Exploring a Resource Adequacy Program for the Pacific Northwest

October 2019

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An Energy System in Transition

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Introduction

The Northwest electricity system is in transition. The resource mix of the past—dominated by hydro but supplemented by thermal generation—is materially different than the emerging paradigm that includes large amounts of renewables. The impending retirement of a number of generators in the region has led to questions about whether the region will continue to have an adequate supply of electricity.

In the past several years, a number of groups—the Bonneville Power Administration (BPA), the Pacific Northwest Utilities Conference Committee (PNUCC), and the Northwest Power and Conservation Council (Power Council), and consulting firm Energy & Environmental Economics (E3)—have examined how anticipated changes to loads and resources in the Pacific Northwest will affect utilities' ability to meet customer needs reliably. Despite differences in assumptions and methodology, these studies identify an urgent and immediate challenge to the regional electricity system's ability to provide reliable electric service. Two key conclusions are of particular concern:

1. ***The region may begin to experience capacity shortages as soon as next year; and***
2. ***By the mid-2020s, the region may face a capacity deficit of thousands of megawatts.***

These developments threaten to upset the balance of loads and resources within the region and, if not properly addressed, could bring an end to a period of stability dating back to the end of the Western energy crisis of 2000-2001.

Meeting customer demands reliably, even on the coldest days of winter or the hottest days of summer, requires a significant amount of advanced planning. Utilities must forecast electric loads years into the future, not just for an average day but for the most extreme weather conditions. They must plan and procure sufficient generation and demand-side resources to meet these projected electricity demands, taking into consideration that not all resources will be available when needed whether due to unanticipated mechanical problems, lack of available water, wind, sunlight or fuel supplies, or transmission constraints. And because no electricity system can be made perfectly reliable, utilities must grapple with the question of how much reliability they should ask their customers to pay for.

The term that is most often used to describe an electricity system's ability to meet demand under a broad range of conditions, subject to an acceptable standard of reliability, is "resource adequacy." Resource adequacy is becoming an increasingly prominent topic in the Northwest and across North America as the continent's resource mix transitions away from coal and towards cleaner generating sources. Wind and solar energy have expanded their market share dramatically in recent years, while the pace at which aging coal-fired generators are being retired has accelerated. The loss of this "firm" generation—generation that can be turned on at will (with sufficient advance notice)—threatens to create a reliability gap if not replaced with equivalent capabilities. Wind, solar and even hydroelectric energy are limited in their ability to replace this firm generation because their energy supplies are dependent on the weather. Despite exciting developments in the field of electric energy storage, currently commercial technologies cannot fully substitute for firm resources because they have limited duration and rely on energy produced by other resources for charging. Many recent studies have shown that it is possible to cost-effectively replace coal generation with a combination of lower-carbon resources and significantly reduce electricity sector carbon emissions[1]. However, careful planning is required to ensure that resource adequacy is maintained during and after this transition.

The Northwest has faced resource adequacy challenges before. In the late 1990s, the effects of load growth, resource retirements, a lagging pace of new resource development, and California's experiment with electricity deregulation left the Western Interconnection in a situation of tight electricity supplies. A severe drought in 2000-2001 combined with manipulation of California's electricity market by Enron and other companies created the Western energy crisis, during which many utilities in the Northwest scrambled to find electricity supplies to keep the lights on for their customers. The cost of this crisis was high; average electricity rates across the region rose by over 25% between January of 2000 and June of

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[1] See, for example, E3 "Pacific Northwest Low Carbon Scenario Analysis", https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/.

2002[2], and electricity-intensive manufacturers such as aluminum smelters that had been an important source of family-wage jobs in some communities shut down for good.

In the aftermath of the crisis, a number of natural gas-fired power plants were developed throughout the west and policies were put in place in California to ensure resource adequacy going forward. In the Northwest, over 5,000 MW of natural gas generation capacity was constructed between 2001 and 2010, some 75% of it by independent power producers[3]. As a result of these developments and the significant reductions in electricity demand following the energy crisis and, later, the 2008 recession, the region has enjoyed a resource surplus for over 15 years. Significant efforts by the region's utilities to implement all cost-effective energy efficiency also contributed to much lower levels of load growth than in the past.

Recent developments are rapidly changing this picture. Construction of new gas generation has slowed dramatically; only four natural gas plants have come online since 2011 in the Northwest, totaling 1,100 MW of capacity. Instead of developing new capacity resources, many utilities in the region have opted to rely on "front office transactions"—planned purchases of energy and capacity through the region's wholesale electricity market—to meet their reliability needs. In addition, driven by environmental imperatives and increasingly adverse economics, nearly 2,000 MW of coal-fired generating capacity will retire in 2020 and additional retirements numbering in the thousands of megawatts are expected over the next decade. While construction of gas generation has slowed, renewable resource development has accelerated; as of 2019, the Northwest now has 450 MW of grid-scale solar and 9,400 MW of wind capacity[4]. However, while renewables can readily replace the *energy* that coal resources have

[2] Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/, original data Electric Sales and Revenue series.

[3] Northwest Power and Conservation Council, Map of power generation in the Northwest, https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest.

[4] Ibid.

traditionally provided, they cannot easily replace the *capacity* that is needed for resource adequacy due to the variable nature of their energy sources.

As a result of these developments, after years of surplus, the region now finds itself once again looking at significant resource deficits of thousands of megawatts now and into the future. Deficits of this magnitude pose risks of both extraordinary price volatility and unacceptable loss-of-load; indeed, the Power Council's most recent studies find that the region's Loss-of-Load Probability in 2024 could exceed what was calculated in 1999, just prior to the Western Energy Crisis, if coal plant retirements accelerate beyond current published closure dates as many expect.

The scale and scope of this challenge has led a broad coalition of electric utilities across the Pacific Northwest to agreement that collective action is necessary. Acting through the Northwest Power Pool, these utilities have undertaken an effort to explore the nature of the challenge and investigate mechanisms that will assure a high likelihood of supply and demand being in balance. The Northwest Power Pool convened working groups during the summer of 2019 to examine different dimensions of the current situation. The working groups consisted of utility members of NWPP with an interest in the topic of regional resource adequacy. These working groups were responsible for five tasks:

1. Review existing regional studies of resource adequacy;
2. Review current resource adequacy planning practices among Northwest utilities;
3. Survey best practices for resource adequacy programs throughout the country and world;
4. Investigate implications of possible constraints on fuel supply and transmission deliverability; and
5. Communicate results and findings to the appropriate audiences.

The following questions were posed to the working groups:

1. How are changes in loads and resources in the region expected to affect its capacity position in the coming years?
2. Are current practices in the region well-suited to meet the upcoming resource adequacy challenges?

3. What lessons can the Northwest learn from experiences in other regions?
4. How should electricity transmission constraints be considered when assessing resource adequacy needs?
5. How should the availability of fuel supplies be considered when assessing resource adequacy needs?

This report summarizes the findings of these working groups and offers some potential paths forward for the region to establish new institutions to help ensure that reliable electric service is maintained during the ongoing clean energy transition.

Resource Adequacy Overview

What is “Resource Adequacy”?

Electric power systems must continuously balance instantaneous supply and demand. However, neither supply nor demand are perfectly predictable. Thermal electric generators are sometimes unavailable due to either planned or forced outages, the outputs of some renewable generators are subject to large

What is the Difference Between Planning & Operating Reserves?

Within the electricity sector, the topic of “reserves” comes up in two contexts: planning and operations. “Planning reserves” refer to capacity resources procured by a utility, typically on a yearly time scale, to ensure that enough resources will be available during the most constrained periods on the grid. In contrast, “operating reserves” typically refer to the various ancillary services that system operators hold in day-to-day operations on time scales of minutes to hours. Operating reserves ensure enough generating capacity is available to respond to forecast errors, contingency events, and other operational challenges. Typical operating reserve products include frequency regulation, frequency response, spinning reserves, and non-spinning reserves. The existing reserve sharing pool administered by the NWPP allows utilities within the region to share operating reserves and should not be confused with the prospect of a regional resource adequacy program explored in this report.

variation due to the availability of sunlight or wind, and loads vary for reasons ranging from weather to behavioral factors. In order to ensure that supply always matches demand, electric system operators and planners rely on reserves. There are two principal types of reserves: shorter-term operating reserves and long-term planning reserves.

Resource adequacy (RA) refers to having enough resources – generation, efficiency measures, and demand-side resources – to serve loads across a wide range of conditions with a sufficient degree of reliability. The North America Electric Reliability Corporation (NERC) defines resource adequacy as "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components."[5]

Who Administers Resource Adequacy Standards?

Although both NERC and WECC publish information on resource adequacy planning, ensuring resource adequacy is the responsibility of utilities, state utility commissions, and other local and regional governing bodies. Traditionally, vertically integrated utilities engaged in near-term and long-term planning for their own generating capacity to ensure their systems were resource adequate. In such framework, utilities plan for reliability using their owned resources, resources that are under long-term contract and purchases from bi-lateral markets.

This traditional planning paradigm does not typically incorporate a rigorous assessment of regional market conditions, often relying instead on rules of thumb based on historical experience. The concern with this approach is that historical experience may not reflect future capacity availability, especially given the rapid transformation of the electric sector discussed above. Failing to take a broader

[5]2018 Long-Term Reliability Assessment, North American Electric Reliability Corporation, December 2018, p. 5. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

geographic perspective during a period of rapid change could lead to resource adequacy shortfalls, increasing the risk of loss of load in the region. In response to this concern, some regions have set up capacity sharing mechanisms to facilitate effective planning and exchange of capacity resources. These mechanisms – typically called “resource adequacy programs” (RA programs) – come in many forms, from relatively simple bilateral contracts among individual utilities to centrally cleared capacity markets.

How is Resource Adequacy Measured?

Utilities use a range of different techniques to measure and assess resource adequacy. An emerging “best practice” for utilities consists of the following two steps:

1. **Use loss-of-load probability (LOLP) modeling**, to determine the amount of “effective generation capacity[7]” needed to meet a long run reliability standard such as no more than one outage event in ten years. LOLP modeling uses statistical analytical techniques to simulate load and resource availability across a wide range of plausible conditions, evaluating the frequency, duration, and magnitude of potential reliability events and comparing them against a preset standard.
2. **Calculate a planning reserve margin (PRM)** by dividing the total effective capacity required by the median or 1-in-2-year peak demand. This PRM can then be used in a variety of planning process to help ensure that a sufficient margin of resources above that expected peak demand will be available in case of extreme weather, unexpected plant outages, or other unforeseen conditions. Most North American utilities that use a planning reserve approach set their PRMs between 10% and 20% above the median peak demand. An electric system is deemed “resource adequate” if its reserve margin exceeds its established standard.

This two-step method results in a clear measurement of capacity needed to ensure a specific reliability target.

LOLP modeling requires utilities to develop and maintain detailed statistical models that represent the potential distributions of loads, renewable profiles, and resource outages on their systems. By simulating potential combinations of these factors, LOLP modeling provides detailed measurement of the expected frequency, duration, and magnitude of reliability events. Common reliability metrics quantified using LOLP models include:

- **Loss of load expectation ("LOLE", units of days/yr)**: average number of days per year with loss of load (at least once during the day) due to system load exceeding available generating capacity
- **Loss of load events ("LOLEV", units of events/yr)**: average number of loss of load events per year, of any duration or magnitude, due to system load exceeding available generating capacity
- **Loss of load probability ("LOLP", units of %)**: probability of system load exceeding the available generating capacity during a given time period
- **Loss of load hours ("LOLH", units of hours/yr)**: average number of hours per year with loss of load due to system load exceeding available generating capacity
- **Expected unserved energy ("EUE", units of MWh/yr)**: average total quantity of unserved energy over a year due to system load exceeding available generating capacity

What Resource Adequacy Standards are used in the United States??

There is no single industry standard for resource adequacy. In fact, utilities, state agencies, and regional transmission operators use a variety of different approaches to establish resource adequacy standards. Many standards are tied to the notion of avoiding loss of load more frequently than one day in ten years (a "1-in-10" standard). Jurisdictions using such a standard either use it directly in LOLP modeling or translate it into an equivalent PRM requirement; others define PRM requirements based on the size of the single largest contingency event or simply rely on common industry best practices. [6] Table 1 lists a range of resource adequacy standards in use across North America and Europe and illustrates the diversity of approaches and standards that have evolved in the industry.

[6] For instance, California relies on a 15% PRM but does not regularly perform reliability modelling to confirm this value against a loss-of-load metric.

Table 1. Example of reliability standards used in various jurisdictions

Jurisdiction	Reliability Metric(s)	Standard Value	Notes
CAISO	PRM	15%	Stipulated, not based on an explicit reliability standard[7]
ERCOT	N/A	N/A	Tracks PRM for information purposes; "Purely information" PRM of 13.75% achieves 0.1 events/yr; Economically optimal = 8-10.5%; Market equilibrium = 10.25%
MISO	LOLE	0.1 days/year	8.4% UCAP PRM; 17.1% ICAP PRM[8]
SPP	LOLE	0.1 days/year	PRM assigned to all LSE's to achieve LOLE target: 12% Non-coincident PRM & 16% Coincident PRM
Great Britain	LOLH	3 hours/year	LOLH standard translated to a target PRM of 5% for 2021/22 (actual PRM of 11.7% for 2018/19 exceeds this standard)

[7] While the CAISO's PRM requirement is not updated regularly based on a reliability study, the California Public Utilities Commission has established a 0.1 days/year LOLE target to assess long-term reliability in its IRP proceeding.
[8] UCAP = unforced capacity (i.e. available capacity after accounting for generator forced outages or de-rates). ICAP = installed capacity (i.e. available capacity before accounting for generator forced outages or de-rates). UCAP equals ICAP after accounting for forced outages.

Resource Adequacy in the Northwest Today

Today, there is no formal approach to regional capacity planning in the Northwest.[9] Regional entities like the Northwest Power and Conservation Council (NWPCC), Bonneville Power Administration (BPA), and the Pacific Northwest Utility Conference Committee (PNUCC) periodically conduct regional reliability assessments. However, these studies are not directly tied to the planning and procurement decisions of individual utilities. Instead, the Northwest electricity system is operated, planned, and regulated by a patchwork of entities spread across its states, provinces and sub-jurisdictions therein. Load-serving entities (LSEs) in the region range from large investor-owned utilities (IOUs) to small rural-electric co-ops and direct access providers.

Current Practices Among Northwest Utilities

Planning and procurement to meet resource adequacy needs is handled by individual utilities under the oversight of regulators, cooperative boards, and city councils. Typically, individual utilities develop plans and procure resources that are sufficient to meet their forecasted peak load requirements plus a stipulated planning reserve margin. In order to meet those requirements, utilities rely on combinations of self-owned generation, bilateral contracts, and planned market purchases. This utility-by-utility planning framework is sufficient to meet regional resource adequacy needs if (and only if):

- Each utility calculates its own needs using a robust methodology;

[9] The Northwest does have a sharing mechanism for operating reserves, specifically contingency reserves, that is administered by the Northwest Power Pool. Operating reserves include spinning and non-spinning reserves. Spinning reserves include both generation and loads that are synchronized with the electric system and can respond to short-term fluctuations in demand. Non-spinning reserves include generation and load resources that can be synchronized within a short period of time, typically less than ten minutes.

