WECC

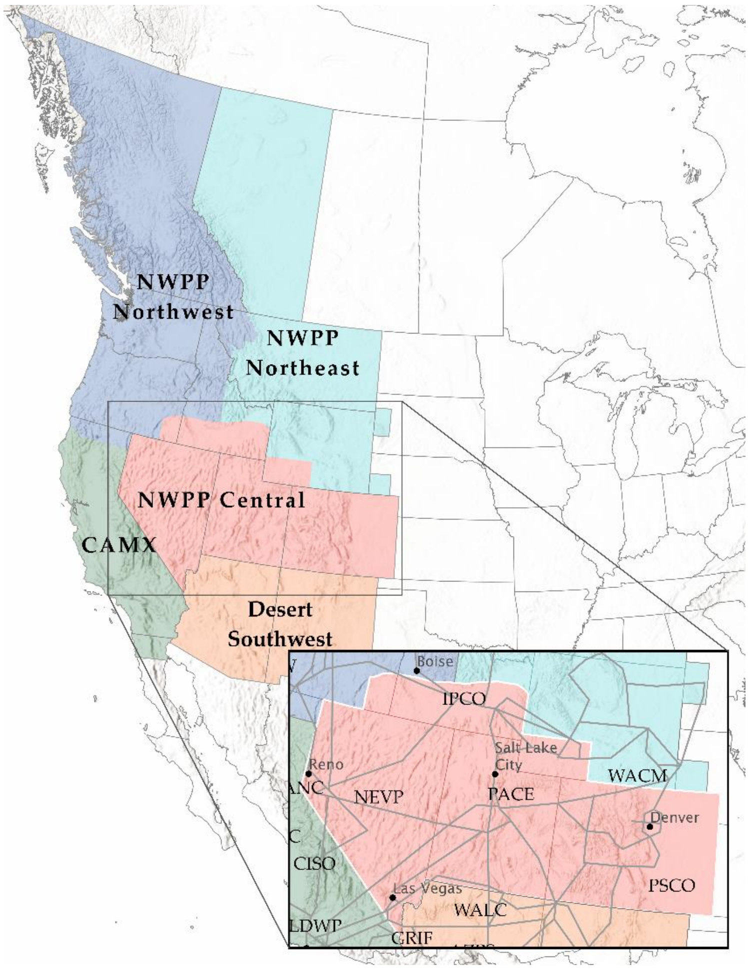
Western Assessment of Resource Adequacy Subregional Spotlight: Northwest Power Pool—Central

February 26, 2021

Northwest Power Pool—Central 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—Central (NWPP-C) subregion. The NWPP-C subregion is the summer-peaking section of the Northwest Power Pool and covers all of Utah, Colorado, most of Nevada, and parts of Idaho and Wyoming.

Figure 1: Northwest Power Pool—Central 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-C subregion is expected to peak in mid-July at about 36,400 MW. However, there is a 5% probability that the subregion could peak as high as 42,200 MW, which means a 16% uncertainty in load forecast. Overall, the NWPP-C subregion should expect a 104% ramp, or 18,500 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 42,400 MW. However, under low availability conditions, the NWPP-C subregion may only have 30,500 MW available to meet the expected 36,400 MW peak. Although there is only a 5% probability of this occurring, significant imports would be needed to meet the demand under low availability conditions. Baseload resources account for roughly 30,500 MW of the subregion's resource availability and, under low availability conditions (5% probability), baseload resources could supply as little as 25,600 MW. In addition, utility-scale solar generation availability could range from an expected availability of 3,900 MW to a low of 1,500 MW (5% probability).

Planning Reserve Margin

For 2021, an annual planning reserve margin of 21% is enough to maintain the median resource adequacy ODITY threshold for the NWPP-C subregion. However, in the months in which variability in energy supply and demand is highest, a planning reserve margin around 32% may be needed to maintain the ODITY threshold. If a flat reserve margin were applied to all hours of the year, for example 15%, almost 100% of the hours would not meet 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 maintain resource adequacy.

Annual Demand at Risk

Hours at Risk

In 2021 and beyond, even with all planned resource additions, the NWPP-C subregion needs external assistance to maintain resource adequacy. In 2021, in the Stand-alone EX[2] scenario, the NWPP-C

[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.

subregion could experience as many as 822 hours in which the ODITY threshold of resource adequacy is not maintained. Under the Stand-alone T1[3] scenario, potential demand at risk is reduced to 791 hours. This is further reduced to 708 hours under the Stand-alone T2[4] scenario.

In 2021, under the Import EX scenario, there are 14 hours in which the ODITY threshold may not be met and load is at risk. In 2022, there are 30 hours at risk in the Import EX scenario and 14 hours at risk in the Import T1 scenario. In 2024, this increases to 49 hours and 20 hours, respectively.

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 2,000 GWh. Spread over the 800 hours at risk in this scenario, this means there are about 2,500 MW of unserved demand per at-risk hour. This trend continues through 2024, with increasing levels of demand at risk each year.

