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SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	**§**	**BEFORE THE STATE OFFICE**
ELECTRIC COMPANY TO	**§**	**OF**
CHANGE RATES	**§**	**ADMINISTRATIVE HEARINGS**

CITY OF EL PASO'S RESPONSES TO
TIEC's THIRD REQUEST FOR INFORMATION TO
CITY OF EL PASO TIEC 3-1—TIEC 3-4

TIEC's Third Requests for Information were served on December 15, 2021. Pursuant to the scheduling Order, the 5th working day after November 15, 2021 is December 22, 2021.

Dated: December 22, 2021.

Respectfully submitted,

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By:______________________________________
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I certify that a true and correct copy of this document was served by e-mail and/or US mail on all parties of record in this proceeding on December 22, 2021.

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Norman J. Gordon

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CITY OF EL PASO'S RESPONSES TO
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3-1. Please provide all documents Mr. Johnson citied in, or relied upon in connection with, his cross-rebuttal testimony.

ANSWER:

All documents cited and relied upon by Mr. Johnson in his cross rebuttal are publicly available on the internet and are so cited. Footnotes reference documents on the interchange. These documents may be accessed through the PUC Interchange. The cross-rebuttal footnotes and workpapers provide URL addresses to access the reports on-line. Referenced pages of the NARUC Cost Allocation Manual are attached. The testimony provided the web address for U.S. Bureau of Labor Statistics data. The excel files downloaded from that site are provided in this response for convenience.

RFI 3-1 Attachment A-Referenced pages of NARUC Cost Allocation Manual

RFI 3-1 Attachment B-Excel Files from Bureau of Labor Statistics (Attachment 3-1 b 1—Attachment 3-1 b 8) Electronic Files only

Prepared and Sponsored by Clarence Johnson

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3-2. Referring to Mr. Johnson's cross-rebuttal testimony at page 9:

a. Does the Western Electric Coordinating Council (WECC) engage in system planning? Please explain your response.

b. Please provide a detailed explanation of how WECC analyzes peak demand. Please provide all supporting documents.

c. Please explain whether the Southwest Power Pool and the Midcontinent Independent System Operator examine reliability on both monthly and annual bases and evaluate different peak demand scenarios using varying weather parameters. Please provide all supporting documents.

RESPONSE:

a. WECC co-ordinates system planning by member electric utilities. As part of this co-ordination, WECC evaluates reserve margins for the sub-regions within its scope. WECC is the NERC designated reliability entity for the Western region. In that role, WECC provides reliability requirements and guidance to its member electric utilities. WECC's role in system planning is similar to SPP and RTOs.
b. Please see the discussion on pages 9 (ll.14-21) and 10 (l. 1-11) of the cross-rebuttal testimony. Mr. Johnson's understanding is that balancing authorities provide WECC with forecasts of peak demand for monthly periods based on a 50% probability. WECC then adjusts the forecasts in order to develop a 99% probability reserve margin. Please see "Western Assessment of Resource Adequacy Report," particularly pages 11-22. The PDF file is provided as an attachment.
c. Mr. Johnson has not reviewed the most recent reserve margin planning documents for SPP and MISO.

RFI 3-2 Attachment Western Assessment of Resource Adequacy Report

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3-3. Referring to Mr. Johnson's cross-rebuttal testimony at page 14, lines 15-18, please provide the basis for the statement that the referenced accounts are known to involve large components of materials and consumables which vary with kWh generation.

RESPONSE:

The statement is based on the types of consumables associated with FERC Accounts 519, 520, and 523. A519 (Nuclear Coolants and Water) includes purchased water, chemicals and fluids used in the reactor system, pumping supplies and lubricants. A520 (Nuclear Steam) includes fuel handling (removal, insertion and disassembly of fissionable material), nuclear waste disposal, lubricants, decontamination supplies, health safety monitoring equipment, and boiler inspection fees. A523 (Nuclear Electric) includes lubricants and control system oils, generator cooling gases, parts and brushes for motors and generators, operating condensers and circulating water systems, and oil purification systems. Expenses such as this are variable inasmuch as they are necessary for the conversion of fissionable fuel into thermal and electric energy.

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3-4. Referring to Mr. Johnson's cross-rebuttal testimony at page 17, please list the months in which EPE had a negative reserve margin for the last five years.

RESPONSE:

Mr. Johnson has not performed the requested analysis over that time period. Mr. Johnson would expect that a negative reserve margin is a rare occurrence.

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CITY OF EL PASO'S RESPONSES TO
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<u>CITY OF EL PASO TIEC 3-1—TIEC 3-4</u>

RFI 3-1 Attachment A-Referenced pages of NARUC Cost Allocation Manual

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]

Other Power Generation Operation

546, 548-554	All Accounts	x	-
547	Fuel	-	x

Other Power Supply Expenses

555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

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RFI 3-2 Attachment Western Assessment of Resource Adequacy Report

WECC

The Western Assessment of Resource Adequacy Report

December 18, 2020

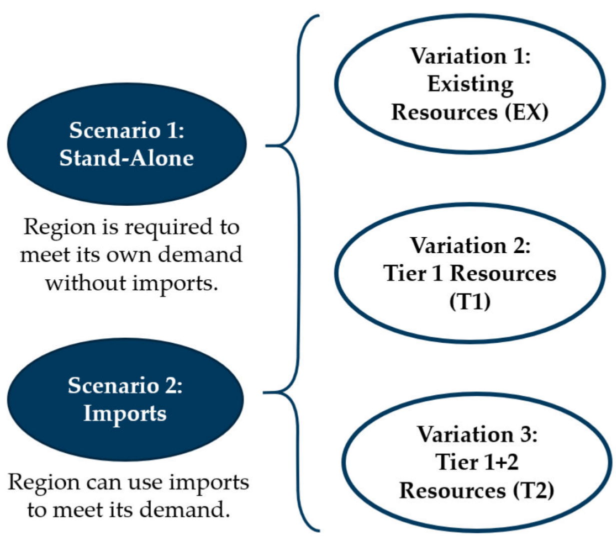
Executive Summary

Resource Adequacy is one component of Bulk Power System (BPS) reliability, and the subject of the Western Assessment. It is evident, based on the findings of the Western Assessment, that traditional methods of resource planning will not be adequate in the future due to the increasing variability on the system. If high levels of resource adequacy are to be preserved, resource planning methods and practices must adapt.

The Western Assessment is a probabilistic analysis of resource adequacy across the entire Western Interconnection at an hourly level for the next 10 years. WECC developed the assessment based on data collected from Balancing Authorities (BA) describing their demand and resource projections for that period. The Western Assessment evaluates two scenarios for each of five subregions in the West (See Figure 1). Each scenario comprises three variations (See Figure 2). These scenarios highlight a broad range of future resource possibilities, including known and expected resource retirements.

Figure 1: Western Assessment Subregions

Figure 2: Western Assessment Scenarios



Key Findings

Finding 1: Under Scenario 1, which requires each subregion to meet its own demand without imports, all subregions show some risk of unserved demand, regardless of the addition of Tier 1 and Tier 2 resources.

Under all variations studied in Scenario 1, there are hours with insufficient resources to supply demand and maintain planning reserve margins.

Finding 2: When subregions can import energy (Scenario 2) most hours of potential unserved demand can be resolved.

Under the most optimistic assumptions about future loads, resources, and imports, there are still hours in which the interconnection does not meet the ODITY threshold for all 10 years studied. The Desert Southwest (DSW) and Northwest Power Pool-Central (NWPP-C) subregions, and the southern California portion of the California and Mexico (CAMX) subregion are most at risk of experiencing unserved load.

> **ODITY**
>
> The One-Day-in-Ten-Years (ODITY) threshold represents a tolerance level of experiencing a loss of load event once every 10 years. The ODITY threshold translates to a 99.97% probability of being resource adequate over a 10-year period.

- The analysis indicates that in 2021, under Scenario 2 Variation 3, which includes the most optimistic generation availability assumptions, there could be one to eight hours in which subregions will not be able to meet the planning reserve margin required to maintain the ODITY threshold.
- The results worsen as the assumptions about resource construction and reliance on imports span to the more realistic, less optimistic end of the spectrum.

Finding 3: Increasing levels of variable resources drive the resource adequacy issues observed in this analysis.

While load variability affects resource adequacy, increasing levels of variable resources, like wind and solar, primarily drive the results of this analysis. The resource mix will continue to change rapidly, and variable resources will continue to grow as consumers demand and states push toward clean energy sources.

- Variable resources provide less certainty and fluctuate more than traditional baseload resources such as coal, natural gas, nuclear, and some hydro. Increasing levels of variable resources have led to inconsistent availability. As a consequence, resource planning becomes more challenging because a greater number of resources are not consistently available to meet load.
- Load variability continues to escalate due to factors such as the changing climate, increases in distributed energy resources, and electrification of the transportation sector. Behind-the-meter

resources, such as rooftop solar, also increase demand variability. Load growth is projected to stay relatively flat in the future due to the expected increase of behind-the-meter resources.

The compounding effect of retiring baseload resources and increasing variable resources contributes to the increased resource adequacy risks described in this assessment.

Finding 4: Historical approaches to resource planning, if unchanged, will result in a significant degradation of resource adequacy.

- The typical deterministic approach to resource planning identifies the peak demand hour, applies a flat, fixed planning reserve margin, and compares this information to the expected generation capacity. This approach assumes that if the highest demand hour is resource adequate, all other periods are as well. Historically, this approach was successful because system variability was relatively low, and entities could rely on the consistency of resource availability. However, as variability increases, the certainty of generation availability for imports decreases, meaning, reliance on imports becomes more precarious.
- Reduced availability of excess generation coupled with an increase in the demand for imports can result in multiple entities relying on the availability of the same imported resource. The result is a shortfall in generation to meet load, as was the case during the Western Heatwave Event of August 2020.

Western Heatwave Event, August 14–19, 2020

What: Extreme heatwave

Temperatures: 10°–20° F above normal

Resource demand: Increased beyond forecast levels

Resource supply: Shortages

Result: August 14 and 15, California shed load resulting in multiple blackouts

Recommendations

In the interest of achieving high-levels of system reliability, WECC recommends the following adaptations for planning entities:

Recommendation 1: Planning entities and their regulatory authorities should consider moving away from a fixed planning reserve margin to a probabilistically determined margin. As variability grows, a dynamic planning reserve margin will better ensure resource adequacy for all hours.

Recommendation 2: Planning entities should consider not only how much additional capacity is needed to mitigate variability, but also the expected availability of the resource. Understanding the differences in resource type availability is crucial to performing resource adequacy studies.

Recommendation 3: Planning entities should coordinate their resource planning efforts on an interconnection-wide basis each year to help ensure they are not all relying on the same imports to maintain resource adequacy. This coordination will help subregions make assumptions about import availability in the context of the entire interconnection.

In addition to recommendations for planning entities, WECC will continue its stakeholder engagement on resource adequacy (e.g., Resource Adequacy Forum) and expand its engagement as needed to complete specific work.

Table of Contents

Introduction

With its independent, interconnection-wide perspective, WECC is uniquely positioned to undertake impartial assessments of risks to the reliability of the BPS in the Western Interconnection. In doing so, WECC can provide regulators, policymakers, Registered Entities, and other interested stakeholders with credible and reliable information and useful insights that facilitate informed decision making.

In support of its mission to mitigate reliability and security risks to the BPS, in June 2020, WECC published and adopted the 2020 WECC Reliability Risk Priorities (WRRP).[1] The four priorities reflect the most significant challenges to reliability in the Western Interconnection. Resource adequacy is one of the four priorities. As such, WECC has undertaken an in-depth resource adequacy assessment of the Western Interconnection. This report, the Western Assessment of Resource Adequacy (Western Assessment), is the product of that initiative. WECC expects to produce the Western Assessment annually in the future.

> **Planning Entities**
>
> The following groups perform resource adequacy assessments in the Western Interconnection. They are collectively referred to as Planning Entities throughout this report.
>
> - Regional Planners
> - Balancing Authorities
> - Load Serving Entities

The Western Assessment examines resource adequacy over the next 10 years across the Western Interconnection and provides a series of key findings and recommendations. It complements NERC's Long-Term Reliability Assessment (LTRA)[2] of North America as well as resource adequacy assessments performed by western subregional planning groups. As requested by stakeholders in 2019, the Western Assessment provides additional analysis of resource adequacy in the Western Interconnection under assumptions that differ from those in the LTRA. Specifically, the differences include:

- Analysis of scenarios that reflect the least favorable resource assumptions (a conservative view of future capacity availability);
- Information on capacity surpluses and deficits given in megawatts in addition to planning reserve margin percentages;
- Analysis of planning reserve margins prior to net firm imports, to demonstrate what happens when subregions must rely on their own resources.[3]

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[1] 2020 WECC Reliability Risk Priorities

[2] 2020 NERC Long-Term Reliability Assessment

[3] WECC's assessment process evaluates resource adequacy on a Western Interconnection-wide basis, which ensures resources, including imports, are counted once and only once to avoid reliance by multiple entities on a single resource.

The Western Assessment comprises four sections:

1. **About This Assessment**: Detail about the analytical methods, tools, and data
2. **Western Interconnection Findings**: Findings for the Western Interconnection
3. **Subregion Findings**: High-level findings for each of the five subregions
4. **Appendices**: Additional technical detail on WECC's Multi-Area Variable Resource Integration Convolution (MAVRIC) model and a list of resource retirements assumptions used in the analysis.

The Western Assessment will be published in two phases. This report provides the information, analysis, key findings, and recommendations for the entire Western Interconnection, as well as a high-level view of the findings for each of the subregions. The second phase will include in-depth analysis and findings for each of the subregions. WECC anticipates publishing the subregional analyses in the first quarter of 2021. WECC will undertake outreach and educational briefings in 2021, which promote the findings of the Western Assessment to regulators, policymakers, Registered Entities, and interested stakeholders.

About This Assessment

This section offers an in-depth explanation of WECC's process for developing the Western Assessment, including the tools, data, assumptions, and thresholds WECC uses.

Reliability Analysis Components

The Western Assessment addresses the first of the following three components of a comprehensive reliability analysis:

1. **Resource adequacy assessments** examine whether existing and planned resources (those expected to be built by a certain time) will meet forecast demand plus a reserve margin. They further evaluate uncertainties in future scenarios, e.g., planned generation is not built, existing generation is retired, or demand is greater than expected.
2. **Transmission adequacy assessments** examine whether there is enough transmission built or planned to be built to transfer energy from generation to load.
3. **Contingency analysis and system stability assessments** examine the effects on the power system during and immediately after disturbances.

WECC addresses transmission adequacy and system stability through other initiatives it undertakes in keeping with its reliability mission.

