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WECC

Western Assessment of Resource Adequacy

November 2023

OVERVIEW

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Executive Summary

Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long term have increased significantly compared to last year's assessment. Three risks merit particular attention.

Increasing variability

Variability remains the greatest risk to resource adequacy in the Western Interconnection. To be resource adequate, the industry must have enough energy to meet demand under a range of possible conditions. Variable resources cannot be called on and dispatched to meet demand the same way traditional resources can. System-wide variability increased substantially between the 2022 and 2023 Western Assessments. Large, planned additions of variable resources, retirements of traditional baseload resources, and extreme weather events are three of the main drivers of resource and demand variability.

Rate of demand growth and uncertainty of future load patterns

Demand is expected to increase by 16.8% over the next 10 years, almost double the 9.6% growth reported in WECC's 2022 assessment. The biggest driver of this increase is the expansion of data centers, particularly in the Northwest. WECC sees no indications of this risk abating and expects the risk to grow and expand geographically as cloud computing and artificial intelligence needs grow. Entities outside the Northwest are starting to see increases in data center expansion.

Electrification drives load growth and uncertainty in load forecasts because it is difficult to determine how much it will be adopted in different areas and how it will affect load use patterns. Without a historical reference, entities must rely on new techniques and information to account for electrification in load forecasting. Only 40% of Balancing Authorities incorporate electrification assumptions directly into their load forecasting methods. Another 40% conduct separate electrification modeling and use the results to inform their load forecasting. This is an area in which the West must advance to ensure all entities are adequately accounting for ongoing and increasing changes from electrification.

Pace of new resource growth necessary to meet energy demand

To meet changes in demand, replace retiring resources, and cover increasing variability, the industry plans to build new resources at an unprecedented rate in the face of numerous challenges. Supply chain disruptions, increasing costs, production obstacles, and an overwhelmed interconnection queue threaten industry timelines to build new resources. While entities are trying to account for these delays in their resource plans, those plans have no room for adjustment, and there are other drivers like demand increase uncertainties and new policy changes for which the entities cannot fully account.

Risks to Reliability

WECC's Western Assessment answers two questions.

Question 1: Are current resource plans sufficient to meet future demand for the interconnection and subregions over each of the next 10 years under the range of possible system conditions?

Current resource plans are not sufficient to meet future demand over each of the next 10 years. In the near-term (2024–2025), WECC's analysis shows very few demand-at-risk hours with nominal amounts of demand at risk. However, starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude. This indicates that current resource plans do not fully cover demand under a full range of potential conditions.

Question 2: How does variability in the system increase with the changes in resources and demand currently reflected in resource plans, and how does this affect resource adequacy risk?

Variability increases over the next 10 years across the interconnection and in all subregions except the NW-Northwest. This variability is driven primarily by the addition of non-dispatchable variable energy resources (VER), the retirement of dispatchable resources, and the increase in load uncertainty due to extreme weather events. Variability creates risk in the system because it increases uncertainty, which makes it more difficult to reliably plan and operate the system. By this measure, resource adequacy risk is increasing.

Actions to Address the Risks

Industry is working to address these risks. In recent years, entities and states have taken urgent action to delay the retirement of resources to ensure continued reliability, particularly under extreme conditions. Between their 2022 and 2023 resource plans, entities increased the total number of new resources they plan to build over the next 10 years. Planning entities are developing new methods for incorporating changes like electrification and extreme events into system planning. The industry continues to discuss transmission expansion and recognizes its critical role in meeting resource adequacy needs. Discussions about the interconnection queue continue. The electric power industry, its regulators, and its partners understand and are acting to maintain the reliability of the system. The question is whether the West can act quickly enough. The changes the West faces are faster, broader, and deeper than anything it has faced before, and it will take continued, concerted, and focused effort to maintain reliability.

WECC remains committed to evaluating evolving trends and risks, conducting comprehensive analyses, and providing unbiased and objective information to industry stakeholders on resource adequacy. WECC intends the 2023 Western Assessment to be a resource for planners, regulators, policymakers, and other stakeholders as they contemplate resource planning challenges and decisions.

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Introduction

Reliability of the bulk electric system in the Western Interconnection would be impossible to maintain without sufficient resources to serve customer load. Resource planning decisions are often made years before resources are needed, and the decisions entities make affect their neighbors and the interconnection. Consequently, a long-term, recurring assessment of resource adequacy across the interconnection is necessary to ensure the reliability of the electric grid.

WECC's Western Assessment of Resource Adequacy (Western Assessment) examines resource adequacy through an energy-based probabilistic approach, looking broadly across the entire Western Interconnection and more specifically within each of five subregions over the next 10 years (Figure 1). This analysis, together with analyses by other western stakeholders, provides valuable insight into resource adequacy risks. This information can help stakeholders target specific areas for deeper examination and mitigation.

This work examines the drivers of resource adequacy changes as well as the associated risks. The results are presented in three time frames:

- Near-term: 2024–2025
- Mid-term: 2026–2028
- Long-term: 2029–2033

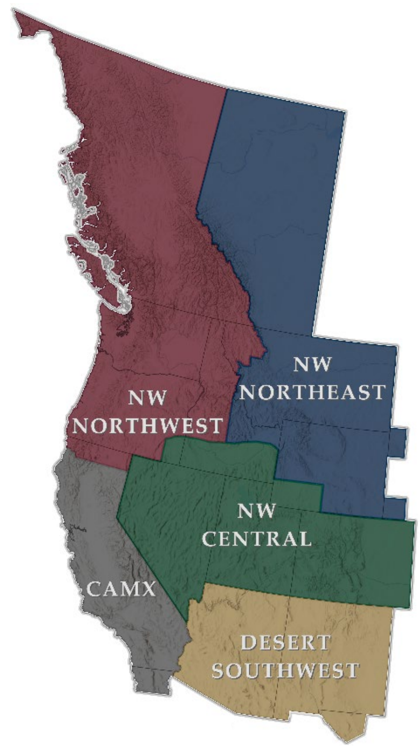


Figure 1: Western Assessment Subregions

As the Regional Entity responsible for ensuring the reliability and security of the Western Interconnection, WECC's work directly affects approximately 90 million people in the western United States and parts of Canada and Mexico. WECC is committed to conducting comprehensive analyses and providing objective information on resource adequacy risks throughout the Western Interconnection. These analyses rely on input and feedback from industry and other stakeholders. WECC thanks the stakeholders who provided input and recommendations that helped shape this year's Western Assessment.

Resource Adequacy Risk Drivers

Over the next decade, entities in the West plan to add 95 GW of resources to meet demand while satisfying requirements for clean energy. Demand is expected to grow at rates much higher than over the last decade. In addition, nearly 18 GW of coal and natural gas generators will be retired. Building to current plans will require a substantial increase in resource growth compared to the last 10 years. To keep pace with anticipated demand growth and retirements, industry will need to build new resources more quickly than in the past. Disruptions to the timely addition of resources pose a risk to reliability.

Western Interconnection Resource Retirements and Shutdowns

Over the next 10 years, entities plan to retire 27 GW of generation resources, mostly coal and natural gas (Figure 2). This is a 50% increase over the 18 GW of resources retired over the last 10 years. In recent years, some entities delayed retirements as a short-term way to reduce resource adequacy risk and compensate for delays in new resources. Entities continue to adjust retirement dates. In their 2023 resource plans, they further delayed retirements compared to their 2022 plans (Figure 3). These delays should help mitigate demand-at-risk hours in the near term until new resources can be built to replace resources that are scheduled to retire.

