# Western Assessment of Resource Adequacy Appendix

January 24, 2025

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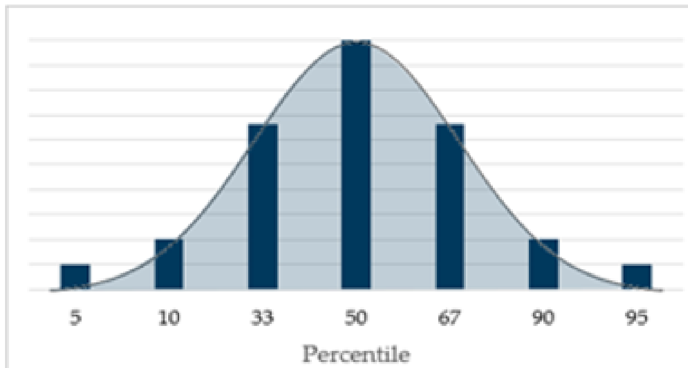
## Appendix A: Modeling Methodology

To determine the demand at risk hours (DARH) in the Western Assessment of Resource Adequacy (Western Assessment), WECC uses the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy-based probabilistic assessments by applying the convolution method. In addition to applying the convolution method, a subset of assumptions within the model are also derived via a Monte-Carlo Markov-Chain method (see Appendix B). For a primer on Monte Carlo simulations and convolution methods, please see NERC's Probabilistic Adequacy and Measures Report.

MAVRIC examines the probability that demand and resource availability will intersect at expected energy values given their probability distribution curves. Figure 1 is an example of a probability curve. The curve shows the probability of potential outcomes based on an expected value. For example, if an expected value falls at the 50th percentile, this value has a 1-in-2 chance of occurring. MAVRIC evaluates the probability curves of demand and resource availability together (Figure 2). The overlapping area of the demand and resource availability curves represent the potential for unserved load, or DARHs. The more the two curves overlap, the greater the potential for demand at risk. The goal is to keep the two curves far enough apart that overlap is kept below a certain threshold. For the Western Assessment, WECC has set this threshold to the one-day-in-ten-year (ODITY) level, meaning 99.98% of the demand for each hour is covered by available resources. Put another way, the area of overlap for the availability and demand curves is equal to no more than 0.02% for any given hour.




| Probability | Percentile | Likelihood of Occurrence |
|---|---|---|
| 1-in-20 | 5th | 5% |
| 1-in-10 | 10th | 10% |
| 1-in-3 | 33rd | 33% |
| 1-in-2 | 50th | 50% (expected) |
| 1-in-3 | 67th | 33% |
| 1-in-10 | 90th | 10% |
| 1-in-20 | 95th | 5% |

Figure 1: A conceptual normal probability curve with percentiles and likelihood of occurrence

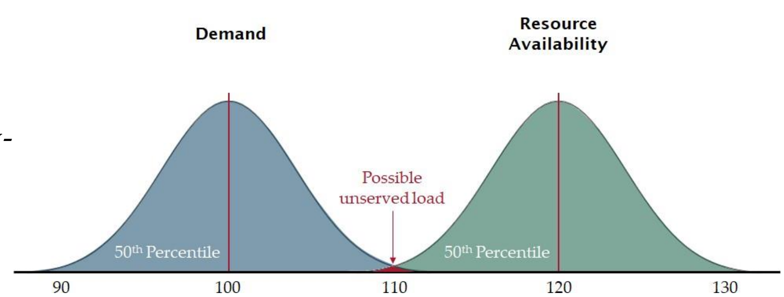



Figure 2: Evaluation of the supply side and demand probability curves for overlap which represents demand at risk

The potential for DARHs can increase or decrease when the demand or availability curves shift, expand, or contract. A shift in the position of a demand curve closer to the availability curve happens when demand uniformly increases without a corresponding increase in resource availability. When rare events occur more frequently, the demand probability curve changes shape and expands. When one or both curves change shape in this way, the overlap can increase, making it more likely that demand will exceed resource availability, as shown in Figure 3. For example, heat waves like those that occurred in the West in 2020 and 2021 were once rare events. The August 2020 Heat Wave was a 1-in-30 event. But, when evaluated considering climate change, it becomes a 1-in-20 event, widening the demand curve.

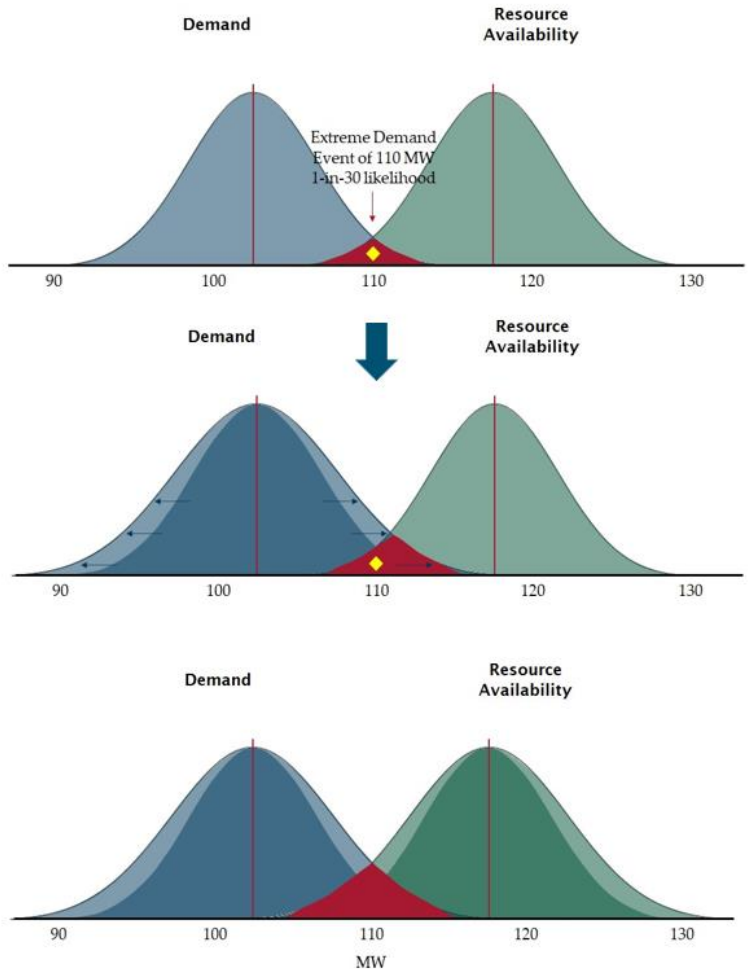



Figure 3: Demand and resource availability curves with increasing overlap due to increased frequency of extreme weather events

As additional variable energy resources (VER) are added to a portfolio, the resource availability curve expands like the demand curve expands when extreme events become more frequent. The variability in output of wind, solar, and hydro resources widens the potential range of expected values. Conversely, a decrease in unplanned outage frequency, or mean time to return from outages, would move the tails of the resource availability curve away from the demand curve. If resource availability decreases, the resource availability curve will shift closer to the demand curve, increasing overlap.

## Calculating the Planning Reserve Margin

Assessing DARHs allows for the creation of planning reserve margins (PRM). Figure 4 shows a system with a 1-in-2 chance that demand is 100 MW and resource availability is 120 MW. A 20-MW—or 20%—PRM is needed to maintain 99.98% resource adequacy. This is based on the shapes of the demand and resource availability curves. If the availability curve shifts to the left, and only 115 MW of resources are available, the reserve margin has decreased to 15 MW. This amount of reserve margin will no longer maintain the ODITY threshold. Figure 5 shows the increased DARHs if the PRM does not increase to accommodate the change in distribution shape. To accommodate the change in distribution shape and maintain 99.98% resource adequacy, the PRM must increase. If the PRM is increased to 22 MW, the system returns to being 99.98% resource adequate, maintaining the ODITY threshold (Figure 6). Actual distributions for each subregion are in Appendix D.