- Each utility builds, or enters into firm contracts with, physical resources to meet its own needs;
- New resources are approved in a timely manner, relative to utility needs;
- Utilities do not collectively rely excessively on "market purchases" that exceed the physical capability of the Northwest system to meet reliability needs

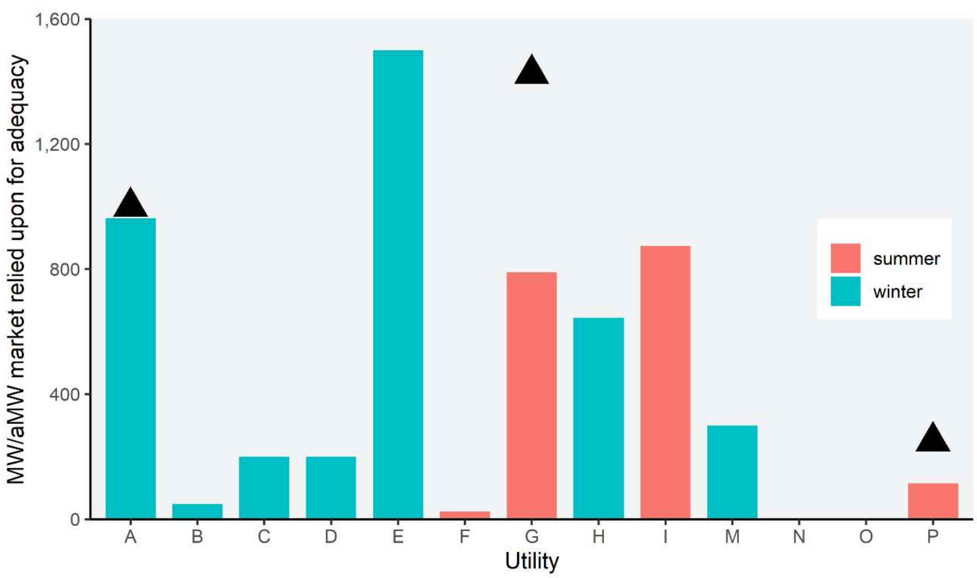
If these criteria are not met, the total capacity available to the region could fall below what is required to maintain reliability.

PNUCC staff and NWPP members recently surveyed a subset of utilities within the region to identify the range of planning practices used across the region. Those survey results are discussed in detail in Appendix D, but key conclusions highlight the diverse range of approaches to resource adequacy:

- **Utilities rely on a range of different methods and planning standards.** Most utilities within the region rely on a planning reserve margin to measure resource adequacy; however, there is significant variation among utilities in how that requirement is established and applied. A number of larger utilities use LOLP modeling to derive an appropriate target PRM, while smaller utilities tend to rely on industry standard practice or rules of thumb as the basis of their requirements. Utilities also take different approaches to evaluating resource adequacy throughout the year: some utilities maintain a single annual requirement, whereas others—typically utilities with dual peaks—have established separate requirements for both summer and winter.
- **Utilities use different methods to quantify capacity contributions to PRM.** For instance, some utilities use simulation methods to analyze hydro availability, while others rely on a fixed water year, typically a 'critical' water year like 1937. Treatment of renewables' contributions to needs also differs by utility: some rely on historical experience (e.g. the *n*th percentile of production), while others use more rigorous methodologies like effective load carrying capability (ELCC).
- **Load forecasting methods vary by utility.** Load forecasts in the region vary from econometric estimates to bottom-up end-use modelling. Some utilities use a mixture of these approaches, combining bottom-up modelling for residential customers with econometric methods for all other sectors.

- **Utilities have different perspectives and approaches to account for availability of "market purchases" to meet their needs.** While some utilities do not account for market purchases, it is a relatively common practice among utilities in the region to assume that some portion of their reliability needs can be met by market purchases on the wholesale energy market. Market purchases are used differently by utilities in the region and there is no standardized treatment of these resources for resource adequacy purposes (Figure 1).

Figure 1: Select Utilities' Reliance on Market Purchases for Peak Planning Purposes



Note: the height of the bars in this figure depict the amount of market purchases each of the utilities surveyed by PNUCC plan to rely on to serve their peak loads. The color of the bar indicates whether the utility in question is summer or winter peaking. The black triangles denote the amount of market purchases that utilities have assessed is available relative to their planned purchases.

This diversity of planning practices is reflective of the wide variety of different utilities that serve customers in the Northwest. Those utilities operate in very different contexts, ranging from public utilities with small loads and large hydro resources, to investor-owned utilities that serve metro-area load pockets.

Despite these differences, the region's utilities share a common interest in cost-effectively maintaining the region's reliability. To achieve that goal, **it is imperative that individual utility planning practices, when aggregated to the regional level, provide enough physical capacity resources to meet the**

region's loads, as well as a clear signal of potential future needs. Today, however, the fractured nature of the Northwest's planning framework can make it difficult for regulators, board members, stakeholders, and utilities to understand whether, where, and when new capacity is needed in the region.

Current Loads and Resources Outlook

Several different regional entities conduct regular studies of the Northwest's capacity position and annual energy balance. Each study relies on different methods and assumptions, but all involve either summing utility resource plans or conducting probabilistic modelling of generation and load. These studies include:

- **White Book 2018 (BPA):** The BPA White book identifies the load resource balance for both the Federal system and Northwest region as whole. BPA compares the region's expected loads and contract obligations to available resources and contract purchases.

- **Pacific Northwest Power Supply Adequacy Assessment for 2023 (NWPCC)**:[10] The Council's Resource Adequacy Advisory Committee (RAAC), a working group comprising Council members as well as representatives of investor owned utilities, public utilities, state agencies, and other interested parties in the region, generates an annual assessment of regional resource adequacy looking forward five years. This outlook incorporates utility plans for existing resources and new investments as well as the impacts of energy efficiency targets adopted in the Council's power plan.

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[10] At the time this report was developed the NWPCC was working on development of its upcoming 2024 Power Supply Adequacy Assessment; however, the Council had not at this time released results that it deemed appropriate for use in regional resource adequacy discussions.

- **2019 Northwest Regional Forecast (PNUCC):** PNUCC compiles Northwest utilities' 10-year projections of electric loads and resources into the annual Northwest Regional Forecast. In that document, PNUCC examines the ability of the Northwest system to meet average energy, seasonal energy, and both winter and summer peak loads.

In addition to these regular studies, several other sources provide additional perspective on resource adequacy through 2030. These include:

- **Northwest Loads and Resources Assessment (PGE/E3, 2018):** In the development of its 2019 Integrated Resource Plan, Portland General Electric commissioned a study to examine the regional load-resource balance to inform its own assumptions for the availability of "market capacity" in its integrated resource plan. In support of that effort, E3 developed several load-resource balance scenarios for the Northwest region.

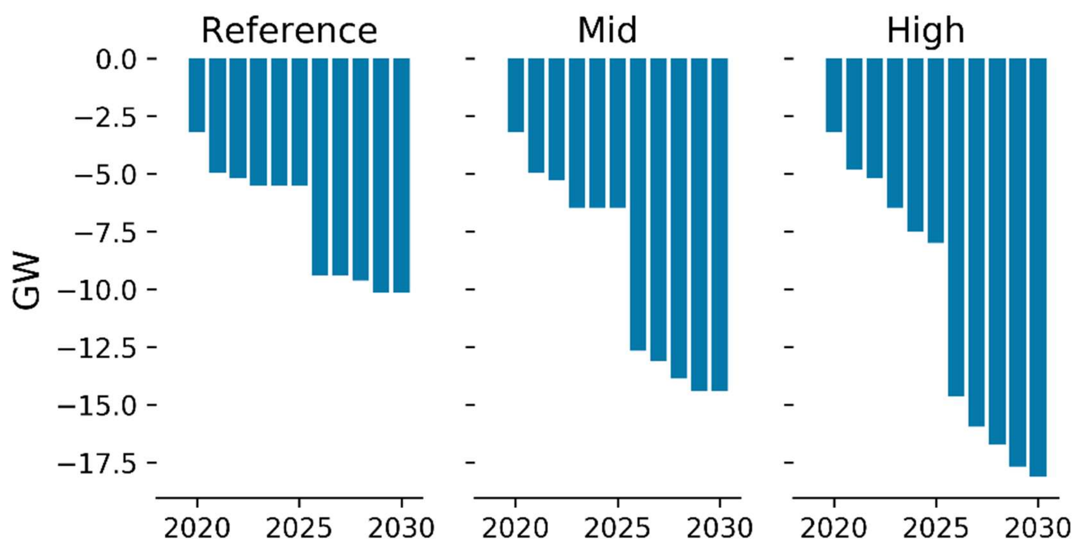
- **2018 Long-Term Reliability Assessment (WECC/NERC)**: As part of a national NERC reliability report, WECC develops an annual assessment of the load and resource balance within its footprint. As part of that analysis, WECC staff evaluate the resource adequacy of the NWPP region. A key differentiator of this study is that its values for NWPP relate to that region's summer peak. In contrast, the other studies referenced above mostly focus on the challenges of serving load during the Northwest's winter peak.

Although each study differs in scope and methods, a common finding across most of these studies is that **the Northwest is either capacity-short today or will be within the next two years**. The capacity challenges facing the region are the result of two key factors: (1) planned retirements of a substantial amount of aging baseload generation capacity; and (2) expected peak load growth within the region, which will be only partially offset by energy efficiency and demand response.

The largest resource adequacy challenges facing the region is the replacement of the firm capacity of retiring coal plants within the next five to ten years. The E3, NWPCC, PNUCC, and BPA studies all point to planned and prospective coal retirements as key drivers of decreased firm capacity available to the region. Based on current utility plans, over 2,000 MW of the region's coal plants will retire between

2019 and 2023, and an additional 1,500 MW will retire by 2029; these figures could increase as utilities continue to evaluate the viability of maintaining aging baseload assets. Coal retirements are a West-wide phenomenon, meaning that the quantity of firm capacity across the entire interconnection is expected to decrease (Figure 2). These retirements both directly implicate the load-resource balance of the Northwest and the potential availability of surplus capacity from other regions of the West on a going-forward basis.

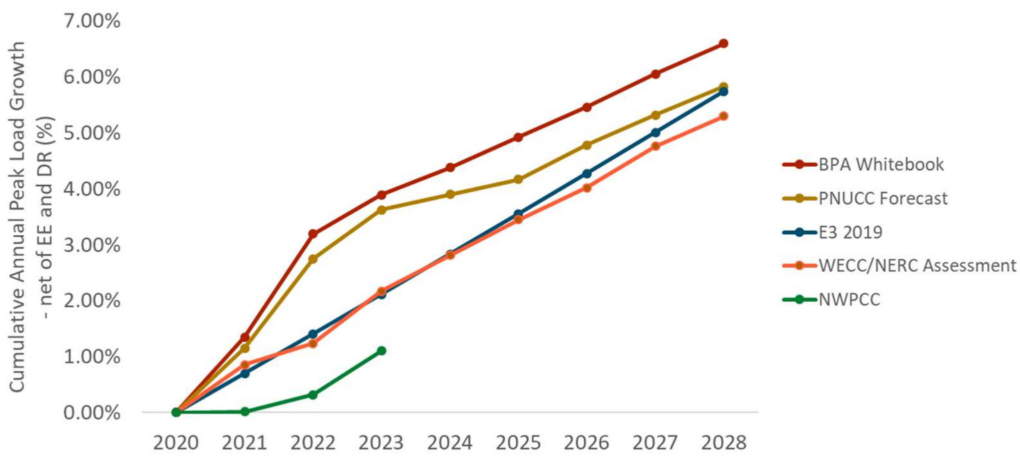
Figure 2: Reference, mid, and high case cumulative coal retirement scenarios - US Western Interconnection



Note: These coal retirement scenarios were developed by PNUCC. PNUCC researched announced and potential retirements from across WECC.

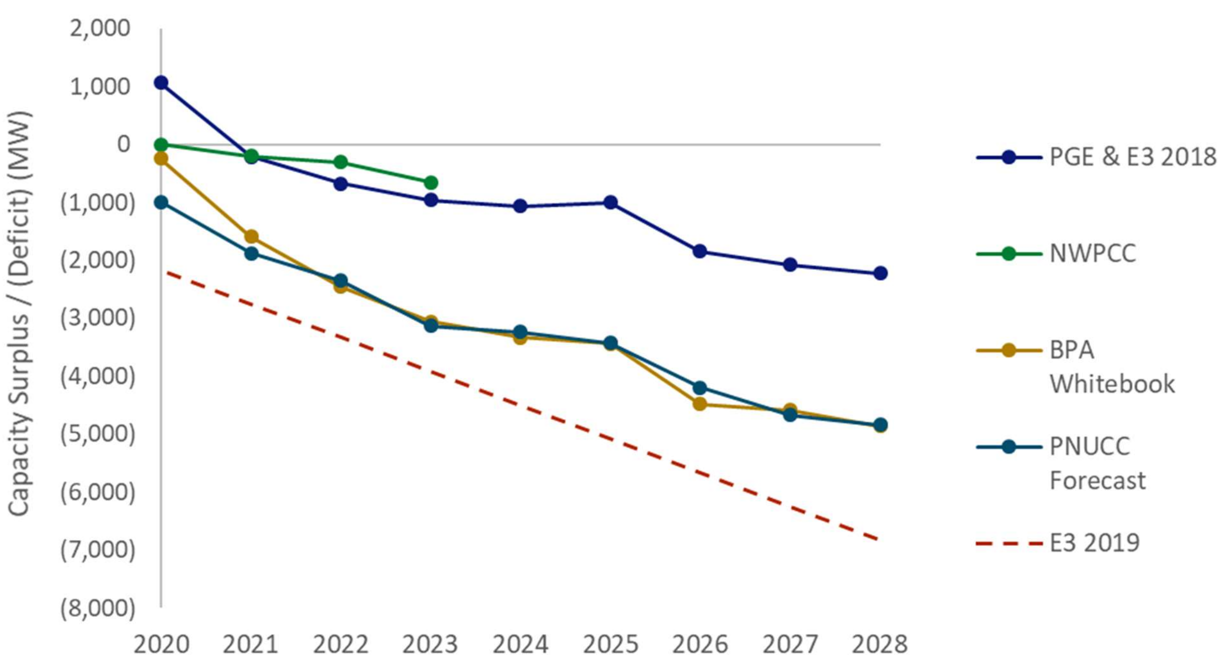
The second driver of future needs is load growth: even after accounting for the impacts of energy efficiency, loads within the region are forecasted to increase after being flat for much of the past two decades (Figure 3). The exact magnitude of that growth is uncertain, but at minimum new loads are expected in the near term from the data processing and agricultural sectors.