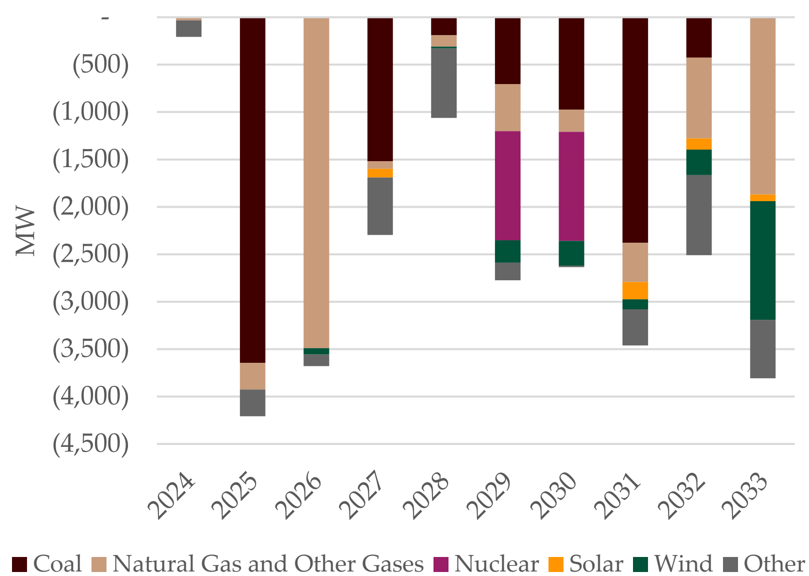


Figure 2: Western Interconnection Planned Retirements 2024–2033

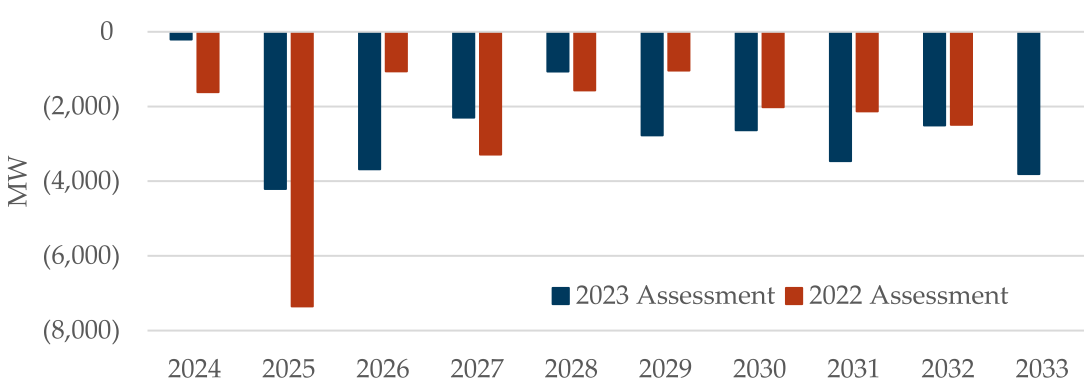


Figure 3: Comparison of Planned Retirements for 2022 & 2023 Assessments

Subregional Snapshot
Planned Resource Retirements & Shutdowns

	Near-Term (2024–2025)	Mid-Term (2026–2028)	Long-Term (2029–2033)
NW-Northwest	● 730 MW		● 660 MW ▲ 100 MW
NW-Central	● 1,260 MW ▲ 280 MW	● 1,145 MW ▲ 300 MW	● 1,650 MW ▲ 3,300 MW
NW-Northeast			● 200 MW
CAMX	● 1,230 MW	▲ 2,900 MW	
Desert Southwest	● 400 MW	● 560 MW ▲ 500 MW	● 2,000 MW ▲ 400 MW

● Coal ▲ Natural Gas

In addition to coal and natural gas, entities plan to retire 2,500 MW of early-generation wind and solar resources over the next 10 years.

According to current plans, the Diablo Canyon nuclear units will be retired in the CAMX subregion in 2029 and 2030.

Planned Resource Additions

Between their 2022 and 2023 resource plans, entities increased the total number of new resources they plan to build over the next 10 years, with most of the increase planned for the near-term (Figure 4).

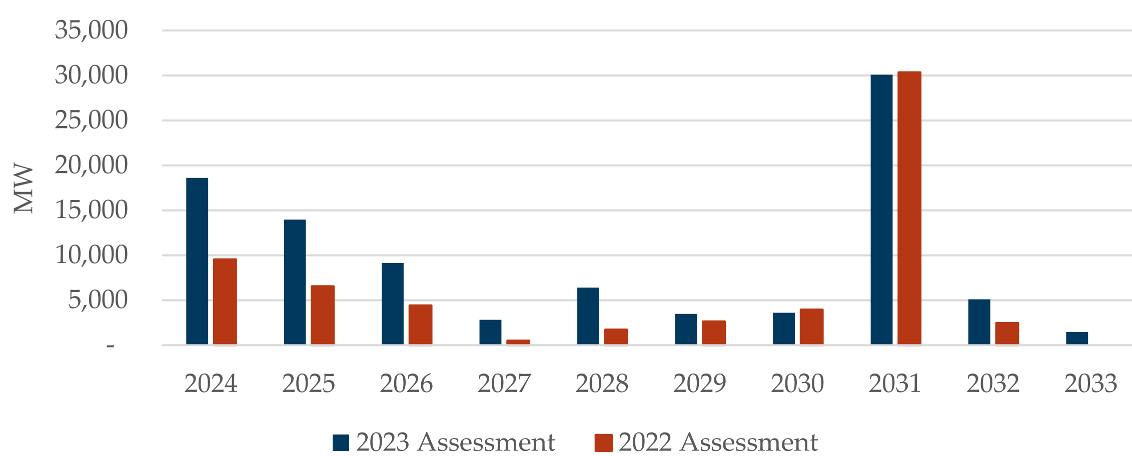


Figure 4: Comparison of Planned Resources for 2022 & 2023 Assessments

Entities plan to add 95 GW of resources in the next 10 years. Solar, energy storage, and wind make up more than 80% of these new resources (Figure 5). The new resources can help mitigate the risk of load loss due to resource shortfalls in the near term if they are built on time.

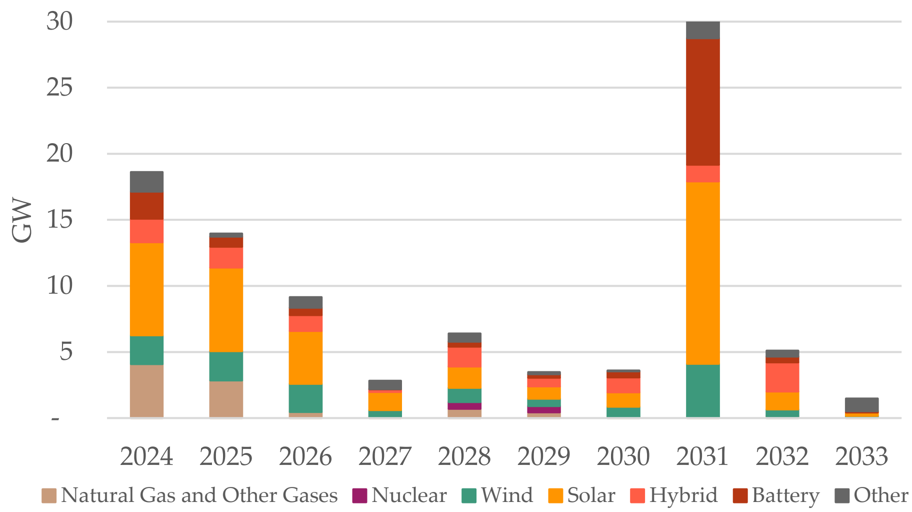
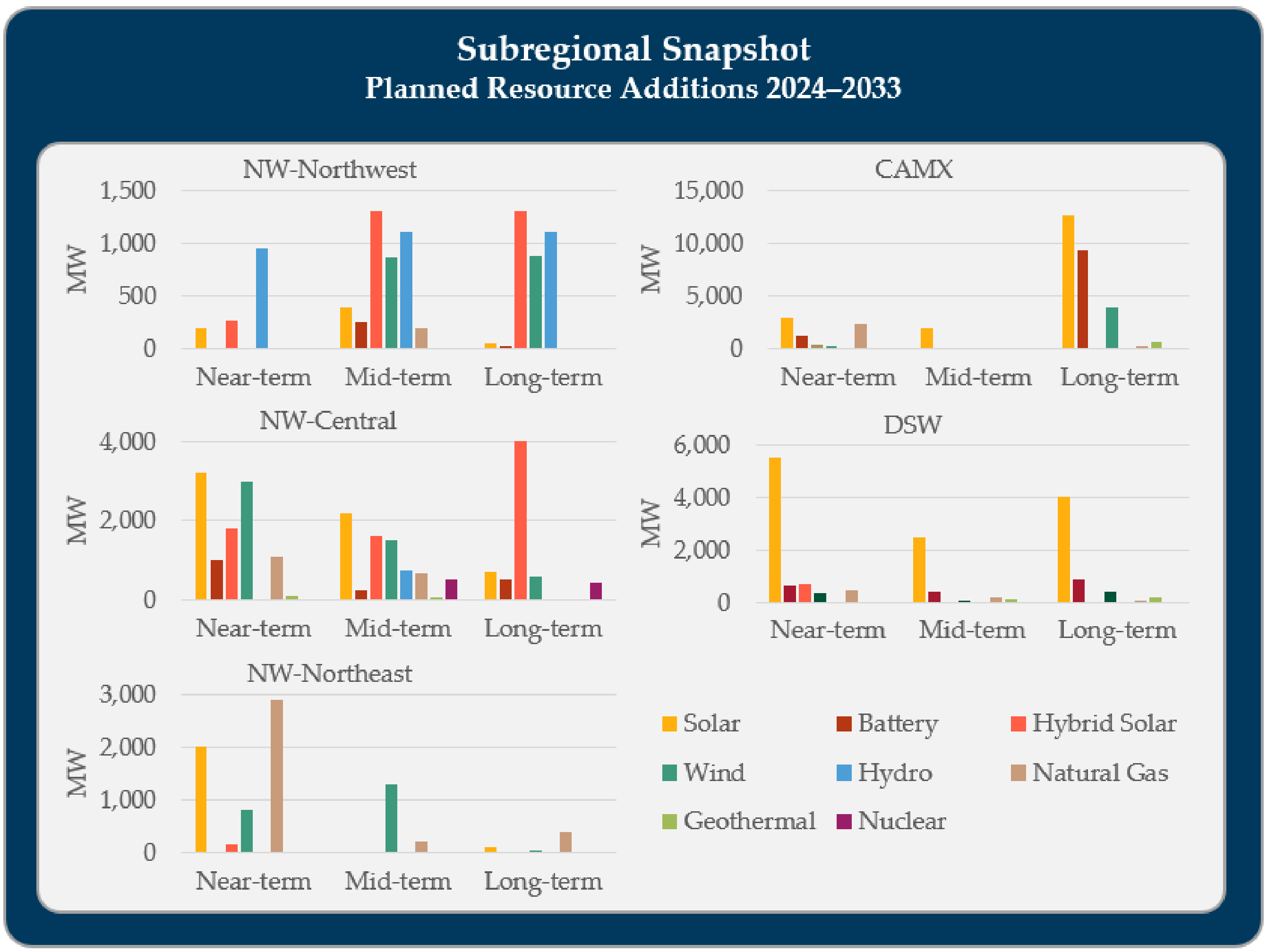