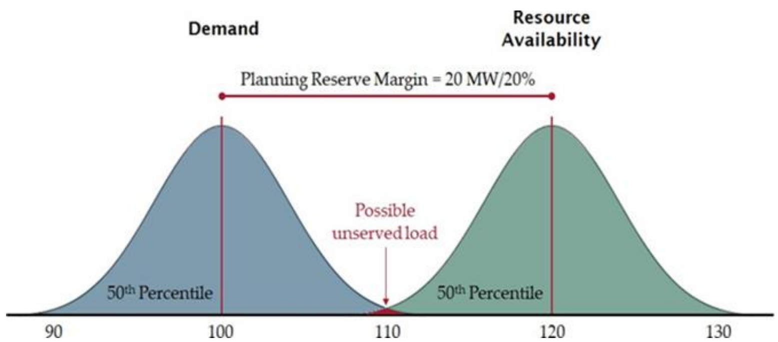



Figure 4: Conceptual system with 99.98% resource adequacy at a PRM of 20 MW

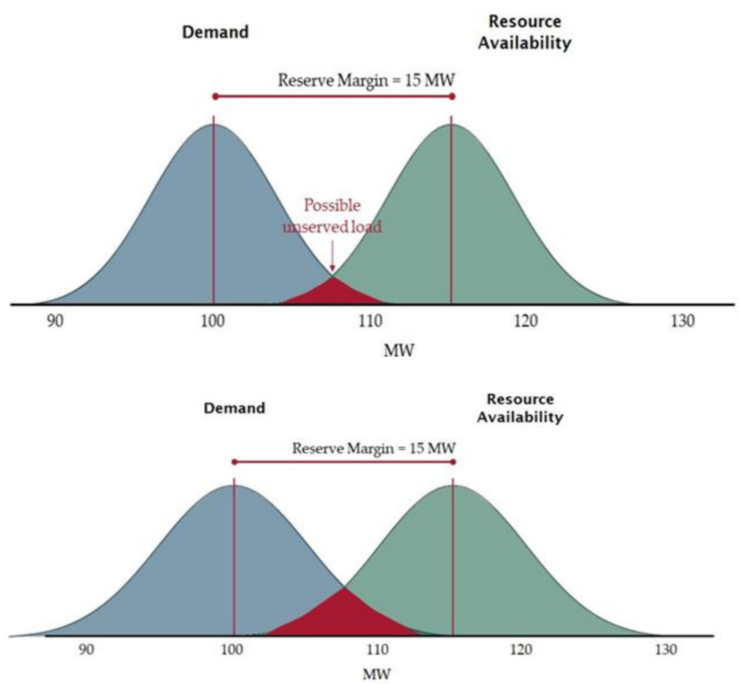



Figure 5: Demonstrates the increased demand at risk if the distributions expand or shift

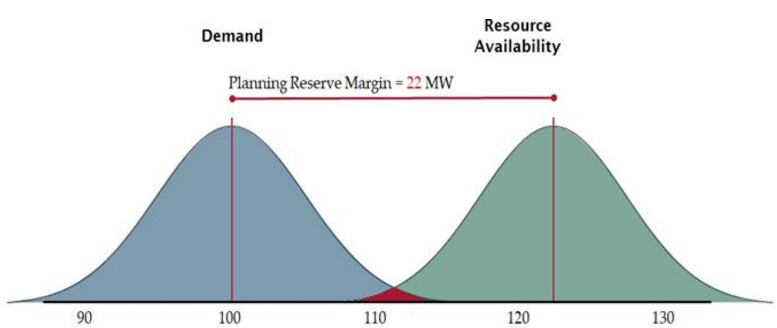



Figure 6: Shows the increased PRM required to maintain 99.98% resource adequacy with the wider distributions

## Appendix B: MAVRIC Inputs, Assumptions, & Processes

The Western Interconnection has many transmission connections between demand and supply points, with energy transfers playing a significant role in reliable operations. On top of this, the Western Interconnection is geographically large and contains both winter-peaking and summer-peaking areas. To add to the complexity, there is a large amount of hydro capacity that experiences seasonal variability, and rapid adoption of solar and wind resources, which can vary hourly in output. WECC developed MAVRIC to handle these intricacies. MAVRIC can study all hours of the year, it can factor in dynamic imports from neighboring areas, and account for varying generation patterns dependent on geographical location and resource type. MAVRIC calculates resource adequacy through loss-of-load probabilities (LOLP). It calculates LOLPs on each of the stand-alone Balancing Authorities (BA) without transfers, then balances the system cohesively with transfers to a probabilistic LOLP (see Appendix A). This section will discuss the inputs, assumptions, and processes within MAVRIC required to perform this LOLP calculation. Figure 7 provides an overview of the MAVRIC process.

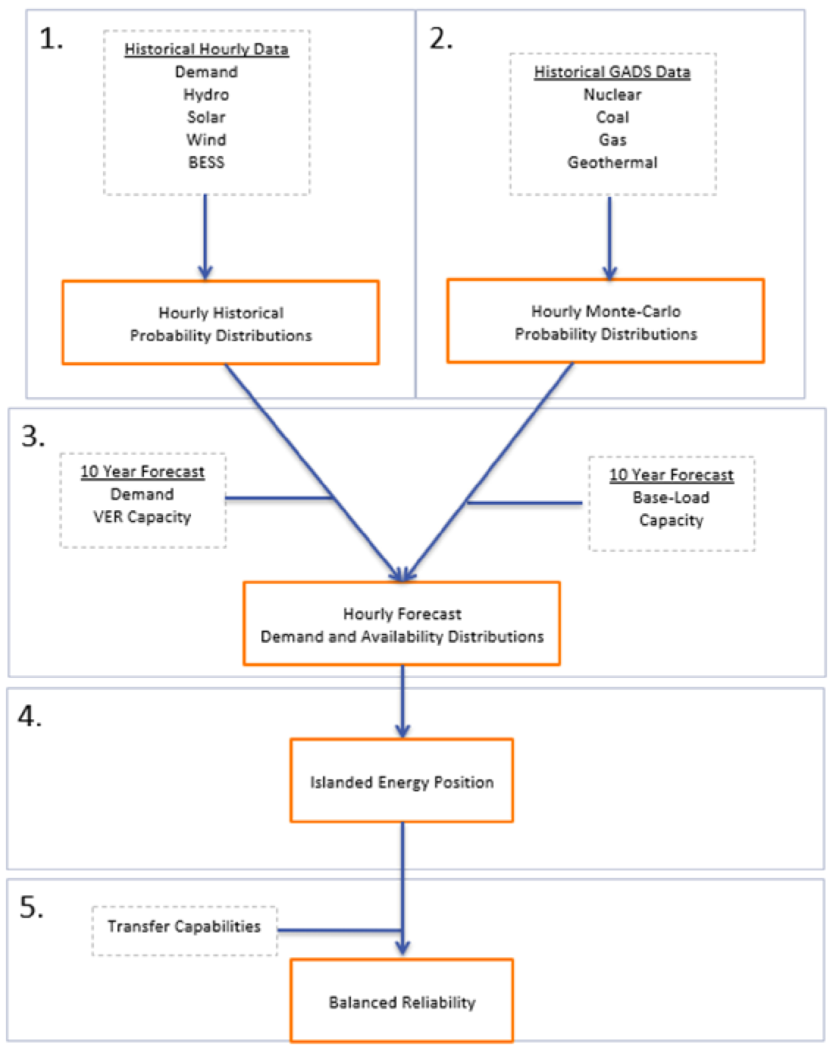



Figure 7: MAVRIC inputs and processes

In step one of Figure 7, hourly historical data for demand and energy output from hydro, solar, wind, and battery energy storage system (BESS) resources are collected in WECC's annual Loads and Resources (L&R) Data Request. To develop hourly probability distributions for demand, hourly demand from previous years must be aligned. 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 three weeks before and three weeks after the given hour for each historical year. The output of this step is a series of hourly percentile profiles with different probabilities of occurring. Figure 8 represents a demand probability distribution for a single hour. The peak is the expected deterministic forecast and is set at 100%. The profiles to the right of the peak are greater than 100% and those to the left are lower than 100%.

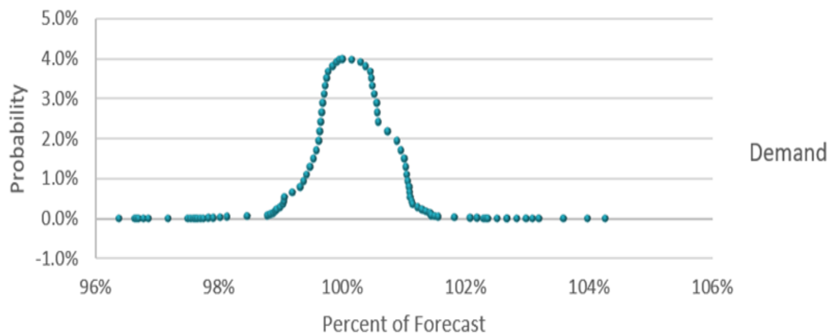



Figure 8: Example of a single hour's demand profile

The availability probability distributions for the VERs, which includes hydro, wind, and solar resources, is derived in a similar manner to that of the demand calculations but with two notable differences. The primary difference is the period used in calculating the VER availability distributions. For VERs, the day of the week does not influence variability, as weather is always variable. Therefore, the need to use 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. The second difference is that the historical generation data is compared against the nameplate capacity to determine the historical capacity factor for that hour, which is then used in the percentile probability calculation. Using nameplate in the denominator allows for the incorporation of unit outages due to non-fuel-related issues. 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 9. Wind and hydro run-of-river units are positively skewed, whereas solar and hydro storage units are negatively skewed, meaning their distributions "lean" to the left and right, respectively. The highest point of the distribution indicates the most frequently anticipated capacity factor from the resource for a given hour. For instance, the hour represented in Figure 9 for wind tends to perform at the lower end of the capacity factor spectrum, whereas solar frequently performs at capacity factors above 90%. Hybrid resources such as solar with BESS or wind with BESS, are treated as VERs. MAVRIC does not account for the BESS properties of these resources.

