WECC

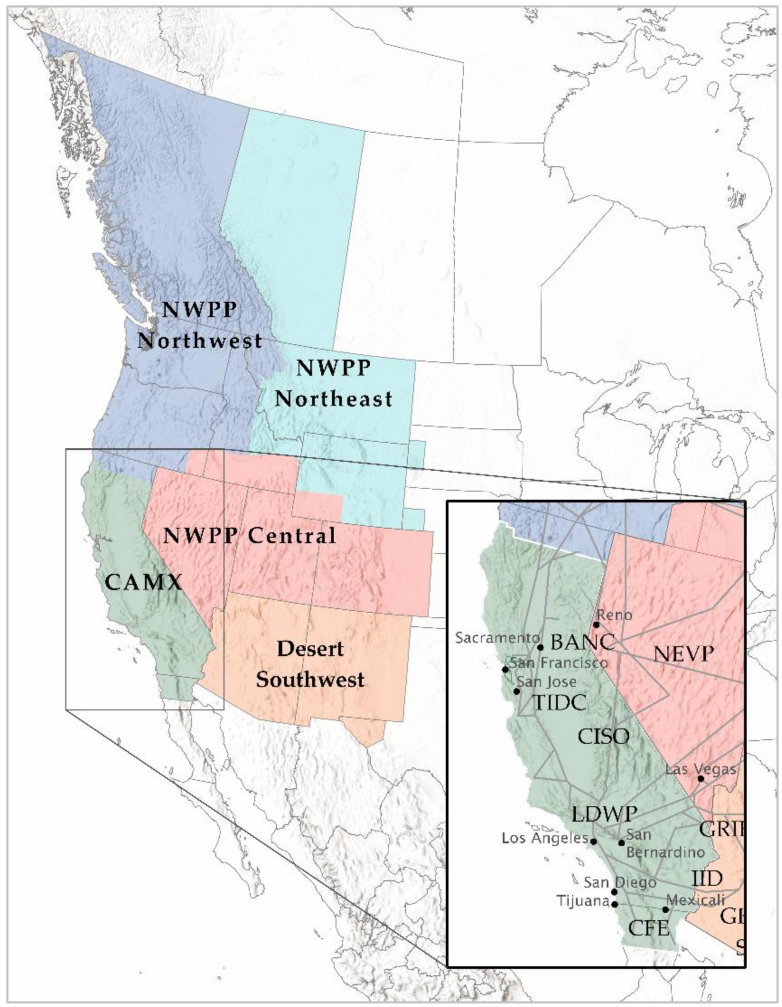
Western Assessment of Resource Adequacy Subregional Spotlight: California and Mexico (CAMX)

February 12, 2021

The California and Mexico 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).[2] 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 California and Mexico (CAMX) subregion. The CAMX subregion is a summer-peaking subregion that consists of most of the state of California and parts of Nevada and Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California. To highlight how the different peaks affect resource adequacy, the External Assistance and the Demand at Risk sections report southern California and northern California separately.[3]

Figure 1: California and Mexico 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.

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[1] The Western Assessment was released on December 18, 2020. The assessment contains an explanation of terms and WECC's methods and tools. Readers are encouraged to review the Western Assessment prior to reading the subregional reports.

[2] Balancing Authority of Northern California (BANC) and Turlock Irrigation District (TIDC) are analyzed as part of the Northwest Power Pool—Central subregion.

[3] The northern California area includes Pacific Gas and Electric (PGAE). The southern California area includes Los Angeles Department of Water and Power (LDWP), San Diego Gas and Electric (SDGE), and Southern California Edison (SCE).

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.

Key Findings

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

Demand

In 2021, the CAMX subregion is expected to peak in late August at about 51,300 MW. However, there is a 5% probability that the subregion could peak as high as 63,000 MW, which equates to a 25% load forecast uncertainty. Overall, the CAMX subregion should expect an 81% ramp, or 23,300 MW, from the lowest to the highest demand hour of the peak demand day. The high periods of risk occur in the hours following the peak hour when solar generation rapidly declines. Analyzing the peak day addresses both the peak hour and the net peak hour.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 57,800 MW. However, under low availability conditions, the CAMX subregion may only have 44,400 MW available to meet a 51,300 MW expected 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 45,000 MW of the subregion's resource availability and, under low availability conditions (5% probability), baseload resources could supply as little as 41,000 MW.[4] In addition, utility-scale solar generation availability could range from an expected availability of 6,500 MW to a low of 1,000 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 CAMX subregion. However, in May and June, the months when variability in energy supply and demand is highest, a planning reserve margin near 40% may be

[4] Baseload resources include coal, natural gas, nuclear, geothermal, and some hydro.

needed to maintain the ODITY threshold. In fact, if a flat 15% planning reserve margin were applied to all hours of 2021, over 40% of the hours would not meet the ODITY threshold.

As the CAMX subregion continues to add variable resources 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—Northern California

Hours at Risk

In 2021 and beyond, even with all planned resource additions, the CAMX subregion needs external assistance to maintain resource adequacy. In 2021, in the Stand-alone EX scenario, the northern California part of the CAMX subregion could experience as many as 32 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 13. This is further reduced to 10 hours under the Stand-alone T2 scenario.

In all variations of the import scenario (EX, T1, and T2), all hours 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 EX scenario is about 2.7 GWh. Spread over the 32 hours at risk in this scenario, this means about 84 MW of unserved demand per at-risk hour. The amount of energy at risk in the Stand-alone EX scenario fluctuates from year to year, revealing no trend through 2024.

Annual Demand at Risk—Southern California

Hours at Risk

In 2021 and beyond, even with all planned resource additions, the southern California area within the CAMX subregion needs external assistance to maintain resource adequacy. In 2021, in the Stand-alone EX scenario, the southern California area within the CAMX subregion could experience as many as 300 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 140. This is further reduced to 124 hours under the Stand-alone T2 scenario.