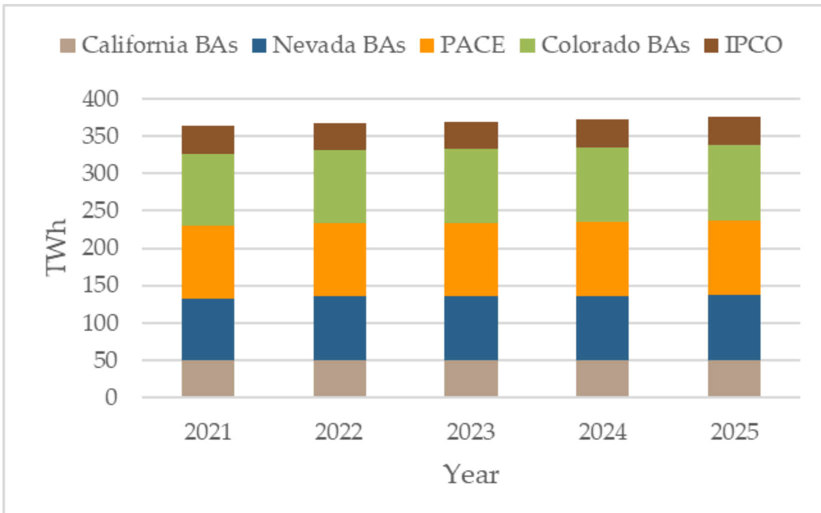
Demand Analysis

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-C subregion is expected to increase from 191.2 TWh to 196.5 TWh. The Colorado BAs account for the largest part of the demand in the subregion (See Figure 2).

Figure 2: Annual Demand



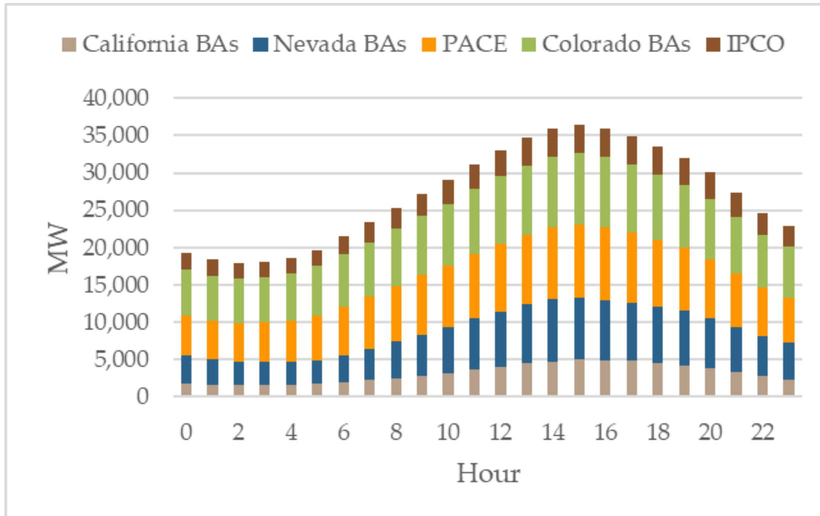
3 Tier-1 (T1): Resources that are under construction and expected to be complete and available for the year being studied.

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

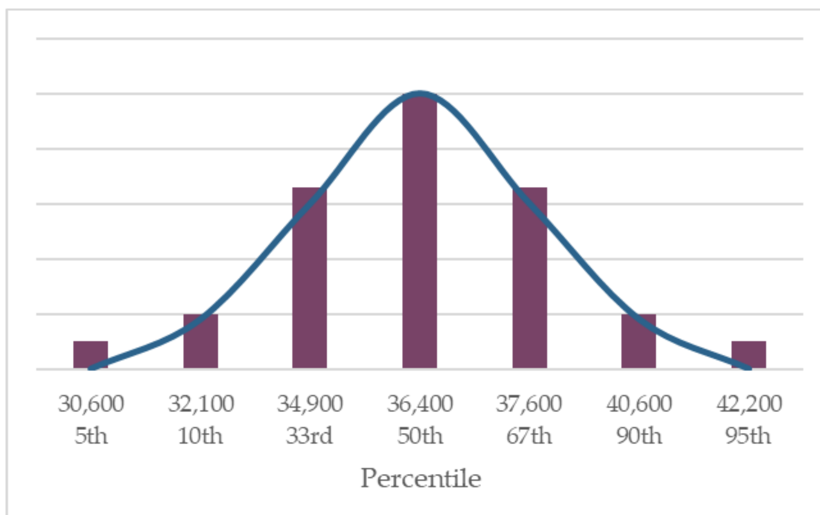
In 2021, the NWPP-C subregion's coincident peak demand hour is expected to be at 3:00 p.m. on the peak demand day. The lowest demand that day is expected to be at 2:00 a.m. (See Figure 3). Over the 13 hours from 2:00 a.m. to 3:00 p.m., demand is expected to increase more than 104%—from 17,900 MW to over 36,000 MW across the subregion. The Colorado BAs are expected to see a 3,700 MW (63%) ramp on the peak day; while the PacifiCorp East (PACE) area is expected to see a ramp of about 4,500 MW (89%). The Nevada BAs and Idaho Power Company (IPCO) area are expected to see 5,300 MW (178%) and 1,800 MW (92%).