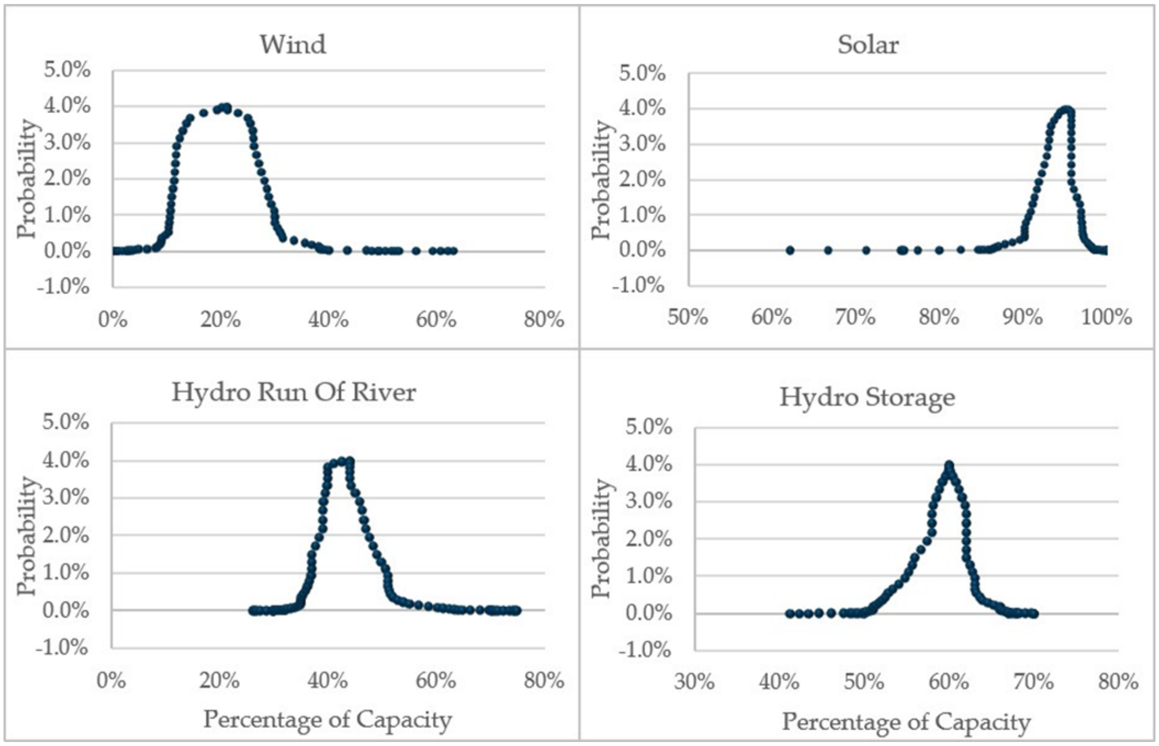



Figure 9: Examples of hourly profiles for each of the VER resource types

Hydro facilities with storage capability are highly correlated with demand. The ability to store the fuel leads to different operating characteristics between weekdays and weekends. Therefore, the availability distributions for hydro facilities with storage are calculated in the same manner as the demand distribution.

For the purposes of baseload resources, MAVRIC uses a Monte-Carlo Markov-Chain method (Step 2 in Figure 7). The distributions of nuclear, coal-fired, gas-fired, biofuel and geothermal resources, are determined by using the historical rate of unexpected failure and the time to return to service from NERC's Generation Availability Data System (GADS). The annual frequency of unexpected outages and recovery time from these outages is used to calculate the availability probability distributions for baseload resources. Based on this data, a random value is calculated for the first hour of the year for each of the units within a BA. If that random value falls below the frequency calculation to be available, the model will force the unit offline. Conversely, if the random value does not fall below the availability frequency calculation, the unit is deemed as available. Available resources are capable for their maximum winter or summer capacity rating, depending on the season. Once the status of each resource is determined, the next hour is then processed. If the resource was determined unavailable in the previous hour, the model will keep the resource unavailable until the average duration of the historical unplanned outages is reached. If the unit was determined as available the previous hour, the random variable for the next hour is checked against the forced outage frequency calculation and the process repeats. Through this random sampling method, MAVRIC performs 1,000 iterations for each resource for each hour. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. Figure 10 demonstrates a baseload availability distribution. It is consistent with the VER distributions, in that a series of expected values for capacity factors are produced for each hour. BESS resources are treated in the same manner as baseload generators. Their full capacity is available to be discharged when the resource is not in outage. MAVRIC does not account for the charging behavior of batteries.

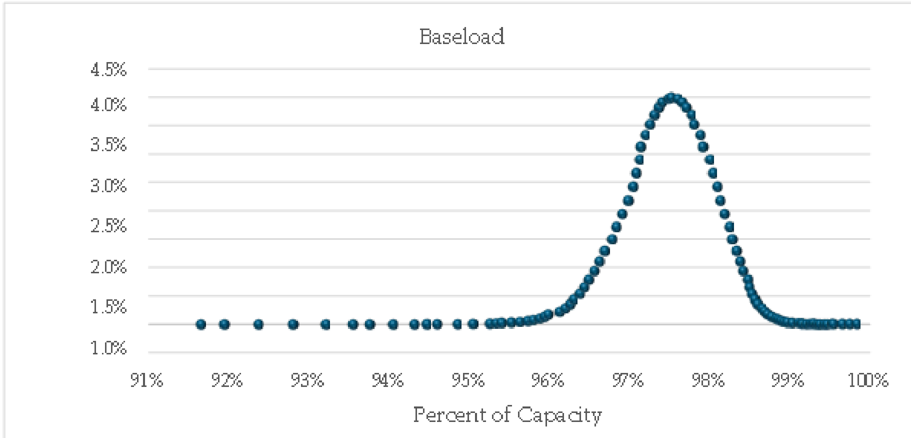



Figure 10: Example hourly probability distribution for thermal resources

In Step 3 of Figure 7, MAVRIC combines the 10-year demand forecast and resource availability to represent the hourly forecast demand and availability distributions. The 50th percentile of the demand distributions is set equal to 100% (as displayed in Figure 8), with the low and high side variability represented by the percentiles to the left and right, respectively. The hourly demand forecast in megawatts is multiplied by each of the percentiles of the probability distribution, creating a distribution of hourly megawatt forecasts. For availability, each of the probability distributions represent capacity factors. Therefore, by taking an expected capacity of each of the different types of resources and multiplying it by each of the hourly profiles, a distribution of hourly megawatt forecasts is derived.

Step 4 represents the comparison of the hourly demand distributions with the hourly availability distributions. 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 availability distribution. The amount of overlap represents the LOLP. If the probability for a given hour is greater than a selected threshold (such as the ODITY threshold discussed in Appendix A), then that hour is a DARH.

If DARHs are identified in in Step 4, MAVRIC analyzes potential transfers to mitigate them. This is Step 5 in Figure 7. MAVRIC undergoes a step-by-step balancing logic in which excess energy, which is energy above an area's PRM, can be used to satisfy another area's resource adequacy shortfall. This depends on neighboring areas having excess energy and available transfer capability to allow the excess energy to flow. MAVRIC only allows for first and second order transfers to occur. Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow (see Appendix C). MAVRIC considers first-order transfers (external assistance from an immediate neighbor) and second-order transfers (external assistance from a neighboring entity's immediate neighbors). After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system as needed. The result is an analysis of the Western Interconnection that reflects the ability of all defined areas or subregions to maintain a PRM equal to, or less than, the ODITY threshold.

## Appendix C: MAVRIC Topology

Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow and season. MAVRIC topology uses a zonal approach, considering the transfer capability between regions but not accounting for nodal congestion. The transfer capabilities within MAVRIC are provided by BAs and Transmission Operators (TO) and resemble expectations during system peaking conditions. The transmission topology in MAVRIC is shown in Figures 11 and 12 for the summer and winter seasons, respectively.