Figure 3: Load Growth in Regional Studies



These two key drivers lead to a consensus among these studies that that the Northwest is currently short on capacity or will be within two years. Figure 4 plots the trajectory of the Northwest's capacity position in each study over the coming decade.

Figure 4: Summary of the region's capacity position across the studies considered



Note: This figure shows the central case from each study. The E3 2019 line is a linear interpretation of results for 2018 and 2030 in that study. The work groups also considered WECC's report to NERC in its Long-Term Reliability Assessment. However, that study was excluded from this figure because it examines the load and resource balance of the NWPP region in the summer, where the other studies agree that the largest challenges for the region are in the winter.

Long-Term Resource Adequacy Considerations

Most recent studies of resource adequacy in the Northwest focus on the region's near-term planning and resource adequacy challenges. Those studies highlight thermal power plant retirements and load growth as two key trends that are driving the region towards a capacity deficit. However, in considering resource adequacy, it is important to consider longer-term trends. Particularly salient are recent legislative targets for electric supply decarbonization and broader policy-maker interest in economy-wide emissions reductions pathways. Both longer-term trends implicate the need for and design of a regional resource adequacy program.

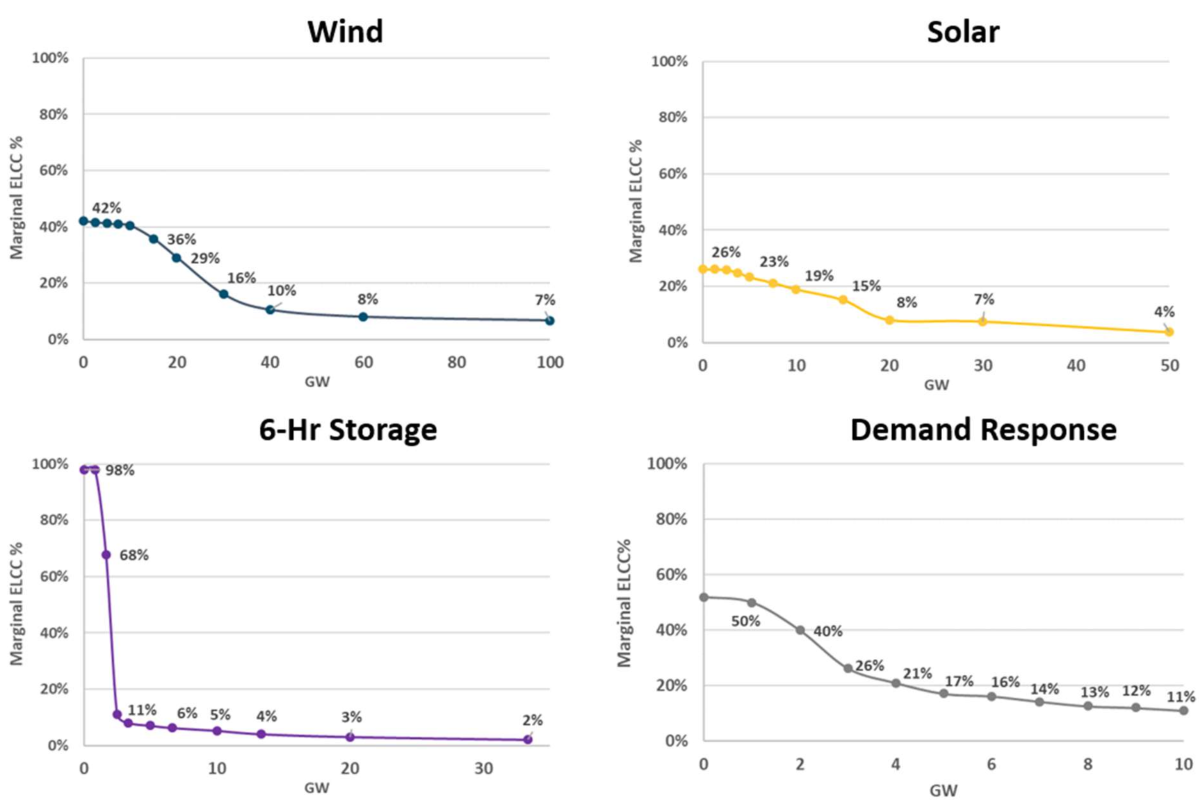
Electric Sector Decarbonization

The Northwest's electricity system is on a pathway to realize deep emissions reductions by mid-century. Commitments to electric supply decarbonization have been established by individual utilities (e.g., Idaho Power, Xcel Energy, and Avista) and codified in Washington's recently passed Clean Energy Transformation Act.

While most regional resource adequacy studies focus on near-term needs, E3's *Resource Adequacy in the Pacific Northwest* report examines the technical challenges of meeting long-term resource adequacy needs in a deeply decarbonized electricity system, using scenario analysis to study how the region's decarbonization goals will interact with its resource adequacy needs. The study primarily focuses on exploring how increasing reliance on carbon-free resources (predominantly wind, solar, and storage) will impact the region's remaining resource adequacy needs.

Of particular relevance to resource adequacy program design is the study's findings on the "effective load carrying capability" of renewables and storage resources within the region. Because of limitations on availability for renewables and constraints on duration of discharge for storage, these resources' capacity contributions are both typically less than 100% of their respective nameplate capacities and decline with increasing levels of penetration (Figure 5). Variable energy resources cannot provide a one-for-one substitute for traditional "firm" resources—for example, natural gas and nuclear power. However, they do provide meaningful contributions to resource adequacy, especially in combination due to interactive "portfolio" effects, e.g., solar being used to charged battery storage. It will be increasingly important to accurately assess the contribution of these resources as more and more of them are added to the system. A resource adequacy program would offer a reliable, consistent methodology to ensure that capacity contributions of these resources are being properly accounted for on a regional level.

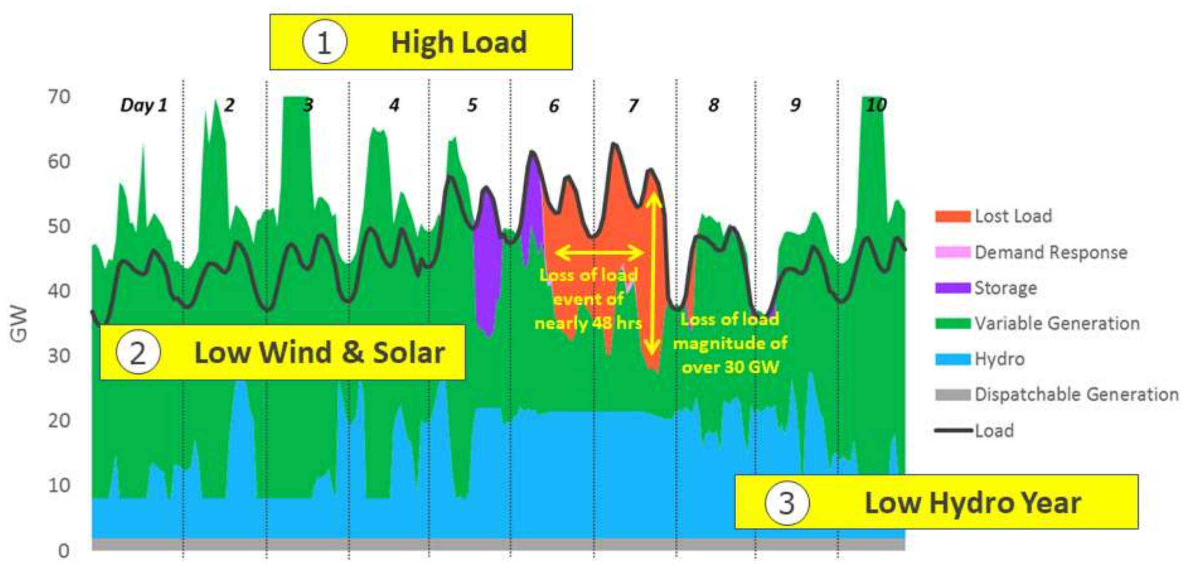
Figure 5: ELCCs of Wind, Solar, Storage and Demand Response from the E3 *Resource Adequacy in the Northwest* Report



Another significant finding, built on the recognition that non-firm resources are inherently limited in their contributions to regional resource adequacy, is that **some form of firm capacity will be needed**

within the region to ensure long-term resource adequacy, even out through 2050 on a deeply decarbonized system, and that the region will face a substantial reliability challenge in the absence of firm resources. That challenge becomes particularly acute in winter peak load events that occur during a region-wide period of low wind and solar output in a drought year. In the absence of firm resources, the region will need to build large amounts of renewables and storage capacity. However even with levels of renewables and storage that strain plausibility in terms of pace of deployment, the region's electricity system would still be vulnerable to large loss of load events. Figure 8 illustrates this vulnerability, showing a week with high loads, low renewables and in a drought year with limited hydro availability.

Figure 6: Example Lost of Load Event with No Firm Capacity



Note: This figure shows a cold week with low wind and solar output across the Northwest region in a drought year. Loss-of-load occurs despite a large variable generation overbuild, with accompanying storage, because there is not enough energy available to recharge the nearly 20 GW of storage assumed in this example.

The E3 study concludes that **a deeply decarbonized electric system in the Northwest is feasible but maintaining reliability at reasonable cost requires firm capacity**. A resource adequacy program would be a transparent means through which regional entities could asses when and where such firm capacity is needed in the Northwest.

Electrification

Recent studies in the region have examined different pathways to achieve economy-wide decarbonization at sub-state, state, and regional levels.[11] A common finding is that achieving decarbonization will require large amounts of electrification. In these studies, transportation electrification is the largest driver of annual load increases, while building electrification could cause a marked increase in the region's winter peak load. These load impacts are more speculative than electricity decarbonization mandates and goals, but their magnitude alone makes them a worthy consideration in the context of developing and designing a regional RA program.

Other Considerations for Resource Adequacy

There are several other issues that merit consideration in a discussion about maintaining resource adequacy in the Northwest, most of which are recurring themes identified in existing regional outlooks. They relate to these questions:

- To what extent should the Northwest count on imports of non-firm power from other regions in the Western Interconnection to meet its resource adequacy needs?
- How could internal transmission constraints within the region impact the ability to deliver generation to loads during constrained conditions?
- How could constraints on the natural gas pipeline system affect the availability of natural gas generating resources during peak periods?

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[11] Clean Energy Transition Institute 2019, Portland Gas and Electric 2018, Energy and Environmental Economics 2018, Evolved Energy Research 2017.

Reliance on the Western Interconnection

A key source of uncertainty in these studies are the dynamics of electricity trade between the Northwest and the rest of the Western Interconnection. The resource shift that is occurring in the Northwest (i.e., firm resources being replaced by variable resources) is also occurring elsewhere in the West, particularly in California. This could mean that historical experience may not be a reliable predictor of import capability in the future. The NWPCC *Pacific Northwest Power Supply Assessment Adequacy Assessment for 2023* examines several sensitivities on the level of available imports from California and finds that reduced imports would significantly worsen the region's resource adequacy position. **Error! Reference source not found.** shows the region's 2023 capacity deficit as a function of import capacity and load growth. Non-zero values indicate the magnitude of the capacity shortfall facing the region in 2023.

Table 2: NWPCC Power Supply Assessment, LOLP as a function of load growth and regional import capacity

Import (MW)	1500 MW	2000 MW	2500 MW	3000 MW
High Load	1650	1500	1100	600
Medium Load	1400	1050	650	50
Low Load	950	550	0	0

Note: This table is a reproduction of Table 3 from the NWPCC Pacific Northwest Power Supply Adequacy Assessment for 2023. Columns are equal to the expected available import capacity during peak hours, rows are different load growth scenarios

In 2018, E3 examined the amount of import capacity that could be available to the Northwest in its *Long-Term Assessment of Load-Resource Balance in the Pacific Northwest* study[12], conducted for PGE, by considering both historical imports and the ongoing shifts in load-resource balance in the CAISO system. E3 found that a combination of growing winter peak loads and retirements of thermal generation in the CAISO system could mean that the dependable winter import capacity from that region to the

[12] Study can be downloaded here.

Northwest could fall to zero as soon as 2023. Furthermore, E3 found that the dependable import capacity from CAISO was always below 2,500 MW post-2025, even in a scenario that includes the most favorable assumptions about winter resource availability in the CAISO system.

In-Region Transmission Constraints

Resource adequacy programs are typically designed to ensure an appropriate balance of loads and resources, but should also consider how key transmission constraints might affect the "deliverability" of generation to loads during peak periods. In 2019, the NWPP began to study this issue, examining the implications of the region's shifting resource mix on the region's transmission system over 5- to 10-year time horizons. NWPP found that over a 5-year planning horizon the available transmission capacity in the region is sufficient to deliver quantities of renewable energy expected over that timeframe. Over the longer term, NWPP found that transmission system upgrades will be needed to address regional load and resource imbalances.

Gas Pipeline & Transportation Constraints

The Northwest natural gas transmission and storage system delivers gas to buildings, industry, and electric generation. Building or contracting with natural gas generators for firm gas transportation service is one potential strategy that entities in the region could use to meet future capacity obligations.

The Northwest gas system has enough capacity today to meet forecasted load growth, though spare capacity in the system is limited. Given the tight regional gas picture, increased utilization of gas for resource adequacy purposes could require additional pipeline capacity to the region. Peak loads in the Northwest typically occur on cold days in the winter, so sufficient gas capacity will be needed to serve both gas generators and building heating needs on those days. An important consideration going forward is that gas pipeline operators in the region note that new projects take at least five years to complete.

Reliance on the gas pipeline network for "just-in-time" delivery of fuel to generators in the region also raises a question on the potential impact of contingency events on the gas system and corresponding downstream implications for electricity generation. While the electricity system is designed to withstand large contingency events itself, a contingency event on the gas system could simultaneously disrupt fuel supply to multiple generators within the region. A recent Wood Mackenzie and E3 study, commissioned by WECC, explored the potential for such events and concluded that "the ability of the gas/electric systems to handle both everyday variability as well as unforeseen disruptions becomes critical for ensuring energy security in the West." Indeed, the 2018 Enbridge pipeline outage illustrates that while the region's gas system can handle a single contingency, doing so may result in curtailment of non-firm loads.

The availability of firm fuel supplies is an important consideration for the design of a regional resource adequacy program. For instance, firm fuel, either delivered or stored, could be a consideration when qualifying the capacity contributions of thermal generators.

Challenges Under the Status Quo

The current patchwork approach to resource adequacy inhibits the ability of utilities, regulators, and stakeholders alike to fully understand the region's capacity position and how it relates to utility resource plans. In the absence of a centralized, transparent program to administer resource adequacy within the region, utilities either plan their systems to meet their own resource adequacy needs, irrespective of potential benefits from the greater regional grid; or they make assumptions on the availability of market capacity to contribute to their resource needs, which may not align with the amount of physical capacity actually available.

Relying on market purchases can be beneficial in that doing so captures the load and resource diversity across the region. However, **over-reliance on market purchases risks leaving the region capacity-short** if different utilities double-count identical resources in planning to meet their own peak needs—a particularly salient concern given findings that the region is or will soon be short on physical capacity. In March 2018, wholesale electricity prices at Mid-Columbia reached nearly $900/MWh during a high load and contingency event, an indicator that capacity scarcity conditions exist today.

