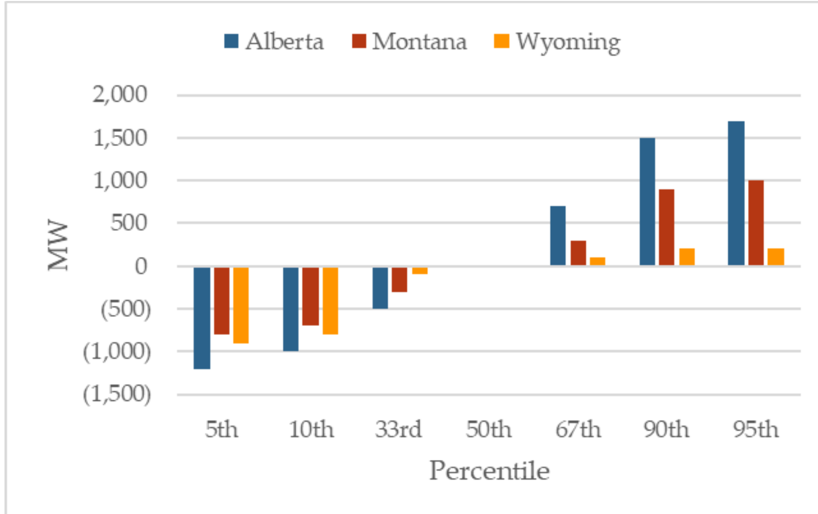


Figure 9 shows the expected variability of generation availability in the NWPP-NE subregion. The figure highlights the subregion's total generation availability at different levels of probability. In 2021, at least 19,600 MW of generation is expected to be available 50% of the time, while 50% of the time availability is expected to be less than 19,600 MW. Likewise, the chart shows that 33% of the time generation availability could be lower than 18,700 MW, 10% of the time the availability could be lower than 17,100 MW, and in extreme cases, 5% of the time the availability could be lower than 16,700 MW.

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

Figure 10 shows the differences in resource variability within the NWPP-NE subregion. The Alberta area has the greatest amount of variability in resource availability, ranging from 1,200 MW less to 1,700 MW more than expected, both cases with a 5% probability. The Montana and Wyoming parts show roughly the same amount of variability with about 850 MW less than expected to between 200 MW (Wyoming) and 1,000 MW (Montana) above expected availability.

Figure 10: Resource Variance by Area—2021



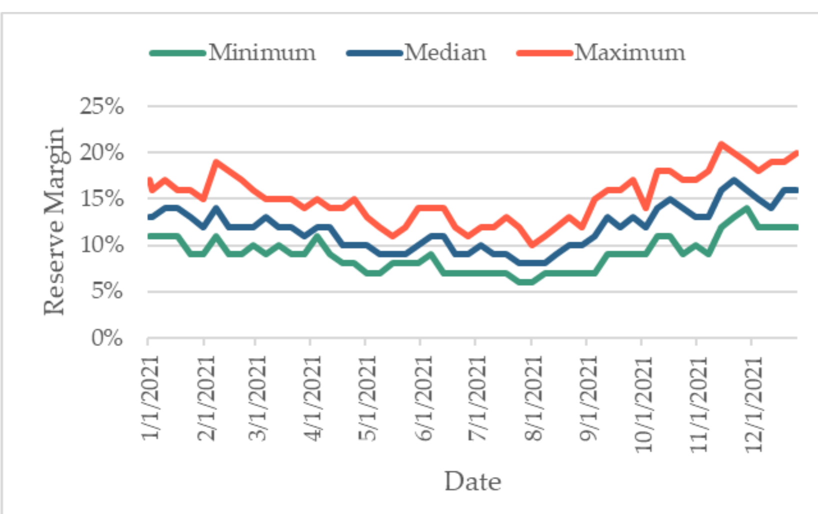
Planning Reserve Margin Analysis

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 needed 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-NE subregion in 2021.