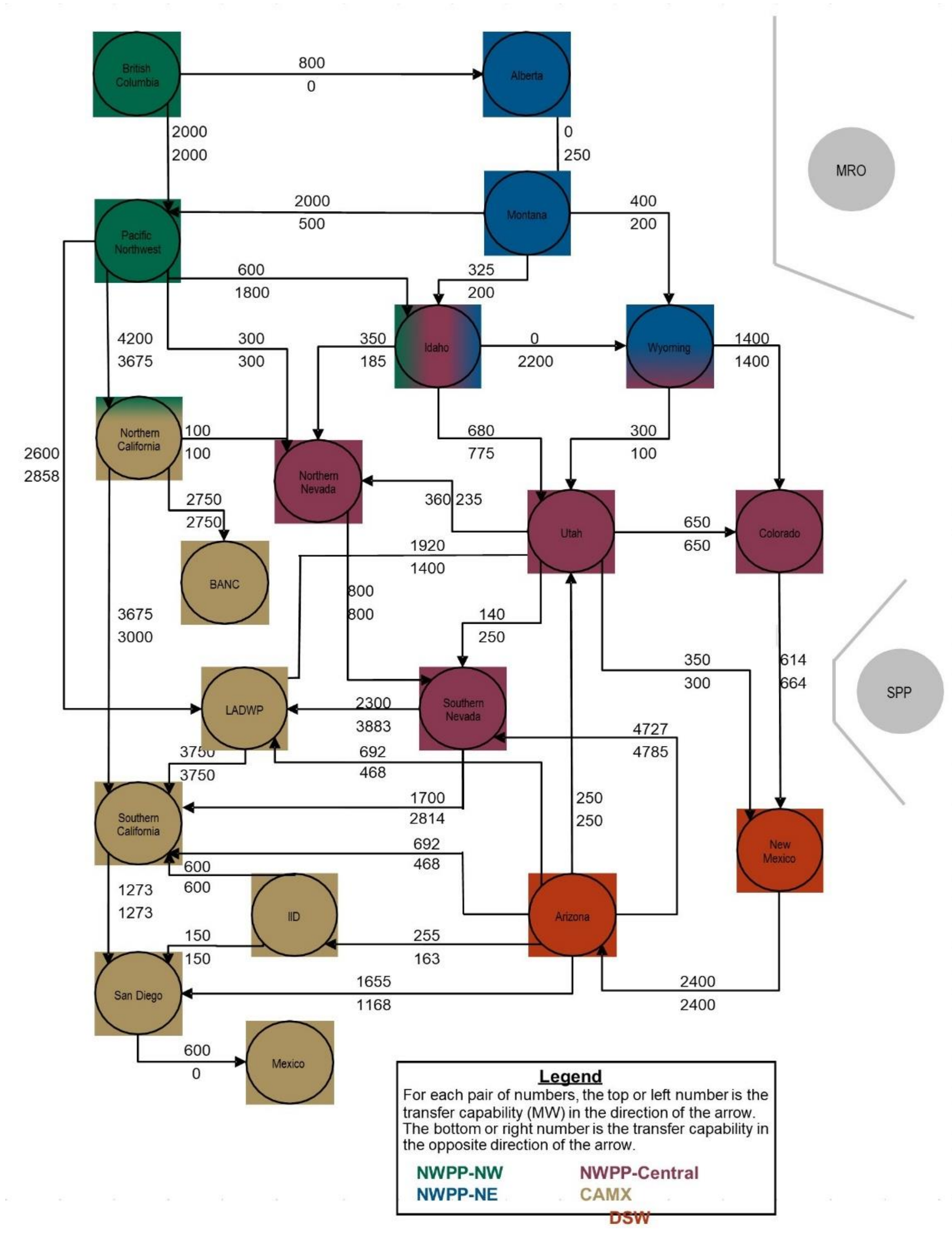



Figure 11: Summer topology in MAVRIC

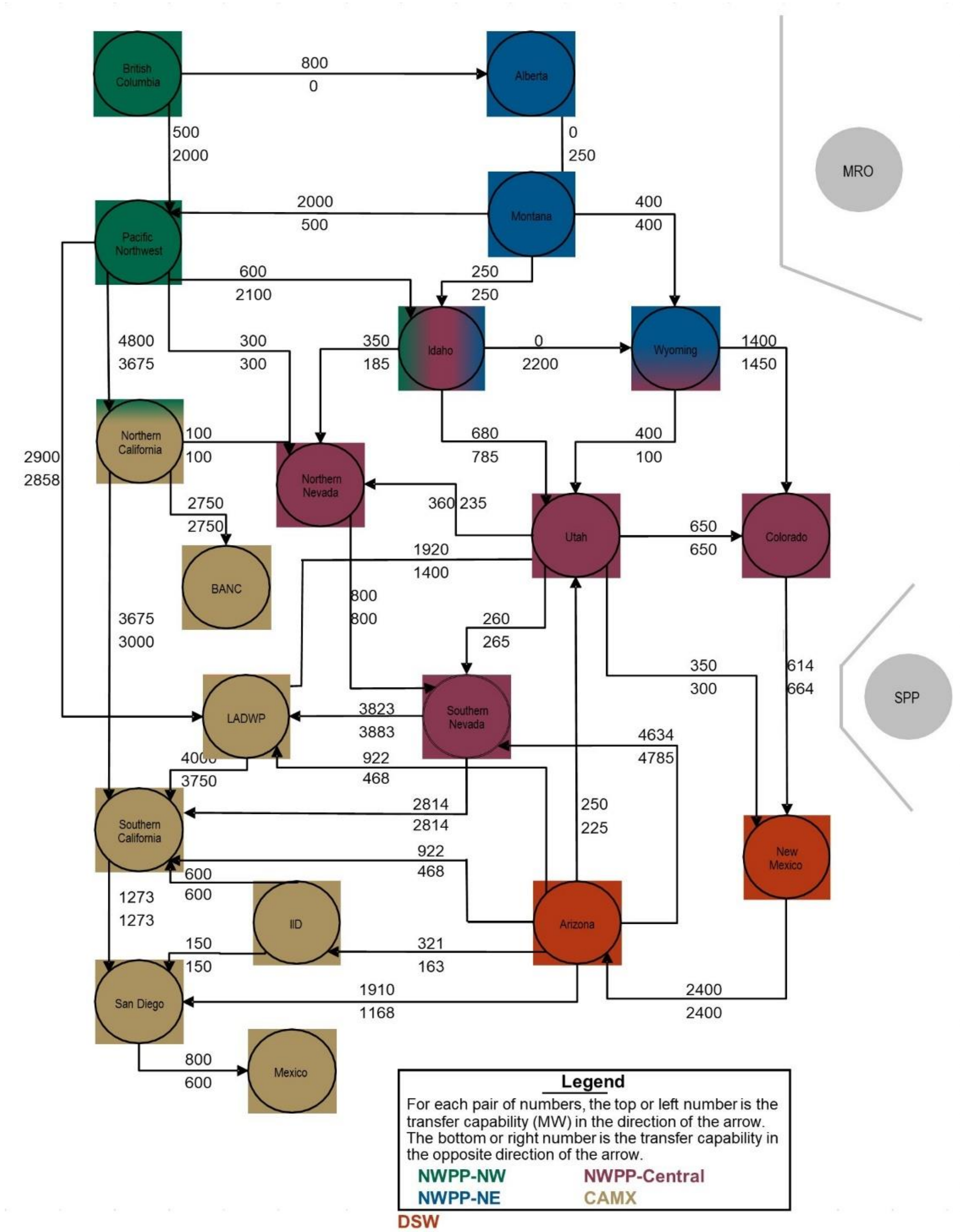



Figure 12: Winter topology in MAVRIC

## Appendix D: Regional Portfolios, Variability, & Volatility

Figures 13 through 17 show each subregion's resource portfolio on a capacity basis, demand and supply probability distributions, and demand and supply volatility curves in the 2028 assessment year. The 2028 assessment year was selected for this section to balance current data trends and resource plans without extending so far into the future that the data becomes mostly speculative. As discussed in Appendix A, many factors influence the shape of the demand and availability curves. Increasing the frequency of extreme weather events in a subregion will result in the demand curve developing a positive skew. General forecast growth moves the center of the demand curve closer to the availability curve. Conversely, adding VERs to a subregion's portfolio will widen the availability curve, but also move the center of the availability curve away from the demand curve due to the increase in capacity. Adding thermal and BESS resources will shift the center of the availability curve away from the demand curve. A decrease in forced outage rate will tighten the availability curve. Volatility represents the percent deviation from the 50/50 case that the demand has in the 95$^{th}$ percentile and the availability has in the 5$^{th}$ percentile. Put another way, volatility shows the potential down-side availability risk and high-side demand risk. Availability volatility correlates with a portfolio's share and type of VERs, the capacity factor distributions of those VERs, and forced outage rates. Volatility of demand will be greater in subregions prone to extreme or prolonged weather events. The overlap of the availability and demand distributions represents DARHs. This appendix adds to the insights provided in the subregional documentation for the DARHs calculated in the Scenario Analysis portion of the Western Assessment. The charts below do not account for transfers that may mitigate DARHs.