Subregion Description

Resource adequacy impacts are observed at an interconnection-wide level, while resource availability and demand occur at a more granular level and are highly dependent on location and system topology. To account for this, the Western Assessment examines resource adequacy both at the interconnection-wide level and within each of the following subregions (See Figure 3):

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

These groups align with the three reserve sharing groups in the interconnection—the California

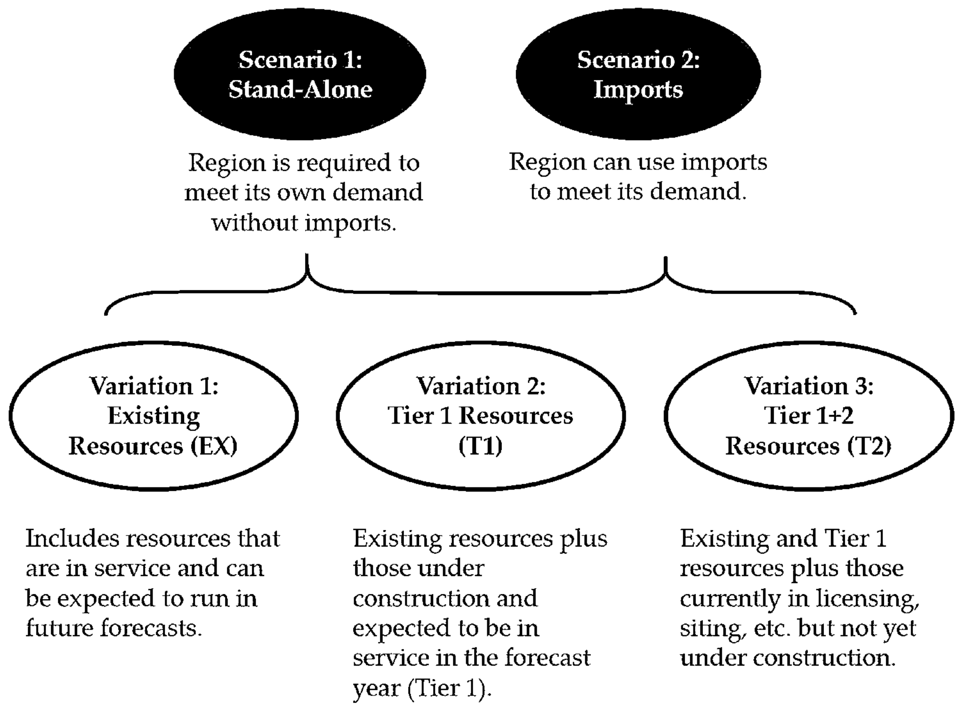
Figure 3: Subregions Studied in the Western Assessment

Independent System Operator (CISO), the Southwest Reserve Sharing Group (SRSW), and the Northwest Power Pool (NWPP). However, the largest reserve sharing group, NWPP, has been divided into three separate subregions according to peak season. The summer-peaking Balancing Authority Areas (BAA) are grouped together into the central subregion. The northwestern and northeastern regions are both winter-peaking.

Scenarios

The Western Assessment evaluates two scenarios for each of the five subregions in the West, and each scenario comprises three variations (See Figure 4). These scenarios highlight a broad range of future resource possibilities, including known and expected resource retirements.

Figure 4: Western Assessment Scenarios and Variations

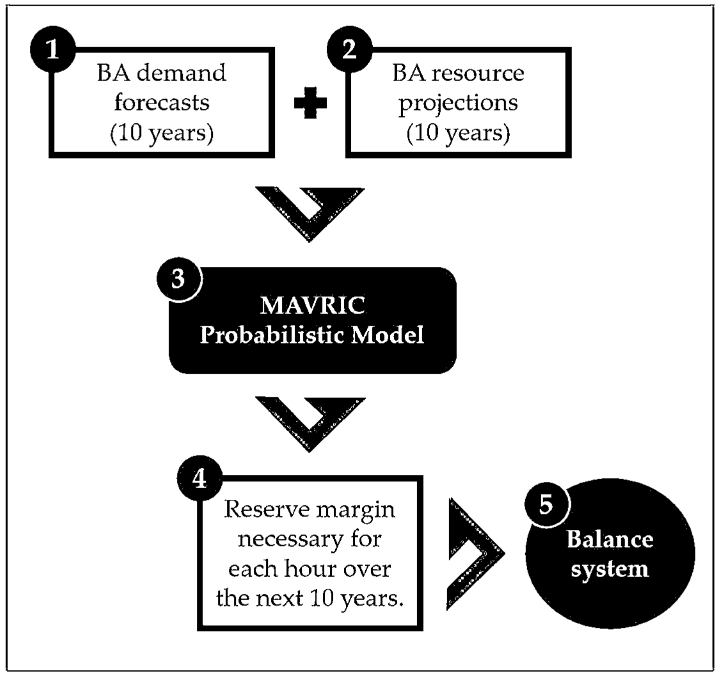


Methods

Historically, the electricity industry analyzed resource adequacy using a deterministic or static approach. This approach compares the amount of available generation capacity to demand on the highest demand-day of the season or year, plus a planning reserve margin. It assumes that if resources can cover demand under peak conditions, the same is true for all other hours of the year. This process was sufficient when load was relatively predictable and the majority of generating resources had consistent output, e.g., thermal, natural gas, coal, nuclear, and some hydro resources. As loads have shifted and the resource mix in the Western Interconnection has changed to include more variable resources, the methods used to analyze resource adequacy have also changed. Today resource adequacy is largely analyzed using probabilistic processes, looking at hourly results across a range of supply and demand scenarios.

The Western Assessment is a probabilistic analysis of resource adequacy across the entire Western Interconnection, at an hourly level, for the next 10 years (See Figure 5). The Western Assessment was developed based on data collected from BAs describing their demand and resource projections for that period. WECC inputs this data into its MAVRIC model to conduct the probabilistic analysis.[4] The MAVRIC model balances the system (matching generation to load) for each hour of the study period to calculate a planning reserve margin. Then the model balances the system to the expected demand. The model determines whether there are enough resources in the interconnection to meet expected demand while maintaining reserves to account for any variations from the expected forecasts or loss of generation. The results from this analysis are used to determine where resource shortfalls may occur in the system over any given study period. WECC's resource adequacy analysis is described in detail in the following sections.

Figure 5: WECC's Resources Adequacy Analysis Process



1. Demand Forecasts

Each year WECC requests 10-year demand forecasts from BAs. The BAs provide monthly energy and monthly peak information for the 10-year study period which is presented in three time frames: annual, peak day, and peak hour. Annual demand is the amount of energy in megawatt-hours (MWh) needed to serve an area during the forecast year. Annual demand information shows how energy demand is expected to fluctuate based on weather and seasonal patterns. Peak hour and peak day demand indicate the maximum demand expected on the peak hour of the day in which the peak hour occurs. In resource adequacy analysis, the shape of daily demand is important in determining how available resources must respond to changes in demand (i.e., ramping).

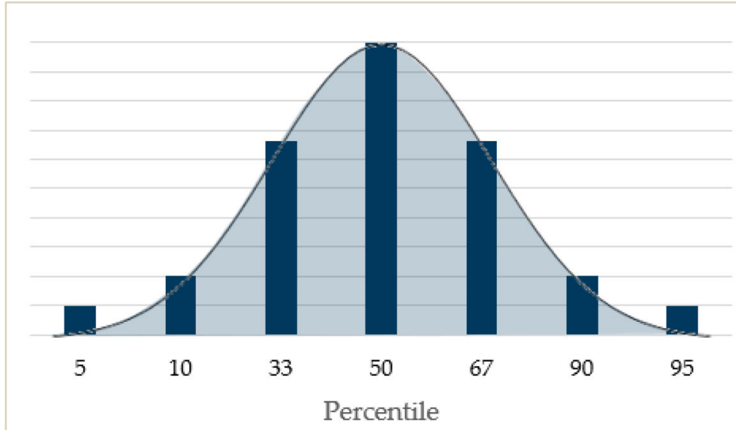
Demand forecasts are inherently inaccurate because actual demand is subject to influences that are impossible to predict, such as weather events, technology and efficiency developments, operational

[4] More information on the MAVRIC is provided on page 14. Detailed information appears in Appendix A.

decisions, and changes in use patterns. The further out the forecast year, the more inaccurate the forecast is, both annually and on the peak day and hour.

To account for the inevitable variability, WECC looks at every demand forecast using a representative distribution (See Figure 6). The distribution shows the range of demand at different likelihoods or probabilities. The expected demand is the demand level at the 50th percentile, also referred to as the "1-in-2 scenario" or "50/50" demand, because 50% of the time demand may be below and 50% of the time demand may be above this number. At the 67th percentile there is a 67% chance demand will be at that level or lower while there is a 33% chance that demand will be higher. Conversely, at the 33rd percentile there is a 33% chance demand will be at or lower than that level, and a 67% chance it will be higher. The pattern follows for the other percentiles. The 90th and 10th percentiles are referred to as 1-in-10 scenarios, the 95th and 5th percentiles are referred to as the 1-in-20 scenarios.

Figure 6: Sample Demand Forecast Distribution Curve



WECC's resource adequacy analysis looks at not only the 50/50 demand, but also each of the other probability distributions. This results in a range of possible demand levels for every hour of the day over 10 years, each with its own probability of occurring. The model then attempts to match each demand level with resources.

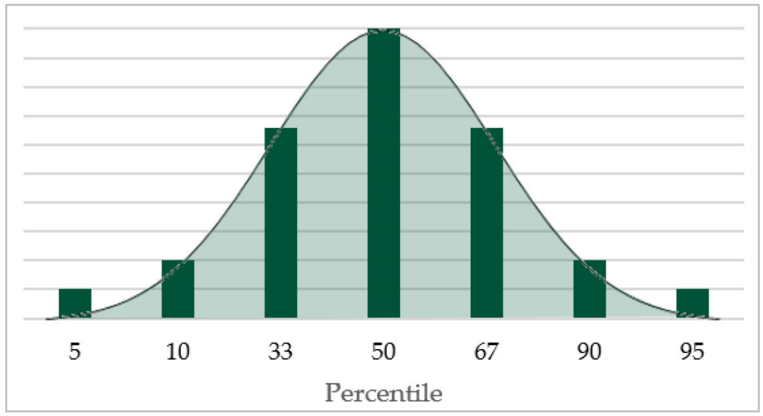
2. BA Resource Projections

Resource availability must accommodate demand variability; however, like demand, resource availability fluctuates. Probabilistic analysis evaluates the range of resource availability for every hour of the year over the 10-year study period. Determining resource availability is complicated due to factors that constrain how much energy the assessment can assume a resource can provide at any given time. These factors include:

- Resource type, specifically related to the consistency of energy generation
  - Baseload resources have relatively consistent output
  - Variable resources, like run-of-river hydro, wind, and solar, are heavily dependent on environmental factors. Their output changes frequently throughout the hour, day, season, and year
- Weather and temperature

- Fuel supply
- Equipment failure
- Equipment age

Figure 7: Example Supply Forecast Distribution Curve



Probabilistic analysis helps account for the variability of resource availability by evaluating the range of possible output levels of each resource. This is done using a representative distribution that shows the probability of a resource being available, similar to the manner in which demand is analyzed (See Figure 7).

In addition to factors that may change the amount of energy a resource can produce, the analysis must account for circumstances that may prevent a resource from producing any amount of energy, such as retirement and delays in building (called "build status").

Resource retirements are a key assumption in resource adequacy analysis. The retirement of resources is often driven by financial, operational, and political factors, making them complex to predict. Unit retirements that are reported to WECC, and additional units that are anticipated to retire, are removed from the dataset on the effective retirement date. This treatment assures the exclusion of retired units from the studies post-retirement. WECC annually revisits the resource retirement assumptions for the Western Interconnection. Appendix B lists the name and effective retirement date for all units retired during the study period.

Another critical assumption in resource adequacy analysis is the build status of new resources included in forecast years, but not operating in the current year. Resource adequacy analyses must account for the possibility that generation plants may be delayed or canceled. To account for changes in build status, WECC evaluates scenarios with different assumptions about resource availability, defined by three categories of resources[5]:

1. Existing (EX): Resources that are in service and can be expected to run in future forecasts, barring unforeseen circumstances that take them off-line;
2. Tier-1 (T1): Resources that are under construction and expected to be complete and available for the year being studied; and

[5] A list of all resources included in this analysis can be found in the MAVRIC Resources.

3. 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.[6]

Together with demand information, resource availability information is put into WECC's probabilistic model to determine required planning reserve margins.

3. MAVRIC Model

The MAVRIC model is WECC's in-house probabilistic modeling tool that overlays forecast demand and forecast resource availability to calculate planning reserve margins needed to maintain resource adequacy. Unlike other probabilistic models and methods, the MAVRIC model does not require a planning reserve margin as an input. Instead, the MAVRIC uses forecast demand and resource availability to calculate a planning reserve margin that meets a predetermined resource adequacy threshold for each hour of the study period.

A resource adequacy threshold represents a planning entity's tolerance to unserved demand. While there are many ways to assess tolerance to unserved demand, WECC applies the commonly used One-Day-in-Ten-Years (ODITY) threshold. The ODITY threshold represents a tolerance level of experiencing a loss of load event once every 10 years. The ODITY threshold translates to a 99.97% probability of being resource adequate over a 10-year period.

To measure resource adequacy against the ODITY threshold, WECC uses a Loss-of-Load Probability (LOLP) metric. The LOLP measures the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. While there are many metrics used in the electric utility industry to measure resource adequacy, WECC uses the LOLP metric because it aligns with the results produced by the MAVRIC model.[7]

Using the demand and resource availability data and applying the LOLP metric to measure resource adequacy against the ODITY threshold, WECC determines planning reserve margins for every hour of the study period.

4. Planning Reserve Margins

A planning reserve margin is an amount of energy held by an entity above what is necessary to meet demand at any given time. Planning reserves are used to compensate for variability in demand or resource availability. For simplicity, planning reserve margins are typically expressed as a percentage of the total demand; however, it is useful to know the amount of power, called megawatts (MW),

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[6] Entities provide WECC data on a third tier of resources. Tier 3 resources are generic placeholder resources that an entity knows will be necessary in future years but has not yet specified, planned, or sited.

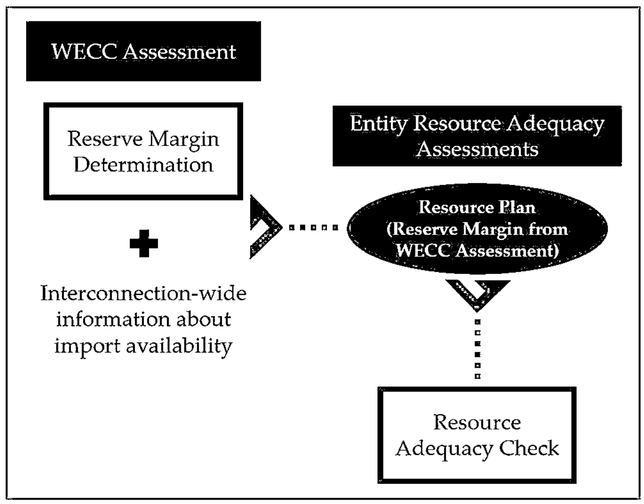
[7] Other resource adequacy metrics include: Loss-of-Load Hours (LOLH), Loss-of-Load Expectation (LOLE), Loss-of-Load Event (LOLEV), and Expected Unserved Energy (EUE). For more information on these metrics see the 2018 NERC Probabilistic Adequacy and Measures.

represented by the percentage. Demand is variable, so 15% of demand for one hour does not equate to the same number of megawatts as 15% for another hour. The Western Assessment provides planning reserve margins as both a percentage and actual megawatts.

Calculating dynamic planning reserve margins across the entire Western Interconnection is how WECC's Western Assessment differs from many subregional assessments. The Western Assessment complements and enhances the work of subregions in three ways:

1. WECC uses demand and resource availability information to calculate planning reserve margins. This may differ from subregional assessments that use demand and resource information, as well as a static planning reserve margin to check the sufficiency of resources. If the expected resources can meet the expected peak demand, with a proper planning reserve margin, the resource plan is deemed adequate. The two methods complement each other because WECC's method can help entities determine what planning reserve margin to use in their evaluation of resource plan sufficiency (See Figure 8).