Figure 3: Peak Day Demand—2021



Demand Variability

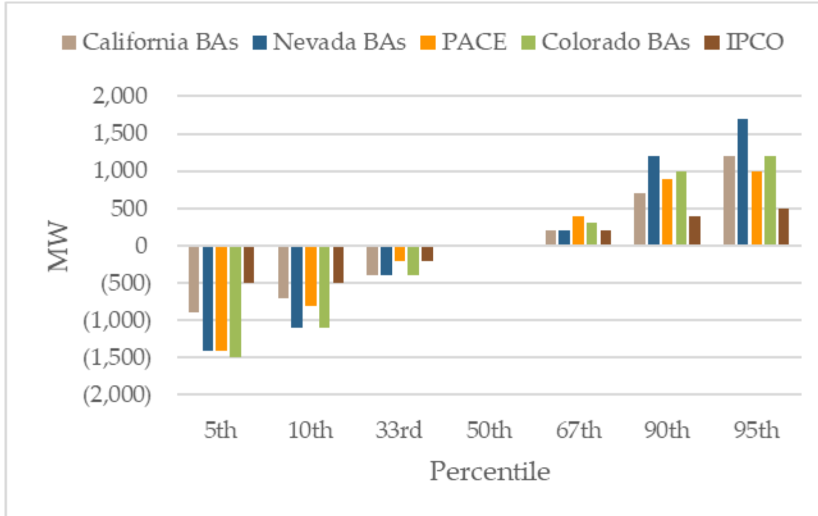
Figure 4: Peak Hour Demand Distribution Curve—2021



Variability in demand occurs every hour. Understanding how demand variability can affect resource adequacy allows planners to account for variability. Many factors drive demand variability: 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 shows the degree of demand variability in the NWPP-C subregion. On the peak hour of 2021, there is an equal probability that demand could be higher or lower than 36,400 MW. In an extreme scenario (a 5% probability of occurring), demand could increase from the forecast demand of 36,400 MW to 42,200 MW, which is 5,800 MW or 16% higher than expected. Likewise, there is a 10% possibility that demand could be 40,600 MW, which is 4,200 MW higher than expected.

Figure 5: Demand Variance by Area—2021



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-C subregion, reported by area.

The Colorado area has the largest demand in the subregion, which can range from 1,500 MW below the expected demand to 1,200 MW above it. The Nevada area has the most variable demand in the subregion, ranging from 1,400 MW below the expected demand to 1,700 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-C subregion is expected to be about 35,800 MW (See Figure 6). The planned retirement of coal-fired and other baseload resources reduces this number 800 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 38,400 MW.

Figure 6: Peak Demand Hour Availability by Tier

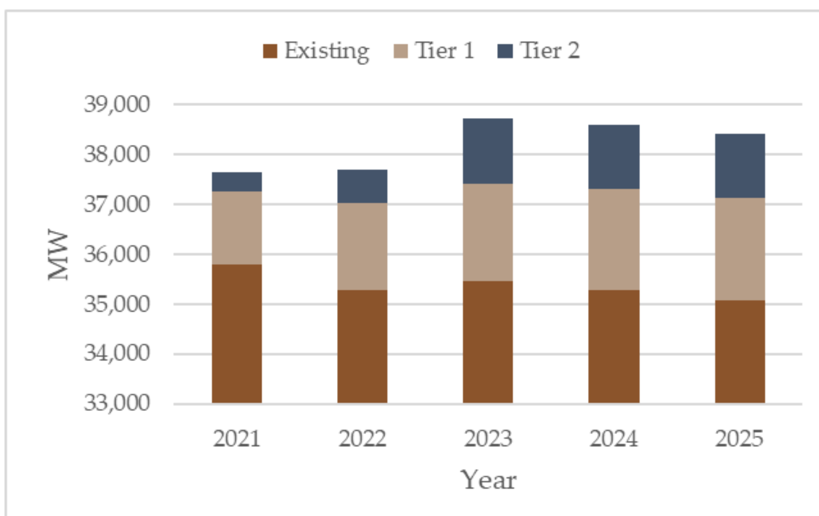


Table 1 shows the total megawatts each resource type is expected to contribute to resource availability during the peak hour over the next five years. Baseload resources account for about 27,500 MW, or 73%

of the available generation in 2021, but decline through 2025 to below 26,800 MW. Solar resource availability is expected to increase from 3,750 MW in 2021 to over 5,200 MW in 2025.

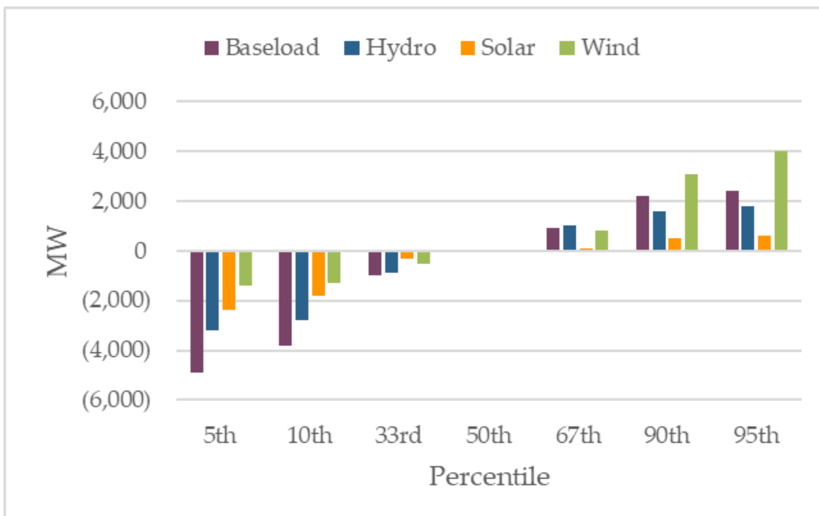
Table 1: Peak Demand Hour Availability by Type