## California & Mexico (CAMX)

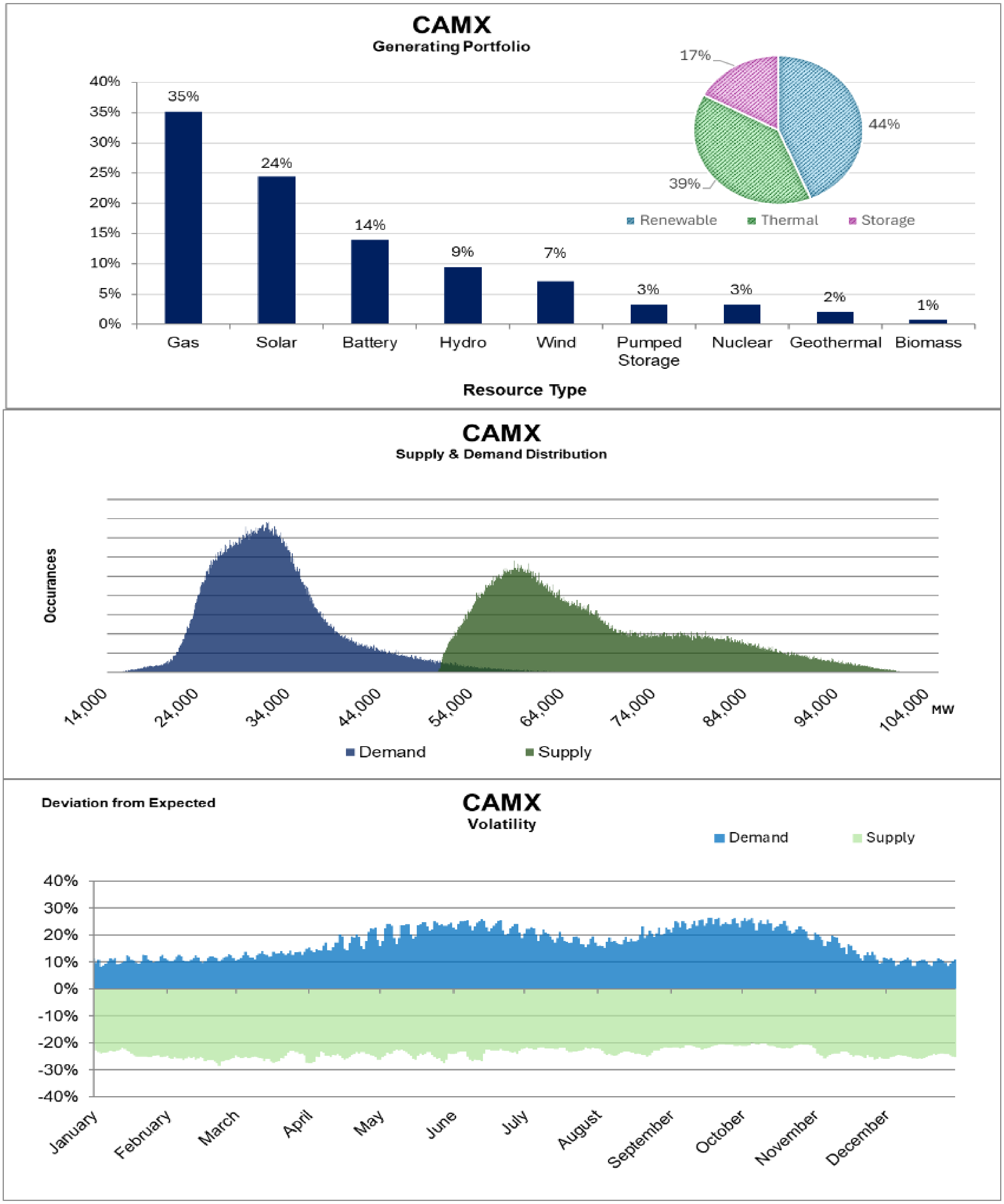



Figure 13: CAMX resource portfolio and variability

For 2028, CAMX shows little overlap of the demand and supply distributions. This indicates that CAMX should be able to meet demand under all but the most extreme circumstances coupled with resource underperformance. In 2028, the CAMX portfolio is forecast to be 39% thermal resources, 17% BESS resources, and the remainder attributed to VERs. A large share of thermal and BESS resources helps maintain certainty in resource output while minimizing volatility on the supply side. CAMX has significant solar contribution in its portfolio, which typically presents at higher capacity factors than other VERs when available. CAMX shows less supply-side volatility than other subregions and a long tail at the high end of its supply curve due to the high percentage of thermal, BESS, and solar contributions. CAMX is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Two of these events resulted in new hourly peak loads for the Western Interconnection. This amplifies the positive skew of the demand curve as well as the demand volatility in the early summer through early fall months.

## Desert Southwest (DSW)

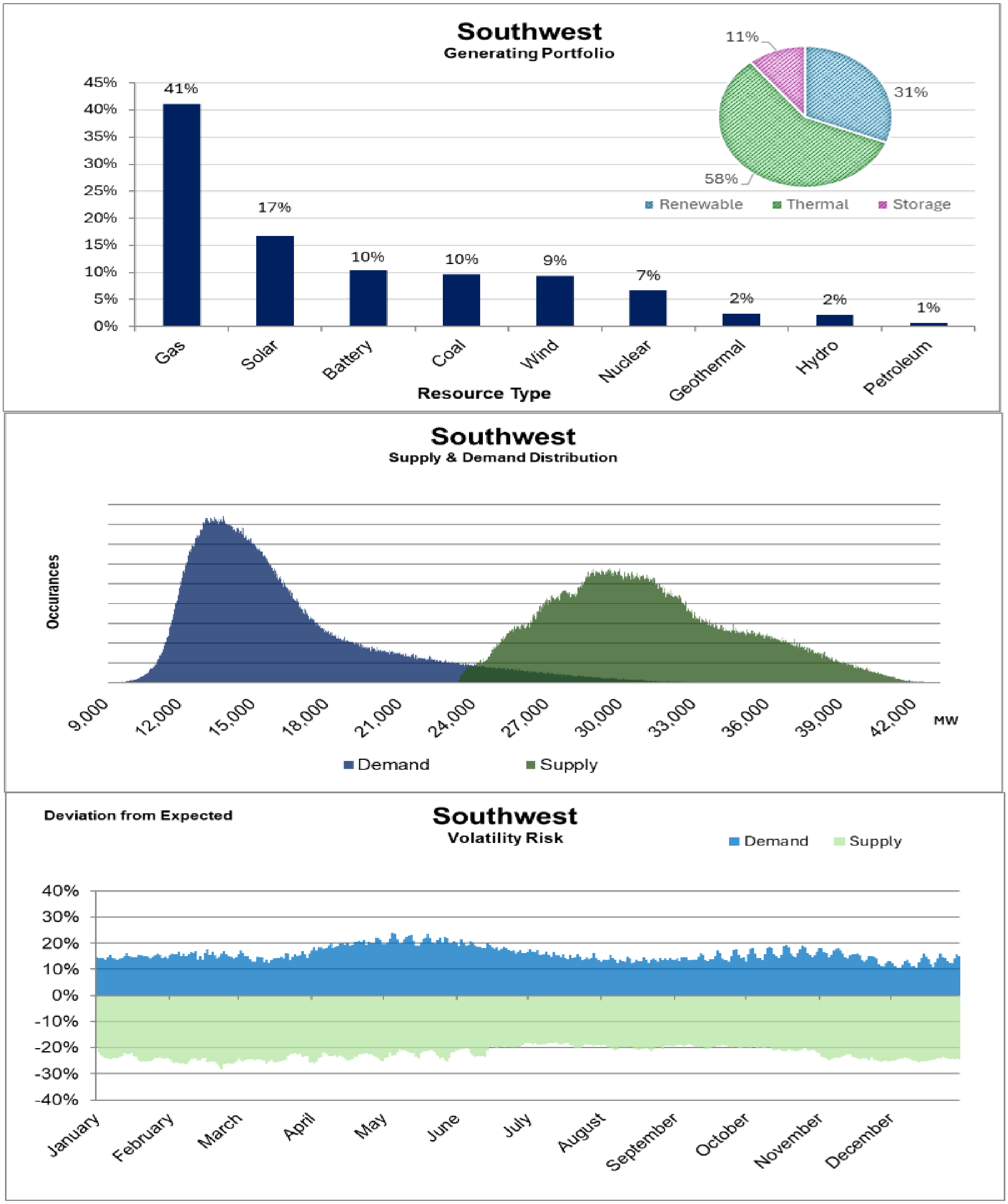



Figure 14: DSW resource portfolio and variability

In 2028, thermal resources are anticipated to comprise 58% of generating capability in the DSW, followed by VERs at 31%, and the remaining being supplied by BESS resources. The DSW is forecast to have the highest share of thermal sites of all subregions, with 41% of its portfolio being natural gas. The DSW is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Natural gas resources can be derated in high temperatures which can lower expected contribution during heat wave events. Despite this, the large share of thermal and BESS resources gives the DSW lower volatility on the supply side than other subregions. The DSW also has a large share of solar resources, which are projected to make up 17% of its portfolio. Solar tends to generate at the high end of the capacity factor distribution when available, resulting in less supply side volatility than other VERs. Recent extreme weather events have resulted in the positive skew of the demand distribution and high volatility of demand in the early summer through early fall months.