When imports are included in addition to existing resources, there are 34 hours in 2021 in which the southern California area may not maintain the ODITY threshold. That increases to 77 hours in 2024. When Tier 1 resource additions are included in the analysis, the number of hours in which the ODITY threshold is not met decreases to 10 in 2021 and 29 in 2024. Adding all Tier 2 resources to the analysis reduces the hours at risk for unserved load to two hours in 2021 and eight hours in 2022.

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 EX scenario is about 650 GWh. Spread over the 300 hours at risk in this scenario, this translates to about 2,150 MW of unserved demand per at-risk hour. The amount of energy at risk in the Stand-alone EX scenario fluctuates through 2024.

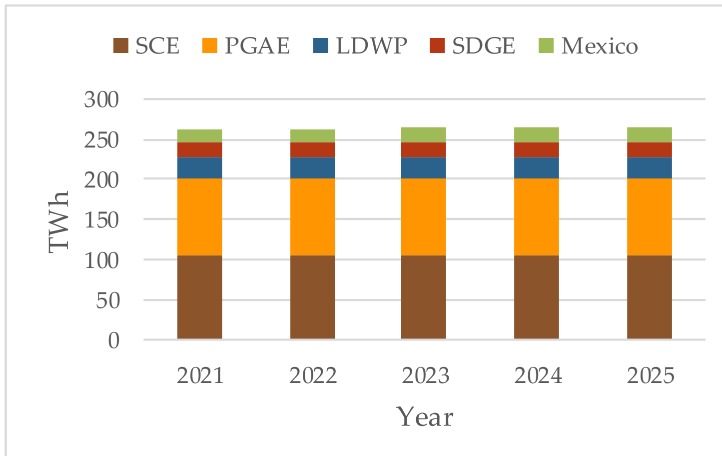
Demand Analysis

WECC examines 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 CAMX subregion is expected to increase from 262.6 TWh to 265.5 TWh. The Southern California Edison (SCE) part of the CAMX subregion accounts for the largest percentage of the demand in the subregion, although this is not much larger than Pacific Gas and Electric (PGAE) part of the CAMX subregion area (See Figure 2).

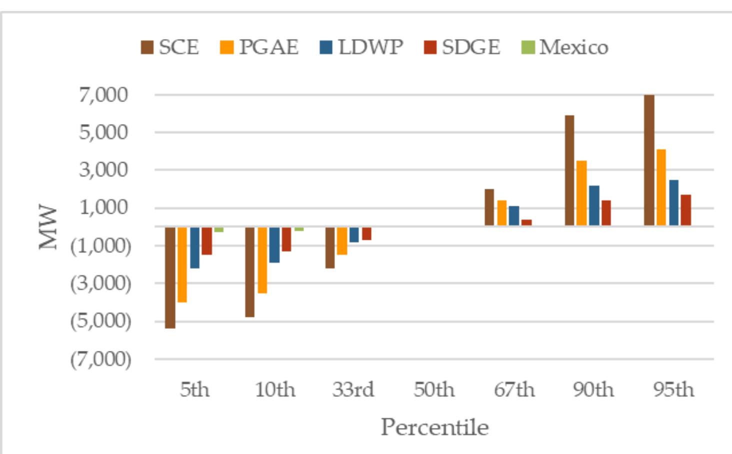
Figure 2: Annual Demand



Peak Demand

In 2021, the CAMX subregion's coincident peak demand hour is expected to be at 5:00 p.m. on the peak demand day. The lowest demand that day is expected to be at 3:00 a.m. (See Figure 3). Over the 14 hours from 3:00 a.m. to 5:00 p.m., demand is expected to increase more than 81% from 28.5 GW to 51.8 GW across the subregion. The SCE part of the subregion is expected to see an 11-GW ramp on the peak day, while the PGAE part of the subregion expects a 6.5-GW ramp. The SDGE and Mexico parts expect to see much smaller ramps of 1.5 GW and 1.0 GW, respectively. The LDWP part is expected to experience a 4.2-GW ramp, which is a 183% difference between the low demand and the high demand for the peak day. The morning and evening ramps are expected to increase as more solar resources are added to the

Figure 3: Peak Day Demand—2021



grid. System planners need to understand the resources they have available to respond to resource adequacy requirements associated with these ramps. As greater variability is introduced through variable resources such as roof-top solar, understanding the daily shape of demand and the ramping requirements associated with the ramps is important so that operators know how many resources they will need to bring online and when.

Demand Variability

Variability in demand is inherent in 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 show 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 technologies such as home batteries, electric vehicles, roof-top solar, and demand response programs are added, variability in demand will continue to grow. Increased variability means more uncertainty in demand forecasts, which may affect resource adequacy for the entire interconnection.

Figure 4 shows the degree of demand variability in the CAMX subregion. On the peak hour of 2021, there is an equal probability that demand could be higher or lower than 51,800 MW. In an extreme scenario (a 5% probability of occurring), demand could increase from the forecast demand of 51,800 MW to 63,200 MW, which is 11,400 MW or 22% higher than expected. Likewise, there is a 10% possibility that demand could be 60,200 MW or 8,400 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 such as weather. Figure 5 shows the variability within the CAMX subregion by area. The SCE part of the subregion has the largest and most variable demand in the subregion. SCE demand