	2021	2022	2023	2024	2025
Baseload	27,512	27,159	27,180	26,994	26,798
Hydro	4,955	4,870	4,955	4,955	4,955
Solar	3,747	4,356	5,143	5,225	5,225
Wind	1,439	1,315	1,439	1,439	1,439

Variability by Resource Type

Figure 7 shows how resource availability varies by resource type across the NWPP-C subregion. Under expected conditions, baseload resources can provide about 27,500 MW. Under low availability conditions, baseload resources could supply 4,900 MW less than expected, reducing availability to 22,600 MW. There is a 5% probability of the low availability conditions occurring. Likewise, there are conditions under which baseload generation could produce 2,400 MW more than expected, increasing availability to 29,900 MW. Hydro generation has an expected availability of about 5,000 MW, but under low availability conditions (a 5% probability), hydro could supply 3,200 MW less than expected. This will reduce availability to 1,800 MW. Although wind is expected to produce around 1,500 MW, that value can vary from a low availability of about 100 MW to a high of over 5,500 MW, both with a 5% probability.

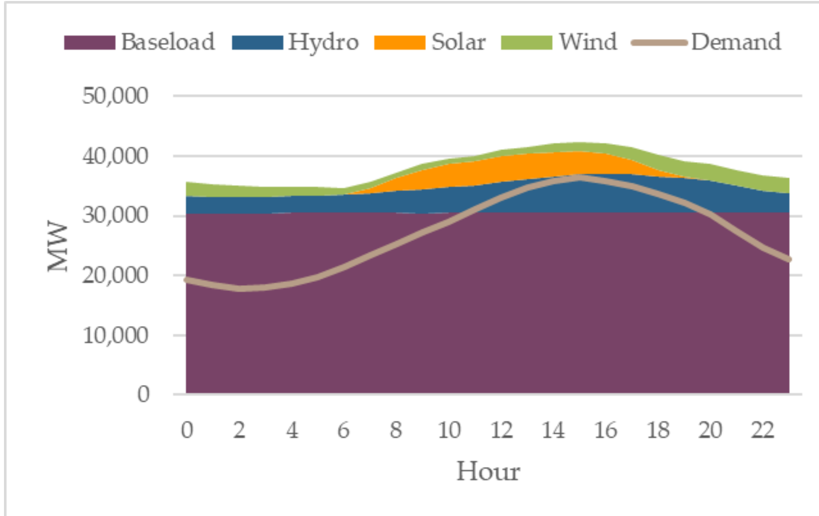
Figure 7: Resource Variance by Type—2021



Peak Day Availability

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

Figure 8: Peak Day Resource Type Availability—2021

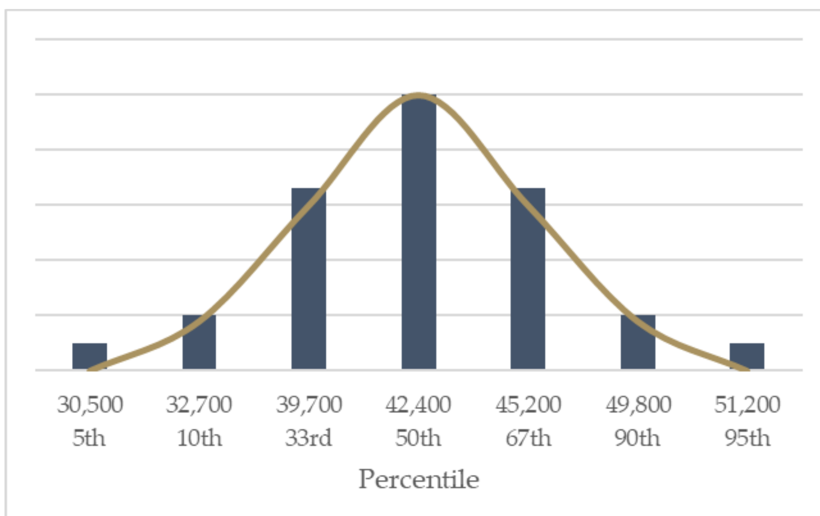


Resource Availability Variability

The NWPP-C 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 shows the expected variability of generation availability in the NWPP-C subregion. The figure highlights the subregion's total generation availability at different levels of probability. In 2021, at least 42,400 MW of generation is expected to be available 50% of the time, while 50% of the time availability is expected to be less than 42,400 MW. Likewise, the figure shows that 33% of the time generation availability could be lower than 39,700 MW, 10% of the time the availability could be lower than 32,700 MW, and in extreme cases, 5% of the time the availability could be lower than 30,500 MW.