The region's **planning challenges will be made more acute by impending thermal plant retirements**. Replacing thousands of megawatts of retiring capacity over the next five to 10 years will require proactive planning by utilities and careful oversight by regulators during a period when significant investments will be needed in a relatively short time frame. To the extent that uncertainties surrounding the status quo lead to deferral and delays of new investments, the region may face significant resource adequacy challenges.

At the same time, the region's increasing reliance on non-firm resources — particularly wind, solar, and storage — to meet clean energy policy goals will lead to heightened scrutiny of the analytical methods used to quantify their contributions towards resource adequacy needs. Attributing capacity values to a portfolio of non-firm resources will become increasingly complex due to interactive effects among those resources, and commonly used approaches based on rules of thumb will become difficult to justify. In that context, a standardized and transparent analytical approach to value non-firm resources could provide all parties with greater confidence.

Resource Adequacy Programs

Regional resource adequacy programs have been developed in other regions in North America, and throughout the world, to ensure future reliability. While ensuring resource adequacy is typically included in individual utilities' long-term resource planning processes, a resource adequacy program provides a regional framework to bring about near-term compliance with a given reliability standard. These programs enable load-serving entities (LSEs) to leverage load and resource diversity benefits by meeting their collective needs jointly rather than individually while also establishing a robust, standardized, and transparent view of regional loads and resources that could meet them. Resource adequacy programs also include compliance requirements to ensure that sufficient resources are contracted and perform as expected. These measures guarantee that participants do not make overly optimistic assumptions about the availability of supply, thereby avoiding potential future reliability challenges.

RA Program Functions

Resource adequacy programs exist in many forms throughout the world but generally perform the following functions[13]:

- Assess and allocate a regional capacity need
- Determine the capacity contributions of supply- and demand-side resources
- Monitor and enforce compliance
- Ensure resource availability during operations

This section explains how resource adequacy programs fill these various roles.

Assess and Allocate RA Need

RA programs define both a methodology for calculating reliability and a reliability standard to achieve. An RA program's capacity requirements are typically based on metrics (e.g., LOLE, LOLP, or EUE). RA programs often translate these targets into a PRM, which translates the standard into a capacity requirement expressed as a function of expected hourly peak demand. Consequently, RA programs must designate acceptable load forecasting techniques for participants' use or, alternatively, designate a single entity to provide load forecasts for all parties.

In addition to identifying a regional RA need, some programs feature sub-regional RA requirements to capture intra-regional transmission limitations. These programs, known as "Local RA" or "Zonal RA," vary in their implementation across regions. In general, local and zonal RA requirements restrict the

[13] Appendix B provides a broader view of the technical design elements of resource adequacy programs and a survey of how RA programs in the US, Canada, and Europe are designed.

quantity of resources that can be imported from other zones within the region administered under the RA program.

Once a regional RA need is established, programs allocate that need among member utilities. A common approach to RA allocation is based on the coincident peak load share for each utility, since doing so ensures that the sum of individual RA obligations equals the regional need.

Determine the Capacity Contribution of Resources

RA programs need to define the amount of capacity that is reliably contributed by each resource type, ranging from thermal resources to demand-side resources.

- **Thermal resource** capacity contributions are typically based on the resources' installed capacities. The amount of capacity these resources receive typically incorporate forced outage rates, either via a derate of the resource itself or as an increase in the required PRM level.
- **Variable energy resource** capacity contribution methods vary. Some programs use a calculation of the contribution of these resources during peak periods, while others use more rigorous approaches such as ELCC. Evaluating ELCCs for non-firm resources is a computationally intensive task. For instance, ELCC modelling must capture "interactive effects" where the ELCC attributed to any individual non-firm resource will depend on the composition of the rest of the portfolio, and specifically, on the other non-firm resources on the grid.
- **Hydro capacity** contributions are typically calculated based on historical flow conditions and the specific requirements for a given project. Given the Northwest's large hydro resources, this will be a critical element of any Northwest resource adequacy program.
- **Energy storage** capacity contributions are not addressed in a robust manner in most programs, but this will be of increasing importance as storage technologies increase their market penetration. An emerging practice is to use an ELCC approach, which captures the energy-limited nature of storage as a capacity resource.
- **Demand response** capacity contributions must also be determined. This could include programs for large industrial loads as well as programs that aggregate residential and small commercial demand response products, some of which have use limitations that may impact their capacity

contributions. ELCC may also be an appropriate approach to value demand response resources, though this practice is not yet mature.

- **Import capacity** contributions must be determined from resources located outside the footprint of the program. This may include requirements regarding identification of the physical resources, requirements for transmission service, and requirements to avoid potential double-counting of the same physical capacity. As summarized in **Table 3**, most U.S. RA programs require some combination of a contract with a physical resource (rather than 'unspecified' imports) and firm transmission rights in order for imports from outside their respective regions to count for RA purposes.

Table 3: Import Qualification Requirements by RA Program

RTO	Physical Resource?	Firm Transmission?
CAISO	No	No
ISO-NE	Yes	No
MISO	Yes	Yes
PJM	Yes	Yes
SPP	Yes	Yes

Note: This figure is adapted from a table found in comments from the CAISO Department of Market Monitoring (DMM). It describes how different regional markets treat imports.

Monitor and Enforcement Compliance

RA programs include mechanisms for participants to demonstrate that they have procured sufficient resources to cover their RA obligation. The exact mechanism to demonstrate compliance varies widely by jurisdiction: some jurisdictions use central capacity auctions to secure sufficient resources, while other programs rely on combinations of self-supply and bilateral procurement. These programs typically require load-serving entities to demonstrate compliance (i.e., they have secured enough resources to meet their RA need) by a certain date.

Resource adequacy programs also define the lead-time and commitment period of forward procurement that is required. The lead time can be as short as month-ahead or as long as four years ahead, and commitment periods vary from one month to one year. If a utility does not demonstrate compliance within a commitment period, it typically incurs a penalty based on the cost of a new capacity resource, usually with an incremental charge to discourage free ridership.

Ensure Resource Availability to the Market

The ultimate aim of a robust resource adequacy program is to ensure that sufficient resources are available to meet system needs in the operational timeframe. Resources that have committed to provide resource adequacy capacity typically have a “must-offer” obligation under which they are required to make the capacity available in the spot market. In the context of RTO/ISOs, this means submitting an offer into the day-ahead or real-time organized markets.

Achieving this objective in the context of a bilateral energy market, such as in the Northwest, would require developing new procedures to ensure that capacity that has been committed to meet an entity’s resource adequacy requirements is available to other program participants prior to being offered for sale to non-program counterparties. In this manner, resource adequacy capacity is made available first to meet the firm load needs of the entities participating in the resource adequacy program.

Benefits of a Resource Adequacy Program

The primary benefits of an RA program are **ensuring system reliability** and **enabling cost savings** to program participants. RA programs ensure sufficient resources are installed, contracted, and committed on a forward basis to reliably serve demand with a high degree of confidence. Cost savings accrue primarily as a result of unlocking the benefits associated with diversity in load and resources across the program’s footprint. This enables both planning to a lower coincident peak (compared to individual utility non-coincident peaks) and lower reserve margins (compared to margins required for individual utility systems). Additional cost reductions may accrue due to the dependable capacity contributions of required resources and the reduced transactional and operational costs resulting from allowing members to access excess capacity in neighboring jurisdictions.

Estimating the Financial Benefits of a Resource Adequacy Program to NWPP Utilities

The two principal financial benefits enabled by a planning reserve sharing program would result from (1) the ability to plan the system to the regional coincident peak, rather than the sum of utility non-coincident peaks; and (2) a potential reduction in the required planning reserve margin, due to the increased diversity of loads and resources. Assuming an avoided "capacity cost" of $120/kW-yr, these benefits are estimated to yield savings of up to $500 million per year. This calculation only illustrates the potential scale of benefits and includes a number of simplifications, the most notable of which is that it ignores the possibility that a portion of the savings may already have been achieved via bilateral contracts.

Example Benefits Calculation	
Planning to Coincident Peak	
Individual Utility Peak + 15% PRM	46,398
Regional Peak + 15% PRM	42,896
Reduction (MW)	3,502
Savings ($MM/year)	$420
Reduction in Regional PRM	
Regional Peak + 12%	41,777
Reduction (MW)	1,119
Savings ($MM/Year)	$134
Total Savings ($MM/Year)	**$554**

RA programs also provide a variety of secondary benefits, such as:

1. **Centralized Visibility:** A centralized program allows full visibility into the combined requirements of the footprint and available committed resource adequacy resources, enabling accurate identification of potential reliability risks before they materialize.

2. **Informed Resource Planning Decisions:** There can be significant costs associated with RA planning and procurement that includes inaccurate assumptions, particularly about the availability of imports, commitments of exports, and general load and resource conditions in the region. Lack of visibility can often cause entities to over-procure capacity, which directly increases costs, or to under-procure capacity, which could lead to loss of load. Regional RA programs allow member entities to make decisions that are informed by a regional view during their resource planning and procurement processes, improving their ability to meet their RA needs in the most cost-efficient way.

3. **Improved Market Signals:** The increased coordination and broader visibility gained by a regional Resource Adequacy program will better inform each member entity's procurement processes. This in turn will send more accurate economic signals to the forward bilateral capacity and firm energy marketplace, increasing the efficiency of the procurement process, properly identifying and incenting capacity investments when a need is identified, and thereby lowering costs to ratepayers.

4. **Single, Standardized Approach to Forecasting, Modelling and Analysis:** An RA program establishes a common methodology for establishing resource adequacy needs, qualification of resources, and common tools and modelling practices. Participating entities could leverage these approaches to refine their integrated resource planning processes.

5. **Platform for Further Coordination:** An RA program would provide a regional platform for entities to come together to discuss broader changes to the grid and make modifications to the program as the reliability needs of the region changes.

6. **Regional Support:** An RA program structure can provide valuable support to member entities including program monitoring and program oversight, ongoing objective modelling and analysis services, and objective input and documentation for the member entities' stakeholder processes.

A Resource Adequacy Program for the Northwest

The studies described above indicate that the Northwest is, or will soon be, short on physical capacity. In order to maintain reliability in near term, new generation resources must be developed. In the long term, the region will need to be able to maintain a fleet of generation resources with sufficient aggregate capabilities to maintain reliability in a high variable energy resource system. In this section, we explore examples of the broad range of capacity planning practices used in other regions or countries and how those might reasonably inform the development of a resource adequacy program suited to the unique qualities of the Pacific Northwest.

Relevant Examples of RA Programs Outside the Region

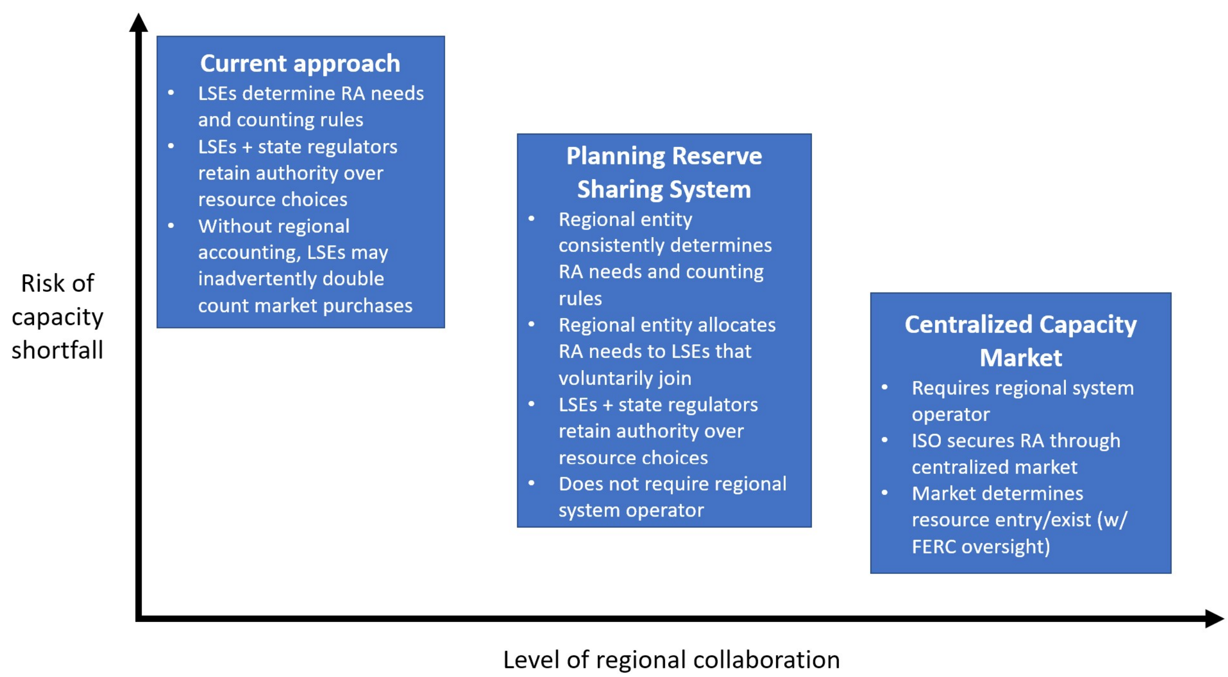
Perhaps the best example of a regional RA program that merits consideration by the Northwest is the Southwest Power Pool (SPP). Like the Northwest, SPP largely consists of vertically integrated utilities, with a mix of both public power and investor owned utilities. The SPP RA construct allows for a large amount of latitude for members to meet their adequacy needs. The SPP RA program serves primarily to assess regional and sub-regional RA needs, allocate those needs to utilities, and qualify participating resources. Capacity procurement is done entirely via self-supply or bilateral contracts. Importantly, despite being a FERC-jurisdictional RTO, SPP's RA governance structure is largely managed by representatives from member states' public utility commissions and the region's public power community.

The California RA program also provides another useful example of a bilateral program with established approaches to determining RA need, allocating needs among load serving entities, establishing common capacity counting methodologies (including the use of ELCC for wind and solar), and establishing compliance and enforcement requirements.

Strawman Design of a Resource Adequacy Program for the Northwest

The Northwest region faces a choice regarding its approach to resource adequacy as it anticipates further plant retirements and the challenges of uncoordinated planning. Figure 7 presents three pathways to a regional resource adequacy program. The first option, to continue current practice, relies on individual LSE planning processes. This would maintain local autonomy but, without a regional accounting of physical capacity, risks over- or under-procurement. A second option, a centralized capacity market, would create a centralized RA market in which federal oversight would determine resource entry and exit. This approach is not currently feasible given the absence of a regional system operator. Further, it may not be desirable given the region's institutional history and policy goals.

Figure 7: Potential Northwest Regional Approaches to Resource Adequacy



In between those two approaches is a voluntary planning reserve sharing system. This approach would designate a regional entity to measure participant RA needs on a consistent basis and allocate those needs to LSEs. LSEs would retain authority over resource decisions, subject to review by their state or local regulators.