Figure 4: Peak Hour Demand Distribution Curve—2021

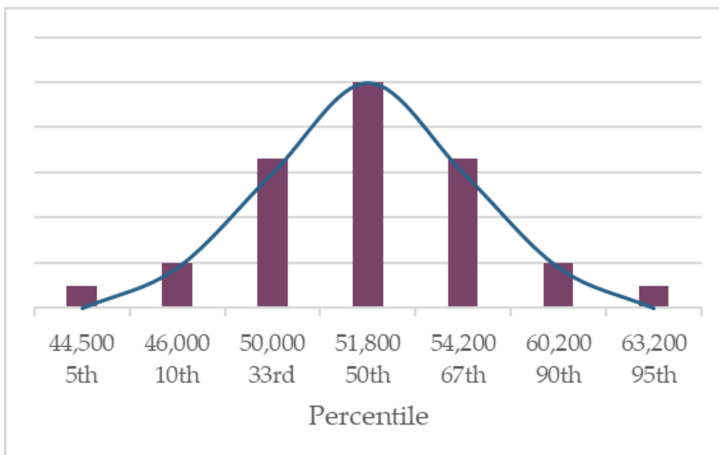
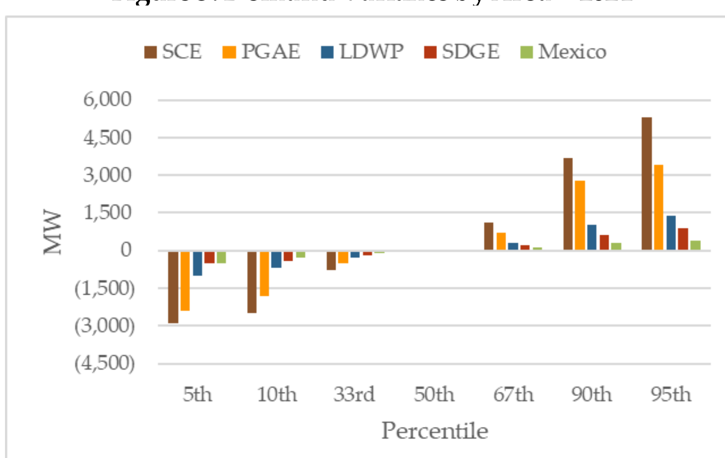


Figure 5: Demand Variance by Area—2021

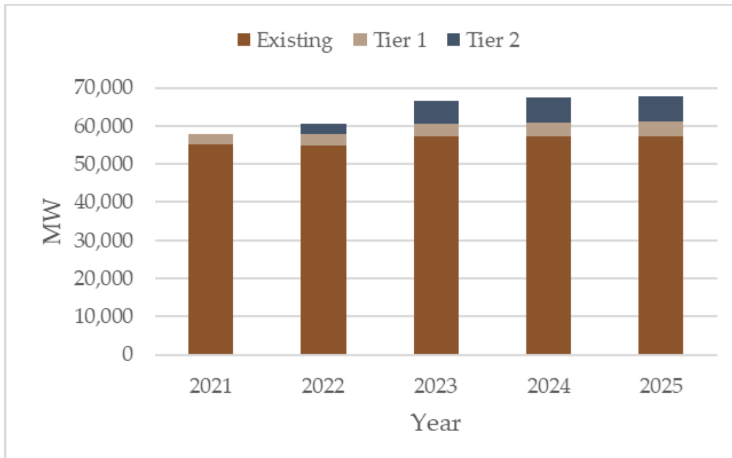


ranges from about 2,900 MW below the expected demand to well over 5,300 MW above it. The PGAE part of the subregion also displayed large variability in demand, ranging from 2,400 MW below expected to 3,400 MW above. The other three parts of the subregion—LDWP, SDGE, and Mexico—have much less variability in demand with the LDWP part of the subregion being the most variable of this group at 1,000 MW below and 1,400 MW above.

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 CAMX subregion on the peak hour is expected to be about 55,000 MW. (See Figure 6). Tier 1 and Tier 2 resource additions that are expected to be online by 2025 are predicted to increase the peak hour available generation to over 67,500 MW.

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.

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

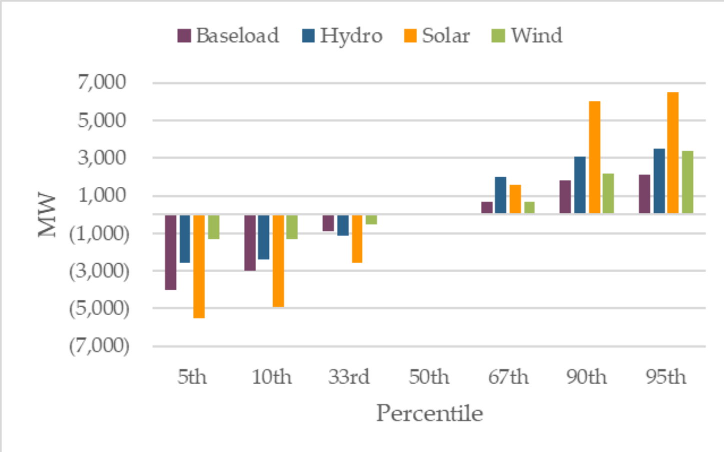
	2021	2022	2023	2024	2025
Baseload	44,517	46,099	46,937	47,718	47,988
Hydro	5,429	5,463	6,438	6,438	6,438
Solar	6,535	7,605	11,169	11,447	11,456
Wind	14,001	1,486	1,988	1,988	1,988

Baseload resources account for about 77% of the available generation in 2021. This increases from 44,500 MW in 2021 to nearly 48,000 MW in 2025. Availability for wind resources on the peak hour is expected to increase from 1,400 MW in 2021 to nearly 2,000 MW in 2025. Solar resource availability is expected to increase substantially from 6,500 MW in 2021 to over 11,400 MW in 2025.

Variability by Resource Type

Figure 7 shows how resource availability varies by resource type across the CAMX subregion. Under expected conditions, baseload resources can provide about 44,500 MW. Under low availability

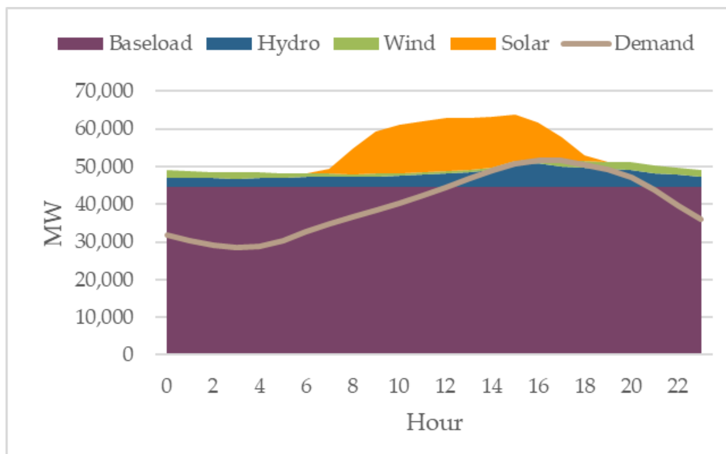
Figure 7: Resource Variance by Type—2021



conditions, baseload resources could supply 4,000 MW less than expected, reducing availability to less than 40,500 MW. There is a 5% probability of the low availability occurring. Likewise, there are conditions under which baseload resources could produce 2,000 MW more than expected, increasing availability to 46,600 MW. Wind generation has an expected availability of about 1,400 MW but, under low availability conditions (a 5% probability), wind could supply 1,300 MW less than expected. This will reduce availability to 100 MW. Although solar generation is expected to have 6,500 MW of availability, that value can vary from a low availability of about 1,000 MW to a high of about 13,000 MW.