## Northwest-Central (NW-Central)

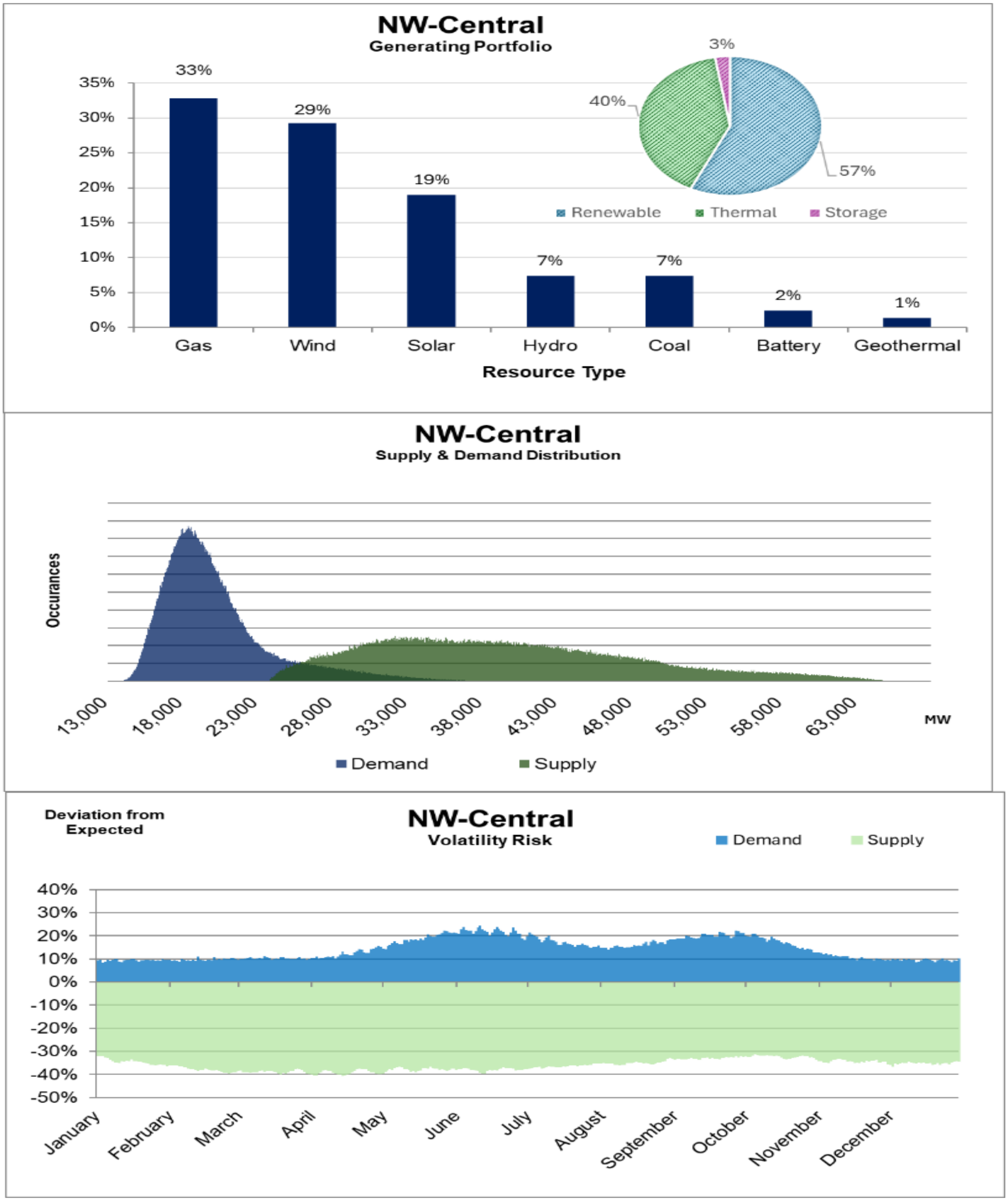



Figure 15: NW-Central resource portfolio and variability

The NW-Central portfolio is forecast to be 29% wind resources in 2028, with solar resources making up just under 20%. The substantial share of wind in this subregion's portfolio results in a wide availability curve due to its high uncertainty in output. The significant wind resources in this subregion also result in supply side volatility that is higher than the other subregions. The spring and winter months carry the greatest supply-side volatility. The large solar contribution results in the extended tail of the availability distribution due to solar resources typically generating at higher capacity factors. The NW-Central subregion is summer peaking and displays the greatest potential for demand volatility in the early summer through early fall months.