Figure 8: WECC's Process Complements Subregional Assessments



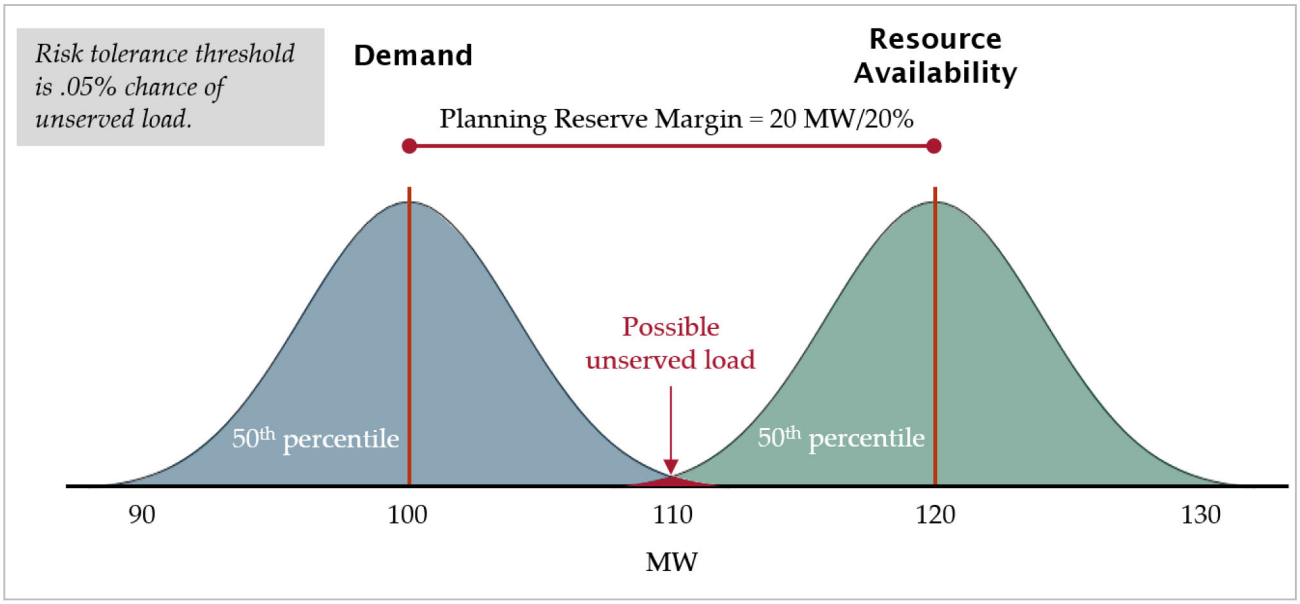
2. WECC calculates dynamic planning reserve margins, which account for the increasing variability on the system. Subregional assessments may use a predetermined planning reserve margin above expected demand to check the sufficiency of resource plans. The planning reserve margin is usually determined based on the peak hour of the summer and winter season.[8]
3. Unlike the analyses undertaken by the subregions, the Western Assessment provides a simultaneous analysis of the entire Western Interconnection that evaluates what happens across and between subregions.

Calculating the Planning Reserve Margins

The MAVRIC model uses demand and resource availability probabilities to determine a dynamic, probability-based planning reserve margin. Overlaying the demand and resource distribution curves helps illustrate how the model determines the planning reserve margin necessary to meet the ODITY threshold for the LOLP metric (See Figure 9).

[8] Regulatory authorities establish planning reserve margins.

Figure 9: Example Planning Reserve Margin Calculation



In the example, the demand curve shows the 50/50 or expected demand at 100 MW, with the possibility of high demand of approximately 110 MW (95th percentile). Likewise, the generation availability is expected to be 120 MW with low availability around 110 MW (5th percentile). In the illustration, the curves intersect at 110 MW, and the overlap of the two curves (colored red in the illustration) is where the probability of loss of load can occur. To calculate the probability illustrated by the overlap of the two curves, the probability of the demand variable is multiplied by the probability of the resource availability. The product is then divided by two to produce the LOLP (See Figure 10).[9]

Figure 10: LOLP Calculation

$$\text{LOLP} = \frac{\text{Probability of Demand (Overlap)} \times \text{Probability of Resource Availability (Overlap)}}{2}$$

In this example, there is a 5% probability of demand being above the 95th percentile, and there is a 5% probability that availability will be below the 5th percentile. Therefore, the LOLP is equal to (.05 x .05)/2 = .00125. This LOLP is then compared to the ODITY threshold (99.97%) to determine whether the subregion is resource-adequate for the hour being studied.

The required planning reserve margin in this example is equal to the difference between the 50/50 demand and 50/50 resource availability scenarios, in this case 20 MW or 20% of the 50/50 demand. This

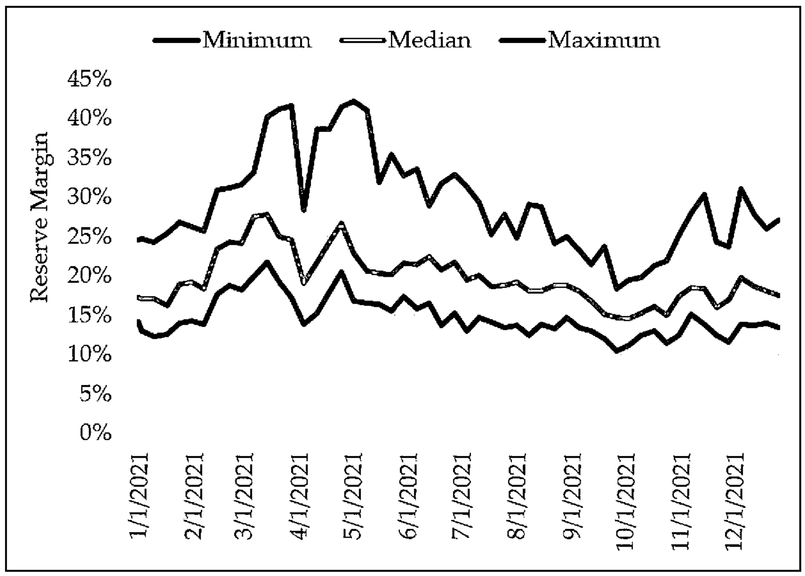
[9] The results are divided by two to reflect the likelihood of demand being higher than supply in the possible unserved load area.

would result in over a 99% probability of zero unserved demand. A margin lower than 20% could result in a higher probability of more unserved demand (the curves would move closer together, increasing the size of the overlap representing possible unserved load). A margin greater than 20% could result in less possible unserved demand (the curves would move further apart). In fact, with a planning reserve margin of 25% the probability of experiencing any unserved load in this illustration is nearly zero because there is no overlap in the curves. In other words, resource availability, in every case, is above demand.

Planning Reserve Margin Range

WECC calculates minimum, median, and maximum hourly planning reserve margins for each BA and aggregates the results into the five subregions. The minimum threshold represents the least amount of planning reserves needed to reach the resource adequacy threshold, while the maximum represents the largest amount of reserve needed to reach the threshold. Likewise, the median level is the amount needed to reach the resource adequacy threshold when half the events are above and half the events are below that threshold.

Figure 11: Example Planning Reserve Margin Plot



Providing a range of planning reserve margins is beneficial in two ways: it shows the variability in required planning reserve margins across the year, and it allows the planner to identify the planning reserve margin that corresponds with their unserved demand tolerance level. As shown in Figure 11, during the winter and summer months the variability in the required planning reserve margin is lower than in the spring and fall. This means the difference between the minimum, median, and maximum planning reserve margin is smaller in the winter and summer. Given all three levels of planning reserve margin, and their corresponding risk tolerance, the planner can see the potential impacts of planning to a particular planning reserve margin.

Once the planning reserve margins are determined for every hour, WECC uses the MAVRIC model to examine potential scenarios for how entities might balance demand and resource availability.

Static vs. Dynamic Planning Reserve Margins

Traditionally, utilities used a static planning reserve margin in their resource adequacy analyses because baseload resources, the primary generation source, have low variability. However, as more variability is added to the system, the static margin may represent a reserve level that is too high or too low, depending on variations in demand and resource availability. Dynamic planning reserve margins help account for variations in demand and resource availability across seasons and hours of the day.

WECC calculates planning reserve margins for every hour of the 10-year study period. Doing so provides information on planning reserve margin changes and patterns across hours, seasons, and years. An examination of these patterns validates WECC's method. When the hourly planning reserve margins for an entire year are plotted and compared to the expected peak demand, it becomes clear that, in many cases, the peak demand time is not when the greatest planning reserve margin is required. In other words, while demand is highest on the peak hour for any given subregion, the variability in demand, resource availability, or both can be greater during a different time. Therefore, planning to a static planning reserve margin to meet the peak demand may result in a system with the potential for unserved load during times of high variability (See Figure 12 and Figure 13).

Figure 12: Example Planning Reserve Margin Plot (%)

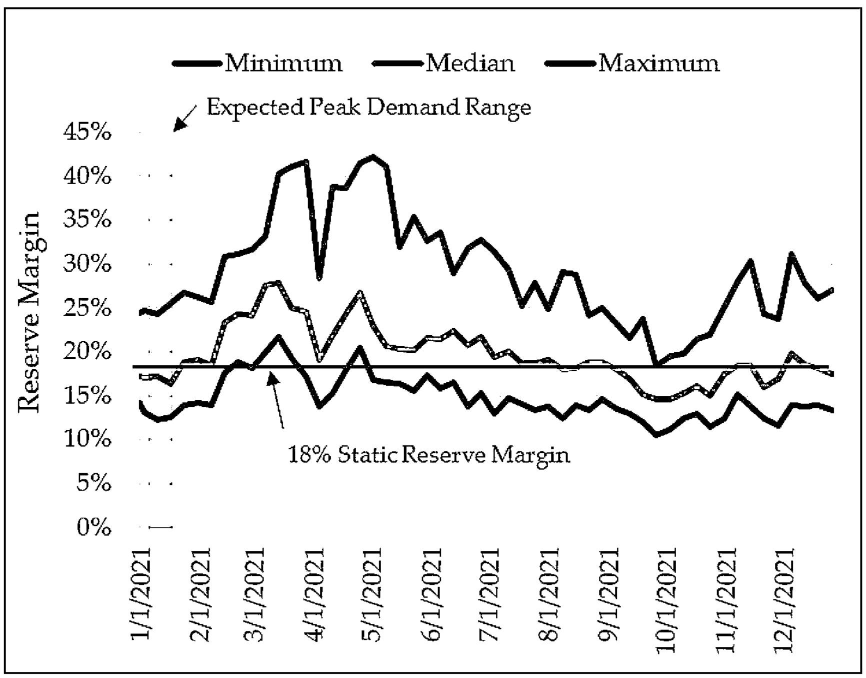
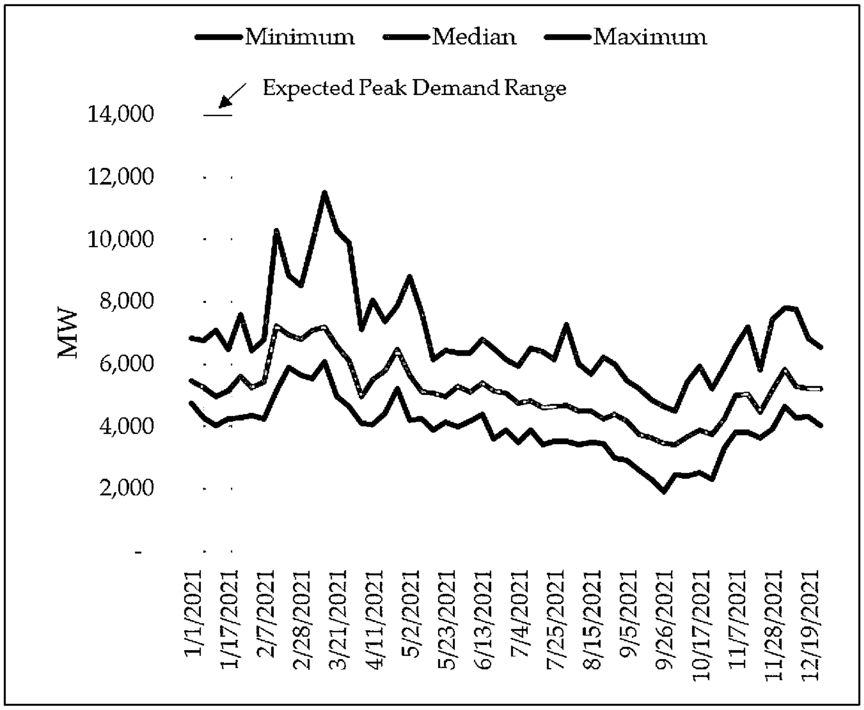


Figure 13 Example Planning Reserve Margin Plot (MW)



The graphs above represent a winter-peaking subregion in which the peak demand is expected to occur sometime in mid-January (represented by the gray bar). During that period the median reserve margin (gold line) ranges from 17% to 19%, which is consistent with a static 18% reserve margin based on the peak hour. As result, during the expected peak hour, the static reserve margin is likely adequate to cover the median (50/50) scenario. However, during the spring and summer months the variability on the system (in demand, resource availability, or both) increases and requires a higher reserve margin, even though the load is lower than the peak hour.

From February to September the median reserve margin ranges from 18% to 27%, meaning an 18% static reserve margin may not be enough to keep the subregion resource adequate at all times. In the case of the maximum dynamic reserve margin, the static 18% reserve margin is insufficient at all times of the year. Even under the minimum reserve margin, there are times in February through May when load may not be served. The same situation exists when analyzing the planning reserve margin in MW (See Figure 13).

Figure 12 and Figure 13 illustrate that the peak day is not the period that necessarily requires the largest planning reserve margin. Planning reserve margins are important when assessing resource adequacy because they provide a layer of security that considers the variability in the system. This is consistent with the understanding that planning reserve margins help compensate for variability on the system. The peak hour is not the time of greatest variability, so it does not require the greatest reserve margin. Therefore, calculating a static reserve margin based on the peak hour results in a reserve margin that may not be adequate during time of great variability, as was the case in the 2020 Western Heatwave Event.

In addition, Figures 11 and 12 illustrate that planning reserve margin requirements by percentage and by MW are not simultaneous. In other words, the highest reserve margin by percent does not correlate to the highest reserve margin by megawatt. This is because the planning reserve margin calculated as a percent fluctuates according to demand (% = reserve margin [MW]/demand [MW]). This means the highest percentage planning reserve margin, and the highest MW planning reserve margin, likely occur on different days. Therefore, it is critical to look at planning reserve margins as both percentages and megawatts.

5. Balancing the System

The MAVRIC model uses demand and resource availability information to balance the system and to ensure planning reserve margins are met for every hour over the 10-year study period. An area such as a subregion can meet its hourly planning reserve margins through a combination of existing resources, new resources in Tier 1 or Tier 2, and imports.

If an area cannot meet its planning reserves from its own resources, it will need to import energy or build more resources. Both remedies have associated risks because neighboring subregions may not have excess power or transmission available to export power, or construction projects may be delayed or cancelled. If these risks materialize, and are not mitigated, there may be hours where demand is at risk of not being served. If the probability of unserved demand is within the entity's risk tolerance, the entity may choose to rely on more speculative options. However, if the probability of unserved demand exceeds the entity's risk tolerance, it may need to change its resource plans, e.g., postpone retirement of resources.

Western Interconnection Findings

This section provides key findings and recommendations for the Western Interconnection.