Figure 5: Western Interconnection Planned Resources 2024–2033



Wind Additions

Wind resources will grow over the next 10 years, but the growth rate will decrease compared to recent years. The annual growth rate has been over 6%. Current plans show a growth rate of 3%, though this translates to a significant amount of capacity. Resource plans show 1.5 times more (53 GW) wind capacity in 2033 than was operational in 2022 (34 GW) (Figure 6).

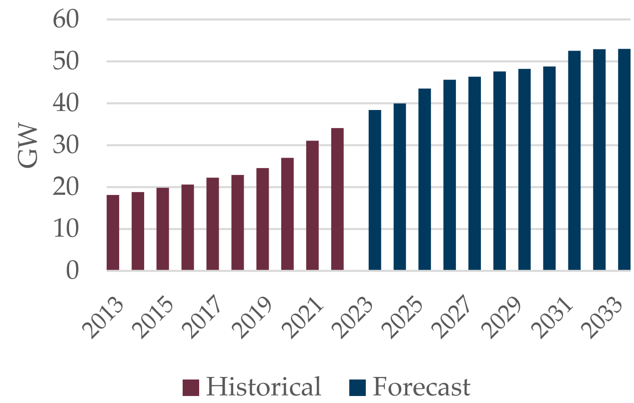


Figure 6: Cumulative Historical and Planned Wind Capacity (2013–2033)

Solar and Hybrid Solar Additions

According to 2023 plans, solar and hybrid solar (solar with storage) resources will grow the most across the interconnection over the next 10 years. In 2023, installed solar capacity will surpass the installed capacity of wind resources. Resource plans show three times (99 GW) the solar and hybrid solar capacity operational in 2033 than was operational in 2022 (31 GW) (Figure 7).

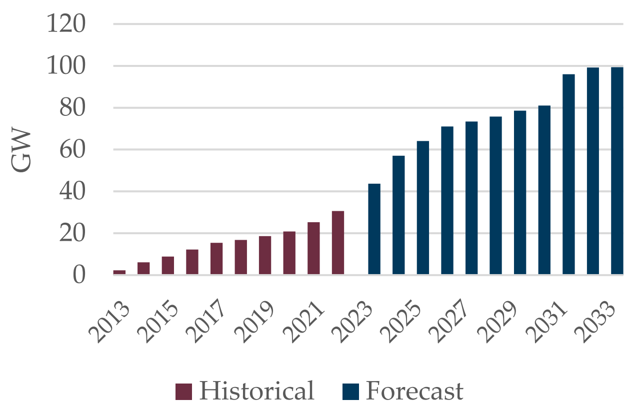


Figure 7: Cumulative Historical and Planned Solar and Hybrid Solar Capacity (2013–2033)

Energy Storage Additions

Planned energy storage, particularly battery storage, continues to grow. Current resource plans include an 800% increase in battery storage from 2022 (2.7 GW) to 2033 (21 GW) (Figure 8). The build rate for battery storage will need to increase significantly over the next decade to meet these plans. Increasing amounts of battery storage could help address some of the resource adequacy risk associated with increasing variability because the dispatch of battery storage can be controlled.

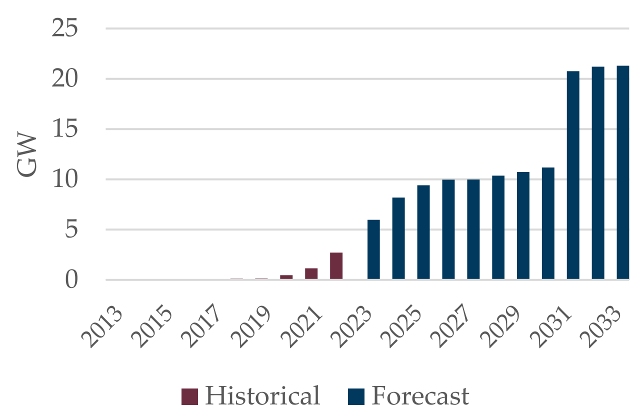


Figure 8: Cumulative Historical and Planned Battery Storage Capacity (2013–2033)

Risks to Planned Resource Additions

The addition of the planned resources listed above is critical to meeting future load. These resources need to be built as planned and on time. In addition to resource planning data, WECC asks Balancing Authorities (BA) to provide information about their resource adequacy risks. The information the BAs provide shines light on the factors that put timelines for new resources at risk.[1]

Supply Chain Disruption

Supply chain disruptions remain an obstacle to building new resources on schedule, connecting customers, and maintaining system elements. Western entities have reported delays and, in some cases, an inability to expand service in capacity-constrained areas. Lingering effects from the COVID-19 pandemic, foreign manufacturing, and shipping congestion are the main causes of delays. Longer-than-anticipated lead times for transformers, circuit breakers, conductors, and utility-scale solar panels have forced entities to revise near-term new resource timelines. Entities are already adjusting their timelines for longer-term future resources to account for possible delays. This should help reduce the risk of supply chain disruption delaying new resources in mid- and long-term forecasts.

Interconnection Queue

Delays due to congestion in the interconnection queue jeopardize industry's ability to build planned resources. Continent-wide, the interconnection backlog increased by 40% in 2022. Wait times are expected to grow as the Inflation Reduction Act (IRA) spurs more variable energy resources (VER), while state mandates push toward clean energy targets. Over 10,000 projects, representing 1,350 GW of generation capacity and 680 GW of storage, are actively seeking interconnection. Together, these projects far surpass the total generation entities plan to add over the next text 10 years, but in many cases the wait time is several years, and a great number of projects will not happen. In July, FERC addressed the issue in Order 2023, which expedites the process for connecting new generating facilities to the transmission system. The order, which took effect in November, is aimed at alleviating the backlog of projects in interconnection queues, providing greater certainty and preventing discrimination against new generation.[2]

[1] Specific responses and information about individual BAs is confidential. This page summarizes the information.

[2] FERC Order 2023, RM22-14-00

Changing Load and Demand

The biggest change to the 2023 resource plans is the increase in load forecasts. Energy policies, changes to energy use, electrification, and an influx of data centers are driving this increase.