## Northwest-Northeast (NW-NE)

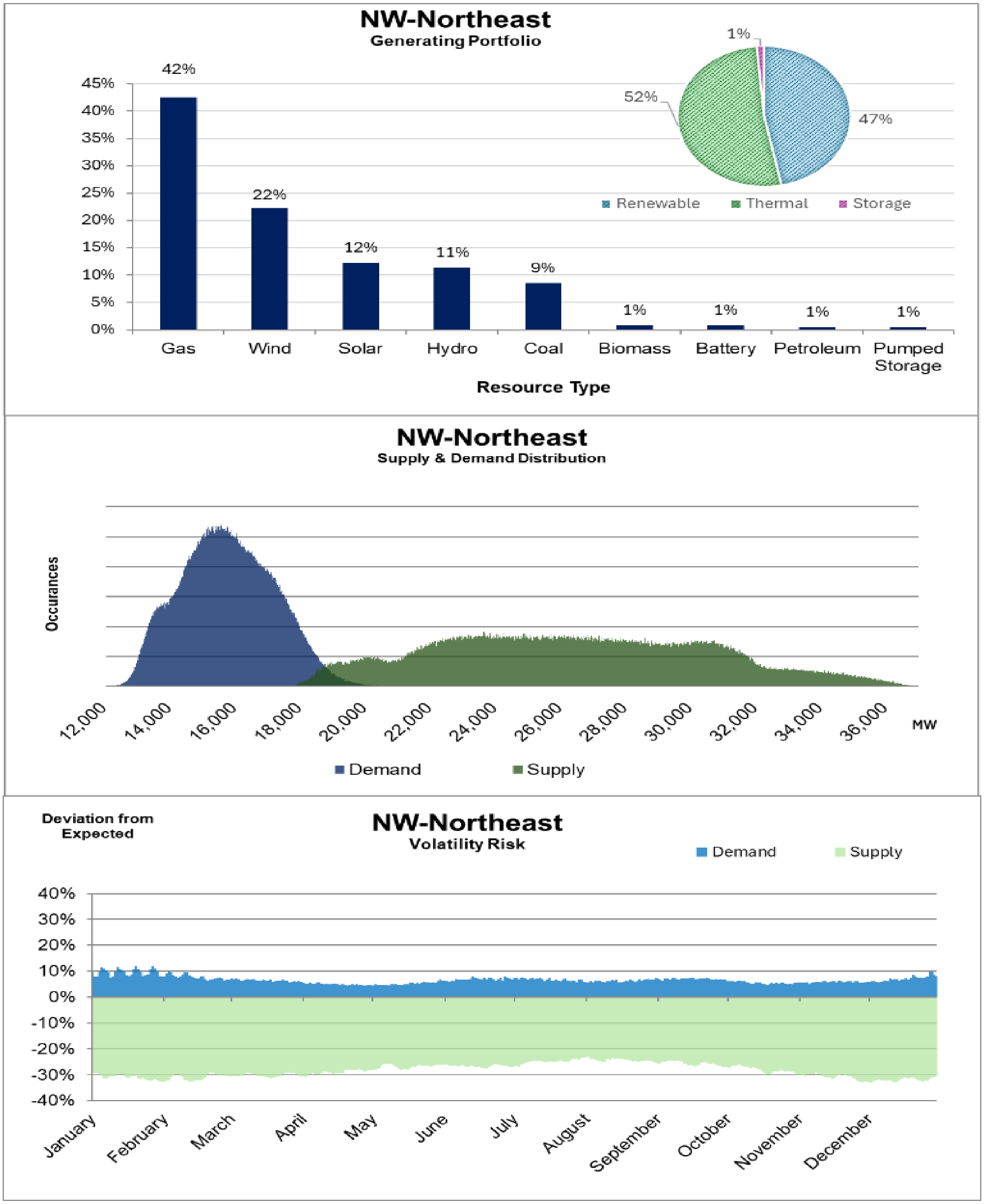



Figure 16: NW-Northeast resource portfolio and variability

The NW-NE is anticipated to have a substantial share of wind that will make up approximately 22% of its generating portfolio in 2028. This results in a wide availability curve due to the high variability of wind resource output. However, the NW-NE also is expected to have a large natural gas contribution, making up 42% of its generating portfolio. The significant share of natural gas in this subregion's portfolio helps shift the NW-NE availability curve away from the demand curve and reduces supply-side volatility in comparison to other regions in the Northwest. The NW-NE can be summer peaking or winter peaking, and generally does not experience extreme heat events to the same degree as the DSW or CAMX subregions. Demand-side volatility is greatest in the winter due to winter storm risk. The NW-NE displays the least demand-side volatility of all the subregions.

## Northwest-Northwest (NW-NW)

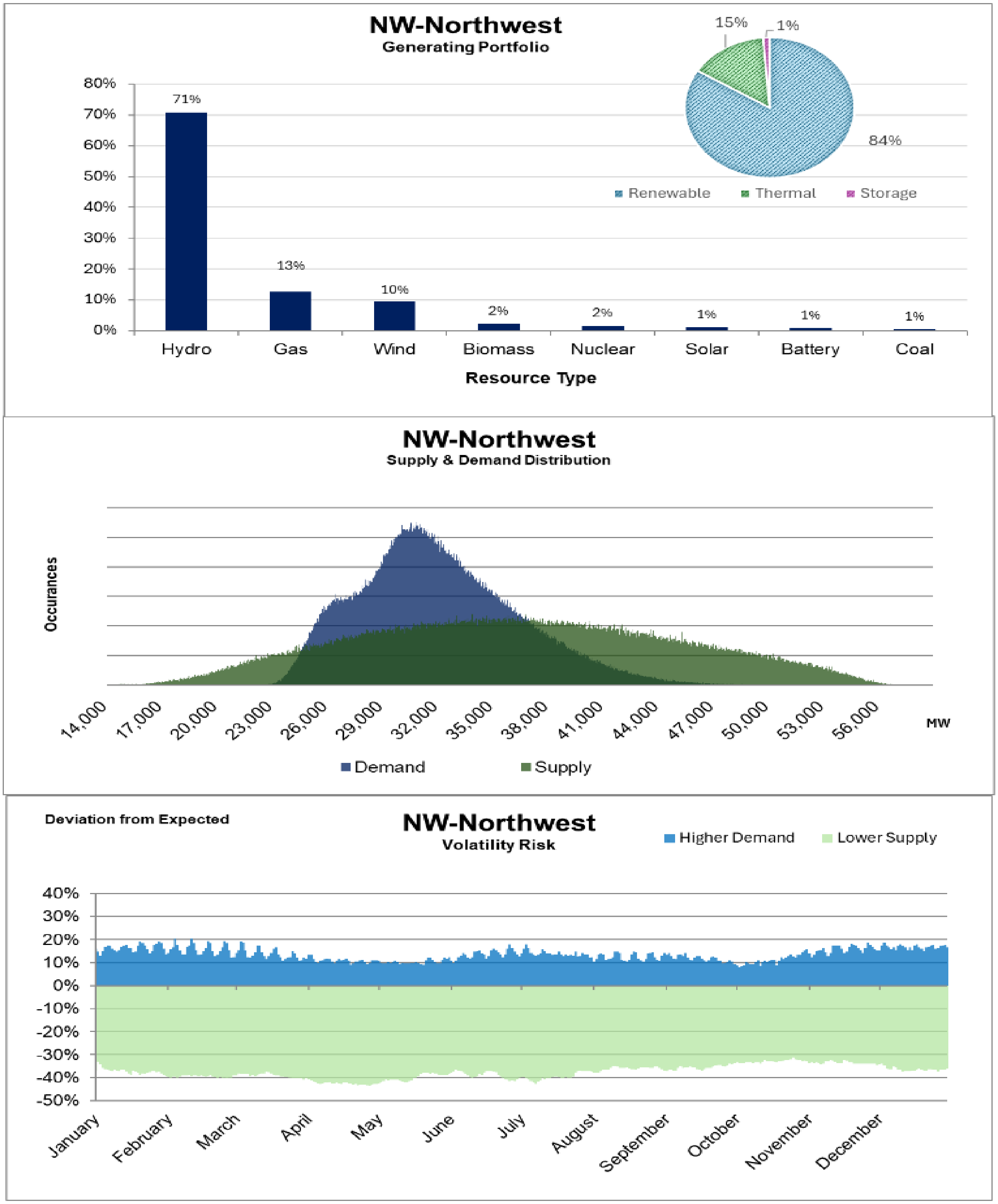



Figure 17: NW-Northwest resource portfolio and variability

The NW-NW portfolio is unique, with over 70% of its generating portfolio projected to be hydro resources in 2028, and over 84% of its portfolio being made up of VERs. The large share of hydro resources gives this subregion an extremely wide availability curve due to historic variability in output. In addition, 10% of the NW-NW generating portfolio is projected to be wind, which further widens the availability distribution. In 2028, the NW-NW subregion shows the greatest overlap of the demand and supply curves, indicating that the potential demand at risk is highest for this subregion. The NW-NW is a winter-peaking subregion, and correspondingly shows increased demand volatility during the winter months due to potential winter storms and cold weather events.

## Appendix E: Demand Forecasts

The demand forecasts for each subregion are derived from WECC's Annual L&R Data Request. In this data request, each BA in the Western Interconnection provides demand forecasts, which are combined into subregions. The methodology and sources of demand for each BA's forecasts differ; however, frequently cited load types and factors that BAs account for are:

- Behind-the-meter solar adoption
- Calendar-driven events (i.e., holidays)
- Data centers
- Employment rates
- Historic peak demand
- Income of population
- Increasing efficiency of appliances
- Irrigation
- Local, state, and federal incentives and policies
- Population
- Residential building electrification
- Residential, commercial, and industrial electric sales
- Transportation electrification
- Weather and climate trends

Figures 18 and 19 show the annual and peak hour demand forecasts by subregion for this year's Western Assessment and the 2023 Western Assessment. All subregions are projected to experience growth in total annual demand and peak demand from 2025 through 2034. All times shown in Apprendix E are Pacific Prevailing Time.