Key Findings

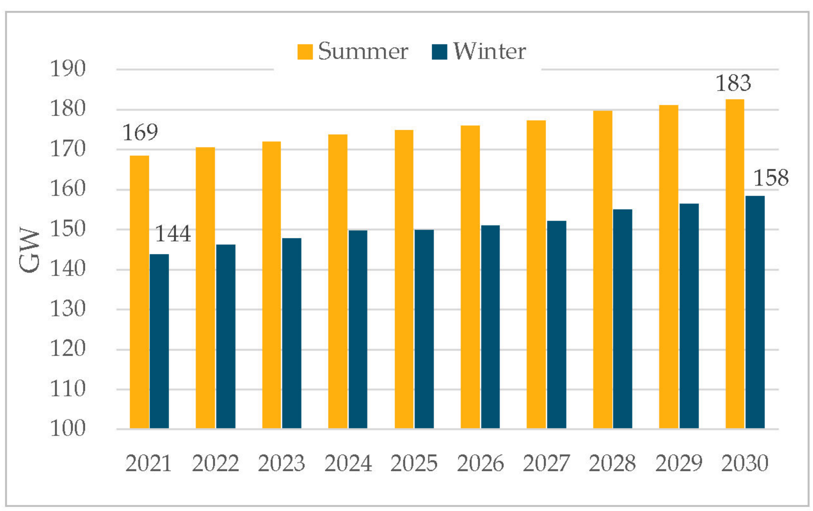
- Based on the ODITY threshold for planning reserve margins, the historical flat planning reserve of 15% falls significantly short not only for extreme cases, but also for expected conditions for the stand-alone scenario (Scenario 1).
- All subregions show a risk of unserved demand in all three variations of Scenario 1 (stand-alone without the ability to use imports).
- The DSW and NWPP-C subregions, and the Southern California portion of the CAMX subregion are most at risk of potentially experiencing unserved load, even when including all Tier 1 and 2 resource additions and importing from other subregions.

Observations

- Over the next 10 years, annual peak demand in the Western Interconnection is expected to increase at about a 1% annual growth rate.
- The Western Interconnection is expected to remain a summer peaking region. However, demand on the winter peak hour is expected to grow faster than the summer peak hour. This change is driven by rooftop solar reducing demand on the traditional summer peak hour.
- Baseload resources typically have higher levels of availability than variable resources. It is expected that baseload resources will continue to be retired and replaced by variable generation resources. Consequently, there will be a decrease in generation availability, which will be further exacerbated without the addition of controllable capacity.

Demand

Figure 14: Western Interconnection Coincident Peak (by Season)



Demand forecasts indicate the Western Interconnection will remain a summer peaking region with the expected coincident peak demand to occur in late July. The 2021 summer coincident peak demand is forecast to be almost 170 GW and is expected to grow by an average of 0.8% per year to over 183 GW by 2030. The winter peak is expected in mid-December each year and is forecast to reach almost 145 GW in 2021 growing by an average of 1% per year to over 158 GW by 2030 (See Figure 14).[10]

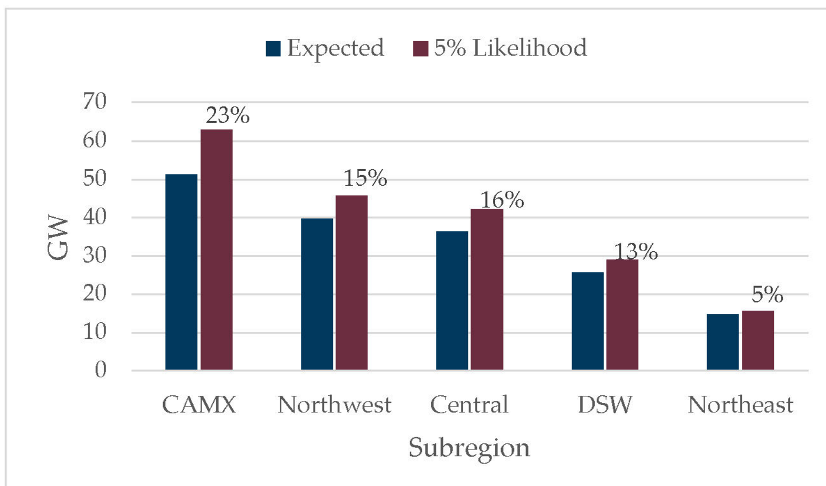
Because of the diversity of the Western Interconnection, each subregion peaks at a different time and season (See Table 1).

Table 1: 2021 Subregional Peak Demand Under Average Conditions

	Peak Time	Peak Demand
NWPP-NW	Mid-January	39,700 MW
NWPP-NE	Early February	14,800 MW
DSW	Early July	25,700 MW
NWPP-C	Mid-July	36,400 MW
CAMX	Late August	51,300 MW

In addition, demand variability varies greatly across the subregions depending on weather and demand composition.

Figure 15: 2021 Subregional Demand Variability



The CAMX subregion has the greatest variability due to the expected increase in rooftop solar. In 2021, the expected (50/50) demand in the CAMX subregion is approximately 51.3 GW, with a 5% probability that the demand could be 23% higher, up to 63.0 GW (See Figure 15). On the opposite end of the spectrum, in the NWPP-NE there is only a 5% variance between the expected demand of 14.8 GW and the extreme demand of 15.6 GW (5% probability). Resource planning in the CAMX subregion must account for much greater demand variability.

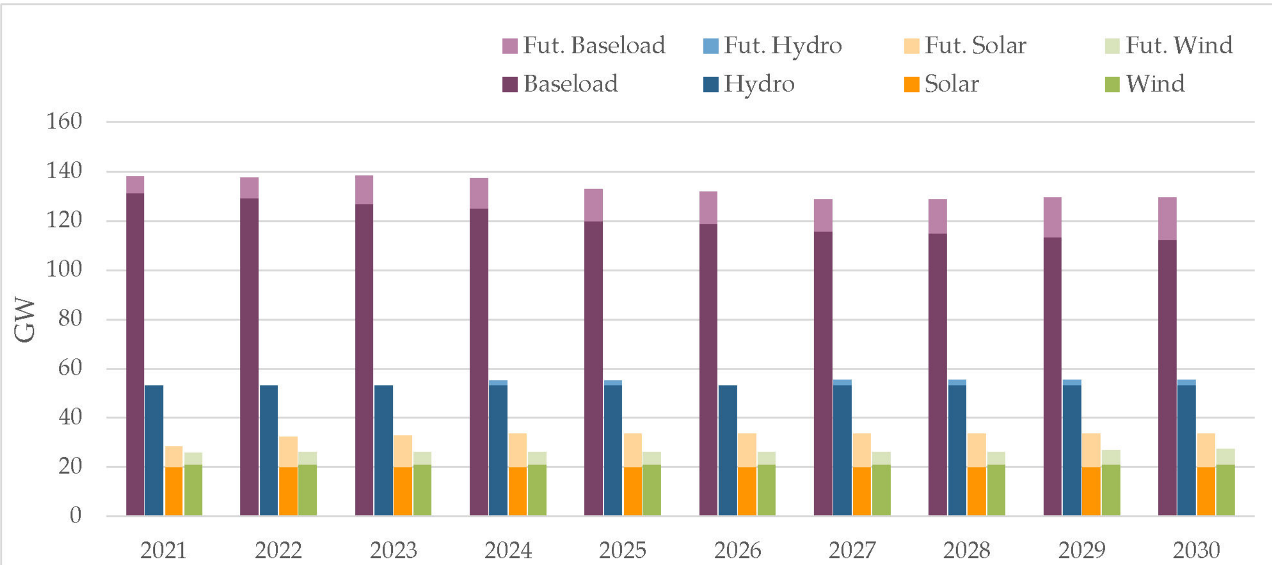
Generation Nameplate Capacity

Additions reported in the assessment are limited to resources that are currently under construction (Tier 1), or that have started an approval process such as licensing, siting, or permitting (Tier 2) (See Figure 16). Most of the Tier 1 and Tier 2 resources are planned to be built by 2025, the fifth year of the

[10] Coincident peak demand is the greatest hourly demand for the entire system at the same time. The coincident peak is not necessarily the peak for individual subregions or entities.

study period. Beyond this time, entities use generic placeholder generation assumptions to account for future resource needs. These resources, called Tier 3 resources, are not included in this assessment.

Figure 16: Western Interconnection Total Nameplate Capacity 2021–2030



Historically, baseload thermal resources have accounted for the largest portion of generation reported in resource portfolios. However, in recent years many coal-fired resources have retired and been replaced by variable generation resources. The 30 GW of coal-fired generation that exists today is expected to drop to 16 GW by 2030; however, some of the coal-fired retirements are expected to be offset by additions in natural-gas fired generation, which is forecast to increase from 91 GW in 2021 to over 96 GW by 2030 (See Figure 17).

Figure 17: Western Interconnection Baseload Breakdown

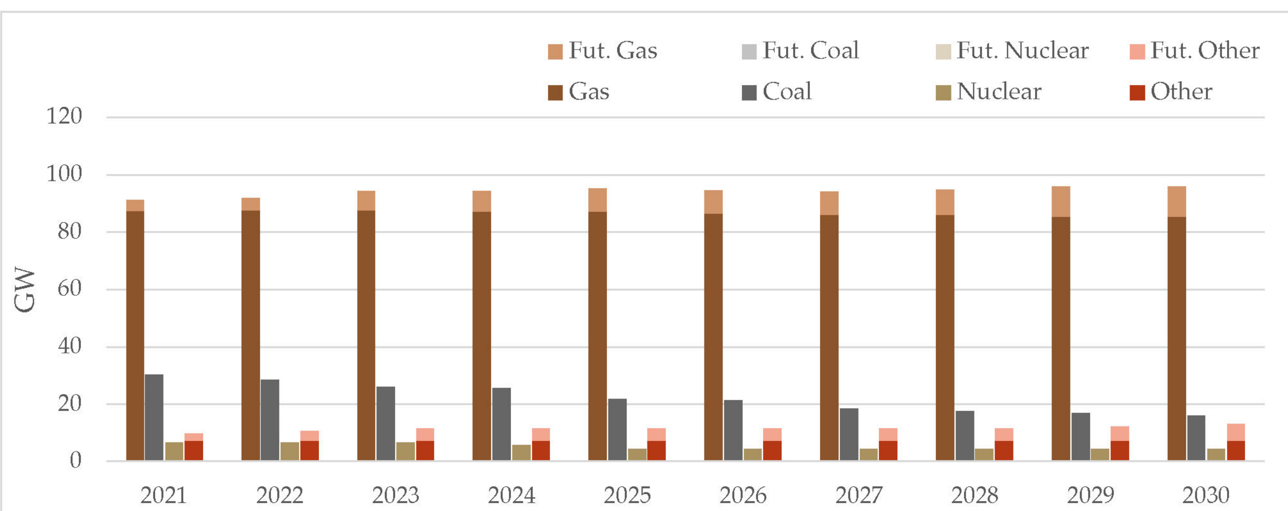
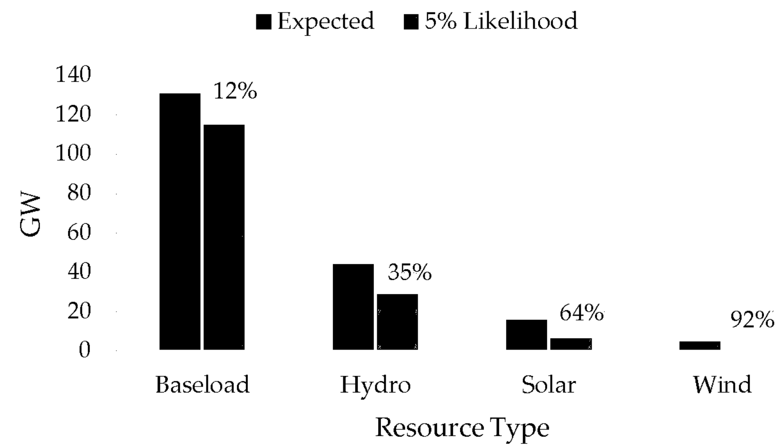


Figure 18: Generation Availability by Resource Type 2021



Hydro resources with storage are critical to reliably operate the western grid as they are able to respond quickly to changes in variable generation; however, run-of-river hydro resources add to the variability in availability. Currently, the Western Interconnection has about 54 GW of hydro resources, mainly located in the Pacific Northwest, and the 10-year resource forecast indicates hydro resources may increase slightly to just over 55 GW by 2030.

In recent years the most common resources added to the western grid have been solar and wind generation. Currently, in the Western Interconnection, wind and solar resources total over 54 GW and it is expected those resources will total over 60 GW by the end of 2030.

Generation Availability

Sufficient generation capacity is critical for serving demand; however, resources are not always available to generate energy when needed. Generation availability can be affected by fuel interruption or maintenance requirements. Fuels like the wind and the sun are not controlled by the generating units and may reduce the resource's availability. Planning for such variations in generation availability is critical when assessing resource adequacy.

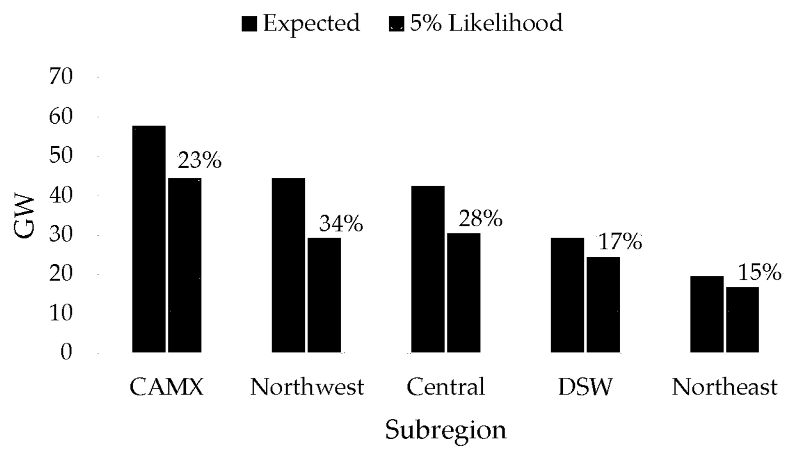
Baseload resources display the greatest generation availability, but availability can be reduced by interruptions in fuel supply or forced outages due to equipment failure (See Figure 18). The Western Assessment indicates that, at the time of the 2021 interconnection coincident peak, ~131 GW of baseload resources are expected to be available. However, in a low resource availability scenario with 5% probability of occurring, baseload resources could drop by as much as ~16 GW.

The availability of hydro resources is typically dependent on two variables, the strength of the water year, and the availability of water storage behind dams. Hydro generation is expected to be capable of producing 44 GW annually, but there is a 5% probability that output could be as little as 28 GW.

Although wind and solar are currently not major sources of energy in the interconnection, the variability of their production needs to be factored into planning processes. During the Western Interconnection's peak hour, solar generation is expected to produce ~16 GW and wind generation is expected to contribute ~5 GW. However, due to the high variability of these resources, under adverse conditions there is a 5% probability that solar generation may drop to as low as 5 GW and wind generation could drop to less than 1 GW.

Generation availability is different for each of the western subregions due to the inherent differences in each subregion's generation portfolio (See Figure 19). As subregions see higher penetration of variable resources, generation availability will change, and higher planning reserve margins will be needed to maintain resource adequacy.