Figure 11: Planning Reserve Margin Plot—Percent



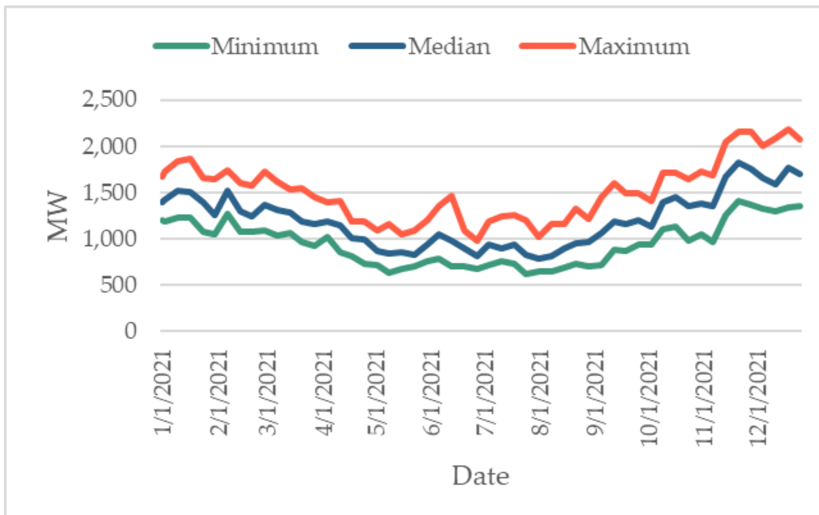
The planning reserve margin is calculated for every hour of the year. The figure shows the minimum, median, and maximum planning reserve margin for each week of 2021. For example, the minimum planning reserve margin for the first week of January 2021 is 11%, while the median planning reserve margin for that week is 14%, and the maximum planning reserve margin for that week is 17%.

The planning reserve margin in 2021 ranges from 7% to 22%, with the lowest value occurring in July and August, and the highest value occurring in November. There are 1,164 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, over 13% of the hours would not meet the ODITY threshold.

Reserve Margin as Megawatts

Figure 12 shows the planning reserve margin ranges for the NWPP-NE subregion in megawatts. For the entire subregion, the minimum planning reserve margin needed to maintain the ODITY threshold is as high as 1,500 MW in the winter to as low as about 700 MW in the summer. The median planning reserve margin ranges from about 1,800 MW in the winter to almost 900 MW in the summer. The maximum planning reserve margin needed to maintain the ODITY threshold ranges from a low of 1,100 MW in early July, to a high of 2,300 MW in mid-December.

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 14 shows the potential imports available for the NWPP-NE subregion's peak demand day in early February, assuming expected demand and resource availability and Tier 2 resources are included. Under this scenario, all subregions outside the NWPP-NE have excess energy available and could provide imports during the NWPP-NE's peak hour, which occurs at 6:00 p.m. However, if all the subregions experience low resource availability at the same time, the potential for them to provide imports is reduced by more than half: from about 30,000 MW to about 12,000 MW (See Figure 14). If all the other subregions experience high demand and low availability at the same time, imports into the NWPP-NE 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 probability of all subregions experiencing high demand and low availability at the same time is small. However, as weather patterns and the resource mix continue to change, the likelihood of extreme demand and supply events stressing resource adequacy also increases.