The key functions of a Northwest RA program might include:

- Developing a centralized administration and accounting of regional resource adequacy. This would include conducting reliability studies, determining regional and zonal PRMs, allocating capacity procurement responsibility to LSEs and maintaining an accurate accounting of both regional and LSEs respective RA positions.
- Implementing a robust capacity qualification approach that accurately captures the capacity contributions of resources including hydropower, wind, solar, energy storage and demand response.
- Establishing a market structure that enables LSEs to self-supply or acquire regional resources bilaterally.
- Developing an approach to manage the operational aspects of an RA program that does not fall within an existing RTO. In that respect, a Northwest RA program will be different from all other regional programs currently in place in the United States.

RA Program and NW Planning Governance

A Northwest RA program will require a governance structure that suits the region. Several foundational issues must be addressed, including the determination of the entity to house the program, the process for designing specific program elements, how the program is enforced, and whether a separate program monitor is required to ensure compliance. A mechanism for ongoing member and stakeholder engagement must also be established. These issues are likely to be particularly challenging in a footprint that spans multiple states, multiple Balancing Authorities and transmission providers, and is not in an RTO/ISO.

This report does not attempt to resolve these issues. Instead, they are meant to serve as points for further discussion as a regional RA program is developed.

Overlap Between a Resource Adequacy Program and Integrated Resource Planning

A resource adequacy program would not replace utilities' ongoing integrated resource planning efforts or the adequacy assessment component of the IRP. In fact, utility IRPs and a regional RA program would have distinct roles and responsibilities. Key differences between an RA program and utility IRPs include:

- **Planning timeframe differences.** Utility IRPs typically look out 10 to 20 years, while resource adequacy programs tend to focus on a one- to four-year timeframe. The longer planning horizon of IRPs is important for assessing long lead time resources and to articulate utilities' plans in the face of a changing power system landscape. For example, utilities may examine a wider range of future load forecasts in their IRPs than an adequacy program or use different assumptions about the impact of climate change on loads and resources over the long-term. However, if a resource adequacy program extends beyond three years, it may overlap more with IRPs given that IRP action plans typically range from two to five years out.
- **Non-adequacy requirements.** IRPs incorporate a multitude of local policy and regulatory directives regarding environmental standards, resiliency goals, conservation potential, energy affordability, customer equity, avoided cost determination and other critical issues. A resource adequacy program does not address these utility and state specific non-adequacy requirements.
- **Utilities may use multiple planning standards.** Utilities may continue using one or more planning standards they have established for their individual utility's resource characteristics and IRP approach. A utility that volunteers to participate in a resource adequacy program will need to meet standards set in both its IRP process and by the regional program.

Despite these differences, a well-designed resource adequacy program could supplement and inform IRP process. For instance, a resource adequacy program may be incorporated into the short-term IRP action plans required by many state commissions. Methodologies and assumptions used in IRPs may also inform the requirements of a successful resource adequacy program.

Conclusions and Next Steps

The Northwest faces an impending shortfall in firm capacity and may not have a planning framework in place to efficiently respond to that challenge. In that context, a regional RA program could offer ratepayers two key benefits. First and foremost, an RA program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Second, a regional RA program could also produce cost savings by allowing utilities to rely on other entities' resources rather than building their own at higher cost.

A Northwest RA program would need to be designed with the region's unique characteristics in mind. The program envisioned in this document is a voluntary one, where the procurement decisions of individual utilities are left to their own respective integrated resource plans (IRPs). And, like other RA programs across the U.S., state regulators and public power leaders would play an active role in its formation and governance.

Given the Northwest's evolving resource mix and deteriorating capacity position, NWPP members have committed to further exploring a regional resource adequacy program. NWPP members view such a program as a key step to ensure that the Northwest electricity system remains reliable as it transitions to a much lower GHG emission resource mix. That transition is accelerating, so NWPP members view the creation of a voluntary regional RA program as a matter of great urgency.

NWPP members intend to develop such a program with substantial stakeholder input. To that end NWPP members will convene a Stakeholder Advisory Committee. The goal of this committee will be to ensure that a broad spectrum of interests from throughout the region have a voice in the RA program's development. The committee will meet on a regular basis to provide NWPP members with input on issues ranging from program design to governance.

Given the urgency of the region's capacity challenges, NWPP members intend to move purposefully through the program design phase. If all goes well, NWPP members have a goal of initiating a regional program by the end of 2021.

Appendix A: Resource Adequacy Attributes and Terminology

This appendix describes the key terminology related to resource adequacy and the attributes of a resource adequacy program.

Resource Adequacy Terminology

Resource Adequacy Metrics Versus Resource Adequacy Programs

A Resource Adequacy metric is a means of measuring resource adequacy. Currently, metrics used by utilities and load-serving entities (LSEs) vary substantially both across the country and within the Northwest. A 2018 NERC technical reference report[14] did, however, publish standardized *definitions* of various adequacy metrics and identified standardized metrics that it will require its regional entities to use. Key RA metrics include:

Loss of load expectation ("LOLE", units of days/yr): average number of days per year with loss of load (at least once during the day) due to system load exceeding available generating capacity

Loss of load events ("LOLEV", units of events/yr): average number of loss of load events per year, of any duration or magnitude, due to system load exceeding available generating capacity

Loss of load probability ("LOLP", units of %): probability of system load exceeding the available generating capacity during a given time period

Loss of load hours ("LOLH", units of hours/yr): average number of hours per year with loss of load due to system load exceeding available generating capacity

Expected unserved energy ("EUE", units of MWh/yr): average total quantity of unserved energy over a year due to system load exceeding available generating capacity

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[14] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

A Resource Adequacy (RA) program is a regulatory planning framework that aims to ensure there are enough resources available to serve peak electric demands under most conditions within a defined regional footprint. While a standardized RA metric or set of metrics is a necessary component of an RA program, an RA program is much broader. RA programs also require:

1. **An RA standard** - a line that separates adequacy from inadequacy for whatever RA metric is being used.
2. **An RA time horizon** - these range from month-ahead to four-years ahead in North American RA programs, though one-year ahead is a typical timeframe.
3. **Policies and procedures for demonstrating resource adequacy** – these include rules around how a resource can be counted, how imports and exports are counted, and frequency with which RA must be demonstrated.
4. **An enforcement mechanism** - for example, CAISO has the authority to procure backstop capacity under California's RA program and allocate costs to deficient LSEs.

It is important to note that, because RA programs typically require that resource adequacy be demonstrated over a shorter time horizon than the IRP process, a RA program does not replace the need for long-term planning. A more detailed discussion of the interactions between RA and IRP can be found in Appendix D.

Resource Adequacy, Reliability and Reliability Standards

Resource adequacy refers to having enough resources – generation, efficiency measures and demand-side actions – to serve loads. NERC defines it as "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components”.[15]

Operating reliability refers to whether those resources will perform when needed. NERC defines operating reliability as “the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.”[16] Operating reliability (sometimes also referred to as security) is achieved largely by having enough reserves that can be brought online quickly in the event of a system disruption and through controls on the transmission system.

Reliability standards are generally focused on ensuring operating reliability and generally do not address resource adequacy. Reliability Standards are developed and administered by NERC and associated regional entities (i.e. WECC). In contrast, resource adequacy programs are developed and administered by either regional entities or state regulatory bodies.

Importantly, NERC defines the reliability of the interconnected bulk power system in terms of both resource adequacy and operating reliability.

Resource Adequacy Versus Resource Sufficiency

Resource adequacy ensures enough resource capability on a year-ahead and potentially multi-year ahead basis to serve peak demand under all but the most extreme conditions. Resources needed to meet an RA standard can either be procured bilaterally or through a centralized market mechanism. This procurement happens in timeframes ranging from months to years in advance of an operating day or hour.

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[15]2018 Long-Term Reliability Assessment, North American Electric Reliability Corporation, December 2018, p. 5. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Resource Sufficiency ensures enough resource capability for each hour on a day-ahead or current day basis. This means the LSEs must have the combination of capacity, contingency and balancing reserves available to operate reliably and meet load obligations. A resource sufficiency framework is typically applied through a voluntary centralized market with multiple Balancing Authorities (BAs) that maintain their NERC reliability responsibilities to ensure fairness and equity among each BA. Applying a common standard of what resource capabilities each BA is responsible for having available and committing to the market ensures that BAs are not "leaning" on the market and their neighbors to meet their capacity and energy needs.

Resource Adequacy Categories: Setting Requirements, Qualifying Resources, and Treatment of Imports/Exports

Resource adequacy can be categorized into different typologies by the supply attributes that are required of a resource portfolio to reliably serve demand. The typologies include Capacity RA, Flexible RA and Energy RA. Each type or category of RA has different, though inter-related, requirements that must be considered and planned for separately, and evaluated using differing metrics.

Capacity Resource Adequacy

Capacity RA programs focus on ensuring that forward planning and procurement processes secure sufficient generating capacity to reliably meet a system's forecasted peak demand. Most RA programs focus primarily, or exclusively, on Capacity RA.

Setting Threshold Requirements for Capacity RA: Capacity RA requirements are set by determining a system's forecasted peak demand in a year, season, or month, using a pre-determined peak requirement forecasting methodology, and generally adds a planning reserve margin to cover (1) uncertainty in the peak demand forecast, (2) operating reserve requirements, and (3) generation outages, derates or other limitations. An alternative approach to (3) is to incorporate outages, derates and other limitations in the quantity of RA capacity each resource is eligible to provide. Appendix B describes how different RA programs across North America and the world approach setting their RA requirements.

In addition to system level requirements, RA programs typically set Zonal RA or Local RA requirements. These requirements follow from studies of resource deliverability, that is the ability of resources from outside a given zone to reliably provide peak capacity. A typical practice to assess the deliverability is to conduct an "n-1-1" study of the ability of a region's transmission system during contingency events. Zonal RA requirements typically cover relatively large geographies. For instance, MISO and SPP zones largely conform to state borders or utility service territories. California's Local RA program includes more narrowly defined geographies, specifying 10 sub-areas of the state that experience import capability constraints and therefore require local resources to be resource adequate.

Resource Qualification for Capacity RA

Capacity RA programs use various methodologies for qualifying different resources types to contribute dependable capacity. These methodologies include elements like the actual historic capability of resources during peak periods and the effect of ambient temperature on output. Under most programs, expected unit outage rates or other sources of unavailability are also considered. For thermal resources, metrics such as Unforced Capacity (UCAP) are used to estimate the amount of capacity that may be relied upon during periods of system stress, taking into account the unit's historic forced outage rate and unavailability rate under the forecasted ambient conditions. For variable energy resources, many programs use an ELCC metric when determining how much capacity credit should be given to variable energy resources.

Treatment of Imports/Exports for Capacity RA

Regional RA programs are not islanded and can rely on imports from non-participating jurisdictions to meet peak capacity needs. However, regional RA programs have more limited visibility into the status and deliverability of generating resources located outside of their footprint. The implication is that that regional RA programs must determine how imports from outside the footprint are treated towards meeting peak capacity needs, with a goal of ensuring that imported capacity is available and deliverable when called upon.

Formal resource adequacy programs in other regions take various approaches to address the eligibility and verification of imports including setting transmission and scheduling requirements, must offer obligations, and data sharing requirements. For example, SPP requires that any imports in the SPP region contracted since the implementation[17] of the RA program must be fully pseudo-tied[18] and delivered on firm transmission in order to count towards their RA program. Similarly, RA programs also include rules with respect to the treatment of firm exports. These rules ensure that resources that have been committed outside a region and are non-recallable are accounted for in determining the capacity needed required for an adequate system.

Flexible Resource Adequacy

Flexible RA focuses on ensuring that a resource portfolio has a sufficient amount of operating flexibility such that it can respond to variations and uncertainty in load and variable energy resource output throughout an operating day. Flexible RA has gained attention recently, as the increasing ramping requirements associated with the penetration of renewable generation in California has stressed the ability of generating portfolios to match the system requirements. For example, a 1000 MW resource portfolio may be *capacity* resource sufficient to meet an 800 MW system peak demand, but maybe *flexibility insufficient* if the generation fleet can only increase output by 175 MW per hour, but the potential upward change in load combined with potential downward change in variable energy output (i.e. the “Net Load” change) may change by as much as 250 MW from one hour to the next. However, it is important to recognize that variable energy resources are also dispatchable, so flexibility needs can be met by, for instance, curtailing some solar output during late-afternoon hours.

Setting Threshold Requirements for Flexible RA

[17] Different rules were applied to import contracts that were entered into prior to the implementation of the RA program.
[18] This means that a resource is located within one BA, but is operationally controlled by a different BA.

Flexible RA requirements are set by evaluating the largest expected ramp need over one or more defined operational period. For example, it may be determined that the largest ramp expected for a system over a 15-minute interval is 200 MW, and the largest expected ramp over a 3 hour period in a day is 1800 MW, and thus separate Flexible RA requirements could be set according to those two differing requirements.

In practice, California's current Flexible Capacity RA requirement – the only such program in operation today — specifies that the resource portfolio must be able to meet the maximum three-hour net-load ramp for the system for each month using the forecasted minute-to-minute system net-load. However, the CAISO and CPUC have been working with stakeholders to potentially further refine those requirements to ensure 5 minute, 15 minute, and inter-hour ramping needs can also be defined and requirements set to ensure the Flexible RA portfolio can respond to net load changes across various time intervals within an operating day.

Resource Qualification for Flexible RA

Resources are qualified for providing flexible RA largely based on their total movement capability and ramp rates over the duration interval defining the requirement. For example, the CAISO calculates an Effective Flexible Capacity (EFC) quantity of each resources using the above parameters applied to a 180-minute (3 hour) ramping interval, while also differentiating between generators based on whether the start-up time of a unit is more or less than 90 minutes.

Treatment of Imports and Exports for Flexible RA

In a similar fashion to Capacity RA, imports can potentially qualify to meet Flexible RA requirements, provided that, in addition to the transmission, scheduling and other requirements that would apply to Capacity RA, those resources are able to meet specific flexibility requirements. This may include, for example, dynamic scheduling rights on the applicable transmission paths. Similar to Capacity RA, any capacity or flexible capacity commitments to serve demand or flexibility requirements outside of the RA footprint must be accounted for when evaluating Flexible RA requirements.

Energy Resource Adequacy

Energy RA refers to the need to ensure that there is sufficient fuel supply, for energy constrained resources, to meet demand over peak periods. For example, in the case of thermal resources, an Energy RA program would ensure there is enough gas supply available to meet peak demand across a winter or summer peak demand period. Similarly, in the case of hydro resources, water supply would be considered.

It is important to note that no Energy RA programs exist today. Instead, the energy-limitations of resources are considered in the capacity qualification process in Capacity RA programs. That said, the Northwest may wish to eventually consider the merits of developing a separate Energy RA type or category given the amount of energy-limited hydro resources in the region and concerns associated with gas supply limitations or disruptions in the region.