Figure 19: Generation Availability by Subregion 2021

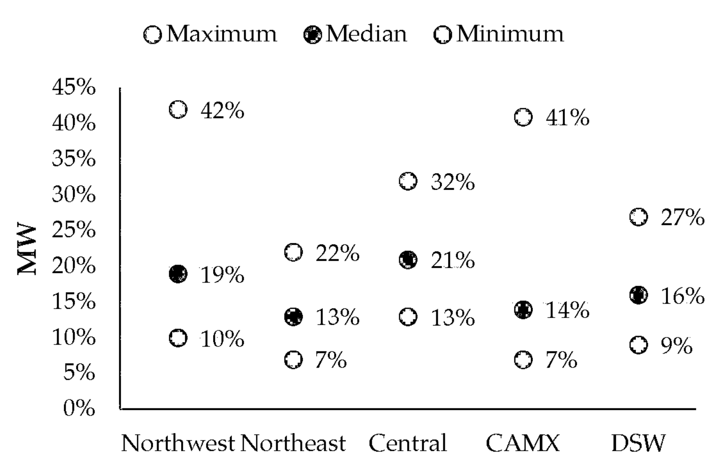


Planning Reserve Margin

Planning reserve margins are important when assessing resource adequacy because they provide a layer of security that accounts for the variability in the system. As the resource mix evolves and demand patterns change, planning reserve margins must be adjusted to capture the increasing variability in both resources and demand. Many entities are transitioning from the traditional deterministic planning model to a probabilistic approach to account for the increase in supply and demand variability.

The Western Assessment demonstrates that a fixed planning reserve margin is not sufficient to assure resource adequacy at all hours of the year. As the resource mix continues to evolve, and demand patterns change, planning reserve margins may need to increase to compensate for variability in supply and demand. Figure 20 and Figure 21 illustrate the planning reserve margins required to meet the ODITY threshold for each subregion, expressed both as a percent and in MW, Scenario 1, Variation 3 (stand-alone scenario with existing, Tier 1, and Tier 2 resources available). The figures show the

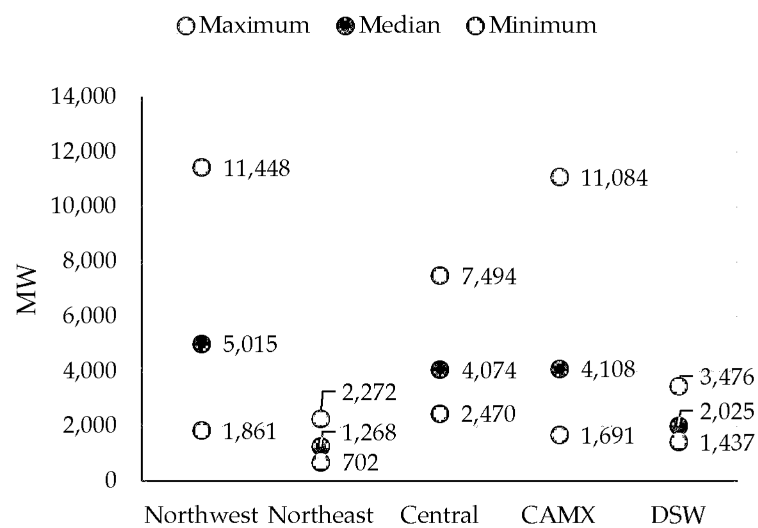
Figure 20: 2021 Reserve Margin Requirement (%)



required planning reserve margins for the following demand and generation probabilities:

- Median (50/50): represents the planning reserve margin required to meet the ODITY threshold for half of the hours of 2021.
- Minimum: represents the smallest planning reserve margin required in 2021 to meet the ODITY threshold.
- Maximum: represents the highest planning reserve margin required in 2021 to meet the ODITY threshold.

Figure 21: 2021 Reserve Margin Requirement (MW)

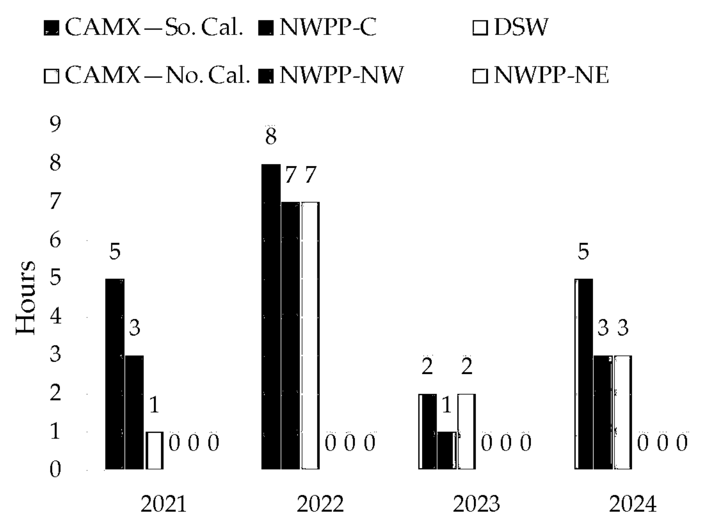


Demand at Risk

The Western Assessment demonstrates that the Western Interconnection will continue to see hours where the ODITY threshold of resource adequacy cannot be maintained even under the most optimistic scenario, i.e., allowing imports and with Tier 1 and 2 resource additions included.

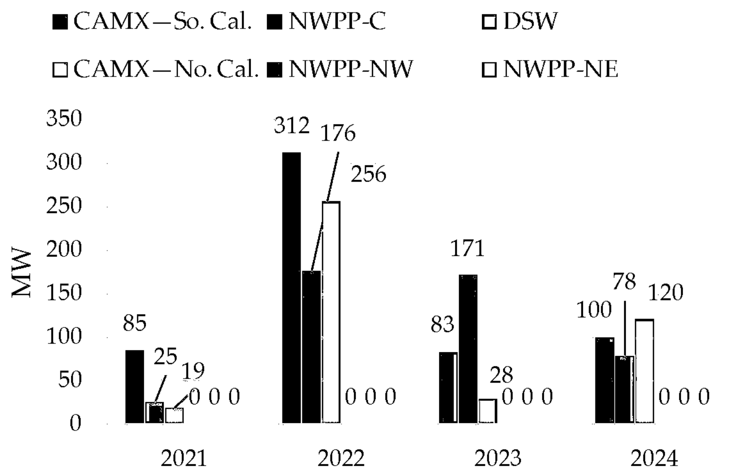
The Western Assessment determines the number of hours where the ODITY threshold is not being met; these hours are referred to as demand at risk hours[11] (See Figure 22).

Figure 22: Demand at Risk Hours



[11] WECC only reports the results of the first four years because beyond 2024 entities use Tier 3 resources to serve demand. Tier 3 resources are generic placeholders for future resources that have yet to be identified, planned, or sited. The Western Assessment does not include Tier 3 resources, which means the potential demand at risk for years five through 10 is exaggerated because demand increases according to the entities' forecasts, but resources do not.

Figure 23: Demand at Risk in Average MW



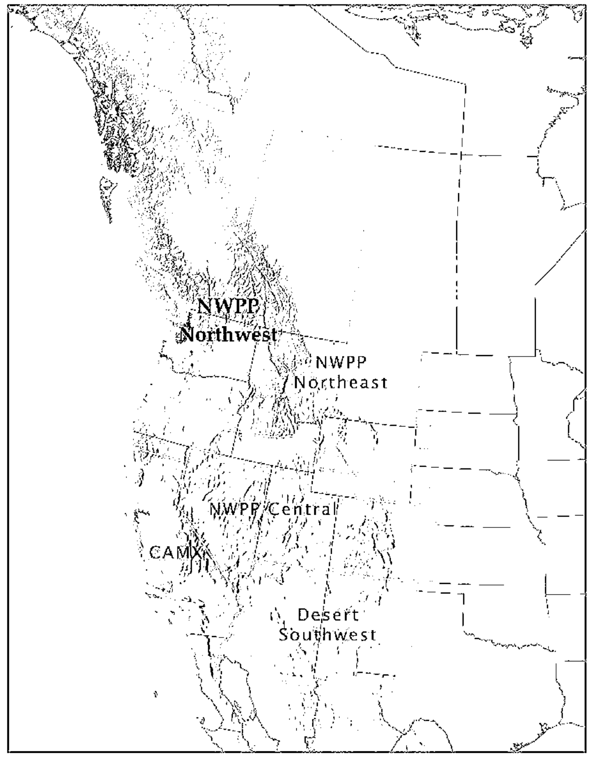
In addition, the assessment determines the average MW (MWa) that are at risk for those corresponding hours (See Figure 23). All subregions show a risk of unserved demand in all three variations of Scenario 1 (stand-alone without the ability to use imports). When subregions can import energy, most hours of potential unserved demand can be resolved. However, even under the most optimistic assumptions about future loads, resources, and imports, there are still hours in which the interconnection does not meet the ODITY threshold for all 10 years studied.

The DSW and NWPP-C subregions, and the Southern California portion of the CAMX subregion are most at risk of potentially experiencing unserved load. Even when including all Tier 1 and 2 resource additions and importing from other subregions these subregions will fall below their planning reserve margins in each of the first four years of the study period. This trend continues into 2025 and beyond, indicating additional resources must be built to mitigate any risk to resource adequacy and its contribution to the reliability of the Western Interconnection.

Subregion Findings

This section provides high-level findings for each of the five subregions. Detailed findings and recommendations for the five subregions will be provided separately in the first quarter of 2021.

Northwest Power Pool—Northwest (NWPP-NW)



The NWPP-NW subregion covers the British Columbia province, the states of Washington and Oregon and portions of Montana, Idaho, and California. The NWPP-NW is a winter peaking subregion that is highly dependent on hydro generation to serve demand.

Key Findings for the NWPP-NW

Demand

In 2021, the NWPP-NW subregion is expected to peak in mid-January at approximately 39,300 MW. 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.

- There is a 5% probability that the subregion could peak as high as 45,300 MW, which equates to a 15% load forecast uncertainty.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 44,400 MW. However, under low resource availability conditions, the NWPP-NW subregion may only have 29,200 MW of resources available to meet the expected 39,300 MW peak demand. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Availability by Resource Type

- Baseload resources account for roughly 14,700 MW of the subregion's resource availability, and under low availability conditions, a 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 reflect the greatest amount of variation in availability. Wind generation availability, under expected conditions, could contribute as much as 300 MW, or under adverse conditions with a 5% likelihood of happening, could have a 0% availability and not produce any energy.

Planning Reserve Margin

For 2021, an annual planning reserve margin of 15% is sufficient to maintain the median (50th percentile) resource adequacy ODITY threshold for the NWPP-NW subregion. However, during 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

Figure 24 shows the number of expected hours in 2021-2024, where the ODITY threshold of resource adequacy is not met for each of the six scenarios studied. In 2021, in the scenario Stand-Alone-EX, the NWPP-NW subregion could experience as many as 208 hours where the ODITY threshold of resource adequacy is not maintained. Under the scenario Stand-Alone-T1, the number of hours with potential demand at risk is reduced to 195. This is further reduced to 194 hours under the scenario Stand-Alone-T2. These results indicate that as early as 2021, even with all planned resource additions the subregion still needs external assistance to maintain resource adequacy.

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

Figure 25: NWPP-NW Potential Demand at Risk Hours

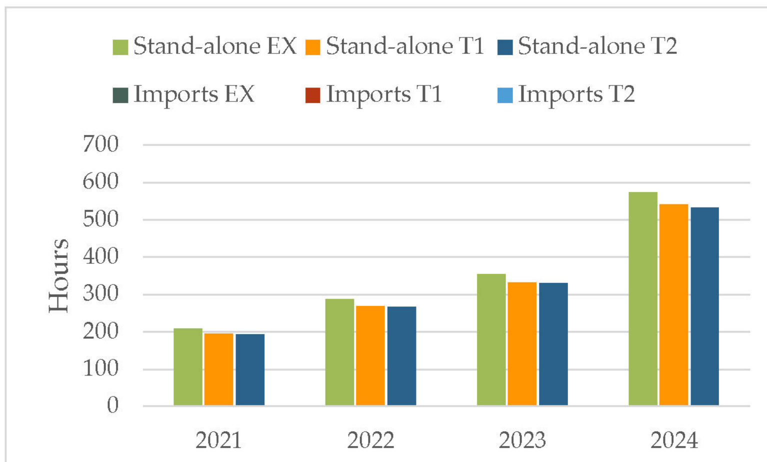
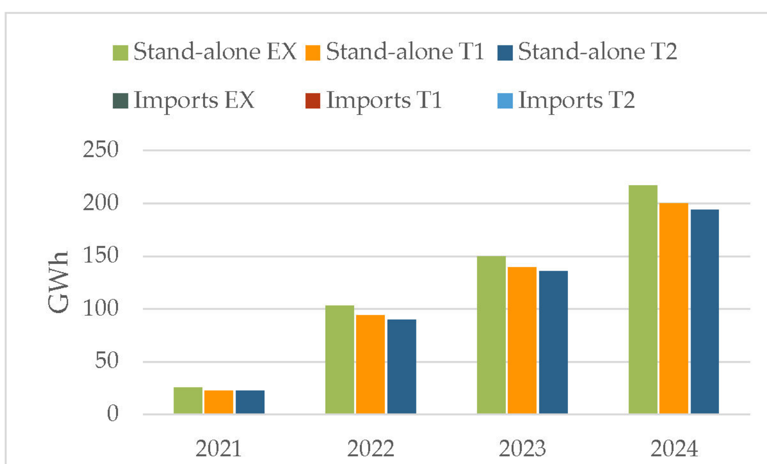


Figure 24: NWPP-NW Potential Demand at Risk GWh

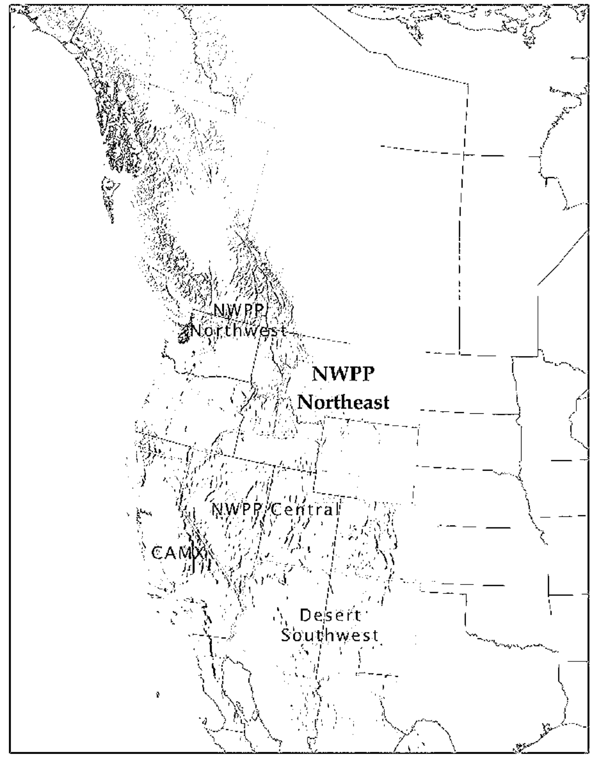


Energy at Risk

In 2021, approximately 26 GWh of demand is at risk in the Stand-Alone-EX scenario (See Figure 25). Spread over the 208 hours at risk in this scenario, (See Figure 24), this translates to about 123 MW of unserved demand per at-risk hour. This trend continues through 2024 with increasing levels of demand at risk each year for the Stand-Alone-EX scenario.

These results indicate that for the Stand-Alone scenario, 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.

Northwest Power Pool—Northeast (NWPP-NE)



The NWPP-NE subregion consists of the northeastern portion, the east side of the Rocky Mountains, of the Western Interconnection. The NWPP-NE is a winter peaking area that covers the Alberta province of Canada and portions of the states of Montana, Idaho, Wyoming, South Dakota, and Nebraska.

Key Findings for the NWPP-NE

Demand

In 2021, the NWPP-NE subregion is expected to peak in early February at approximately 14,800 MW. Overall, the NWPP-NE subregion should expect a 30% ramp from the lowest to the highest hour of the peak demand day. This equates to approximately a 3,400 MW change.