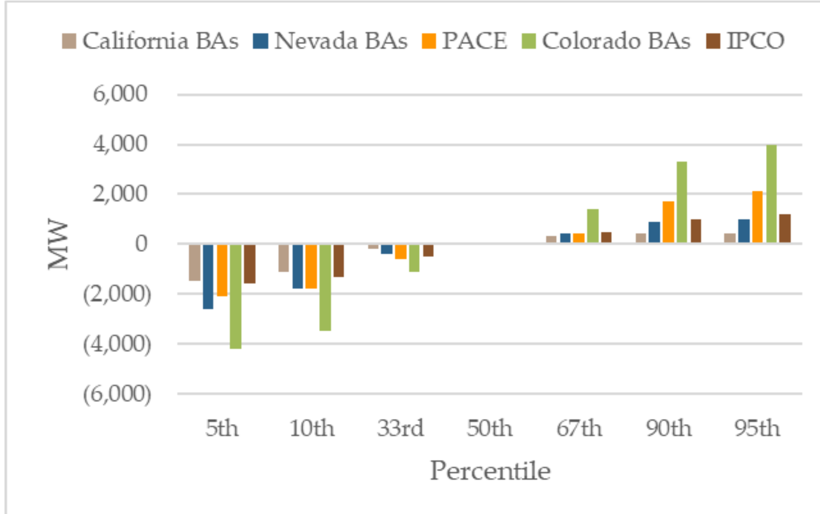
Figure 9: Peak Hour Availability Distribution Curve—2021



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-C subregion. The Colorado area has the greatest amount of variability in resource availability, ranging from about 4,000 MW less to about 4,000 MW more than expected, both cases with 5% probability. The PACE and Nevada BAs show about the same amount of variability, with about 2,000 MW less than expected to between 1,000 MW (PACE) and 2,000 MW (Nevada) above expected availability.

Figure 10: Resource Variance by Area—2021



The resource mix is changing in the NWPP-C subregion, with more variable resources being added each year. As more variable resources are added and more baseload resources are retired, resource variability will increase, which will affect resource availability within the subregion.

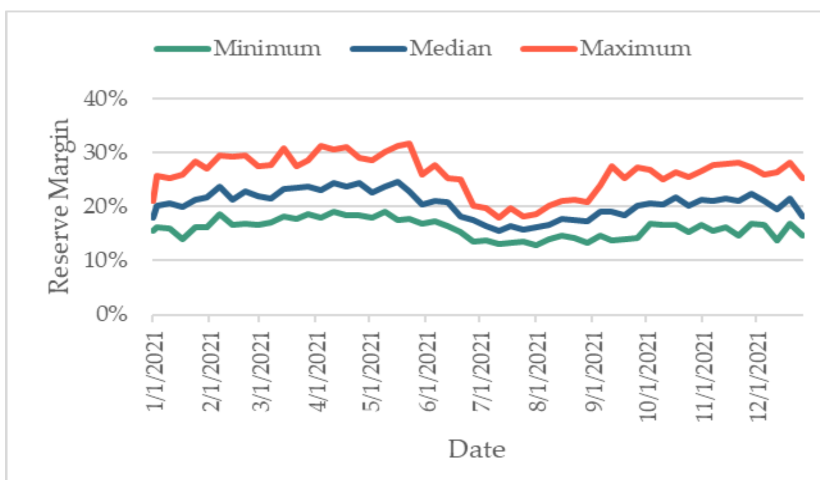
Planning Reserve Margin Analysis

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

Figure 11: Planning Reserve Margin Plot—Percent



reserve margins necessary to cover demand and resource variability across the NWPP-C subregion in 2021.

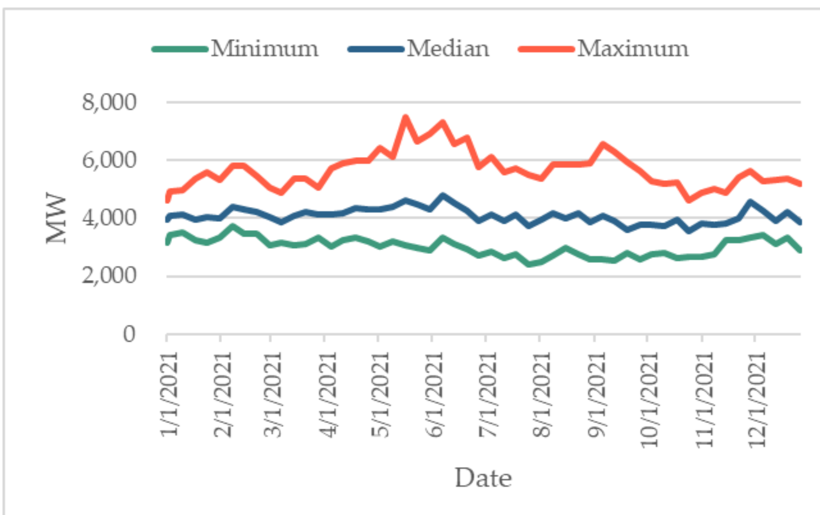
The planning reserve margin is calculated for every hour of the year. The figure shows the minimum, median, and maximum planning reserve margin for each week of 2021. For example, the minimum planning reserve margin for the first week of January 2021 is 16%, while the median planning reserve margin for that week is 18%, and the maximum planning reserve margin for that week is 21%.