The parameters associated with an Energy RA program are likely very different than for a Capacity RA program. For example, for Energy RA, the peak period may be defined as a month or a season, versus the single highest peak hour(s) of the season that would be used to determine requirements under a Capacity RA framework. Assumptions on the availability of energy supply from variable energy resources over the defined energy period under an Energy RA framework would also necessarily be very different from the assumptions of variable energy resource output in a defined peak hour(s) under a Capacity RA framework. And finally, it may be appropriate to assume that the availability of market energy supply over a month or season from other regions may be substantially different for an Energy RA program, whereas the assumptions on the availability of short-term market *capacity* supply from other regions under a Capacity RA program may be assumed to be zero during peak periods.

Setting Threshold Requirements for Energy RA

Given the dominance of hydro generation in the NWPP footprint and recent events that have highlighted the region's sensitivity to gas supply disruptions, consideration might be given to the development of an Energy RA evaluation that would leverage pre-existing hydrological forecasting resources used in the region, combined with a gas infrastructure and supply review.

Resource Qualification for Energy RA

An Energy RA program would have less emphasis on individual resources and would focus more broadly on the energy availability for each participating entity as well as the region as a whole. In this way an Energy RA program would use hydrological forecasting processes, in the case of hydro resources, and fuel supply availability forecasting in the case of thermal resources, to evaluate the expected energy surplus or shortfall on both an entity level as well as a footprint level.

Treatment of Imports/Exports for Energy RA

In contrast to imports associated with Capacity RA, which require a higher threshold of visibility and deliverability to ensure that imports are available during peak load periods, imports related to Energy RA requirements would be less stringent, as energy requirements could be met from energy only sources, and could be accumulated during off-peak periods to meet seasonal or annual requirements. Exports related to firm energy commitments outside the RA would also have to be accounted for to ensure all energy obligations can be met.

Which RA products are relevant for the Northwest?

Given the region's emerging capacity short position, the most appropriate near-term focus of the ongoing NWPP RA effort is the development of a Capacity RA Program. Flexible and Energy RA requirements are unlikely to be needed in the short-term but are worth considering in the future as the region's energy transition continues.

Other Resource Adequacy Categories

In addition to the three main RA categories above, other forms of resource adequacy, related to inertia and frequency response characteristics of the system, have also gained attention in recent years. Whereas traditional dispatchable generation sources have characteristics well suited for frequency regulation and response, the changing resource mix arising from the penetration of renewables have changed the responsiveness of the power system to frequency changes, prompting regulatory bodies to develop frequency response regulatory standards. In the future the NWPP may choose to include consideration of inertia and frequency response RA streams into the NWPP RA framework.

Table of RA Design Elements

The structure of a resource adequacy program follows from several different design elements. This table lists and describes these elements.

Element / Issue	Description
1. Governance	The agency to that oversees the development and implementation of the RA program.
2. Program Design	The entity that is responsible for the specific resource adequacy tariffs or requirements, often a market operator
3. Program Operation	The entity that operates and enforces the RA Program
4. Program Monitoring	The entity that monitors the RA Program
5. Adequacy Objective / Metric	Either a stipulated PRM or a probabilistic figure like LOLE, LOLP or EUE.
6. Demand Forecast Metric	This is usually a forecast which estimates either the coincident, or non-coincident peak demand for the region.
7. Planning Reserve Margin ("PRM")	The amount of capacity required on top of '1-in-2' peak loads for a region to be considered resource adequate.
8. Lead Time For Showings (Forward Period)	The time period between the procurement of capacity and the operational period.
9. Duration Of Obligation / Showings (Commitment Period)	The length of the capacity commitment.

10. Resource Eligibility	Which resources can participate in the RA program.
11. Qualification Requirements	Asset-specific details required to qualify an asset for the RA program.
12. Delisting	Delisting requirement for assets from the RA program
13. Capacity contribution determination	Value establishes the capacity contribution of asset, which is the amount of capacity an LSE can purchase from an asset.
14. Planned and forced outages	The treatment of outages for capacity contribution or PRM setting purposes.
15. RA Import Qualification and Treatment	Requirements for an LSE to purchase capacity from a generation asset outside the regional RA program.
16. Export Obligations	Capacity obligations (e.g. firm energy exports) outside the RA footprint
17. Non-RA Import Assumptions	Determine non-RA imports (spot market purchases) from outside the RA footprint during peak periods
18. Access to RA Pooled Resources	The mechanism by which a member entity can access the RA program's pooled capacity arising from diversity in demand and supply.
19. Deliverability (Transmission Adequacy)	The ability of resources inside and outside an RTO, BA, or LSE's footprint to deliver supply to load.
20. Resource Cost Assumptions	For purposes of calculating costs and benefits, cost assumptions must be made for any required capacity additions or savings

21. Fuel Supply	Eligible resource fuel sourcing requirements, and/or considerations for gas, coal and hydro generation.

Appendix B: Review of RA programs elsewhere in the United States and World

Existing regional capacity sharing systems vary considerably, ranging from centrally administered bi-lateral markets within a single state (such as California's Resource Adequacy program) to centralized capacity markets spanning multi-state wholesale electricity markets (such as PJM's Capacity Market). Additionally, there are some jurisdictions that rely solely on energy-markets to incentivize resource adequacy, most notably ERCOT in the US.[19] The following sections summarize the approaches and key features of various regional approaches, based on the following key design elements:

Market structure: bilateral, centralized, or energy-only.

Administration: who administers the regional resource adequacy approach (e.g. state regulatory agency, ISO/RTO, etc.).

RA requirements: system, local, or flexible requirements.

Planning reserve margin: % above median peak and how it was derived (e.g. through an LOLE study). Regional systems generally use the coincident peak for the region when determining regional capacity needs, which is typically lower than the non-coincident peaks of each LSE on their own.

Forward period: how far ahead LSEs (or the market) must ensure resource adequacy.

Resource commitment period: how far ahead resource commitments must be made.

Capacity accreditation: certifying the reliability contribution from different types of capacity. May be for summer, winter, or both. Unique methods can be used for hydro and renewable resources (such as ELCC analysis).

[19] While energy-only markets like ERCOT technically have no resource adequacy obligation, they are included in this report to illustrate how energy-only markets address resource adequacy through sole reliance on energy market outcomes.

Price formulation approach: how capacity prices are formed, such as bilaterally or through a centralized process via a vertical or sloped demand curve.

Performance incentives: how to incent performance by capacity resources, such as incentive structures for under- or over-performance.

Market power mitigation: how to prevent the exercise of market power or unfair price manipulation.

Deficiency/backstop mechanisms: how to address capacity deficiencies through deficiency payments and/or backstop procurement mechanisms should forward capacity obligations fail to ensure LSE or regional resource adequacy.

Centralized Capacity Markets

Centralized capacity markets function like other organized wholesale markets, whereby centralized auctions set forward prices based on supply bids and a demand curve. These markets function through a single market platform that provides revenue for all regional capacity resources that clear the centralized auction. Auctions are transparent, allowing for price discovery. The use of sloped demand curves ensures some payments are made to incent generators to remain in the market, while providing higher capacity payments as the region nears its planning reserve margin. These markets are used in Eastern RTOs, including the New York Independent System Operator (NYISO), the PJM Interconnection (PJM), and ISO New England (ISO-NE). MISO also operates a central capacity market, but participation is voluntary. While many similarities exist, each RTO takes its own approach to capacity market design, such as different penalties for non-performance, approaches to demand curve design, and strategies to mitigate market power.

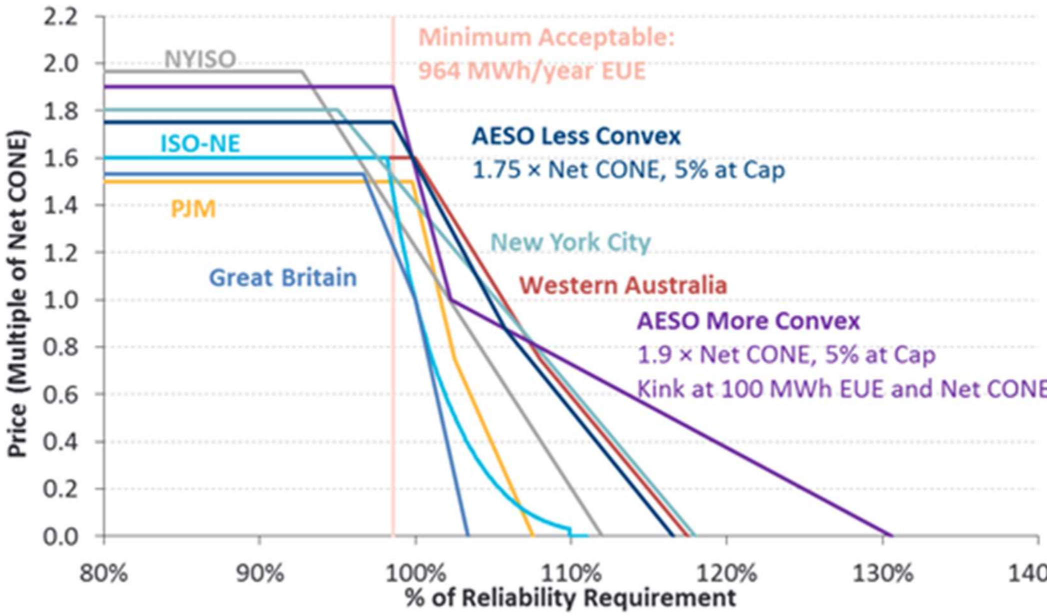
Northeastern US Capacity Markets (ISO-NE, NYISO, PJM)

There are three RTOs – ISO-NE, NYSIO, and PJM – that serve the Mid-Atlantic and Northeastern US and feature many similarities in their approach to resource adequacy. All three markets maintain centralized capacity markets for system and zonal resource adequacy, administered by the RTO through a mandatory auction process.[20] They all seek to maintain a 16-17% planning reserve margin through use of a sloped demand curve. In a market-based RA structure, maintaining a market value for capacity above the PRM is critical to incentivize efficient market entry/exit. A sloped demand curve accomplishes this, while also reflecting the declining value of capacity once the PRM is reached. Capacity prices are capped at ~1.5x the net CONE and the demand curve declines to zero as the system becomes saturated with capacity, informed either by percent above the PRM or by an LOLE metric directly (i.e. the incremental reliability benefit of additional capacity nears zero). Figure 4 shows how this generalized sloped demand curve approach applies to various electricity markets.

Figure 12. Sloped Demand Curve approaches in various wholesale electricity markets[21]

[20] NYISO actually operates three auctions: six-month ahead for summer/winter periods, monthly auctions 14 days before each month, and spot auctions 2-4 days before each month. The first two auctions are voluntary while the last auction (the spot auction) is mandatory.

[21] Source: AESO, Calculation of Demand Curve Parameters.



Forward auction periods range from months-ahead (NYISO) to three years out (ISO-NE and PJM), while resource commitment periods range from months to a year-ahead. There are differences between the markets in their approach to market power mitigation, which generally focus on if and how to impose price floors or caps. PJM and ISO-NE have strong pay-for-performance based performance incentives; for instance, PJM's performance credit is +/- $3,000-4,000/MWh based on net performance during emergency events. Regarding capacity accreditation of resources, all three markets utilize historical averages for wind and solar resources.

While each RTO generally relies on capacity prices to ensure regional resource adequacy and incent market entry as needed, each market takes a different approach for addressing regional deficiencies if capacity auctions do not yield sufficient resources. PJM can hold an additional "Reliability Backstop

Auction" to secure additional capacity for a term of up to 15 delivery years.[22] ISO-NE generally address shortfalls or changes in load resource balance via reconfiguration auctions that update the capacity market results between the initial three years out auction and the actual operating year. NYISO operates a 10-year ahead Reliability Planning Process, whereby long-term RA needs are analyzed and the ISO can solicit for backstop solutions to fill any supply gaps identified[23]. For shorter-term needs, NYISO can use its Reliability Must-Run (RMR) process to maintain specific generators for two-years, with a possible two-year extension, until market-based or transmission solutions can mitigate the reliability concern.

	PJM	ISO-NE	NYISO
Market Structure	Mandatory auction	Mandatory auction	Mandatory auction
Administration	ISO	ISO	ISO
Requirements	System and local	System and local	System and local
PRM	16% PRM (based on LOLE study)	16.8% PRM (based on LOLE study)	16.8% PRM (based on LOLE study)
Forward Period	3 years w/ incremental auctions	3 years w/ incremental auctions	Months-ahead
Resource commitment period	1 year	1-12 months	1-6 months
Capacity accreditation	Summer-based Hydro: based on historical head and/or streamflow during summer test Wind/solar: historical avg. capacity factors during summer peak	Summer and winter seasonal rating Wind/solar: historical avg. during summer/winter peak hours	Summer and winter seasonal rating Wind/solar: historical avg. during summer/winter peak hours

[22] For additional details, see PJM's Open Access Transmission Tariff, Attachment DD, Section 16.

[23] NYISO is currently finalizing its 2019-2028 Comprehensive Reliability Plan, with the April 2019 draft noting the ISO has sufficient resources for resource adequacy across the entire 10-year period, though evolving policy drivers are noted as risk factors for the region.

Price Formulation	Sloped demand curve (uses RA requirement and net CONE)	Sloped demand curve (uses LOLE and net CONE)	Sloped demand curve (uses RA requirement and net CONE)
Performance Incentives	Strong; Capacity performance product focused on emergency events	Strong; Pay-for-performance	Weak; No performance mechanism but forced outages reduce capacity
Market power mitigation	Minimum offer price set at net asset class CONE	Minimum competitive prices; requests to exit are reviewed	Market power tests determine when to impose offer floors and caps
Deficiency / backstop mechanisms	Reliability Backstop auction if all 3 forward years are >1% below PRM	n/a (Addressed through reconfiguration auctions)	Short-term: RMR option available Long-term: 10-yr reliability planning process

Ontario

Ontario recently initiated the creation of a forward capacity market to address its resource adequacy needs. This effort is led by the Ontario Independent Electricity System Operator (IESO). The auction process will work to address incremental RA needs beyond existing contracted and regulated resources.

IESO issues an annual Reserve Margin Requirements report, using a reliability study to identify the PRM required to maintain an annual LOLE of no more than 1-day-in-10-years (or 0.1 days/year). The latest report identifies a 17.4% target PRM in 2019, though it ranges as high as 21.7% for the 2019-2023 period studied.[24] IESO also conducts a five-year forward Reliability Outlook to assess existing system capacity

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[24] IESO, *Ontario Reserve Margins Report, From 2019-2023*, December 2018.

against the target PRM. The Reliability Outlook informs outage scheduling and whether generators can export their capacity to neighboring regions. In this assessment, wind and solar capacity contributions are assessed based on the median of their historical output during peak demand (where peak demand is measured as the top 5 contiguous demand hours over the last 12 months). The capacity contribution of hydro generators is assessed based on their historical output during summer weekday peak demand periods.[25] IESO also conducts an "extreme weather scenario" as a sensitivity that uses the driest hydro year in the historical dataset. Wind, solar, and hydro capacity contributions are all calculated on a monthly basis.