- In 2021, there is a 5% likelihood that the subregion could peak as high as 15,600 MW, which equates to a 5% load forecast uncertainty.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 19,600 MW. Under low resource availability conditions, the NWPP-NE subregion would have approximately 16,700 MW of resources available to meet the expected 14,800 MW peak, an amount sufficient to cover the expected peak demand.

Availability by Resource Type

- Baseload resources account for roughly 17,000 MW of availability with a 5% probability that resources could be as low as 15,200 MW.
- Wind generation could contribute as much as 900 MW under the expected conditions. Under low availability conditions, it is probable (5% likelihood) that wind would generate no energy.

Planning Reserve Margin

For 2021, an annual planning reserve margin of 15% is sufficient to maintain the median (50th percentile) resource adequacy ODITY threshold for the NWPP-NE subregion. The highest reserve margin needed in 2021 is expected to be around 22% due to limited variability in generation availability associated with baseload resources. 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

Figure 26 shows the number of expected hours in 2021-2024 where the ODITY threshold of resource adequacy is not met for each of the six scenarios studied. In 2021, in each of the Stand-Alone scenarios the NWPP-NE subregion could experience up to 4,200 hours where the ODITY threshold of resource adequacy is not maintained. These results indicate that, starting in 2021, even with all planned resource additions, the subregion still needs external assistance to maintain resource adequacy.

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, about 575 GWh of demand is at risk across each of the Stand-Alone scenarios (See Figure 27). Spread over the 4,200 hours at risk in each of the Stand-Alone scenarios (See Figure 26), this translates to about 137 MW of unserved demand per at-risk hour in each scenario. This trend continues through 2024, with increasing levels of demand at risk each year in all Stand-Alone scenarios.

These results indicate for the Stand-Alone scenario, under all variations, additional or different types of resources beyond 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.

Figure 26: NWPP-NE Potential Demand at Risk Hours

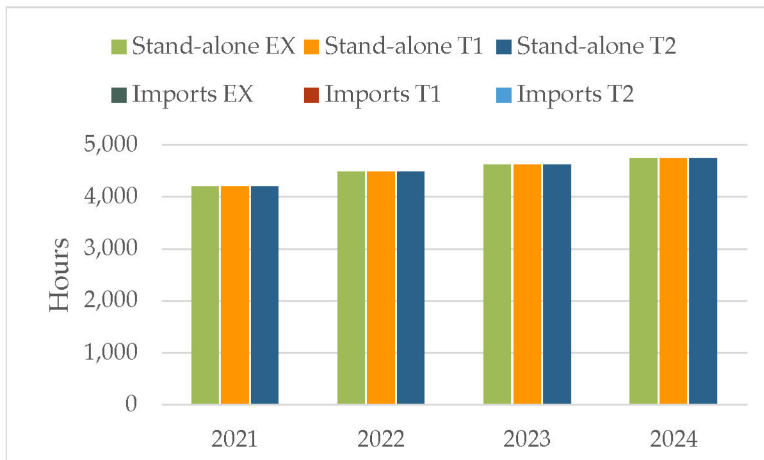
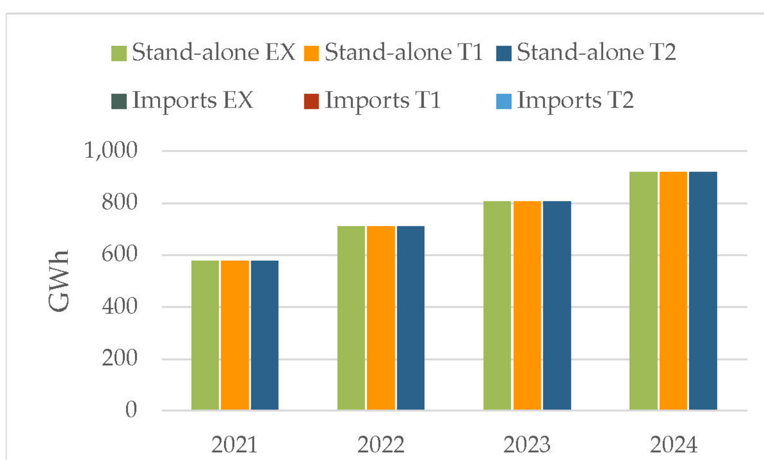
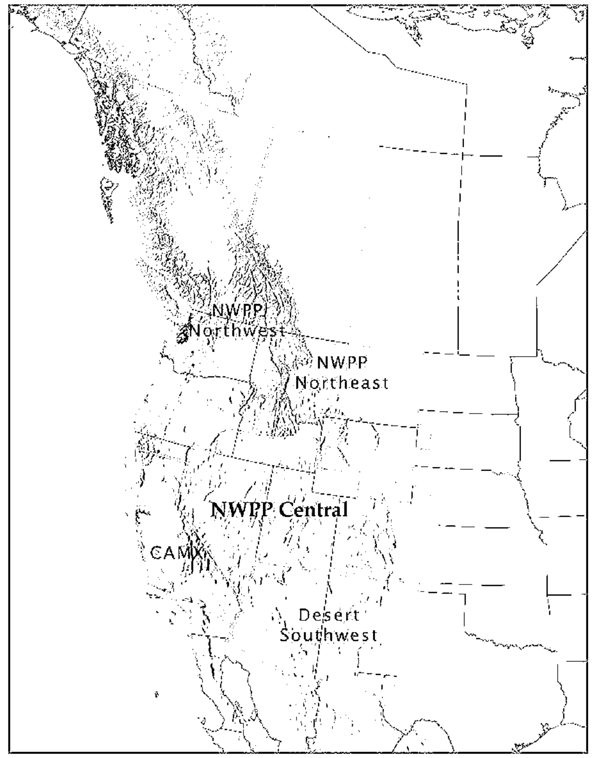


Figure 27: NWPP-NE Potential Demand at Risk GWh



Northwest Power Pool—Central (NWPP-C)



The NWPP-C subregion consists of the central portion of the Western Interconnection. This subregion is the summer peaking section of the Northwest Power Pool and covers all of Nevada, Utah, and Colorado, and parts of Idaho, Wyoming, and California.

Key Findings for the NWPP-C

Demand

In 2021, The NWPP-C subregion is expected to peak in mid-July at approximately 36,400 MW. Overall, the NWPP-C subregion should expect a 104% ramp, or 18,500 MW, from the lowest to the highest hour of the peak demand day.

In 2021, there is a 5% probability that the subregion could peak as high as 42,200 MW, which equates to a 16% load forecast uncertainty.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 42,400 MW. Under low resource 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, a large amount of external assistance would be needed to meet demand under low availability conditions.

Availability by Resource Type

- 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 25,500 MW.
- Solar generation availability could range from an expected availability of 3,900 MW to a low of 1,500 MW.

Planning Reserve Margin

For 2021, an annual planning reserve margin of 21% is sufficient to maintain the median (50th percentile) resource adequacy ODITY threshold for the NWPP-C subregion. However, in the months when variability in energy supply and demand is highest, a planning reserve margin around 32% 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.

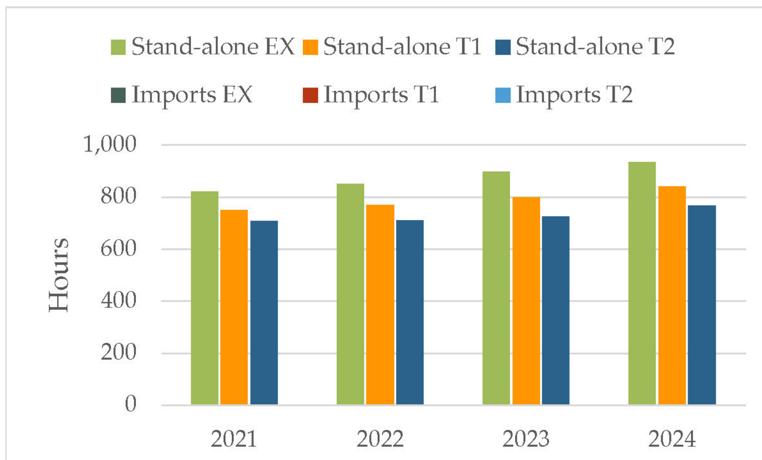
Annual Demand at Risk

Hours at Risk

Figure 28 shows the number of expected hours from 2021 through 2024 where 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 as many as 822 hours where 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 791. This is further reduced to 708 hours under the Stand-Alone-T2 scenario. These results indicate that while additional Tier 1 and Tier 2 resource help, the subregion still needs external assistance to maintain resource adequacy.

In 2021, under the Import-EX scenario, there are 14 hours where the ODITY threshold may not be met and load is at risk. In 2022, in both the Import-EX and Import-T1 scenarios, there are 30 hours and 14 hours at risk, respectively. In 2024, this increases to 49 and 20 hours, respectively. These results indicate that even with all planned resource additions and importing excess energy from other subregions, there are still hours at risk for unserved energy under the Import-EX and Import-T1 scenarios.

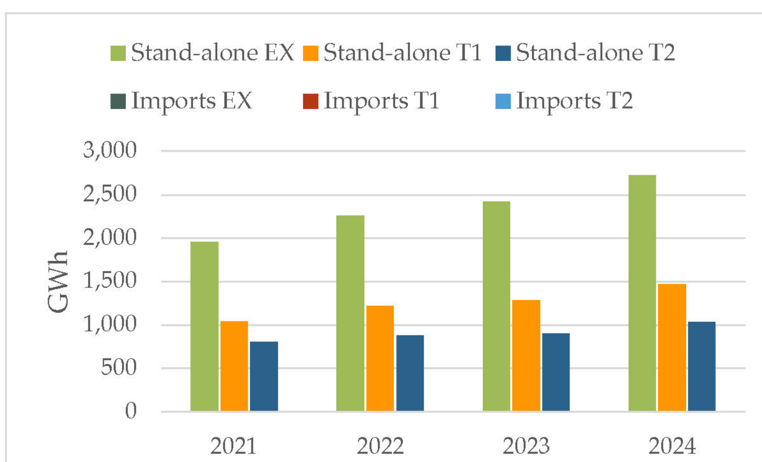
Figure 28: NWPP-C Potential Demand at Risk Hours



Energy at Risk

In 2021, about 2,000 GWh of energy is at risk in the Stand-Alone-EX scenario (See Figure 29). Spread over the 800 hours at risk in this scenario (See Figure 28), this translates to about 2,300 MW of unserved demand per at-risk hour. This trend continues through 2024, with increasing levels of demand at risk each year. Even when

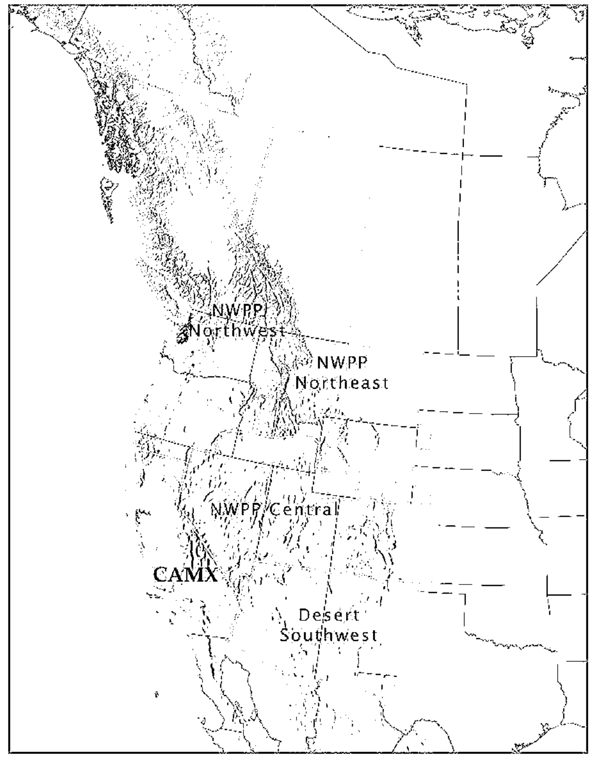
Figure 29: NWPP-C Potential Demand at Risk GWh



the NWPP-C subregion can import energy from outside the subregion, there are still hours where demand is at risk, equaling more than 40 GWh in 2024.

These results indicate for the Stand-Alone Scenario, 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.

California and Mexico (CAMX)



The CAMX subregion is a summer peaking subregion that consists of most of the state of California and a portion of Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California. To highlight how their different peaks impact resource adequacy, the Demand at Risk section reports southern California and northern California separately.

Key Findings for the CAMX

Demand

In 2021, the CAMX subregion is expected to peak in late August at approximately 51,300 MW. 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.

- In 2021, there is a 5% probability that the subregion could peak as high as 63,000 MW, which equates to a 25% load forecast uncertainty.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 57,800 MW. Under low resource 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, a large amount of external assistance would be needed to meet demand under low availability conditions.

Availability by Resource Type

- 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.
- Solar generation availability could range from an expected availability of 6,500 MW to a low of 1,000 MW; again, a 5% probability.

Planning Reserve Margin

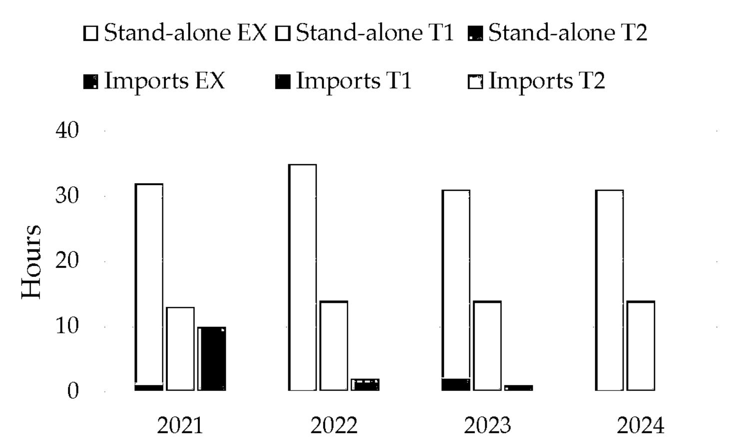
For 2021, an annual planning reserve margin of 15% is sufficient to maintain the median (50th percentile) resource adequacy ODITY threshold for the CAMX subregion. However, in the months when variability in energy supply and demand is highest, a planning reserve margin around 40% may be needed to maintain 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—Northern California

Hours at Risk

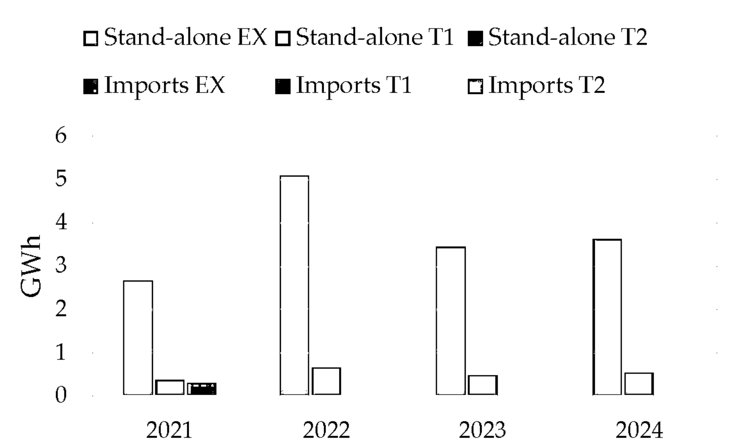
Figure 30 shows the number of expected hours from 2021 through 2024, where the ODITY threshold of resource adequacy is not met in northern California for each of the six scenarios studied. In 2021, in the Stand-Alone-EX scenario, the northern California portion of the CAMX subregion could experience as many as 32 hours where 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. These results indicate that, even with all planned resource additions, the subregion still needs external assistance to maintain resource adequacy.