Peak Day Availability

Figure 8: Peak Day Resource Type Availability—2021



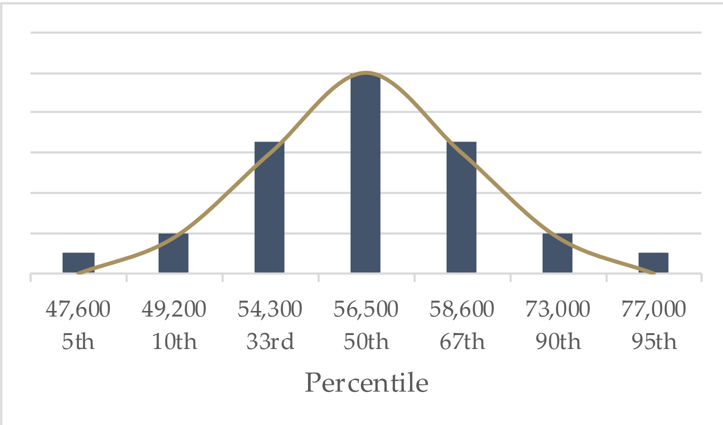
In addition to analyzing generation availability on the peak hour, WECC looks at generation availability on the peak day. Figure 8 shows the peak demand day for 2021 in the CAMX subregion along with the expected resource availability by resource type. The CAMX subregion depends largely on baseload resources; however, as baseload resources are retired and substantial amounts of variable generation are added the generation availability is reduced, which could affect resource adequacy.

Resource Availability Variability

The CAMX subregion's resource portfolio is subject to a range of availability based on the probability distribution within the subregion. The subregion is also dependent on variable resources to meet the peak demand, which may not be available.

Figure 9 shows the expected variability of resource availability in the CAMX subregion. The figure highlights the subregion's total resource availability at different levels of probability. In 2021, at least 57,800 MW of generation is expected to be available 50% of the time, while 50% of the time availability is expected to be less than 57,800 MW. Likewise, the figure shows that 33% of the time resource availability could be lower than 52,700 MW, 10% of the time, the availability could be lower than 46,200 MW. In extreme cases, 5% of the time, the availability could be lower than 44,400 MW.

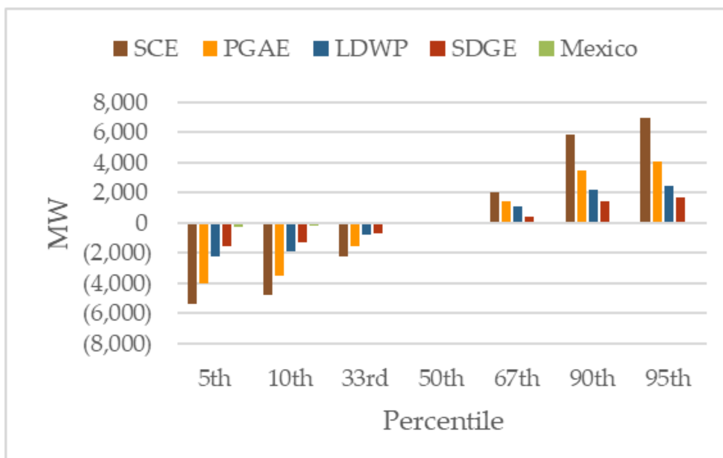
Figure 9: Peak Hour Availability Distribution Curve—2021



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

Figure 10 shows the differences in resource variability within the CAMX subregion. The SCE part of the CAMX subregion has the greatest amount of variability in resource availability, ranging from about 5,400 MW less to about 7,000 MW more than expected, both cases with a 5% probability. The PGAE part of the subregion could be 4,000 MW more to 4,000 MW less than expected. The LDWP and SDGE parts of the subregion display a significant amount of variability relative to the amount of resources in those areas. The Mexico area has little variability, as more resources in Mexico are baseload resources.

Figure 10: Resource Variance by Area—2021



As more variable resources are added and more baseload resources are retired, resource variability will increase, which will affect resource availability within the subregion.

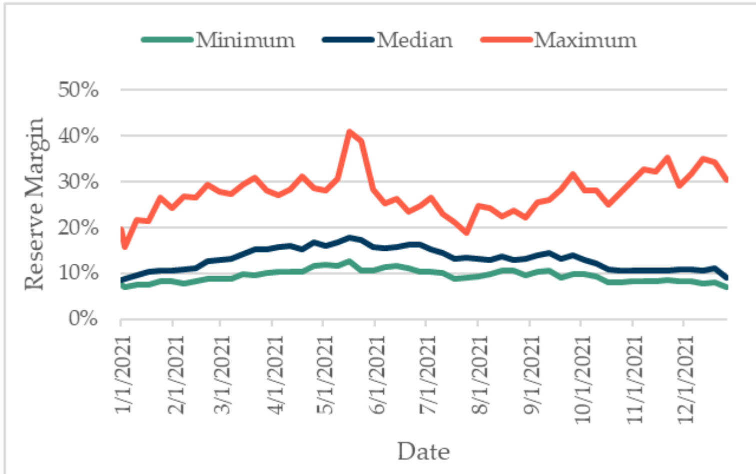
Planning Reserve Margin Analysis

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 necessary planning reserve margin changes. When demand and resource variability are lower, a lower planning reserve margin is needed 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 CAMX subregion in 2021.