Figure 13: Peak Day Expected Import Availability—2021

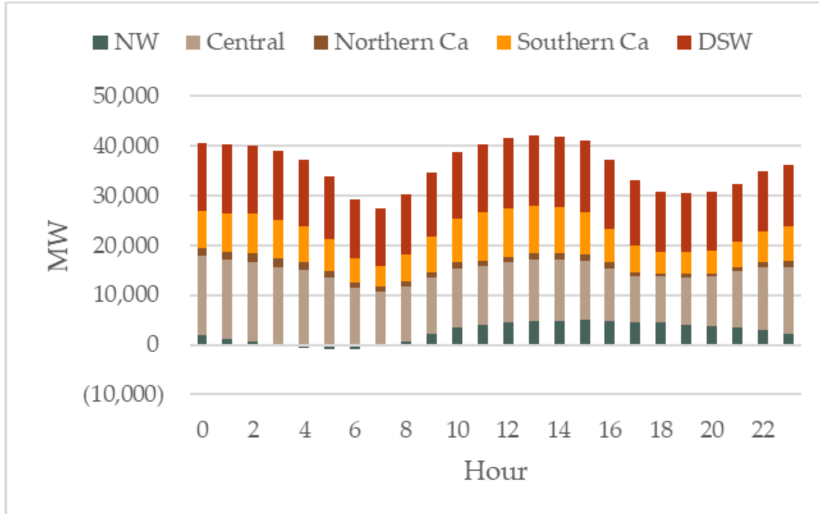
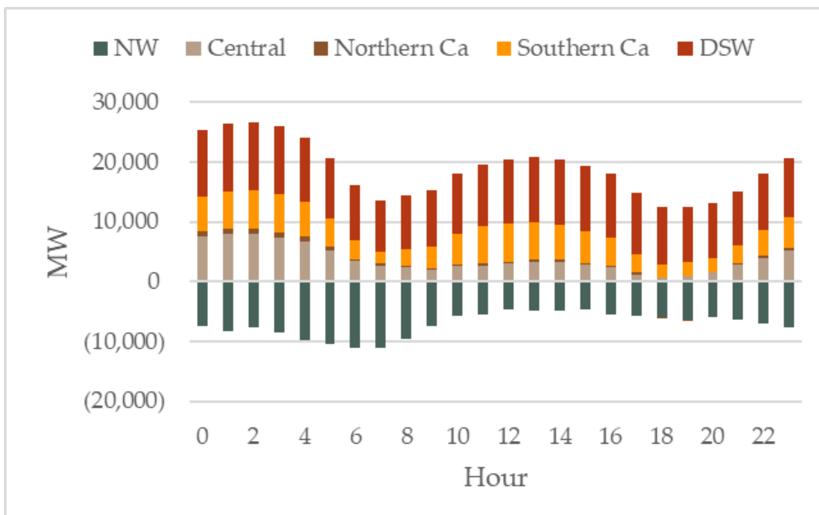


Figure 14: Peak Day Low Import Availability—2021



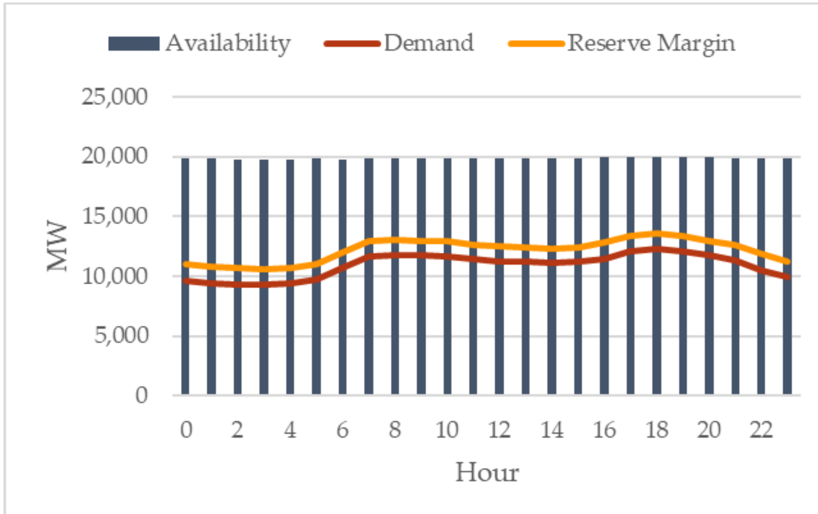
Demand at Risk

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 analyzed demand at risk on both the peak demand day and annually.

Peak Day Demand at Risk

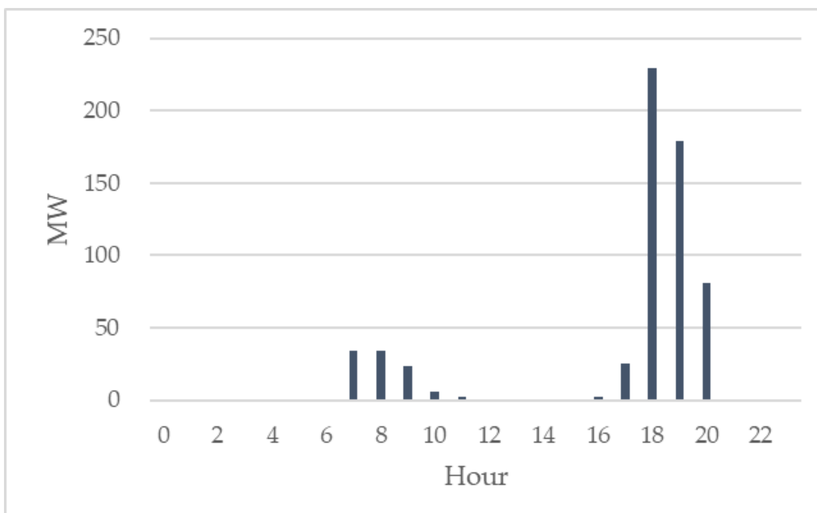
Figure 15 shows expected supply, demand, and planning reserve margin for the NWPP-NE subregion's peak demand day in February 2021. Under expected demand and expected availability of resources on the peak day, the NWPP-NE subregion as a whole is expected to meet demand and reserves with internally available resources.