Figure 30: CAMX—No. Cal. Potential Demand at Risk Hours



In 2022, under the Import-EX scenario, there is one hour where the ODITY threshold may not be met and load is at risk. This increases to two hours at risk in 2024. These results indicate that, even with all planned resource additions and importing excess energy from other subregions, there are still hours at risk for unserved energy in the Import-EX scenario. However, there are no hours that fail to meet the ODITY threshold for the Import-T1 and Import-T2 scenarios.

Figure 31: CAMX—No. Cal. Potential Demand at Risk GWh



Energy at Risk

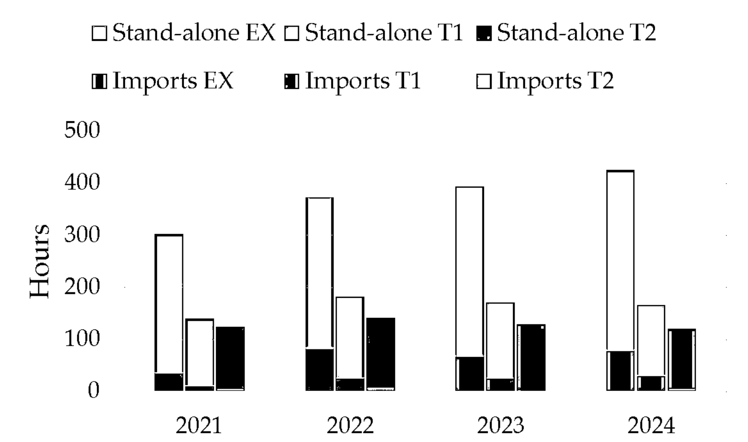
In 2021, about 3 GWh of energy is at risk in the Stand-Alone-EX scenario (See Figure 31). Spread over the 32 hours at risk in this scenario (See Figure 30), this translates to about 84 MW of unserved demand per at-risk hour. The amount of energy at risk in the Stand-Alone-EX scenario fluctuates, revealing no trend through 2024. Even when the northern California portion of the CAMX subregion can import energy from outside the subregion there are still hours where demand is at risk.

Annual Demand at Risk—Southern California

Hours at Risk

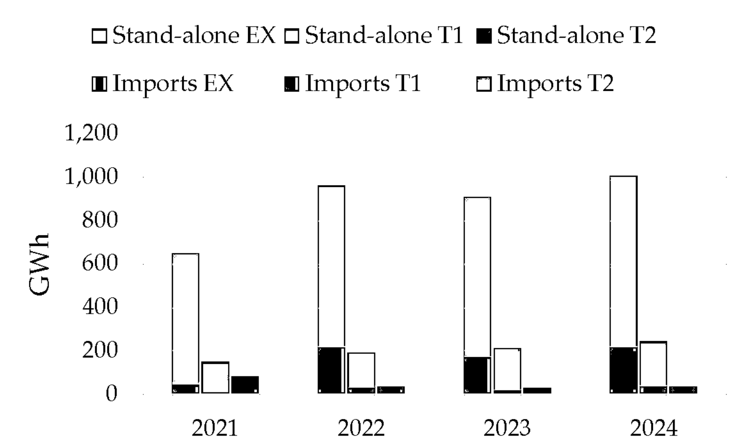
Figure 32 shows the number of expected hours from 2021 through 2024, where the ODITY threshold of resource adequacy is not met for southern California in each of the six scenarios studied. In 2021, in the Stand-Alone-EX scenario, the southern California portion of the CAMX subregion could experience as many as 300 hours where 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. These results indicate that, even with all planned resource additions, the southern California part of the CAMX subregion still needs external assistance to maintain resource adequacy.

Figure 32: CAMX—So. Cal. Potential Demand at Risk Hours



In 2021, under all variations of the Import scenario, there are hours where the ODITY threshold is not met and load is at risk. The number of hours at risk in each Import scenario fluctuates each year through 2024. These results indicate that, even with all planned resource additions and importing excess energy for other subregions, there are still hours at risk for unserved energy.

Figure 33: CAMX—So. Cal. Potential Demand at Risk GWh



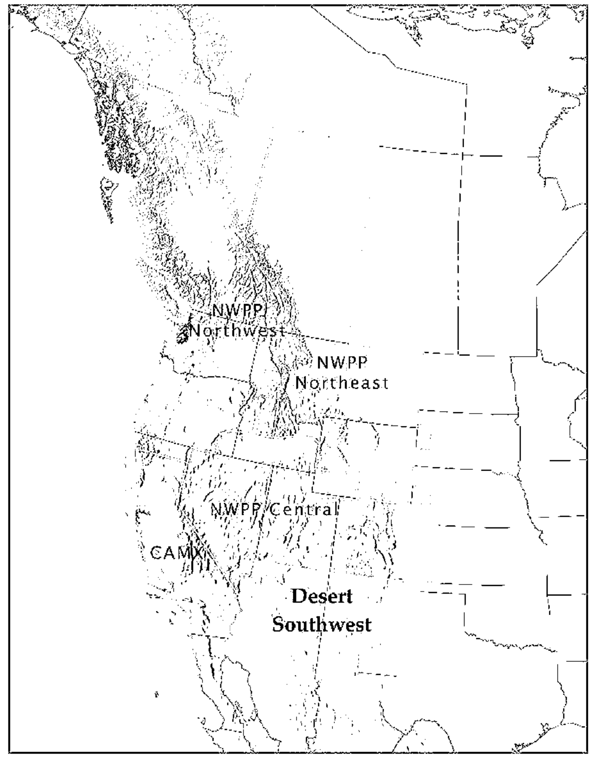
Energy at Risk

In 2021, about 650 GWh of energy is at risk in the Stand-Alone-EX scenario (See Figure 33). Spread over the 300 hours at risk in this scenario (See Figure 32), 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.

Even when the southern California portion of the CAMX subregion can import energy from outside the subregion, there are still hours where demand is at risk.

These results indicate for all variations of the Stand-Alone scenario, additional or different types of resources above those planned to be added over the next four years, are needed for the southern California part of the CAMX subregion to remain resource adequate and avoid unserved demand.

Desert Southwest (DSW)



The DSW subregion is a summer peaking area that covers all of Arizona and New Mexico and portions of Texas and California.

Key Findings for the DSW

Demand

The DSW subregion is expected to peak in early July at approximately 25,700 MW. Overall, the DSW subregion should expect a 100% ramp, or 12,800 MW, from the lowest to the highest demand hour of the peak demand day.

- There is a 5% probability that the subregion could peak as high as 29,100 MW, which equates to a 13% load forecast uncertainty.

Resource Availability

The expected availability of resources on the peak hour in 2021 is 29,300 MW. Under low availability conditions, the DSW subregion may only have 24,300 MW available to meet a 25,700 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low availability conditions.

Availability by Resource Type

- Baseload resources account for roughly 25,000 MW of the subregion's resource availability, and under low availability conditions (5% probability), baseload resources could supply as little as 21,900 MW.
- Solar generation availability could range from an expected availability of 1,400 MW to a low of 800 MW; again, a 5% probability.

Planning Reserve Margin

For 2021, an annual planning reserve margin of 16% is sufficient to maintain the median (50th percentile) resource adequacy ODITY threshold for the DSW subregion. However, in the months when variability in energy supply and demand is highest, a planning reserve margin around 27% 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.

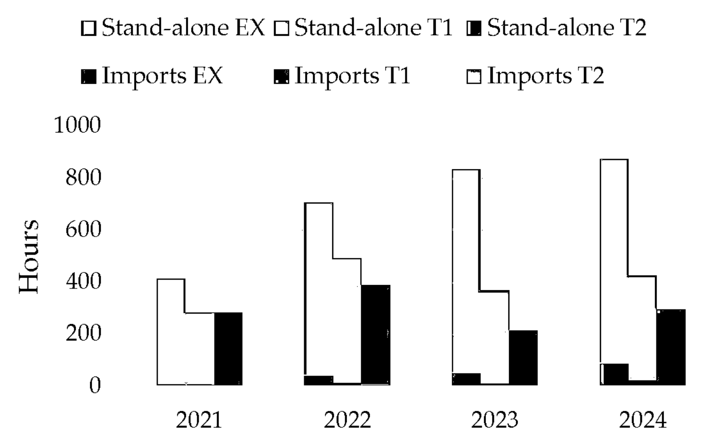
Annual Demand at Risk

Hours at Risk

Figure 34 shows the number of expected hours in 2021-2024, where the ODITY threshold of resource adequacy is not met in each of the six scenarios studied. In 2021, in the Stand-Alone-EX scenario, the DSW subregion could experience as many as 415 hours where the ODITY threshold of resource adequacy is not maintained. Under the Stand-Alone-T1 and Stand-Alone-T2 scenarios, the number of hours with potential demand at risk is reduced to 283 hours. These results indicate that even with all planned resource additions the subregion still needs external assistance to maintain resource adequacy.

In 2022, under the Imports-EX and Imports-T1 scenarios, there are 41 and 14 hours, respectively, in which the ODITY threshold is not met and load is at risk. The number of hours at risk increases for both scenarios between 2022 and 2024. These results indicate that, even with all planned resource additions and importing excess energy for other subregions, there are still hours at risk for unserved energy.

Figure 34: DSW Potential Demand at Risk Hours

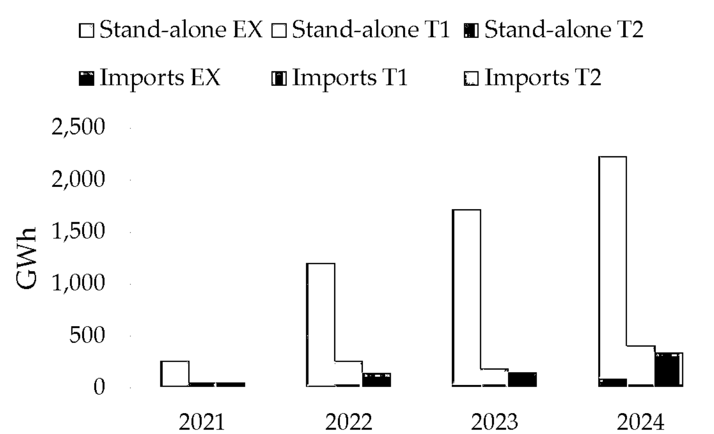


Energy at Risk

In 2021, the total energy at risk in the Stand-Alone-EX scenario is about 259 GWh (See Figure 35). Spread over the 415 hours at risk in this scenario (See Figure 34), this translates to about 624 MW of unserved demand per at-risk hour. This trend continues through 2024, with increasing levels of demand at risk each year.

These results indicate for all variations of the Stand-Alone scenario, additional or different types of resources above those planned to be added over the next four years, are needed for the DSW subregion to remain resource adequate and avoid unserved demand.

Figure 35: DSW Potential Demand at Risk GWh

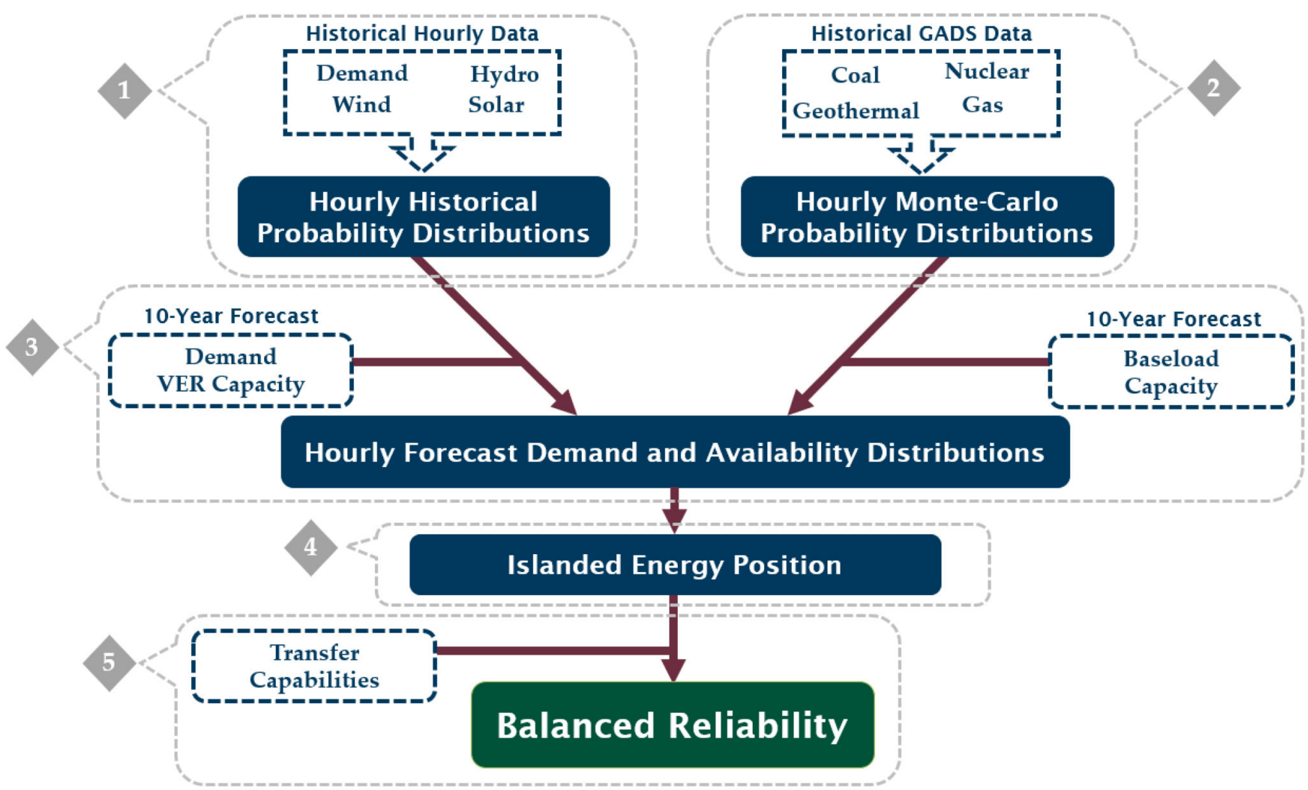


Appendix A

Multiple Area Variable Resource Integration Convolution Model

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points, with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint, with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of Variable Energy Resources (VER), and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through Loss-of-Load Probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models.

Figure 1: MAVRIC Process Flowchart

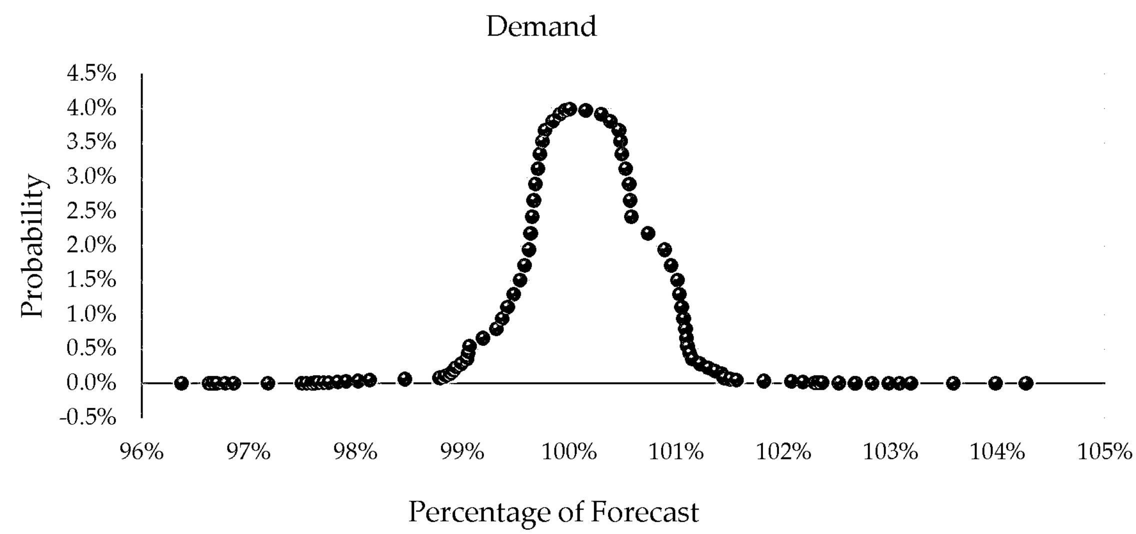


To calculate the LOLP of each of the load-serving areas, probability distributions are needed for each generating resource in the Western Interconnection, as well as for the demand of each Balancing Authority.