IESO also conducts an annual planning process that includes a 20-year forward resource adequacy assessment for the summer and winter seasons. This assessment informs incremental resource procurement needs for resource adequacy. As part of its Market Renewal Project, Ontario is implementing a year-ahead "transitional capacity auction" to expand their demand response auction process to other resources and is currently designing an "incremental capacity auction" that will secure capacity resources on a 3.5 year-ahead basis. The capacity auction will secure resources for both summer and winter peak demand needs based on a co-optimized auction. Similar to other existing capacity markets in North America, IESO will develop a sloped demand curve and the auction will address both system as well as zonal capacity needs. Since the market is co-optimized for summer and winter RA needs, two sloped demand curves will be generated (one for each season), as shown in Figure 5. IESO's summer and winter sloped demand curves (illustrative). Resources receiving capacity payments must offer into the IESO energy markets and receive incentive payments (or non-performance charges) based on their actual availability to the market.

Ontario (Canada)

[25] Hydro, wind, and solar capacity counting approaches are detailed in the *Methodology to Perform the Reliability Outlook*.

Market Structure	Mandatory auction
Administration	ISO
Requirements	System and local
PRM	17.4% PRM (based on LOLE study)
Forward Period	3.5 years w/ incremental auctions
Resource commitment period	1 year
Capacity accreditation	Summer and winter seasonal rating Hydro: historical output during driest year on record Wind/solar: historical output during peak hours
Price Formulation	Sloped demand curve (uses net CONE and seasonal LOLE)
Performance Incentives	Strong; Capacity payment adjustments based on availability vs. commitment
Market power mitigation	Must offer requirements for existing resources; pivotal supplier test determines price cap
Deficiency / backstop mechanisms	n/a (Addressed through rebalancing auctions)

Alberta

In 2017, the Government of Alberta directed the Alberta Electricity System Operator (AESO) to initiate the design of a capacity market, with auctions commencing in 2019 for first delivery in 2021.[29] AESO's impetus for creating a capacity market was based on concerns around revenue sufficiency and revenue certainty in an electricity system transitioning from coal to renewables and natural gas. AESO concluded that raising its energy market price cap from $1,000/MWh to $5,000/MWh may provide sufficient revenue for reliability resource needs, but that a lack of revenue certainty and expected volatility would create unacceptable risks[26.]

AESO has begun implementation of its design for a centralized capacity market auction, with similar design features to the Northeastern US capacity markets. For example, it utilizes a 3-year ahead forward period with incremental auctions, a sloped demand curve (based on an LOLE study that shows the decline in expected unserved energy as the reserve margin increases), market power mitigation based offer caps, and performance incentives based on performance during emergency events as well as capacity commitment versus actual availability throughout the year.

AESO considered the challenges faced by other capacity markets as renewable energy resources grow, often driven by state mandates or subsidies. Resources that received financial support through the first three rounds of the Renewable Electricity Program are ineligible to participate in the capacity market. The reliability contribution of these resources is subtracted from the system capacity targets utilized in the forward capacity auction.

With input from stakeholders, AESO is still determining its Planning Reserve Margin (called the “Minimum Procurement volume”), which is based on meeting the legislatively determined requirement of 0.0011% expected unserved energy (800 MWh currently). Current reserve margins are high (29-39% depending on assumed import capacity), though predicted to decline with forthcoming generator retirements.[27]

Alberta (Canada)

[26] https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-1-Overview-of-Capacity-Market-FINAL.pdf

[27] AESO, *Alberta’s Wholesale Electricity Market Transition Recommendation*, October 2016.

Market Structure	Mandatory auction
Administration	ISO
Requirements	System
PRM	TBD PRM (based on 0.0011% EUE from LOLE study)
Forward Period	3 years w/ incremental auctions
Resource commitment period	1 year
Capacity accreditation	Solar/wind: historical generation at peak or capacity factor based
Price Formulation	Sloped demand curve (use PRM and CONE)
Performance Incentives	Strong (capacity payment adjustments based on availability vs. commitment)
Market power mitigation	Price cap set based on market power screen before each auction
Deficiency / backstop mechanisms	TBD

CENTRALLY ADMINISTERED CAPACITY SHARING SYSTEMS

In centrally administered capacity sharing systems, a regional entity establishes capacity requirements for LSEs that can be met by self-supply or bilaterally procured resources from other LSEs or independent power producers. Contract prices and terms are negotiated bilaterally and LSEs have the flexibility to procure the types of capacity they desire. Bilateral prices rise when supplies are tight and then lower when the system is long (with some generators not receiving any capacity payments). Local regulatory authorities may set limits on prices paid for capacity and the regional entity overseeing the sharing system may set penalties for LSEs that do not meet their allocated share of system need. Prescriptive RA requirements based on resource location or operational characteristics (such as the CAISO's local RA and flexible RA programs) may also be incorporated. These systems allow more state and local control over resource planning decisions than the centralized capacity markets discussed above.

MISO

In the Midcontinent Independent System Operator (MISO) region, utilities are responsible for resource adequacy, but MISO facilitates a regional resource adequacy planning regime for the entities covered by its wholesale electricity market. LSEs may self-supply capacity, purchase capacity bilaterally, or participate in the "planning resource auction", a voluntary capacity auction. MISO covers a large geographic area (15 midwestern and southern states plus one Canadian province) and maintains both a system PRM, established via an LOLE study assuming no internal transmission limitations within MISO, and a zonal reliability requirement for 10 different local resource zones, established via an LOLE study for each zone assuming no import capacity.[28] MISO's current PRM is set at 17.1% for the 2018-2019 planning year.[29]The RA requirements are set based on the summer peak, but seasonal studies are also performed by MISO.

MISO operates an annual voluntary capacity auction for its RA needs. If insufficient capacity clears the auction, the price is set at the cost of new entry (CONE) value. If LSEs do not obtain adequate capacity to meet their share of the coincident peak demand plus the planning reserve margin, they are subject to a deficiency charge of 2.75 * CONE.

The MISO region contains a large supply of wind power resources. Wind capacity counting is based on an annual ELCC study, while solar capacity counting is based on statistical analysis of historical output during system peak.

	MISO
Market Structure	Bilateral w/ voluntary auction

[28] See MISO's Resource Adequacy Business Practice Manual, accessible here: https://www.misoenergy.org/planning/resource-adequacy/

[29] See *Planning Year 2018-2019 Loss of Load Expectation Study Report* by the MISO Loss of Load Expectation Working Group.

Administration	ISO
Requirements	System and local
PRM	17.1% PRM (based on LOLE study)
Forward Period	Year-ahead
Resource commitment period	1 year
Capacity accreditation	Summer-based (seasonal analysis performed) Solar/wind: ELCC for wind, historical contribution for solar
Price Formulation	Vertical demand curve set at RA requirement
Performance Incentives	Weak (MISO monitors must offer obligation but no formal incentive structure)
Market power mitigation	Offer cap set at 2.7*zonal CONE; participants may self-schedule
Deficiency / backstop mechanisms	Deficiency charge of 2.75*CONE

SPP

SPP operates a regional RA program for the Load Responsible Entities (LREs)[30] participating in its 14-state wholesale electricity market. SPP requires LREs to maintain capacity required to meet their peak load and planning reserve obligations on year-ahead basis. Generator owners are also required to participate in the RA program. SPP performs a deliverability study to determine which generators can deliver their energy at the regional system peak.

A probabilistic reliability study is performed (on at least a biennial basis) to determine SPP's target PRM, based on the 1-day-in-10-year LOLE standard. Based on its 2017 LOLE study, SPP determined that a 12%

[30] Load responsible entities is the name assigned to those entities that serve load within SPP's territory (equivalent to load-serving entities or "LSEs" in other jurisdictions).

noncoincident PRM and a 16% coincident PRM is required to meet their target LOLE.[31] As a result, SPP requires LREs to maintain a 12% non-coincident PRM throughout the year and bases its enforcement of compliance during the summer peak season. SPP currently utilizes an accreditation method for wind and solar resources based on the 60th percentile of their historical performance in the top 3% of peak load hours (updated every three years). However, SPP has been actively considering improvements to its LOLE and capacity accreditation methodologies, including better zonal representation in their LOLE study and the use of ELCC values for wind, solar, and battery resources.

Failure by LREs to meet their RA requirement results in a deficiency payment based on the CONE. The current CONE is set at $85.61/kW-yr and is reviewed on or before November 1st each year and filed with FERC. Deficiency payments are set at the CONE multiplied by a CONE factor that increases based on SPP's actual system-wide planning reserves (125% if reserves are greater than or equal to the PRM + 8%, 150% if reserves are greater than or equal to the PRM + 3% but less than the PRM + 8%, and 200% if reserves are less than the PRM + 3%). This deficiency payment provides an incentive to LREs to procure additional capacity, rather than pay high deficiency charges as the system nears its PRM. Revenues are distributed to LRE's and generator owner's with excess capacity on a *pro rata* basis.

	SPP
Market Structure	Bilateral
Administration	ISO
Requirements	System
PRM	12% non-coincident / 16% coincident PRM
Forward Period	Year-ahead
Resource commitment period	Summer peak

[31] SPP, *2017 SPP Loss of Load Expectation Study Report*, June 2018. The different PRM values for noncoincident and coincident peaks reflect the fact that SPP's coincident peak of 51,519 MW is 1,800 MW (or 3.4%) lower than their noncoincident peak of 53,320 MW.

Capacity accreditation	Thermal: based on Accredited Capability Test Wind/solar: based on historical performance in peak load hours (considering use of ELCC)
Price Formulation	Bilateral
Performance Incentives	n/a
Market power mitigation	n/a
Deficiency / backstop mechanisms	Deficiency payment based on CONE and increases as system nears PRM

California

Like other organized wholesale electricity markets, California's resource adequacy (RA) program grew out of the need to address "missing money" concerns to ensure generators had revenue sufficiency after the creation of the wholesale electricity market, including the market reforms instituted after the California energy crisis. It also grew from the desire to move away from "reliability-must-run" (or RMR) contracts, which the CAISO entered into after the energy crisis to provide out-of-market administratively determined payments for capacity needed to maintain grid reliability. California's RA program is administered by the state and not subject to federal jurisdiction, enabling state and local regulators authority over capacity planning decisions.

The California Public Utility Commission's current RA program contains three requirements: system capacity[32] (instituted in 2006, based on a 15% PRM), local (instituted in 2007 to address local transmissions grid constraints, based on CAISO studies of 1-in-10 year weather and an N-1-1

[32] The system requirement also includes a zonal component (with two zones of "North of Path 26" and "South of Path 26") to incorporate transmission limitations and maximum flow constraints in each direction.

contingency), and flexible (instituted in 2015 to address renewable integration needs, based on the largest expected three hour net load ramp).[33] The CAISO and the CPUC are each responsible for specific aspects of RA program design and implementation. CAISO operates two backstop procurement mechanisms for capacity needed for RA and transmission grid needs (the Capacity Procurement Mechanism and Reliability Must Run mechanism, respectively). The CPUC maintains a citation program with financial penalties for deficient LSEs ($5,000-20,000 per incident and up to $6.66/kW-mo). The California Energy Commission oversees resource adequacy compliance for the Publicly Owned Utilities.

In addition to the RA program's focus on year-ahead resource adequacy, the CPUC also maintains long-term reliability planning efforts, previously looking 10 years forward in the Long-term Procurement Plan (LTPP) proceeding and now focused on 2030 in the Integrated Resource Plan (IRP) proceeding. The IRP process is currently utilizing an LOLE-based approach (using a 1-day-in-10-year standard of 0.1 LOLE events/year) to determining resource adequacy in 2030, although the state has not adjusted its standard use of a 15% PRM for system RA in response to analysis completed to date.[34]

The state's RA program continues to develop, focusing currently on how to address retail load shift from incumbent utilities to direct access and community choice aggregation customers, as well as how to provide appropriate levels of flexibility for California's growing share of renewable resources and how to implement ELCC for wind, solar, and batteries.

	California[39]
Market Structure	Bilateral
Administration	ISO + state agencies
Requirements	System, local, and flexible
PRM	System uses 15% PRM

[33] For additional details, see the CPUC's Resource Adequacy Program website.

[34] Summary based on the CPUC's Resource Adequacy Program.

	Local / flex based on grid constraints / 3-hr net load ramp
Forward Period	Year-ahead
Resource commitment period	1 year
Capacity accreditation	Summer-based Thermal and Dispatchable Hydro: Generator Pmax Renewables: ELCC-based
Price Formulation	Bilateral
Performance Incentives	Medium; CAISO's RAAIM[35] process designed to incent availability per must-offer obligation
Market power mitigation	n/a (though backstop procurement subject to soft cap)
Deficiency / backstop mechanisms	Deficiency citation program at CPUC, backstop procurement via ISO (CPM/RMR)

ENERGY-ONLY MARKETS

Energy-only markets are those that rely solely on wholesale market revenues to ensure adequate generating capacity. This structure relies on scarcity pricing in energy prices (and sometimes operating reserve prices as well) to provide revenue sufficiency for existing generating capacity and to incent new generators to enter the market. The system's planning reserve margin is therefore an output of the market design, whereby low planning reserves drive higher energy and ancillary service prices that incent generator entry, increasing planning reserves until prices reach a market equilibrium. In theory, this market equilibrium determines the "optimal" planning reserve margin by balancing the marginal

[35] RAAIM = Resource Adequacy Availability Incentive Mechanism

cost of capacity against its marginal benefits (based on the value of lost load). This PRM is referred to as an “economic PRM” since it is determined by a market equilibrium, rather than a designated reliability target.

ERCOT

ERCOT is a unique market in the US in that it does not rely on a resource adequacy standard or planning reserve margin to ensure system reliability. Instead, ERCOT relies solely only on energy-market revenues to ensure adequate generating capacity. The Brattle Group recently estimated ERCOT’s economically optimal reserve margin to be 8-10.5%, with the current market structure driving a 10.25% margin.[36] They estimated the current market structure would experience an LOLE of 0.5 events/year, which is lower than their estimated economically optimal level for ERCOT of 0.8 events/year, but significantly higher than the 0.1 events/year standard used by most other regions in the US. ERCOT’s 2019 summer planning reserve margin is estimated to be only 8.1%, driven by generation project delays or cancellations and high load growth in the West Texas oil and gas fields, however the PRM is expected to reach 15.2% by 2021.[37] ERCOT has historically utilized statistical analysis of average renewable output in the top 20 load hours when estimating capacity contribution towards its reserve margin, with recent assessments utilizing 15-58% of installed nameplate capacity for wind and 74% for solar.[38]

A critical part of ERCOT’s scarcity pricing mechanisms is its Operating Reserve Demand Curve (ORDC). ERCOT maintains an ORDC that prices reserves at the value of lost load ($9,000/MWh) below 2,000 MW of available reserves and decrease reserve prices as operating reserves increase. This provides a

[36] Brattle, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update*, December 2018.