Annual Energy

The 10-year load forecasts provided by BAs in 2023 show 16.8% load growth across the Western Interconnection (Figure 9). Load is expected to increase from a forecast 922 TWh in 2024 to 1,077 TWh in 2033. This load growth is much higher than previous projections, particularly in the near- and mid-term years. The 10-year load growth in the 2022 assessment was 9.6%. These new projections reflect electrification policies and, in the Northwest in particular, significant growth of data centers.

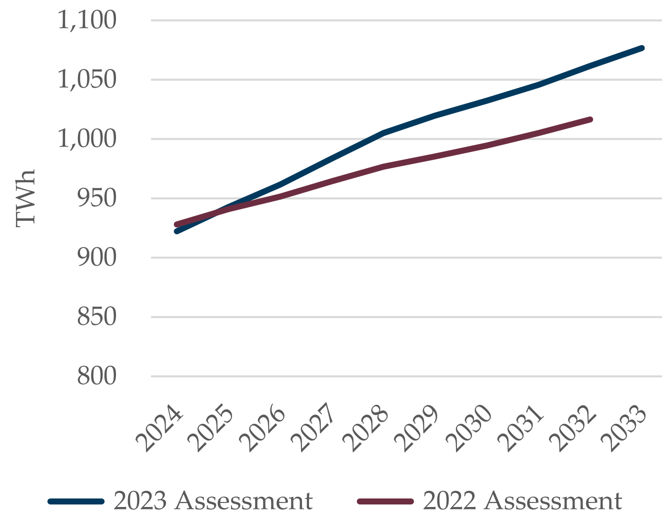


Figure 9: Comparison of Annual Energy Growth in 2022 & 2023 Assessments

Peak Demand

The interconnection-wide peak demand occurs in the summer. Over the next 10 years, peak demand is expected to grow from 159 GW in 2024 to 184 GW in 2033, a 16% increase.[3] The 2023 forecasts show a slightly lower peak demand than the 2022 forecasts (Figure 10). Data center demand profiles are relatively flat, so, while the addition of data centers is driving higher annual energy, it has less of an effect on peak demand. Other types of demand, e.g., building electrification, have a stronger effect on peak demand.

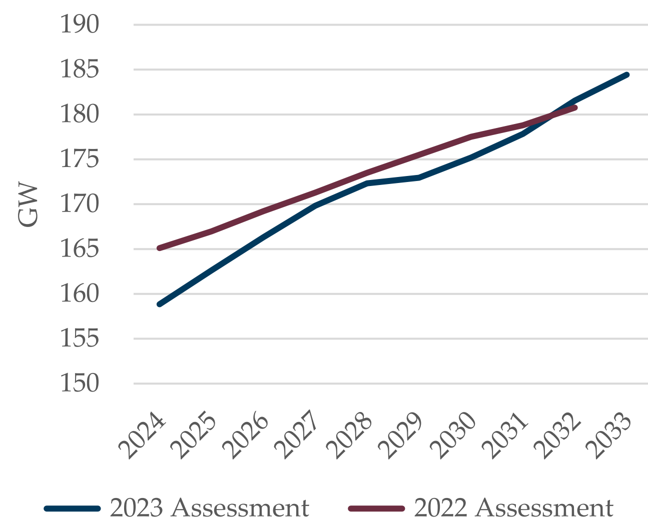
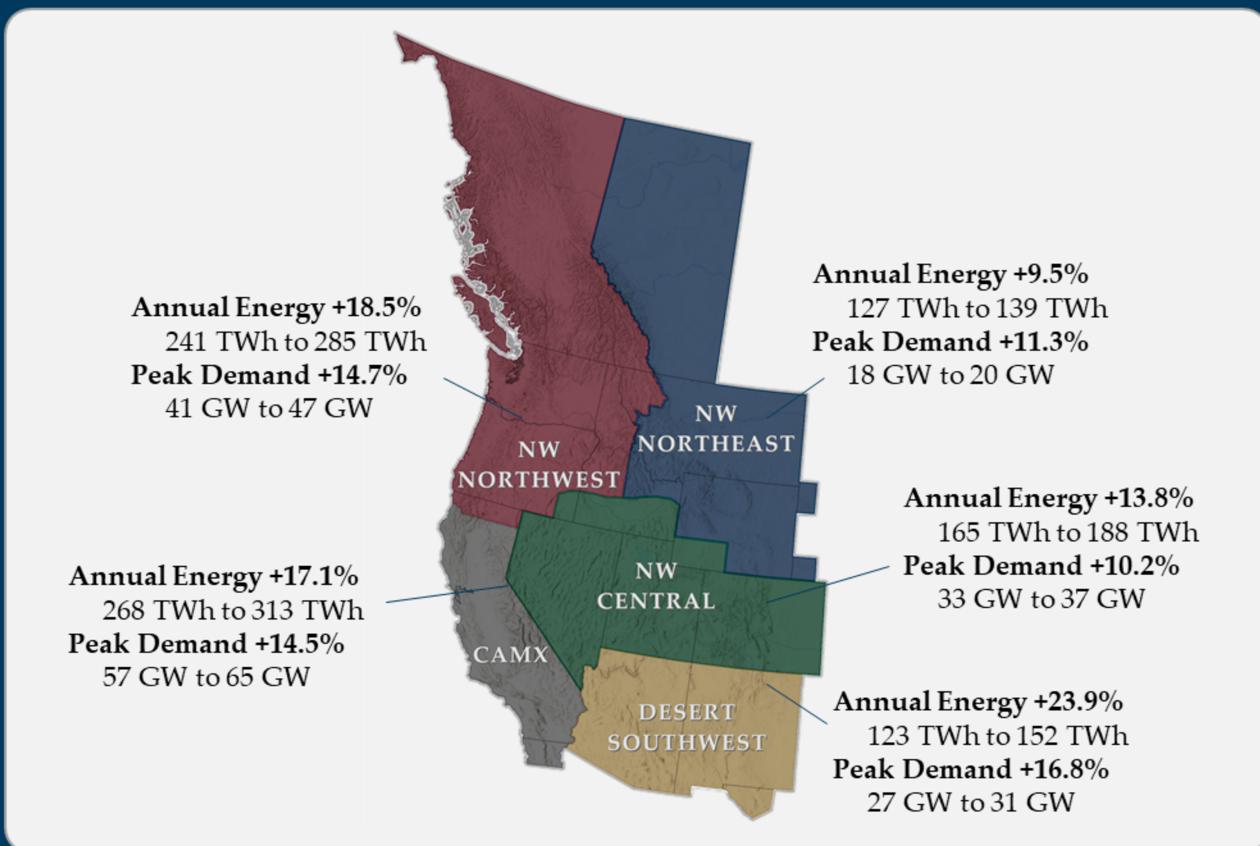


Figure 10: Comparison of Peak Demand Growth in 2022 & 2023 Assessments

[3] Peak demand refers to the expected, or 1-in-2 peak demand for the interconnection.

Subregional Snapshot

Load and Demand Growth: Forecast Annual Energy and Peak Demand 2024–2033



Causes of Increased Demand Growth

Data Centers

The anticipated increase in data centers over the near term is primarily responsible for the large load forecast increase between the 2022 and 2023 Western Assessments. Data centers require significant cooling, which further increases load. Northwest BAs project large increases in data centers, which could increase load by 50% to 200% depending on the BA. The subregional increases in the Northwest are enough to substantially affect the load forecasts for the entire interconnection. Data center expansion is being considered in other parts of the interconnection as well, including the Desert Southwest subregion. This will likely result in changes to demand forecasts in these areas like those in the Northwest.

Electrification

Electrification of transportation, buildings, and industrial customers is increasing across the West. Some estimates of the effect of full electrification adoption on load reach as much as a 75% increase in summer load and a 260% increase in winter load.[4] Only 40% of BAs in the West incorporate electrification assumptions directly into their expected load forecasts. Another 40% consider electrification as a separate forecast. Without accounting for the potential effects of electrification in their forecasts, it will be difficult for planning entities to ensure they will have adequate resources to meet load, both in terms of capacity and energy. Improvements in load forecasting for electrification are needed and should be universally employed.

Risks Associated with Demand Growth

Extreme weather conditions and growth of behind-the-meter resources create increasing variability in demand forecasts (Figure 11). The 2024 expected peak demand for the interconnection is 159 GW. However, there is a 3% chance that the 2024 peak demand could be as high as 186 GW. This might occur under an interconnection-wide heat event, for example. The variability in the peak demand forecast increases over the next 10 years. The expected summer peak in 2033 is 184 GW, and there is a 3% chance it could reach 221 GW or higher. If planning entities do not account for this variability in their resource plans they may not be resource adequate under some extreme conditions.