Figure 11: Planning Reserve Margin Plot—Percent



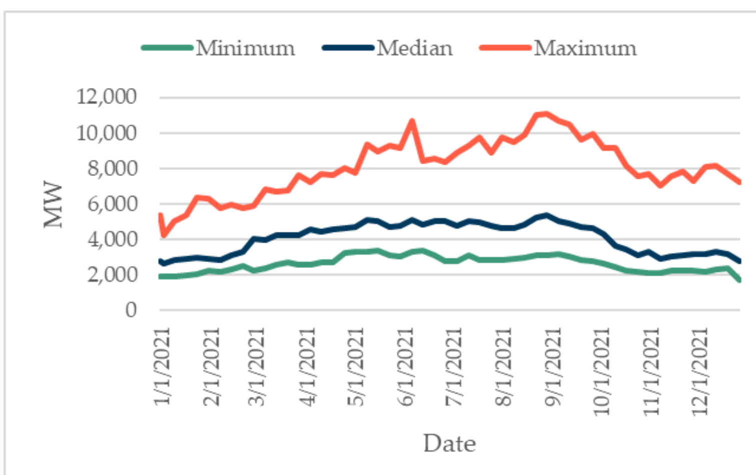
The planning reserve margin is calculated for every hour of the year. The figure shows the minimum, median, and maximum planning reserve margin for each week of 2021. For example, the minimum planning reserve margin for the first week of January 2021 is 7%, while the median planning reserve margin for that week is 9%, and the maximum planning reserve margin for that week is 20%.

The planning reserve margin in 2021 ranges from 7% to 41% with the lowest value occurring in January and the highest value occurring in May. There are 3,624 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 40% of the hours would not meet the ODITY threshold.

Reserve Margin—Megawatts

Figure 12 shows the planning reserve margin ranges for the CAMX subregion in megawatts. For the entire subregion, the minimum planning reserve margin needed to maintain the ODITY threshold is relatively constant through the year—about 2,700 MW. It can range from a high of 3,300 MW in the summer months to a low of 1,700 MW in December. The median planning reserve margin ranges from about 5,100 MW in the summer to about 3,000 MW in the winter.

Figure 12: Planning Reserve Margin Plot—MW



The maximum planning reserve margin needed to meet the ODITY threshold ranges from a low of 4,300 MW in January to a high of 11,000 MW in September.

External Assistance Analysis

Northern California

External assistance, or energy that is available to import from other subregions, can only be counted on when the energy and transmission are actually available. **Error! Reference source not found.** shows the potential imports available for the northern California area's peak demand day in late July, assuming expected demand and resource availability and Tier 2 resources are built. Under this scenario, all subregions outside the northern California area have excess energy available and could provide imports during the northern California area'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 75%, from about 20 GW to about 5 GW (Figure 14). If all the other subregions experience high demand and low resource availability at the same time, imports into the northern California area may not be available. This was the case 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 Expected Import Availability—2021

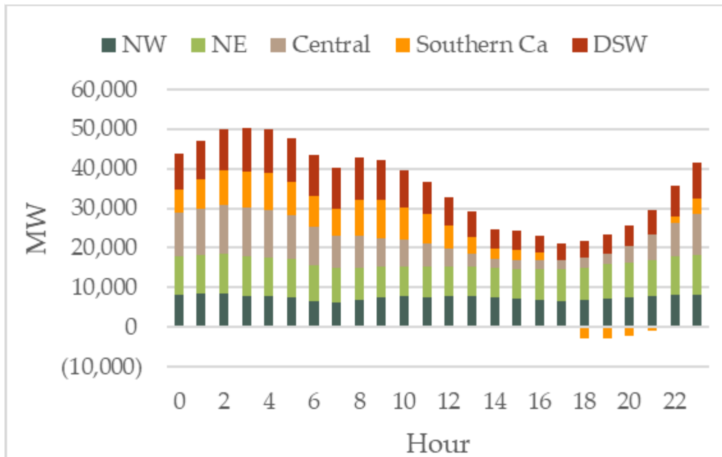
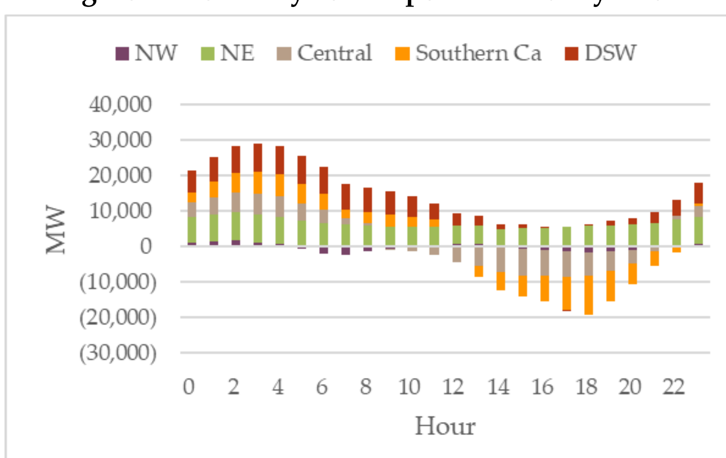


Figure 14: Peak Day Low Import Availability—2021



Southern California

Figure 15 shows the potential imports available for the southern California area's peak demand day in late August, assuming expected demand and resource availability and Tier 2 resources are included. Under this scenario, all subregions outside the southern California area have resources available and could provide imports during the southern California area's peak hour, which occurs at 4:00 p.m. However, if all the subregions experience low resources at the same time, the potential for them to provide imports is reduced by more than 50% from about 18 GW to about 8 GW (See Figure 16). If all the other subregions experience high demand and low resource availability at the same time, imports into the southern California area may not be available.