Figure 15: Peak Day Condition Expectations—2021



On the peak hour of 2021, the NWPP-NE subregion has just over 330 MW of demand at risk of not being served with Tier 1 and 2 resources without imports from external areas. In addition, the hours immediately following the peak hour have high levels of demand at risk, roughly 180 MW at 7:00 p.m. and 80 MW at 8:00 p.m. The results of this stand-alone scenario also show the NWPP-NE subregion with potential demand at risk in the morning peak with roughly 35 MW for each hour from 7:00 to 9:00 a.m. If resources fall short of expected availability or demand is higher than expected, demand may be at risk of not being served (See Figure 16).

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, under all stand-alone scenarios, the NWPP-NE subregion could experience 4,196 hours in which the ODITY threshold of resource adequacy is not maintained. The assessment indicates that as early as 2021, even with all planned resource additions, the subregion will still rely on external assistance to maintain the ODITY threshold.

In all variations of the import scenario (EX, T1, and T2), every hour meets the ODITY threshold.

Figure 17: Potential Demand at Risk Hours

Energy at Risk

In 2021, nearly 575 GWh of energy are at risk of not being served in all the stand-alone scenarios (See Figure 18). Spread over the 4,196 hours at risk in these scenarios, this means about 137 MW of demand at risk per hour. This trend continues through 2024 with increasing levels of demand at risk each year for the stand-alone scenarios.

Figure 18: Potential Demand at Risk GWh

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-NE subregion to remain resource adequate and avoid unserved demand.

Conclusion

As early as 2021, under expected conditions, the NWPP-NE subregion may experience 4,196 hours during the year 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-NE subregion can eliminate all hours in which the ODITY threshold is unmet. The assessment indicates that entities in the NWPP-NE 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 also 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 ODITY 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 - NE	AB	Sundance	6	401.00	Subbituminous Coal	10/1/2001	4/2/2021
NWPP - NE	AB	Sundance	4	406.00	Subbituminous Coal	9/1/2007	4/2/2021
NWPP - NE	AB	Battle River	5	385.00	Subbituminous Coal	1/1/1981	4/1/2022
NWPP - NE	AB	Sundance	3	368.00	Subbituminous Coal	1/1/1976	4/2/2022
NWPP - NE	AB	Keephills	1	395.00	Subbituminous Coal	1/1/1983	4/2/2023
NWPP - NE	AB	Keephills	2	395.00	Subbituminous Coal	1/1/1984	4/2/2023
NWPP - NE	AB	Sheerness	1	400.00	Subbituminous Coal	1/1/1986	4/2/2023
NWPP - NE	AB	Sheerness	2	390.00	Subbituminous Coal	1/1/1990	4/2/2023
NWPP - NE	AB	Keephills	3	463.00	Subbituminous Coal	6/1/2011	4/2/2024
NWPP - NE	MT	Colstrip	1	307.00	Subbituminous Coal	11/1/1975	12/31/2027
NWPP - NE	MT	Colstrip	3	740.00	Subbituminous Coal	1/1/1984	12/31/2027
NWPP - NE	MT	Colstrip	4	740.00	Subbituminous Coal	4/1/1986	12/31/2027
NWPP - NE	AB	Genesee	2	400.00	Subbituminous Coal	1/1/1989	4/2/2028
NWPP - NE	AB	Genesee	1	400.00	Subbituminous Coal	1/1/1994	4/2/2028
NWPP - NE	AB	Genesee	3	466.00	Subbituminous Coal	11/1/2004	4/2/2029
NWPP - NE	AB	Battle River	4	155.00	Subbituminous Coal	1/1/1975	12/31/2030