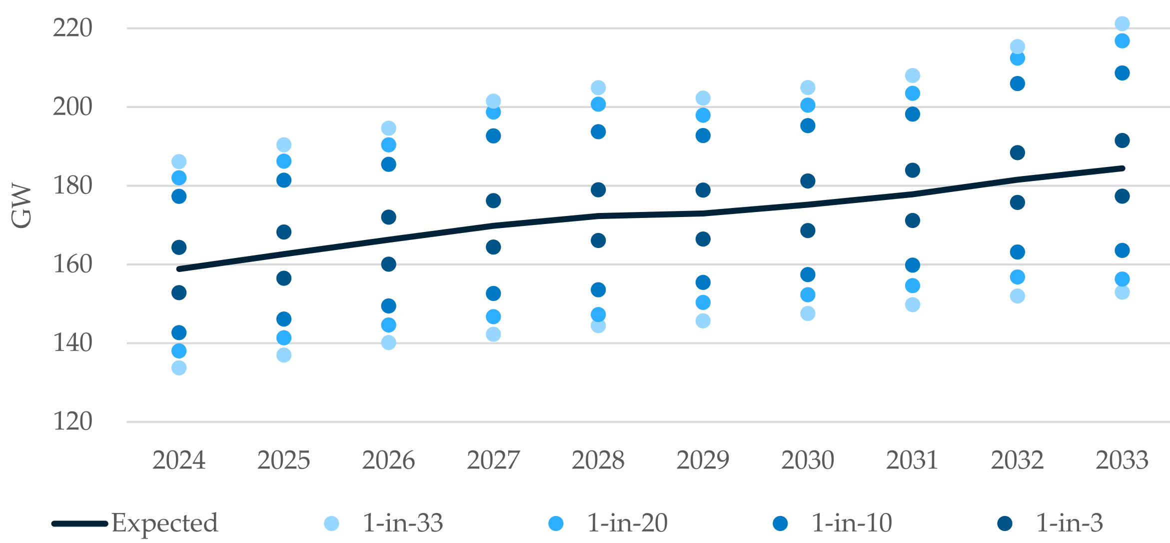


Figure 11: Western Interconnection Expected Summer Peak Demand with Uncertainty Ranges

[4] See the Seattle City Light Electrification Assessment, pages 1-7, https://powerlines.seattle.gov/wp-content/uploads/sites/17/2022/01/Seattle-City-Light-Electrification-Assessment.pdf.

Resource Adequacy Risk Analysis

WECC's analysis of resource adequacy risk focuses on answering two questions.

1. Are current resource plans sufficient to meet future demand for the interconnection and subregions over each of the next 10 years under the range of possible system conditions?
2. How does variability in the system increase with the changes in resources and demand currently reflected in resource plans, and how does this affect resource adequacy risk?

WECC uses two resource adequacy risk measures to answer these questions.[5]

Demand-at-risk Indicator (DRI): This measures the number of hours in a year when there is a risk for load loss (demand-at-risk hour) that exceeds the one-day-in-ten-year (ODITY) outage threshold. WECC calculates the probability that demand might be shed for any given hour, and, if that probability is greater than the ODITY threshold, that hour is counted in the DRI.

Variability Margin Indicator (VMI): This measures the variability of resource portfolios by calculating the reserves needed to ensure there are enough resources available to meet load under the ODITY outage threshold. As variability increases, so does the reserve margin needed to cover it. WECC measures reserve margins under a range of conditions as a proxy for system variability.[6]

Demand-at-risk Analysis

The DRI for the Western Interconnection decreased in this year's assessment (Figure 12). This is largely due to the new resources entities added to their 2023 resource plans, particularly resources planned over the next three years. However, with the increase in the demand forecasts, there are still demand-at-risk hours. Most of the demand-at-risk hours are in the NW-Northwest subregion, a result of the large demand growth that area is experiencing from data center expansion.

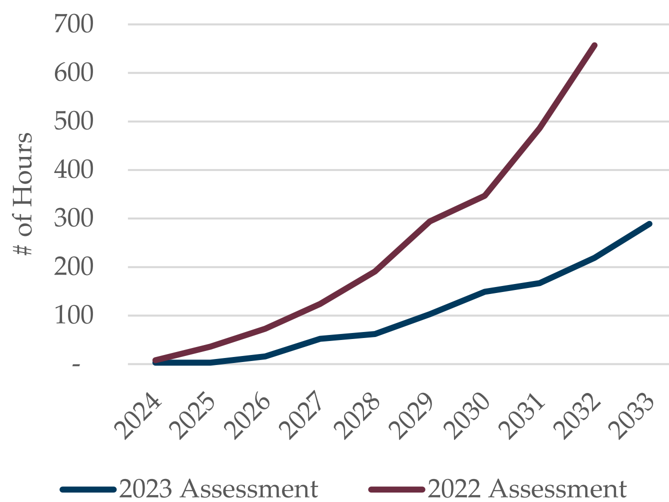


Figure 12: Comparison of DRI for the Western Interconnection in 2022 and 2023 Assessments

[5] For more information on how WECC calculates these metrics, see the 2022 Western Assessment of Resource Adequacy on WECC.org.

[6] The Variability Margin Index was previously referred to as the Planning Reserve Margin Index (PRMI).

Near-term DRI (2024–2025)

The DRI provides the number (frequency) of demand-at-risk hours each year, but it does not provide information on the amount (magnitude) of demand at risk. WECC examines the magnitude of the demand at risk in conjunction with the DRI to put the DRI value in context.

In the near term, January is the only month with demand-at-risk hours for the entire Western Interconnection. The magnitude of the demand at risk is relatively low, averaging 16 MW per at-risk hour in January 2024 and 7 MW in January 2025 (Figure 13).

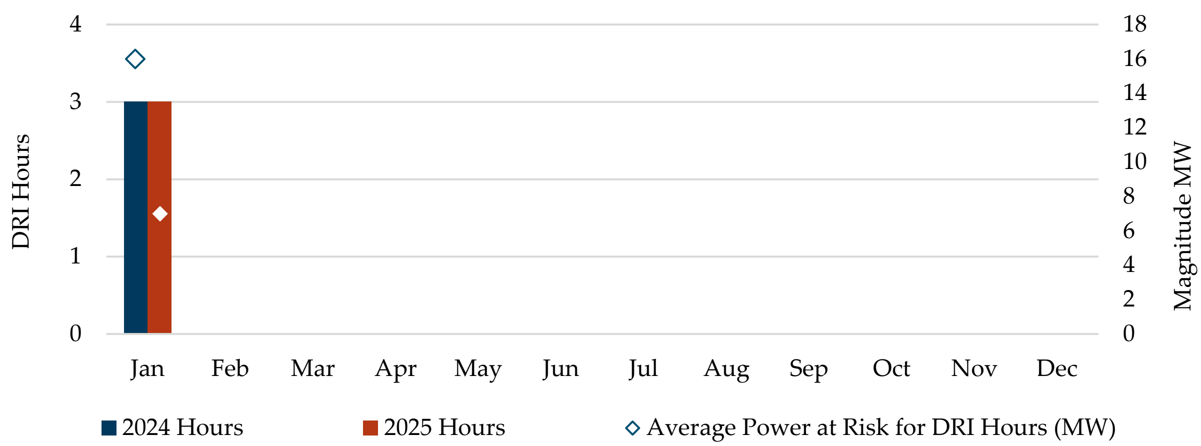


Figure 13: Near-term DRI Hours and Magnitude for the Western Interconnection

Subregional Snapshot
Near-term DRI in the Pacific Northwest

Only the NW-Northwest subregion has demand-at-risk hours over the next two years. The total demand at risk in the subregion is 47 MWh in 2024 and 22 MWh in 2025. This area is evolving into a dual-peaking region, but it is still a winter peaking area. Adding new resources quickly enough to manage demand-at-risk hours in the next two years will be difficult. Entities should monitor these hours closely in the operational time frame.

Across the other subregions, between the 2022 and 2023 assessments, the demand-at-risk hours were eliminated by reductions in demand forecasts, additions of new resources, and delayed retirements.

Mid-term DRI (2026–2028)

Demand-at-risk hours increase across the interconnection in the mid-term and spread to other months. Both the number of hours and magnitude increase, with August and December as the highest risk months each year (Figure 14).