Figure 15: Peak Day Expected Import Availability—2021

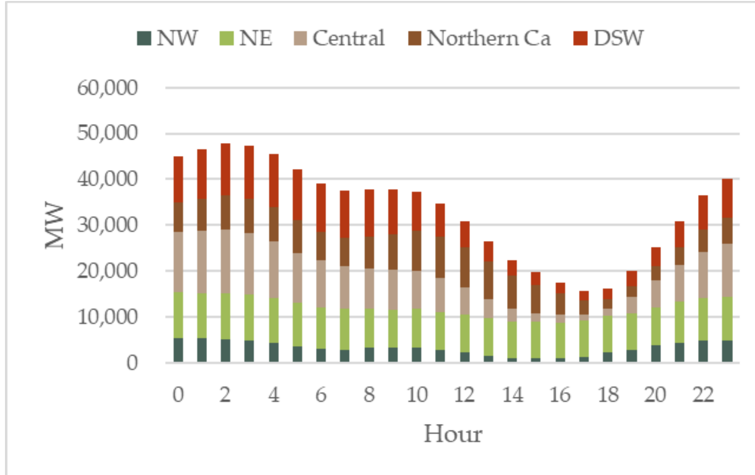
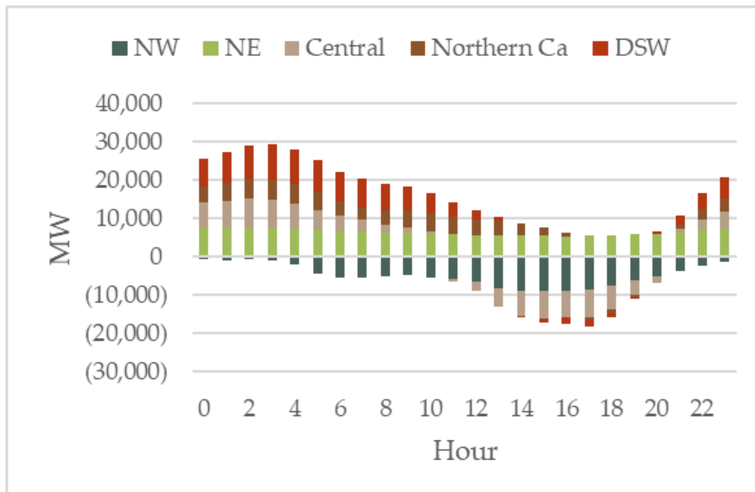


Figure 16: Peak Day Low Import Availability—2021



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 on an annual basis.

Northern California

Peak Day Demand at Risk

Figure 17 shows expected supply, demand, and the planning reserve margin for the northern California area's peak demand day in late July 2021. Under expected demand and expected availability of resources on the peak day, the northern California area may experience some hours in which demand is at risk of not being served with internally available resources (See Figure 18). During these hours, the northern California area may need imports from another region to maintain the ODITY threshold. On the peak hour of 2021, 6:00 p.m., the northern California area has nearly 20 MW of demand at risk of being unserved. However, around 7:00 p.m., after the sun sets and solar generation has declined, there is about 110 MW of demand at risk of being unserved 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 17: Peak Day Condition Expectations—2021

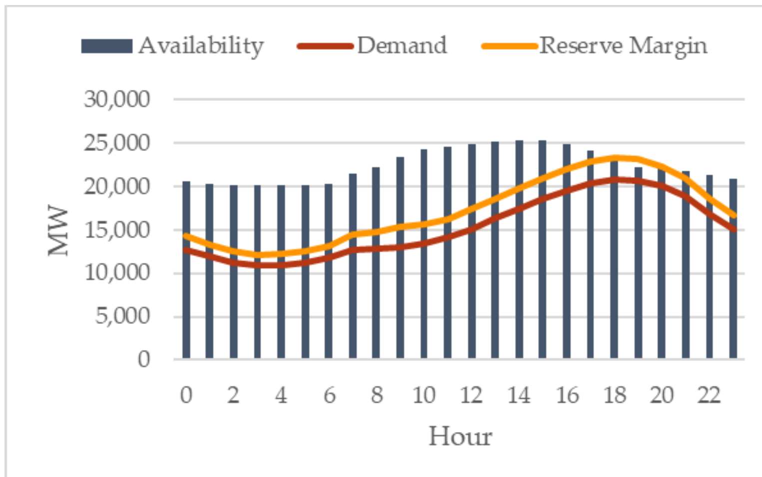
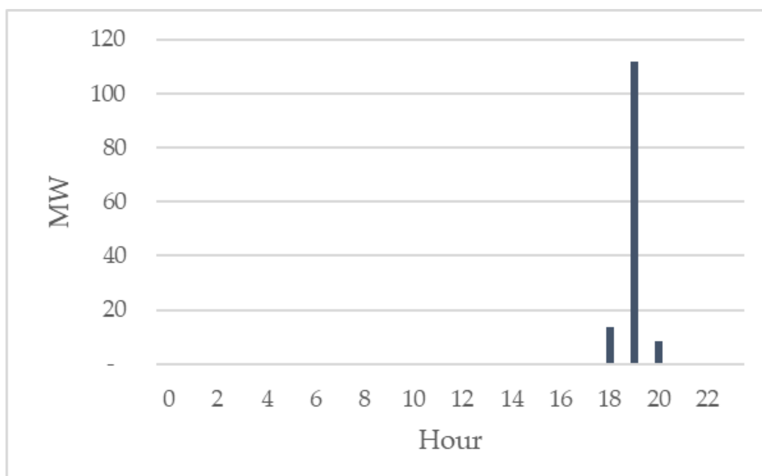


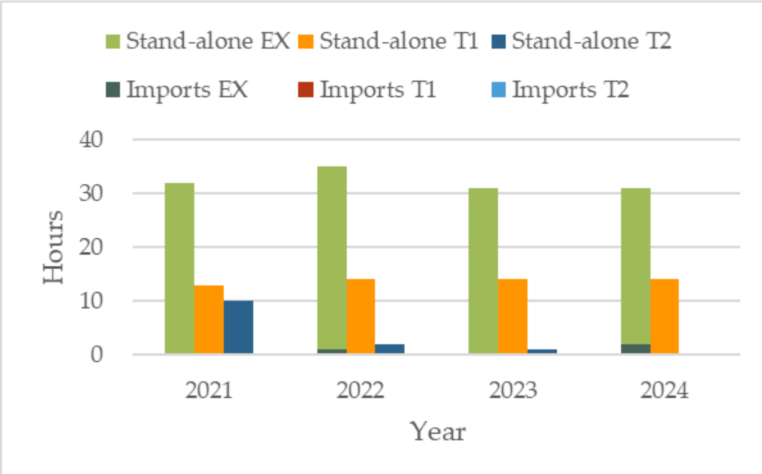
Figure 18: Peak Day Potential Demand at Risk—2021