The planning reserve margin in 2021 ranges from 13% to 32% with the lowest value occurring in August and the highest value occurring in May. There are 8,664 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 100% of the hours would not meet the ODITY threshold.

Reserve Margin as Megawatts

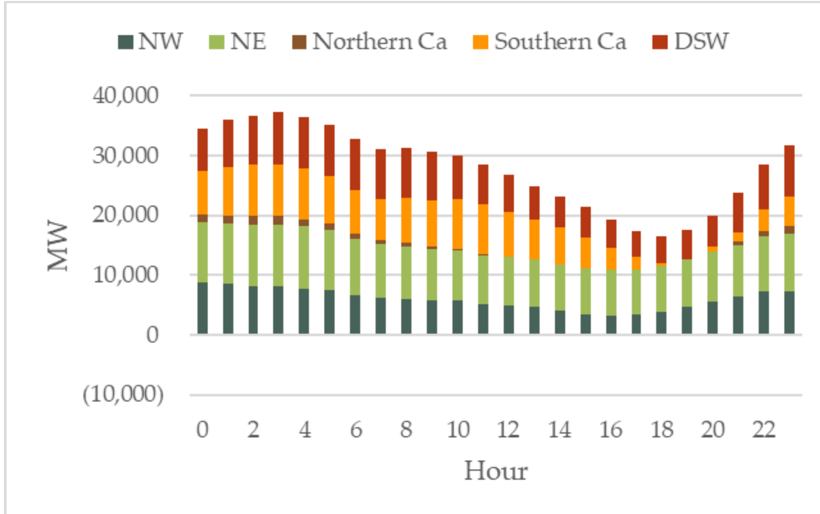
Figure 12 shows the planning reserve margin ranges for the NWPP-C subregion in megawatts. For the entire subregion, the minimum planning reserve margin needed to maintain the ODITY threshold is as high as 4,000 MW in the February to as low as 2,500 MW in the August. The median planning reserve margin ranges from 4,800 MW in the summer to 3,500 MW in the fall months. The maximum planning reserve margin needed to maintain the ODITY threshold ranges from a low of 4,600 MW in early October, to a high of 7,500 MW in May.

Figure 12: Planning Reserve Margin Plot—MW



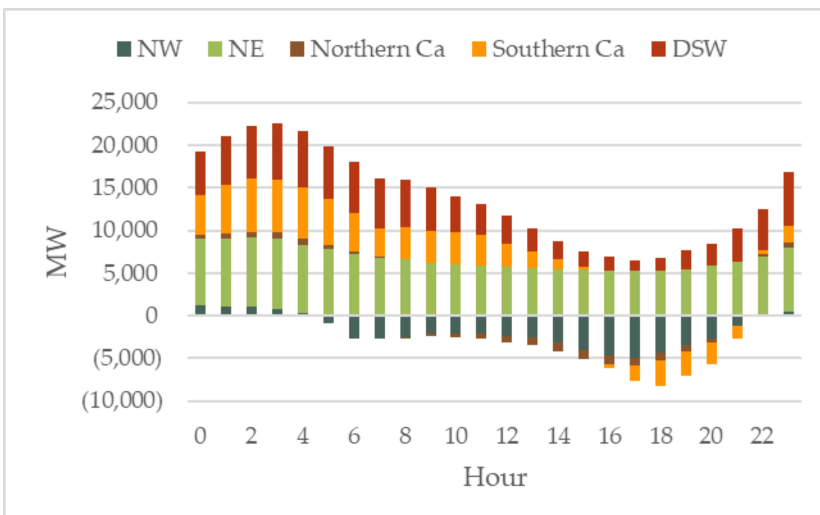
External Assistance Analysis

Figure 14: Peak Day Expected Import Availability—2021



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–C subregion's peak demand day in mid-July, assuming expected demand and resource availability and Tier 2 resources are built. Under this scenario, all subregions outside NWPP-C have excess energy available and could provide imports during the NWPP-C's peak hour, which occurs at 3:00 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 half: from about 20,000 MW to about 10,000 MW (See Figure 13). If all the other subregions experience high demand and low resource availability at the same time, imports into the NWPP-C 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 very low. 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 Low Import Availability



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 the expected supply, demand, and planning reserve margin for the NWPP-C subregion's peak demand day in mid-July 2021. Under expected demand and expected availability of resources on the peak day, the NWPP-C subregion may experience some hours in which demand is at risk of not being served with internally available resources (Figure 16). During these hours, the NWPP-C subregion may need imports from another region to maintain the ODITY threshold. On the peak hour of 2021, 3:00 p.m., the NWPP-C subregion has just over 7,300 MW of demand at risk of not being served with Tier 1 and 2 resources without imports from external areas. In fact, most hours of the peak day show demand at risk of not being served, with a spike to over 10,000 MW at 7:00 p.m. after solar generation has declined. If resources fall short of expected availability or if demand is higher than expected, demand may be at risk of not being served.