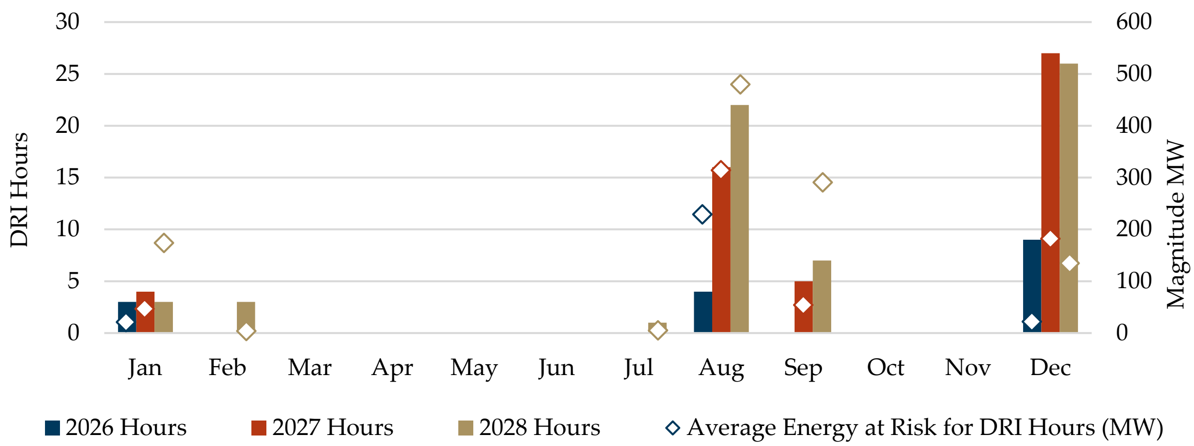
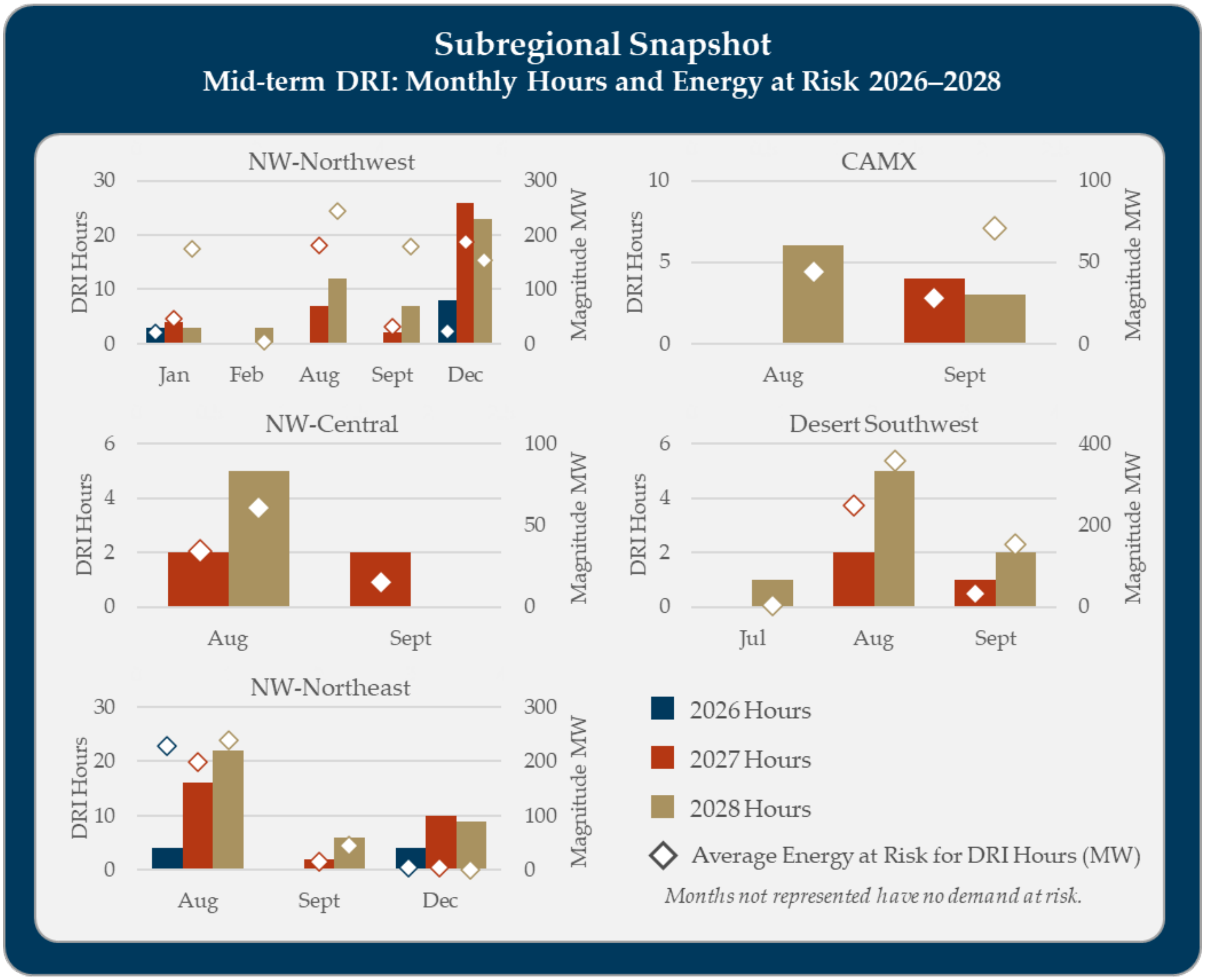


Figure 14: Mid-term DRI Hours and Magnitude for the Western Interconnection

The increase in August demand-at-risk hours is due to load and solar generation patterns in the southern subregions, specifically the timing of solar output reduction at sunset and daily peak loads. New resources will alleviate these demand-at-risk hours, but most of the new resources are planned to come online after 2028. The increase in demand-at-risk hours in December can be attributed to increased load forecasts in the NW-Northwest and relatively few new resources planned in that subregion.

In addition, many of the retirements that entities delayed to mitigate near-term resource adequacy risks were pushed into the mid-term time frame. This accounts for some of the substantial increases in demand at risk. Entities may need to extend the delays of some retirements further if they cannot mitigate these demand-at-risk hours in the next two years.


Subregional Snapshot
Mid-term DRI: Monthly Hours and Energy at Risk 2026–2028
NW-Northwest
CAMX
NW-Central
Desert Southwest
NW-Northeast
DRI Hours
Magnitude MW
Jan
Feb
Aug
Sept
Dec
Jul
2026 Hours
2027 Hours
2028 Hours
Average Energy at Risk for DRI Hours (MW)
Months not represented have no demand at risk.

Long-term DRI (2029–2033)

Demand at risk spreads further in the long-term timeframe, occurring 10 months of the year almost every year from 2029 through 2033 (Figure 15). The magnitude also increases, in extreme cases five or more times the greatest magnitude in the mid-term. Based on this measure of resource adequacy, the interconnection faces severe resource adequacy risks in the long-term. Entities should evaluate their long-term resource plans to ensure they can mitigate these risks. This is particularly important in cases where entities have added speculative or generic resources to later years. Identifying those resources as early as possible will help determine whether their plans result in demand-at-risk hours and whether additional measures need to be taken.