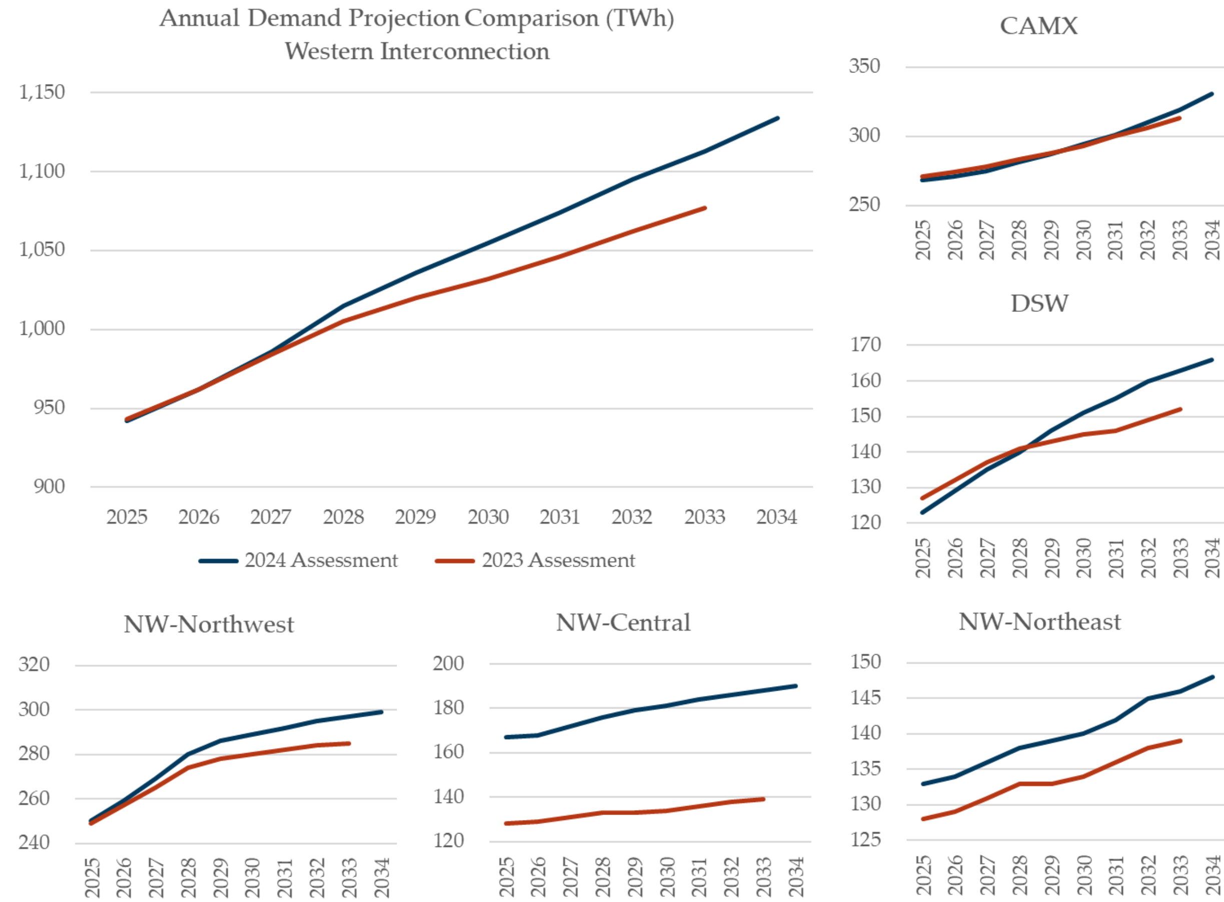



Figure 18: Annual demand forecasts in TWh for the Western Interconnection.

As denoted in the Load Growth section of the Western Assessment, the Western Interconnection is anticipated to grow in annual demand by 20.4% from 942 TWh to 1,134 TWh over the next decade. The greatest rate of growth is seen in the DSW subregion, which forecasts growth from 123 TWh in 2025 to 166 TWh in 2034, an increase of 35%. The majority of this growth has been cited as large industrial and commercial load additions such as data centers. The second-greatest forecast growth is seen in CAMX, which is projected to increase from 268 TWh of annual demand to 331 TWh of annual demand by 2034, a 23.5% increase. This is driven by transportation and building electrification. The NW-NW subregion is forecast to have an annual demand growth rate of 19.6%, increasing from 250 TWh in 2025 to 299 TWh in 2034. This demand is primarily expected to be added in the Pacific Northwest, and is largely correlated with data center additions. Electrification of transportation, buildings, and emerging industries such as hydrogen production account for demand growth in the Canadian portion of the NW-NW subregion. The NW-Central subregion shows annual demand growth of 13.8% from 167 TWh in 2025 to 190 TWh in 2034. Demand growth in this region is driven by data center additions and building and transportation electrification. The subregion showing the lowest growth rate over the next decade is the NW-NE, going from 133 TWh in 2025 to 148 TWh in 2034, an increase of 11.3%. Demand growth in this region is attributed to industrial sources such as gas and oil processing and pulp and paper mill operations, as well as incoming data centers.

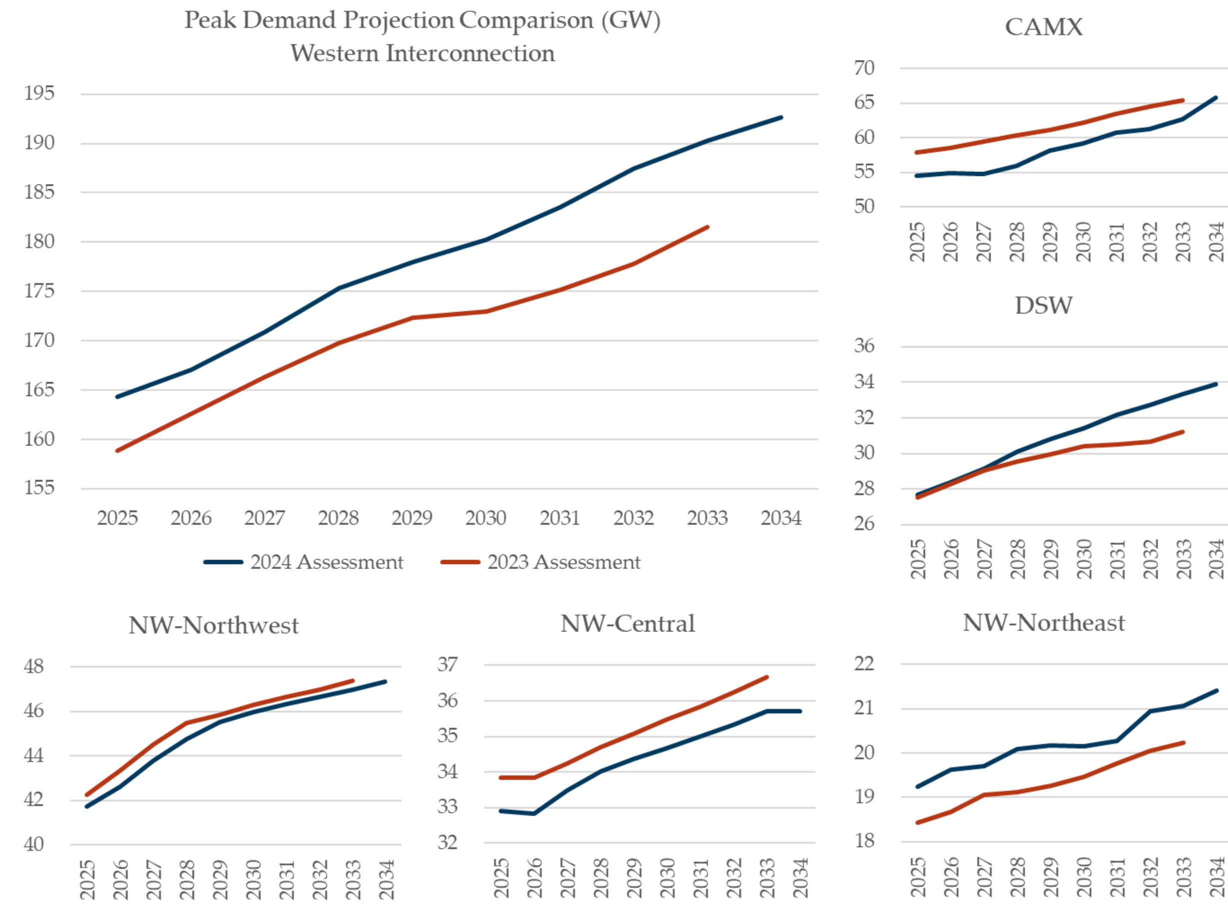



Figure 19: Peak hour demand forecasts in GW for the Western Interconnection.

Peak demand trends closely mimic those observed for annual demand. The DSW subregion leads peak demand growth with an increase of 22.5% over the next 10 years, from 28 GW to 34 GW. CAMX is projecting a peak demand increase of 20.7%, from 55 GW in 2025 to 66 GW in 2034. Both the DSW and CAMX subregions are summer peaking and show peak hours at the same time, hour ending 17:00. However, the month of peak occurrence is different between the two. The DSW peak hour is projected to occur in the mid to late July timeframe, whereas CAMX's peak hour is projected to occur in August or early September. The NW-NW peak hour projection in 2025 is 42 GW and is forecast to increase to 47 GW by 2034, a 13.5% increase. The NW-NW differs from the DSW and CAMX as it is a winter-peaking subregion, with the peak hour projected to occur at hour ending 9:00 in January. The NW-NE shows the second-lowest increase in peak demand growth at 11.3%, forecasting 19 GW as the peak in 2025 and 21 GW in 2034. The NW-NE subregion is dual peaking, meaning a peak hour may occur in either the summer or winter. Summer peak hours are projected to occur in July at hour ending 15:00 or 16:00, and winter peak hours are anticipated to occur in January at hour ending 9:00. The NW-Central shows the smallest percentage increase in peak demand growth, 8.5%, with a projection of 33 GW in 2025 and 36 GW in 2034. This subregion is summer peaking, and is forecast to have peak demand hours in July at hour ending 17:00. From a Western Interconnection perspective, the peak demand is anticipated to grow by 17.2% over the next decade, from 164 GW to 193 GW. The coincident forecast peak for the interconnection is anticipated to occur in August at hour ending 17:00.