Figure 15: Peak Day Condition Expectations—2021

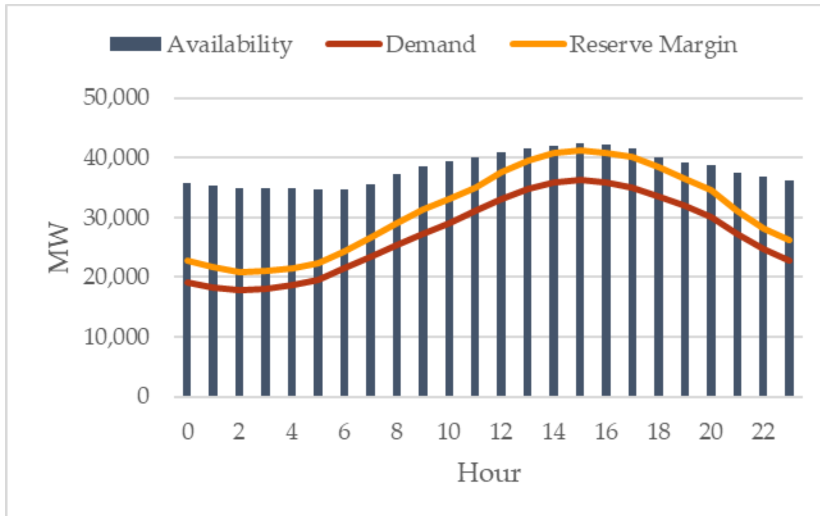
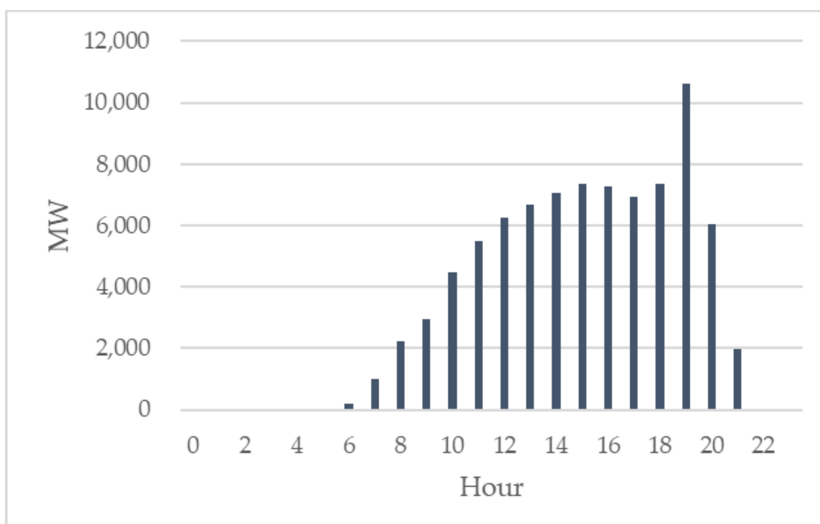


Figure 16: Peak Day Potential Demand at Risk—2021



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-C subregion could experience over 800 hours in which the ODITY threshold of resource adequacy is not maintained. Under the Stand-alone T1 scenario, the number of hours with potential demand at risk is reduced to 750. This is further reduced to 700 hours under the Stand-alone T2 scenario. The assessment indicates that even with all planned resource additions, the NWPP-C subregion will still rely on external assistance to maintain the ODITY threshold as early as 2021.

Figure 17: Potential Demand at Risk Hours

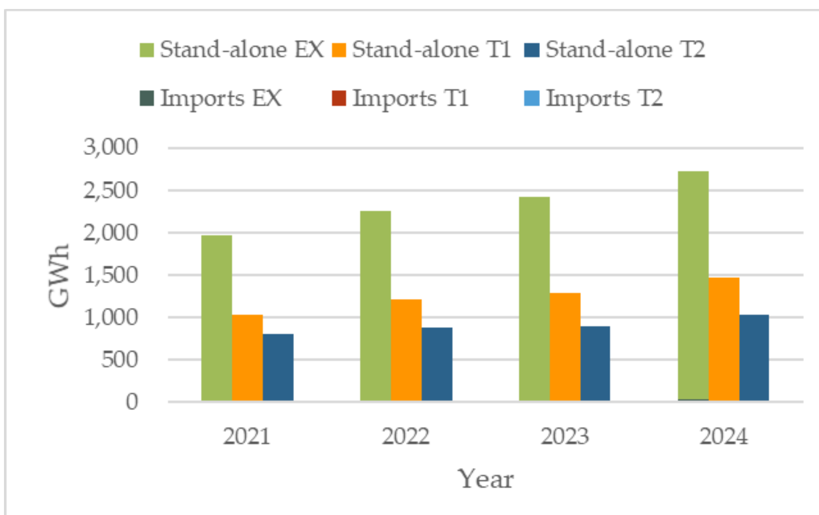
When imports are included with existing resources, there are 14 hours in 2021 in which the subregion may not maintain the ODITY threshold. That increases to 50 hours in 2024 (See data callout in Figure 17). When Tier 1 resource additions are included in the analysis, the number of hours in which the ODITY threshold is not met decreases to three in 2021 and 20 in 2024. Adding all Tier 2 resources to the analysis reduces the hours at risk for unserved load to between three and seven for 2021 through 2024.