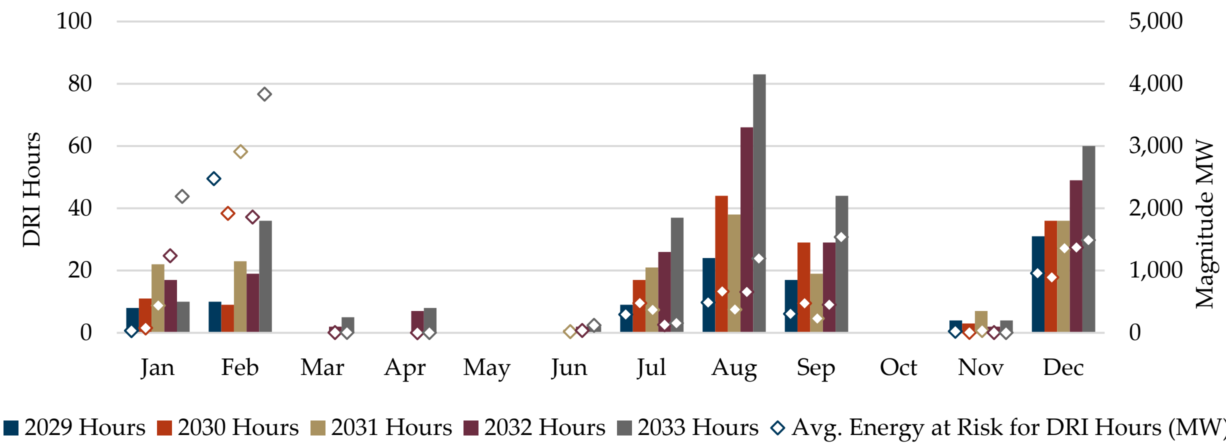
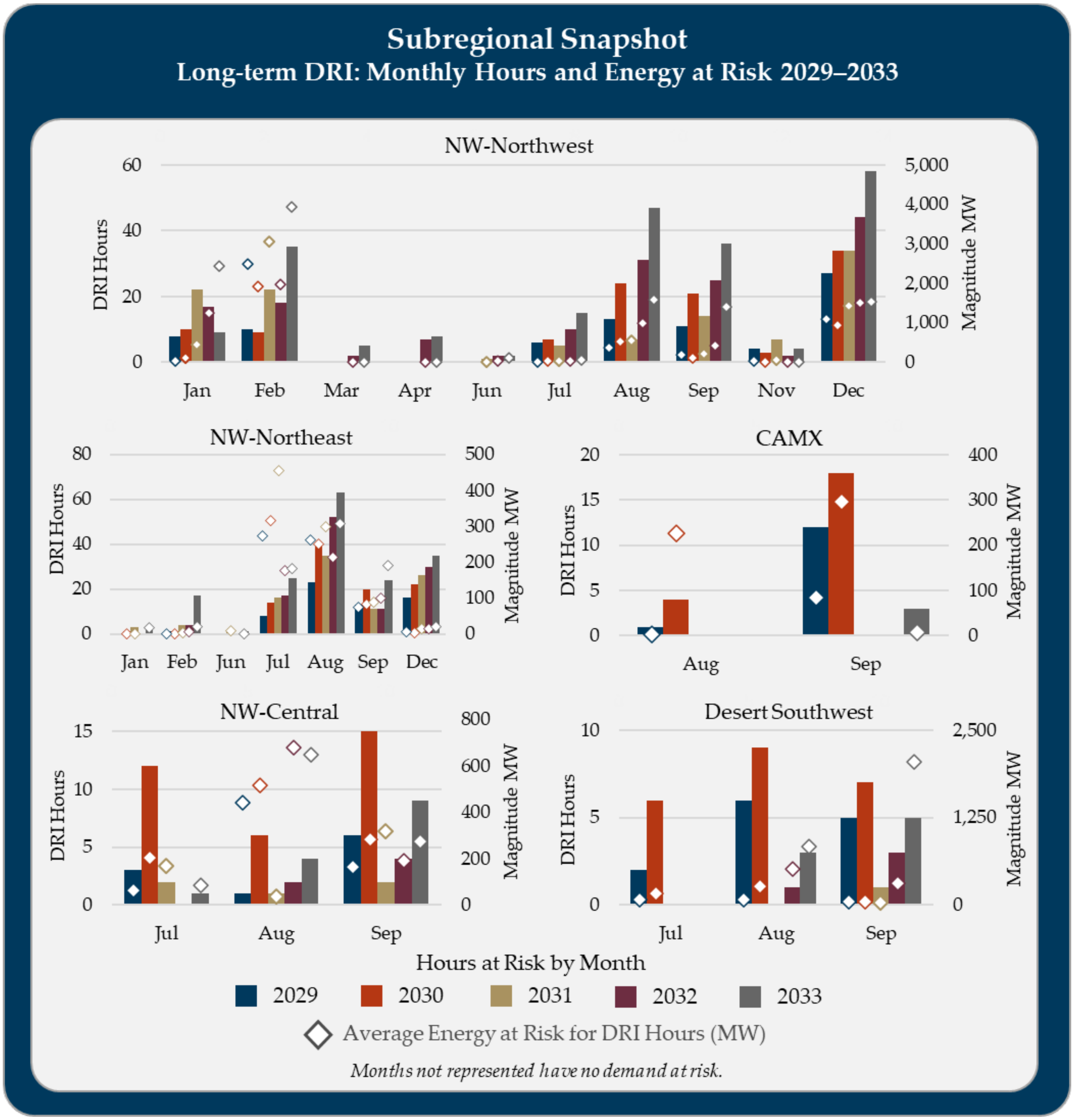


Figure 15: Long-term DRI Hours and Magnitude for the Western Interconnection


Subregional Snapshot
Long-term DRI: Monthly Hours and Energy at Risk 2029–2033
NW-Northwest
DRI Hours
Magnitude MW
Jan
Feb
Mar
Apr
Jun
Jul
Aug
Sep
Nov
Dec
NW-Northeast
CAMX
NW-Central
Desert Southwest
Hours at Risk by Month
2029
2030
2031
2032
2033
Average Energy at Risk for DRI Hours (MW)
Months not represented have no demand at risk.

Variability Analysis

Variability represents the greatest risk to resource adequacy because variability increases uncertainty, and uncertainty creates challenges to planning, paying for, and building resources. As variable generation is added to the system, variability of the system increases. Wind and solar make up two-thirds of the resources entities plan to add over the next decade. While this is a large amount of capacity (more than 60 GW), it also adds a great amount of variability to the system. A comparison of the capacity and energy availability on the peak hours for each of the next 10 years illustrates the challenge (Figure 16). While capacity is expected to increase by 95 GW through 2033, the energy from those additional resources is only expected to increase by 15 GW, and that number can change depending on system conditions.

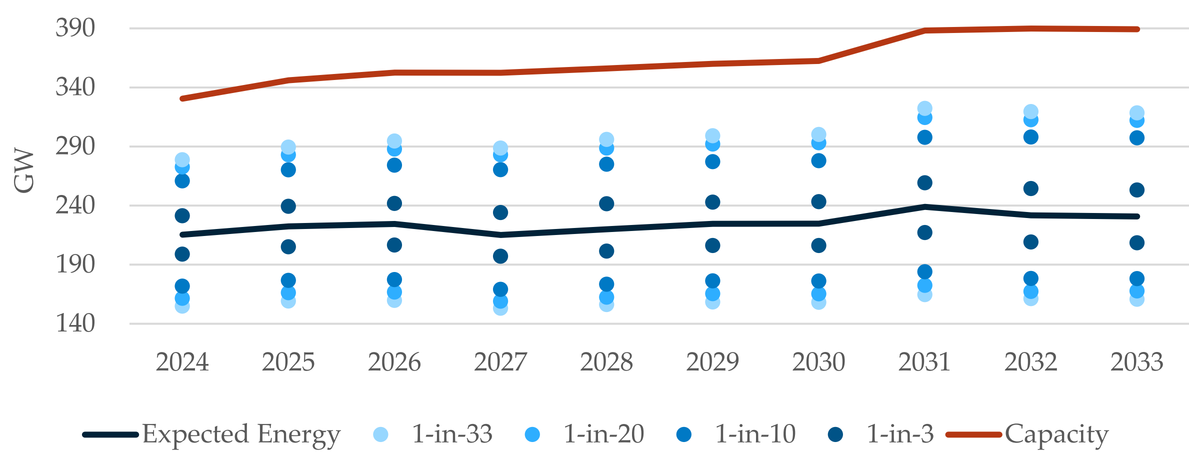


Figure 16: Comparison of Resource Capacity and Energy Variability on the Peak Hour 2024–2033

Variability Margin Analysis

The VMI for the Western Interconnection increases over the next 10 years, signaling growing risk. In addition, compared to the 2022 Western Assessment, the VMI is higher, meaning the variability in current resource plans is greater than previous plans (Figure 17). This is primarily due to increases in the number of planned variable resources. From a variability perspective, risk to the Western Interconnection has grown substantially over last year's Western Assessment.