In step one, probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the Balancing Authorities in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output of this step is a series of hourly percentile profiles with different probabilities of occurring.

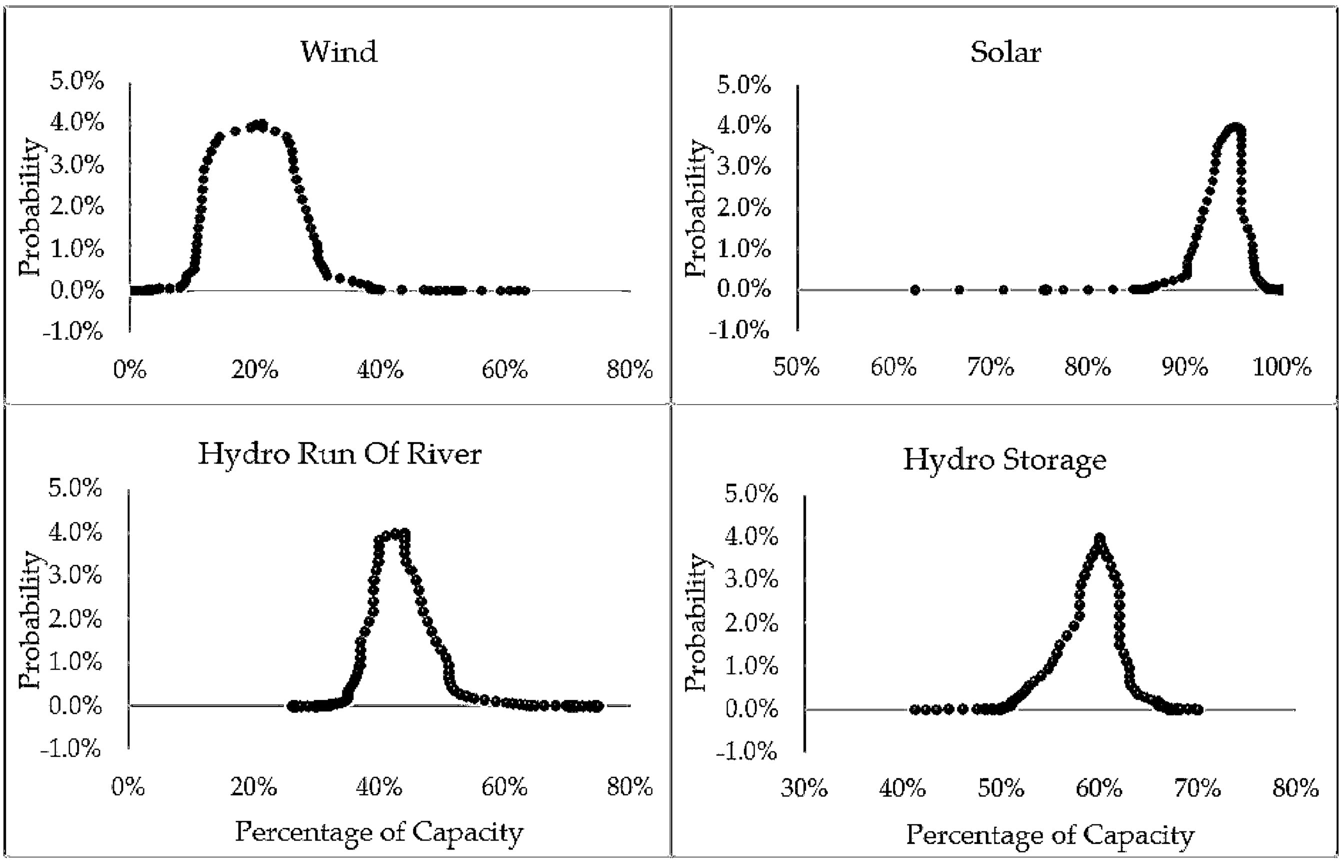
Figure 2 represents the probabilities for one hour. The peak is the expected deterministic forecast and is set at 100%. The profiles above or to the right of the peak are greater than 100% and those below or to the left are lower than 100% depending on the variability for each hour.

Figure 2: Demand Probability Disruption Sample



Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources), is conducted like the demand calculations but with two notable differences. The first, and most significant, difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability, as weather is variable weekday or weekends. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring. A random hour profile for each of the VER types is shown in Figure 3. Wind and hydro run-of-river units are positively skewed, while solar and hydro storage units are negatively skewed, meaning their distributions "lean" to the left and right, respectively.

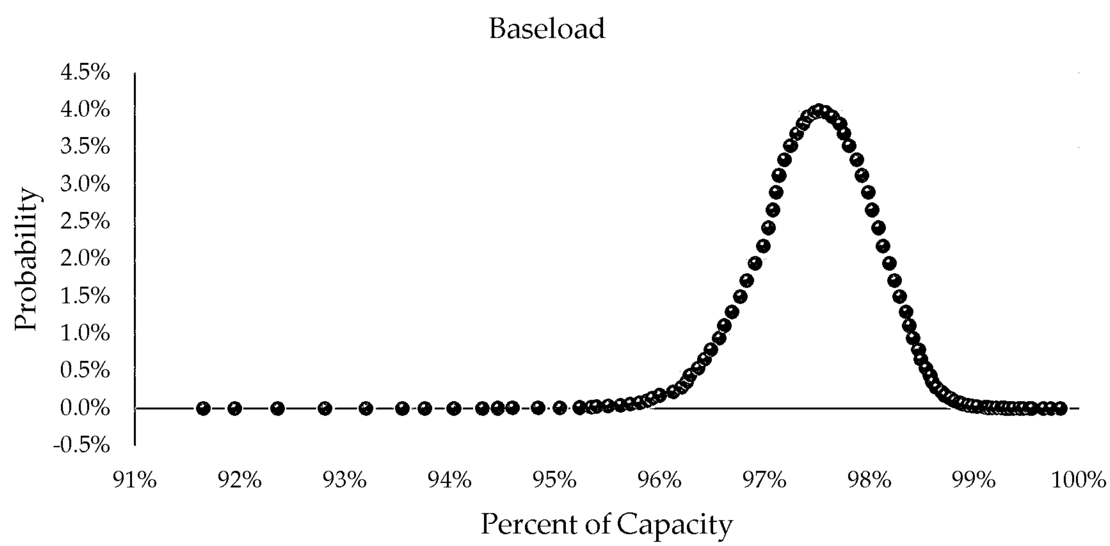
Figure 3: VER Probability Distribution Samples



Hydro facilities with storage capability are highly correlated with demand data. Although the fuel source, rain or snow runoff, is variable and not influenced by the day of the week, the ability to store the fuel leads to different operating characteristics between weekdays and weekend days. Therefore, the availability distributions for these resources are calculated the same as the demand distributions.

The distributions of the baseload resources, nuclear, coal-fired, gas-fired, and in some cases, biofuel and geothermal resources (Step 2—MAVRIC Process Flowchart), is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System (GADS). Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load serving area for each hour, is then computed and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions, in that a series of hourly percentile profiles with different probabilities of occurring is produced. A random hour profile is represented in Figure 4. The peak is the expected deterministic forecast and shows a distribution that is very negatively skewed, meaning the tail to the left is longer than the right.

Figure 4: Baseload Probability Distribution Sample



MAVRIC then combines the 10-year forecast demand and resource capacity to represent the hourly forecast demand and availability distributions (Step 3—MAVRIC Process Flowchart). The 50th percentile of the demand distributions is set equal to 100%, with the other percentiles of the distribution ranging above and below to represent the variability in that hour (See Figure 2). The hourly demand forecast in MW multiplied by each of the percentiles of the probability distribution, is then used to create a distribution of hourly MW forecast. For generation, each of the probability distributions represent capacity factor levels of availability (See Figure 3). Therefore, by taking an expected capacity of each of the different types of resources and multiplying by each of the profiles, a distribution of hourly MW forecast is derived. Once the availability distributions are combined, MAVRIC compares the distributions (Step 4—MAVRIC Process Flowchart).

Step 4 represents the comparison of the hourly demand distributions with the generation availability distributions for each of the load serving areas. For each hour the distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold planning reserve margin can be determined to identify the planning reserve margin needed to maintain a level of LOLP at or less than the threshold.

If there are hours determined from the calculations in Step 4 where the LOLP is greater than the resource adequacy threshold MAVRIC analyzes whether imports can satisfy the deficiency (Step 5—MAVRIC Process Flowchart). MAVRIC goes through a step-by-step balancing logic where excess energy, energy above an area’s planning reserve margin to maintain the resource adequacy threshold, can be used to satisfy another area’s resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas allowing the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers, external assistance from an immediate neighbor, and second order transfers, external assistance from an immediate neighbor’s immediate neighbors, in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Conclusions

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations, and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Appendix B

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 - 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
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
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
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
NWPP - NW	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
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	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
DSW	NM	Escalante	1	285.00	Bituminous Coal	12/1/1984	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
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 - 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 - 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
DSW	NM	San Juan	1	369.00	Bituminous Coal	12/1/1976	6/30/2022
DSW	NM	San Juan	4	555.00	Bituminous Coal	4/1/1982	6/30/2022
DSW	NM	RGD	7	50.00	Natural Gas	6/1/1958	12/31/2022
DSW	TX	NWM	1	81.00	Natural Gas	5/1/1960	12/31/2022
DSW	TX	NWM	2	81.00	Natural Gas	6/1/1963	12/31/2022
NWPP - C	CO	Comanche	1	382.50	Bituminous Coal	12/1/1972	12/31/2022

Announced and Expected Generation Retirements (2020-2030)							
Subregion	State	Unit Name	Unit Number	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date
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 - SO	CO	Martin Drake	6	75.00	Subbituminous Coal	10/1/1968	12/31/2023
NWPP - SO	CO	Martin Drake	7	132.00	Subbituminous Coal	7/1/1974	12/31/2023
NWPP - NW	WY	Jim Bridger	1	577.88	Subbituminous Coal	11/1/1974	12/31/2023
NWPP - NE	AB	Keephills	3	463.00	Subbituminous Coal	6/1/2011	4/2/2024
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
NWPP - SO	NV	Tracy	3	119.80	Natural Gas	10/1/1974	12/31/2024
NWPP - SO	NV	Tracy G240	4	69.70	Natural Gas	3/1/1997	12/31/2024
SRSG	AZ	Cholla	1	113.59	Bituminous Coal	5/1/1962	1/1/2025
SRSG	AZ	Cholla	3	312.30	Bituminous Coal	5/1/1980	1/1/2025
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
NWPP - NW	WA	TransAlta Centralia Gen LLC	ST2	729.88	Bituminous Coal	7/1/1973	12/1/2025
NWPP - SO	CO	Comanche	2	396.00	Bituminous Coal	12/1/1974	12/31/2025
NWPP - NE	CO	Craig	1	446.38	Subbituminous Coal	7/1/1980	12/31/2025
NWPP - SO	NV	North Valmy	1	144.90	Bituminous Coal	5/1/1985	12/31/2025
NWPP - SO	NV	North Valmy	2	144.90	Bituminous Coal	5/1/1985	12/31/2025
NWPP - SO	NV	Harry Allen	1	101.50	Natural Gas	6/1/1995	12/31/2025
NWPP - NW	BC	Silversmith Power & Light	1	0.35	Water	10/1/2016	10/1/2026
SRSG	TX	NWM	3	121.00	Natural Gas	3/1/1966	12/31/2026
NWPP - SO	CO	Alamosa	1	26.60	Natural Gas	12/1/1972	12/31/2026
NWPP - SO	CO	Fruita	1	14.00	Natural Gas	12/1/1972	12/31/2026
NWPP - SO	CO	Valmont	6	59.28	Natural Gas	12/1/1972	12/31/2026
SRSG	TX	NWM 4 GT2	4	85.00	Natural Gas	6/1/1975	12/31/2026
SRSG	TX	NWM 4 GT1	4	85.00	Natural Gas	6/1/1975	12/31/2026
SRSG	TX	NWM 4 ST	4	120.00	Natural Gas	6/1/1975	12/31/2026
NWPP - SO	CO	Alamosa	2	36.60	Natural Gas	12/1/1976	12/31/2026
NWPP - NE	CO	Craig	2	446.38	Bituminous Coal	12/1/1979	12/31/2026
NWPP - SO	NV	Sun Peak	3	74.00	Natural Gas	6/1/1991	12/31/2026
NWPP - SO	NV	Sun Peak	4	74.00	Natural Gas	6/1/1991	12/31/2026
NWPP - SO	NV	Sun Peak	5	74.00	Natural Gas	6/1/1991	12/31/2026

Announced and Expected Generation Retirements (2020-2030)							
Subregion	State	Unit Name	Unit Number	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date
DSW	AZ	Iron Horse Solar	1	2.04	Sun	4/20/2017	4/20/2027
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
DSW	AZ	North Loop	1	27.00	Natural Gas	12/1/1972	12/31/2027
DSW	AZ	North Loop	2	27.00	Natural Gas	12/1/1972	12/31/2027
DSW	AZ	North Loop	3	27.00	Natural Gas	12/1/1972	12/31/2027
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
DSW	AZ	Springerville	1	424.80	Subbituminous Coal	6/1/1985	12/31/2027
NWPP - NE	MT	Colstrip	4	740.00	Subbituminous Coal	4/1/1986	12/31/2027
NWPP - C	CO	Cherokee	4	380.80	Natural Gas	8/13/2017	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
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
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
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
NWPP - C	CO	Hayden	1	190.00	Bituminous Coal	7/1/1965	12/31/2030
NWPP - NE	AB	Battle River	4	155.00	Subbituminous Coal	1/1/1975	12/31/2030
DSW	TX	COP	1	87.00	Natural Gas	7/1/1980	12/31/2030
NWPP - NE	CO	Craig	3	446.38	Bituminous Coal	10/1/1984	12/31/2030

The following files are not convertible:

Attachment 3-1 b 3 BLS covid19-table2-2020-09.xlsx
Attachment 3-1 b 4 BLS covid19-table2-2020-12.xlsx
Attachment 3-1 b 5 BLS covid19-table2-2021-10.xlsx
Attachment 3-1 b 6 BLS covid19-table2-2021-04.xlsx
Attachment 3-1 b 7 BLS covid19-table3-2021-04.xlsx
Attachment 3-1 b 8 BKS covid19-table3-2021-06.xlsx
Attachment 3-1 b 1 BLS covid19-table2-2020-05.xlsx
Attachment 3-1 b 2 BLS covid19-table2-2020-08.xlsx

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.