Energy at Risk

In 2021 nearly 2,000 GWh of energy is at risk of not being served in the Stand-alone EX scenario (Figure 18). Spread over the 800 hours at risk in this scenario, this means there are about 2,500 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-C subregion to remain resource adequate and avoid unserved demand.

Figure 18: Potential Demand at Risk GWh



Conclusion

As early as 2021, under expected conditions, the NWPP-C subregion may experience 722 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-C subregion can eliminate all but three hours in which the ODITY threshold is unmet. The assessment indicates that entities in the NWPP-C subregion need to build the resources currently included in the construction queue and rely on imports to maintain the ODITY threshold, but will still have hours in which the threshold is unmet. 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	Unit Name	Unit Number	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date
NWPP - C	CO	Cabin Creek	2	150.00	Water	12/1/1966	3/31/2020
NWPP - C	CO	Fort Lupton	1	50.39	Natural Gas	12/1/1971	12/31/2020
NWPP - C	CO	Fort Lupton	2	50.39	Natural Gas	12/1/1971	12/31/2020
NWPP - C	NV	Clark	4	72.40	Natural Gas	6/1/1973	12/31/2020
NWPP - C	NV	Fort Churchill	2	115.00	Natural Gas	9/1/1971	12/31/2021
NWPP - C	NV	North Valmy	1	138.60	Bituminous Coal	12/1/1981	12/31/2021
NWPP - C	NV	North Valmy	1	138.60	Bituminous Coal	12/1/1981	12/31/2021
NWPP - C	CO	Comanche	1	382.50	Bituminous Coal	12/1/1972	12/31/2022
NWPP - C	CO	Martin Drake	6	75.00	Subbituminous Coal	10/1/1968	12/31/2023
NWPP - C	CO	Martin Drake	7	132.00	Subbituminous Coal	7/1/1974	12/31/2023
NWPP - C	WY	Jim Bridger	1	577.88	Subbituminous Coal	11/1/1974	12/31/2023
NWPP - C	NV	Tracy	3	119.80	Natural Gas	10/1/1974	12/31/2024
NWPP - C	NV	Tracy G240	4	69.70	Natural Gas	3/1/1997	12/31/2024
NWPP - C	CO	Comanche	2	396.00	Bituminous Coal	12/1/1974	12/31/2025
NWPP - C	CO	Craig	1	446.38	Subbituminous Coal	7/1/1980	12/31/2025
NWPP - C	NV	North Valmy	1	144.90	Bituminous Coal	5/1/1985	12/31/2025
NWPP - C	NV	North Valmy	2	144.90	Bituminous Coal	5/1/1985	12/31/2025
NWPP - C	NV	Harry Allen	1	101.50	Natural Gas	6/1/1995	12/31/2025
NWPP - C	CO	Alamosa	1	26.60	Natural Gas	12/1/1972	12/31/2026
NWPP - C	CO	Fruita	1	14.00	Natural Gas	12/1/1972	12/31/2026
NWPP - C	CO	Valmont	6	59.28	Natural Gas	12/1/1972	12/31/2026
NWPP - C	CO	Alamosa	2	36.60	Natural Gas	12/1/1976	12/31/2026
NWPP - C	CO	Craig	2	446.38	Bituminous Coal	12/1/1979	12/31/2026
NWPP - C	NV	Sun Peak	3	74.00	Natural Gas	6/1/1991	12/31/2026
NWPP - C	NV	Sun Peak	4	74.00	Natural Gas	6/1/1991	12/31/2026
NWPP - C	NV	Sun Peak	5	74.00	Natural Gas	6/1/1991	12/31/2026
NWPP - C	CO	Salida	2	0.58	Water	12/1/1907	12/31/2027
NWPP - C	WY	Dave Johnston	1	113.64	Subbituminous Coal	2/1/1959	12/31/2027
NWPP - C	WY	Dave Johnston	2	113.64	Subbituminous Coal	1/1/1961	12/31/2027
NWPP - C	WY	Dave Johnston	3	229.50	Subbituminous Coal	12/1/1964	12/31/2027
NWPP - C	WY	Dave Johnston	4	360.00	Subbituminous Coal	7/1/1972	12/31/2027
NWPP - C	CO	Cherokee	4	380.80	Natural Gas	8/13/2017	12/31/2027
NWPP - C	WY	Naughton	1	163.19	Subbituminous Coal	5/1/1963	12/31/2029
NWPP - C	WY	Naughton	2	217.59	Subbituminous Coal	10/1/1968	12/31/2029
NWPP - C	NV	Las Vegas Cogen	1	49.79	Natural Gas	6/1/1994	12/31/2029
NWPP - C	NV	Las Vegas Cogen	2	11.50	Natural Gas	6/1/1994	12/31/2029
NWPP - C	CO	Hayden	1	190.00	Bituminous Coal	7/1/1965	12/31/2030
NWPP - C	CO	Craig	3	446.38	Bituminous Coal	10/1/1984	12/31/2030