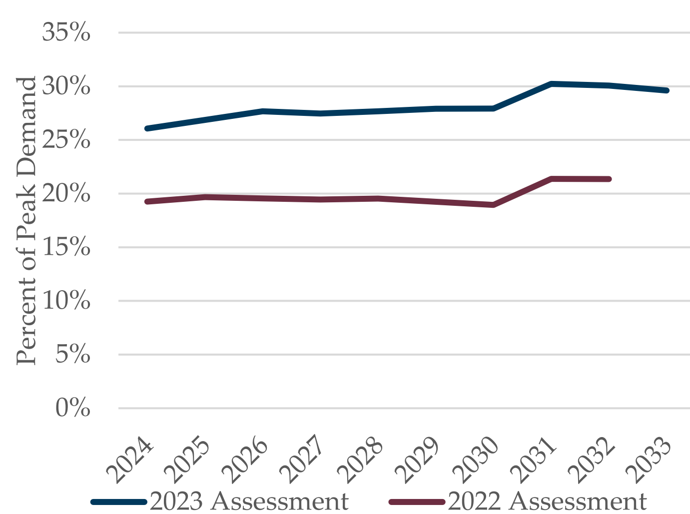


Figure 17: Comparison of VMI for the Western Interconnection in 2022 and 2023 Assessments

High levels of variability drives up demand-at-risk hours. The VMI specifically looks at variability in the resource and load mix. It does not account for actions entities take to mitigate variability, actions that can reduce demand-at-risk hours.

Subregional Snapshot
Comparison of Variability Margin Indicator for 2022 and 2023 Assessments

	2022 Assessment	2023 Assessment	
	2024 VMI	2024 VMI	2033 VMI
NW-Northwest	24.2%	▼ 23.5%	22%
NW-Central	21.3%	▲ 21.4%	25.4%
NW-Northeast	26.6%	▲ 27.4%	30%
CAMX	22%	▲ 25.4%	30.5%
Desert Southwest	18.6%	▲ 19.9%	29%

Incremental Analysis

Over the next decade, variability will increase across most of the interconnection, given current resource plans. Actions entities take to mitigate variability, such as the inclusion of additional less-variable resources, can reduce the number of hours when demand is at risk. While increasing variability is a signal of increasing risk, that risk can be mitigated. To better understand how different resource types contribute to the VMI and DRI measures above, WECC performed an incremental analysis, adding resource types one at a time to see the relative effect each type had on variability and demand-at-risk hours. Using 2030 (the year with the most demand-at-risk hours), WECC added resources in the following order:

1. Existing resources only, including known retirements
2. New non-variable resources, such as natural gas resources
3. New wind resources
4. New solar resources
5. New battery resources

Variability is lowest, but demand-at-risk hours are highest with existing resources (Figure 18). The addition of non-variable resources significantly reduces the number of demand-at-risk hours, with only a slight increase in variability. The addition of solar resources causes a large increase in variability, but a reduction in demand-at-risk hours. These results could change based on the order that resources are added. Therefore, the results should not be construed as the absolute quantification of each of the metrics shown below.

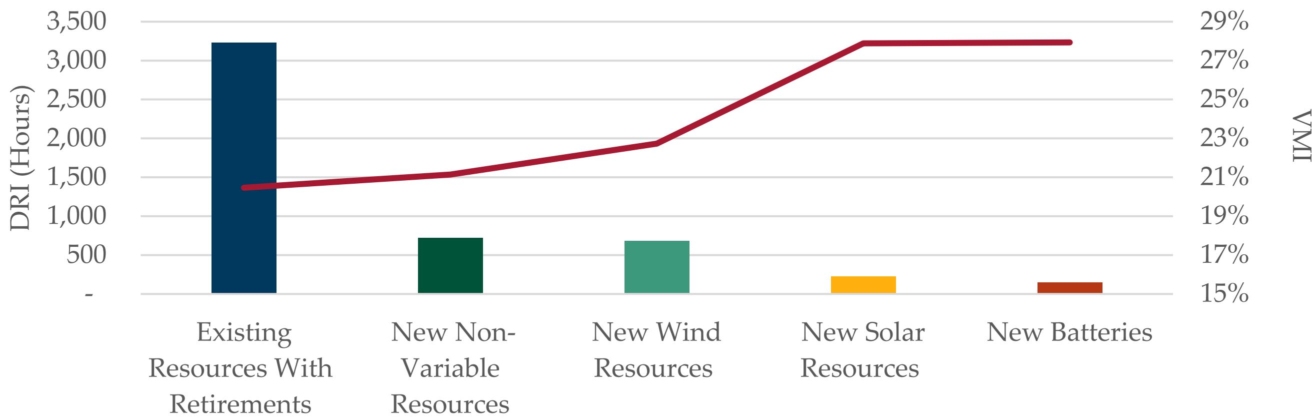


Figure 18: 2030 Western Interconnection DRI and VMI Incremental Analysis

The results for each of the 10 years in the assessment were similar to the 2030 results, but the results are more pronounced in later years (Figure 19). The VMI increases sharply in 2031 when 30 GW of new resources, mostly variable resources, are scheduled to come online. Many of these resources are speculative placeholders because they are so far in the future. In many cases, BAs lump these types of resources into one year, skewing the data. The more important takeaway is the overall increase over the 10-year period.

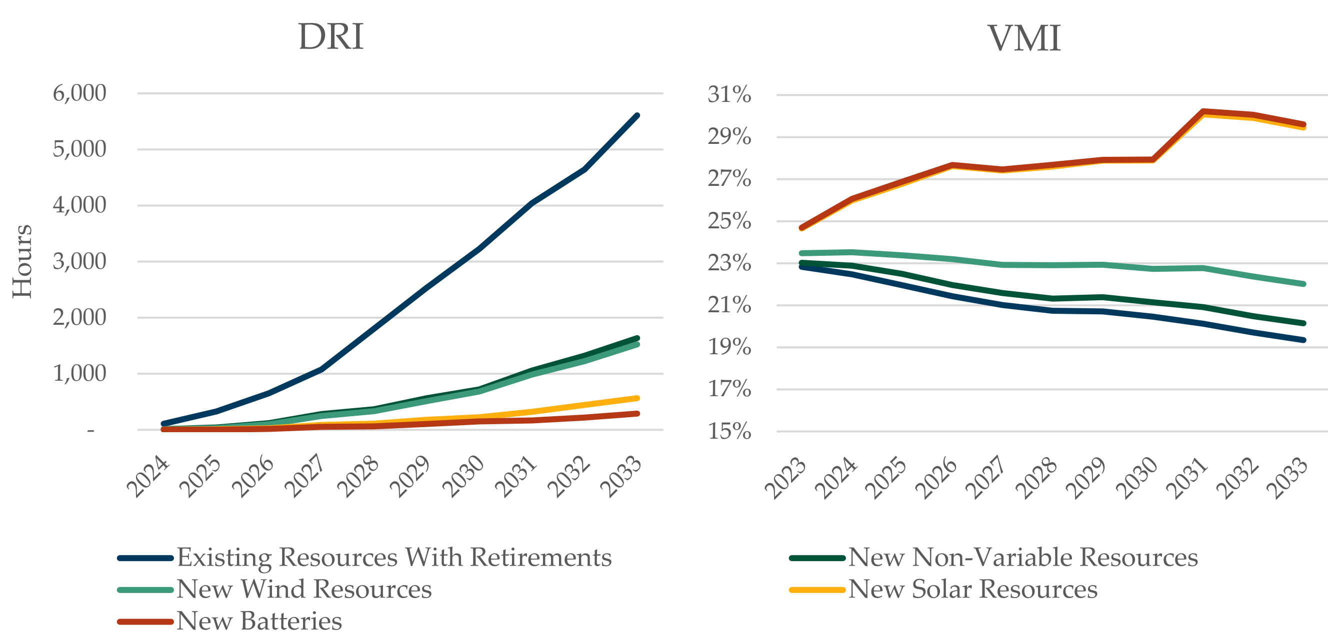


Figure 19: Western Interconnection DRI and VMI Incremental Analysis 2024–2033

Conclusions

High load growth, uncertainty in forecasting, and large amounts of new non-dispatchable resources are some of the factors that continue to challenge resource adequacy in the Western Interconnection. The recommendations and findings from WECC's 2022 Western Assessment have not changed significantly. Resource adequacy risks continue to grow. Variability remains the greatest risk because it contributes to demand-at-risk hours. To be resource adequate, industry needs to have enough energy to meet demand under a range of possible conditions. The more variable the system, the harder it is to accomplish this.

Based on the resource planning information provided by BAs, and WECC's energy-based probabilistic analysis, demand-at-risk hours increase significantly over the next 10 years, indicating that resource plans are not sufficient to meet demand under the range of conditions the interconnection could face. In addition, the variability on the system has increased since the 2022 assessment. Variability continues to increase over the next 10 years. As a measure of risk on the system, increasing variability indicates increasing risk. For these reasons, resource adequacy remains a top interconnection-wide risk.