Annual Demand at Risk

Figure 19 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 northern California area could experience over 30 hours in which the ODITY threshold of resource adequacy is not maintained. Under the Stand-alone T1 scenario, the number of hours with

Figure 19: Potential Demand at Risk Hours



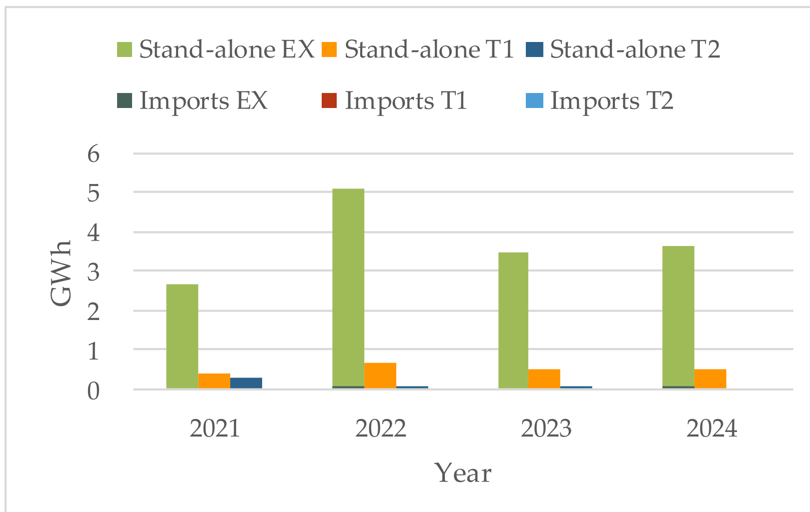
potential demand at risk is reduced to 13. This is further reduced to 10 hours under the Stand-alone T2 scenario. The assessment indicates that, even with all planned resource additions, the northern California area will still rely on external assistance to maintain the ODITY threshold as early as 2021.

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

In 2021, nearly 2.7 GWh of energy is at risk of not being served in the Stand-alone EX scenario (See Figure 20). Spread over the 32 hours at risk in this scenario, this means about 84 MW of demand at risk per hour. The amount of energy at risk in the Stand-alone EX scenario fluctuates from year to year, revealing no trend through 2024.

Figure 20: Potential Demand at Risk GWh



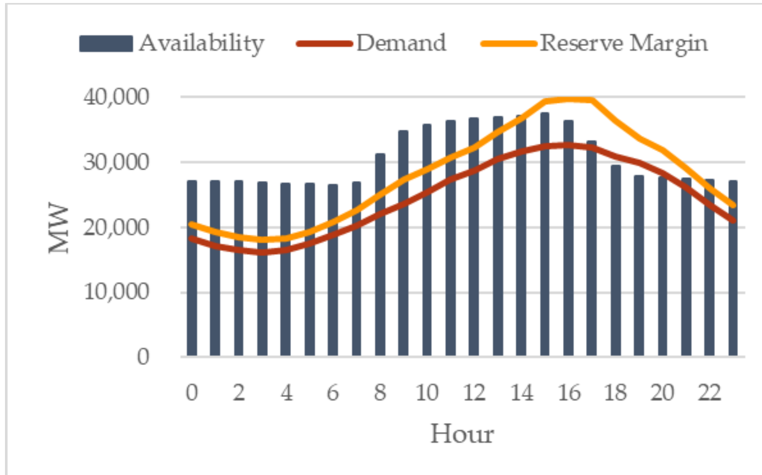
The assessment indicates that, for the stand-alone scenarios, under all variations, additional or different types of resources (above those planned to be added over the next four years) are needed for the northern California area of the CAMX subregion to remain resource adequate and avoid unserved demand.

Southern California

Peak Day Demand at Risk

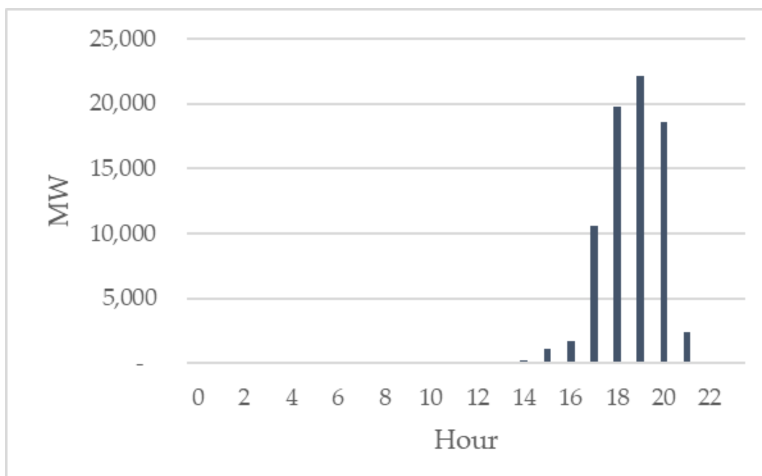
Figure 21 shows expected supply, demand, and planning reserve margin for the southern California area's peak demand day in late August for 2021. Under expected demand and expected availability of resources on the peak day, the southern California area may experience some hours in which demand is at risk of not being served with internally available resources. On the peak day and on a stand-alone basis, the southern California area is expected to be unable to supply demand and reserves for all hours from 3:00 p.m. to 11:00 p.m. (See Figure 22). During these hours, the southern California area may need imports from another subregion to maintain the ODITY threshold.

Figure 21: Peak Day Condition Expectations—2021



On the peak hour of 2021, 4:00 p.m., the southern California area shows the potential for about 1,700 MW of demand at risk of not being served. However, after the sun sets and solar generation has declined, there are several hours with demand at risk of not being served, peaking at over 22,000 MW at 7:00 p.m., without imports from external areas. In addition, the hour immediately before and the hour immediately after 7:00 p.m. show a combined total of about 38,000 MW of demand at risk of not being served. If resources fall short of expected availability or if demand is higher than expected, demand may be at risk of not being served.

Figure 22: Peak Day Potential Demand at Risk—2021



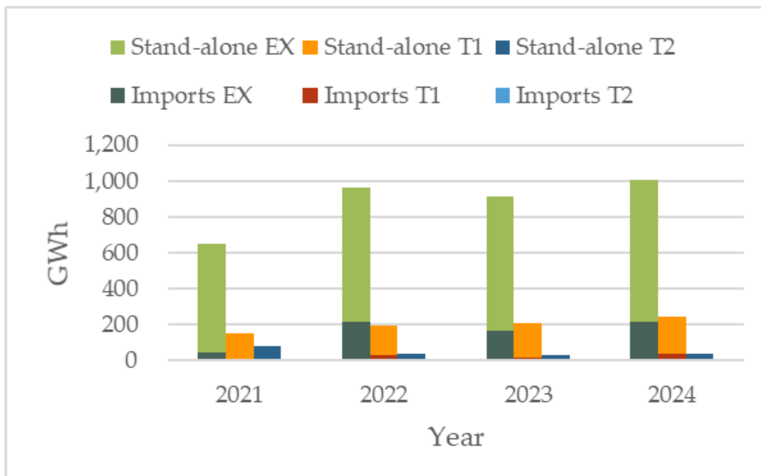
Annual Demand at Risk

Figure 23 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 southern California area could experience over 300 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 140. This is further reduced to 124 hours under the Stand-alone T2 scenario. The assessment indicates that, even with all planned resource additions, the southern California area will still rely on external assistance to maintain resource adequacy as early as 2021.

When imports are included on top of existing resources, there are 34 hours in 2021 in which the southern California area may not maintain the ODITY threshold. That increases to 77 hours in 2024. When Tier 1 resource additions are included in the analysis, the number of hours in which the ODITY threshold is not met decreases to 10 in 2021 and 29 in 2024. Adding all Tier 2 resources to the analysis reduces the hours at risk for unserved load to two hours in 2021 and eight hours in 2022.

Figure 23: Potential Demand at Risk Hours

Figure 24: Potential Demand at Risk GWh



Energy at Risk

In 2021, 650 GWh of energy is at risk of not being served in the Stand-alone EX scenario (See Figure 24). Spread over the 300 hours at risk in this scenario, this means about 2,150 MW of demand at risk per hour. The amount of energy at risk in the Stand-alone EX scenario fluctuates through 2024.

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 southern California area of the CAMX subregion to remain resource adequate and avoid unserved demand.

Conclusion

The CAMX subregion shows different resource adequacy conditions between the northern part of the subregion and the southern part. Over the next five years, under expected conditions, the northern part of the CAMX subregion may experience about 30 hours each year in which demand is at risk of not being served with existing internally available resources. When relying on imports from other subregions across the Western Interconnection, the northern part of the CAMX subregion can eliminate hours in which the ODITY threshold is unmet. The southern part of the CAMX subregion has more variability and potentially more hours in which the ODITY threshold is unmet. Over the next five years, under expected conditions, the southern part of the CAMX subregion may experience between 300 and 425 hours each year in which demand is at risk of not being served with existing internally available resources. Even with imports, the southern part of the CAMX subregion could experience as many as eight hours in which the ODITY threshold for resource adequacy is not met.

The growing variability in both supply and demand across the Western Interconnection, in addition to changing weather patterns, 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
CAMX	CA	Redondo Gen Station	5	178.87	Natural Gas	1/1/1954	12/31/2020
CAMX	CA	Redondo Gen Station	6	175.00	Natural Gas	1/1/1957	12/31/2020
CAMX	CA	Alamitos Gen Station	3	332.18	Natural Gas	1/1/1961	12/31/2020
CAMX	CA	Alamitos Gen Station	4	335.67	Natural Gas	1/1/1962	12/31/2020
CAMX	CA	Iron Gate	1	18.00	Water	2/1/1962	12/31/2020
CAMX	CA	Redondo Gen Station	8	495.90	Natural Gas	1/1/1967	12/31/2020
CAMX	CA	Ormond Beach Gen Station	1	741.27	Natural Gas	1/1/1971	12/31/2020
CAMX	CA	Ormond Beach Gen Station	2	750.00	Natural Gas	1/1/1971	12/31/2020
CAMX	CA	Alamitos Gen Station	5	497.97	Natural Gas	1/1/1999	12/31/2020
CAMX	CA	Huntington Beach Gen Station	2	225.80	Natural Gas	8/11/2018	12/31/2020
CAMX	CA	Diablo Canyon	1	1150.00	Uranium	1/1/1985	11/2/2024
CAMX	CA	Scattergood	1	163.19	Natural Gas	12/1/1958	12/31/2024
CAMX	CA	Scattergood	2	163.19	Natural Gas	7/1/1959	12/31/2024
CAMX	UT	Intermountain	1	820.00	Bituminous Coal	6/9/1986	7/1/2025
CAMX	UT	Intermountain	2	820.00	Bituminous Coal	4/30/1987	7/1/2025
CAMX	CA	Diablo Canyon	2	1150.00	Uranium	1/1/1986	8/26/2025
CAMX	CA	Haynes	1	230.00	Natural Gas	9/1/1962	12/31/2029
CAMX	CA	Haynes	2	230.00	Natural Gas	4/1/1963	12/31/2029
CAMX	CA	Harbor	5	75.00	Natural Gas	1/1/1995	12/31/2029
CAMX	CA	Harbor	1	85.30	Natural Gas	1/1/1995	12/31/2029
CAMX	CA	Harbor	2	85.30	Natural Gas	1/1/1995	12/31/2029