[37] ERCOT, *Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2020-2029*, May 8, 2019.

[38] Ibid.

substantial source of revenue for generating resources that can provide reserve capacity to the ERCOT system during scarcity periods.

Figure 14. ERCOT's Operating Reserve Demand Curve[39]

	ERCOT
Market Structure	Energy-only
Administration	n/a
Requirements	None
PRM	No PRM requirement
Forward Period	n/a
Resource commitment period	n/a
Capacity accreditation	Solar/wind: historical contribution in top 20 load hours
Price Formulation	No capacity price (scarcity prices determined by ORDC curve adder based on LOLE + VOLL)
Performance Incentives	n/a
Market power mitigation	n/a
Deficiency / backstop mechanisms	n/a

Australia

Australia's large size and relatively small population have led to a bifurcated electricity system on the Australian mainland. The Western Australia grid's Wholesale Electricity Market (WEM) maintains a reserve capacity mechanism, which functions as a forward capacity auction backstop if insufficient capacity is available through bilateral trades. The National Electricity Market (NEM), which is about ten times larger on a peak demand basis and serves the major population centers of Eastern Australia,

[39] Surendran et. al. *Scarcity Pricing in ERCOT*, FERC Technical Conference Presentation, June 2016.

operates an energy-only wholesale spot market. The NEM market maintains a very high spot market price cap of over AUD $14,000/MWh (roughly USD $9700/MWh).[40]

The Australian Energy Market Operator (AEMO) publishes a 10-year forward resource adequacy assessment in its Electricity Statement of Opportunities report.[41] The NEM standard for reliability is for unserved energy to be less than 0.002% of consumption per region in a given financial year. This analysis uses different levels of peak lead (based on probability weightings) for each region to determine the expected unserved energy. Some regions currently face near-term or medium-term capacity shortfalls. AEMO produces an estimate of both LOLP as well as the probability of exceeding its 0.002% EUE threshold, as shown in Figure 7 below. As seen in these LOLP values, the Australian regions have generally high loss of load probability.

In general, the Australian approach is to utilize scarcity prices in the energy market to incent resource adequacy, rather than require a planning reserve margin. As operating reserves dip below either the single largest contingency or a maximum forecast error limit, AEMO will declare Lack of Reserve conditions, which may lead to load shedding events. However, as a reliability backstop the AEMO also has the option of utilizing its Reliability and Emergency Reserve Trader (RERT) powers to secure additional reserve contracts for either curtailable load or generation capacity on a short-term (hours to days ahead), medium term (days to weeks head), or long-term basis (over 10 weeks ahead). RERT power was utilized in 2018 and 2019, though for generally either small volumes (40 MW for summer 2018-2019) or short time periods (e.g. 595 MW for January 25, 2019).

	Australia (NEM)
Market Structure	Energy-only

[40] National Electricity Market Fact Sheet, note the NEM "spot price" is determined by averaging six five-minute dispatch prices for every half-hour period.

[41] See AEMO, *2018 Electricity Statement of Opportunities*.

Administration	n/a
Requirements	None
PRM	No PRM requirement (but a 0.002% EUE target exists)
Forward Period	n/a
Resource commitment period	n/a
Capacity accreditation	n/a
Price Formulation	No capacity price (scarcity prices based on VOLL)
Performance Incentives	n/a
Market power mitigation	n/a
Deficiency / backstop mechanisms	RERT backstop for securing additional operating reserve capacity

EUROPEAN MARKETS

In Europe, there remains an ongoing debate between some EU member countries and the European Commission regarding the use of capacity mechanisms and whether to assess and ensure resource adequacy at an individual country level or for the continent as a whole. The European Commission has long been focused on expanding the interconnection capacity between countries to support an increasingly efficient energy market capable of integrating the EU's growing share of renewable energy.[49] In general, the European Commission seeks to utilize a standard method for measuring regional resource adequacy, rely on expanded cross-border energy markets, and apply national capacity markets as temporary measures to maintain reliability during the transition to lower-emitting reliability resources. Additionally, as part of its Clean Energy for All Europeans package, the EU recently adopted a carbon emissions limit of 550 g CO_2 of fossil fuel origin per kWh for any generator that receives payments under a national capacity payment mechanism.[42]

Historically, each European country has taken its own approach to resource adequacy, with many countries adopting some type of capacity payment mechanism. There are five general types of mechanisms utilized in Europe to date[43]:

- **Strategic reserve**: a central transmission system operator or government agency determines capacity needs and competitively contracts capacity for a strategic reserve. These resources are only activated during capacity shortage periods and do not participate in the energy market. Germany, Belgium, and Sweden utilize this mechanism.
- **Capacity auction**: this mechanism is similar to centralized capacity markets in the US, whereby generators bids into a centralized forward capacity auction. These generators then participate in the energy market. The UK initiated a capacity auction in 2014, but the market is currently suspended by the EU courts due to a legal challenge.[44] Poland also initiated a similar mechanism that initiatve faces ongoing legal challenges.[45]
- **Capacity obligation:** this mechanism is similar to centrally administered capacity sharing systems in the US, whereby electricity suppliers must procure capacity to serve their forecasted demand plus a reserve margin, either bilaterally or through voluntary auctions. Financial penalties are utilized for suppliers who fail to contract for their necessary supply. France utilizes this mechanism.

[42] For details, see the new rules for the EU's electricity market adopted in May 2019 as part of the Clean Energy for All Europeans Package.

[43] Adapted from *Capacity Mechanisms for Electricity*, European Parliamentary Research Service, May 2017.

[44] See S&P Global, *UK regulator proposes simplified capacity market rules*, April 2019.

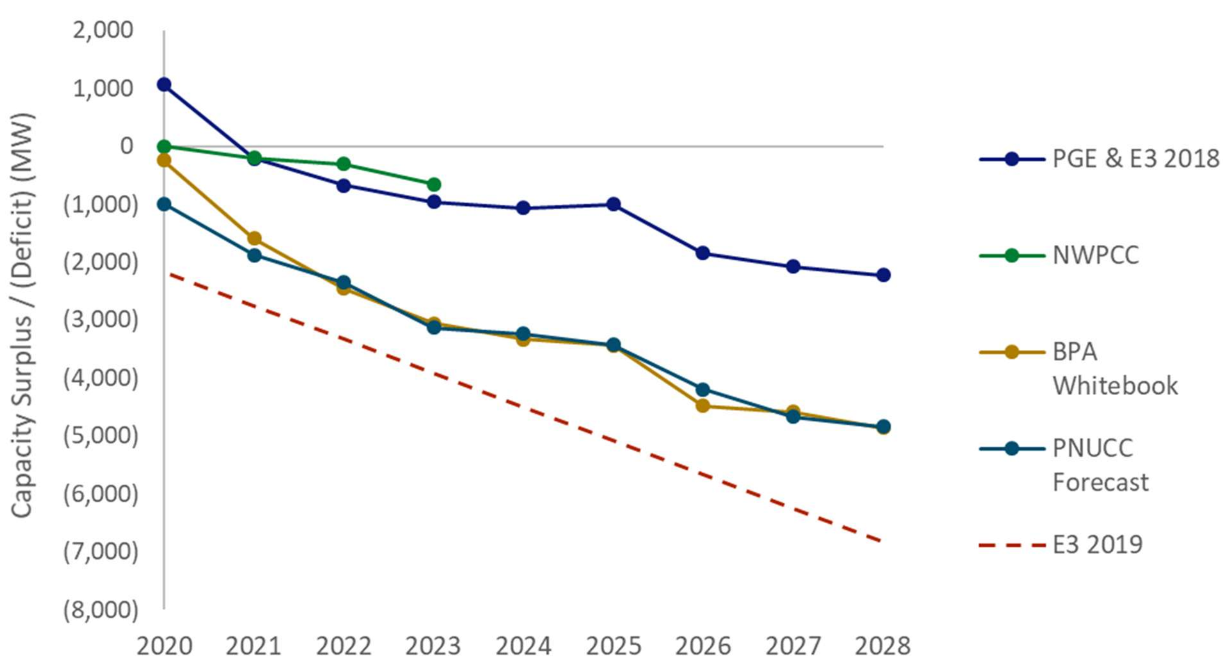
[45] See EnergyPost.eu, *European Commission's decision to approve Poland's capacity mechanism challenged*, March, 2019.

- **Reliability options:** capacity providers enter into options contracts with electricity suppliers, which provides them the option to procure electricity at a predetermined strike price during scarcity conditions. Procurement occurs like a capacity market auction, but with additional financial and operational constraints related to the options portion of the contract. Italy is pursuing such a mechanism.
- **Capacity payments:** targeted capacity payments are fees set by regulators to be paid to generators providing capacity. These plants continue to participate in wholesale energy markets. These types of capacity payments are used in Portugal and Spain.

Appendix C: Review of Regional Resource Adequacy Studies

Several recent studies summarize the capacity position of the Northwest. These studies span different geographies, use different methodologies, but largely come to the same conclusion that the Northwest is capacity short today or will be short in the near-future.

Figure 8: Load and Resource Balance by Study



Note: This figure shows the central case from each study. The E3 2019 line is a linear interpretation of results for 2018 and 2030 in that study. The work groups also considered WECC's report to NERC in its Long-Term Reliability Assessment. However, that study was excluded from this figure because it examines the load and resource balance of the NWPP region in the summer, where the other studies agree that the largest challenges for the region are in the winter.

This section summarizes these studies, describing each individually and comparing their key methodological similarities and differences.

Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2023 (2018)[46]

NWPCC conducts an annual assessment of the capacity position of its member states Idaho, Montana, Oregon and Washington over a five-year period. The Council's work is advised by the Resource Advisory Committee (RAAC), whose membership is drawn from both publicly owned and private utilities, state governments and independent power producers.

The NWPCC study uses stochastic methods to assess resource adequacy in the Council's GENESYS[10] model. This approach accounts for variation in both supply and load conditions, allowing the Council to report the region's capacity position against multiple different reliability metrics. The primary metric used by the Council to assess the region's resource adequacy is LOLP of no more than 5%.

The most recent iteration of this report was released in 2018. In that report, the Council reports that the region will exceed the 5% LOLP standard by 2021, when the LOLP for the region rises to above 6%. That figure is expected to rise to nearly 7% by 2023. The Council attributes the increase in LOLP over time to the retirement of several coal plants in the region. The report notes that the region would need to add

[46] https://www.nwcouncil.org/sites/default/files/2018-7.pdf

300 MW of capacity in 2021 and an additional 300 MW to 400 MW in 2022 to meet Council's planning standard.

In its report, the Council identifies key uncertainties that affect the timing and magnitude of a capacity shortfall in the region. First, the study only captures planned resources that are either sited or licensed. There may be additional resources that are in the development pipeline that could come online further out in the study period. Related, the Council only attributes capacity value to existing demand response resources, not prospective future resources.

Two other key sources of uncertainty are load growth and the availability of imports outside the region. With lower load growth and more imports, the LOLP could be as low as 3.5% in 2023. However, with higher load growth and fewer imports the LOLP could be as high as 14.3%, requiring 1500 MW of additional capacity in between 2021 and 2022 to meet the council's planning standard. **Table 4** summarizes the LOLPs identified by the Power Council across different load growth and imports scenarios.

Table 4: NWPCC 2023 LOLP By Import Availability and Load Growth Scenarios

Import (MW)	1500	2000	2500	3000
High Load	14.3%	12.1%	10.1%	7.8%
Medium Load	11.0%	8.6%	6.9%	5.1%
Low Load	8.0%	6.4%	4.9%	3.5%

Table 5: NWPCC Pacific Northwest Power Supply Adequacy Assessment for 2023, Key Assumptions and Findings

Key Assumptions	
Region	PNW (ID, MT, OR, WA)
Year released	2019

Resources included	Existing and planned resources; IPPs included			
Treatment of hydro	Time dependent hydro flows that account for 80 years of water availability natural stream flows, rule curves for hydro operations (including non-energy constraints)			
Treatment of wind and solar	ELCCs endogenously calculated in GENESYS			
Load Resource Balance				
Year	2020	2021	2022	2023
Total Capacity (MW)	40,167	39,370	39,519	40,049
Total Requirement (MW)	39,096	39,576	40,191	41,003
Capacity Surplus / (Deficit) (MW)	1,071	(206)	(673)	(954)

Pacific Northwest Utilities Conference Committee, Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029 (2019)[47]

The Pacific Northwest Utilities Conference Committee (PNUCC) produces an annual report that aggregates Northwest utilities' IRP data to forecast the region's electric power needs over a 10-year period. The report looks at both peak winter and peak summer needs for the region.

The 2019 PNUCC forecast finds that the region is short of its winter resource adequacy needs today and may be short on its summer needs by 2022. PNUCC attributes these shortfalls to a confluence of factors. One key factor is that coal and other thermal power plant retirements throughout the West have

47 http://pnucc.org/sites/default/files/Xdak24C14w3677n7KsL43OEL4J25MW0b3d5cmx3FGD4d9OQ3B189OF/PNUCC%202019%20NRF.pdf

decreased the available of both firm and non-firm power available to the region. PNUCC finds that 3,646 MW of coal capacity serving the region is planned to be retired by 2028. These retirements are accompanied by uncertainty about the ability of utilities or independent power producers in the region to site and build new gas power plants to replace that firm capacity. PNUCC finds that the majority of the 900 MW of committed resources being built in the region are wind and solar projects. 900 MW of natural gas power plants are noted as "planned" by PNUCC, but none would come online until 2025.

These net decreases in generating capacity in the region occur in the context of increasing winter and summer peak loads. The region remains a winter peaking system, though the summer peak appears to be growing at a faster rate. PNUCC attributes the growth of summer peak load to multiple factors but highlights increased use of air conditioning in the region as a key driver. The forecast also notes that new transportation or building electrification loads could further increase peak electric system requirements in the region.

Table 6: PNUCC Load and Resource Balance by Year and Season

Metric	Winter	Summer
2020 Surplus/ Shortfall	-1GW	+1GW
2024 Surplus/ Shortfall	-3GW	-2GW
2028 Surplus / Shortfall	-5GW	-4GW

PNUCC's methodology reflects the summation of individual utilities' load forecasts and generating resources. It incorporates the effect of ongoing investments in energy efficiency, demand response and both committed and planned new resources. However, PNUCC's capacity accounting methodology does not include non-firm supply options like uncommitted independent power producers or non-firm imports. However, PNUCC notes that WECC wide trends in thermal resource retirements mean that the availability IPP generation and imports may become more uncertain over time.

Table 7: PNUCC Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029, Key Assumptions and Findings

Key Assumptions	
Region	OR, WA, ID; MT west of continental divide; portions of NV, UT, and WY that lie within the Columbia River drainage basin
Year released	2019
Resources	Existing and committed resources; non-contracted IPPs not included in load and

included	resource balance figures			
Treatment of hydro	8th percentile of monthly average conditions, drawn from over 70 different water conditions			
Treatment of wind and solar	Reported for individual projects by PNUCC members. These average out to peak load contributions of 5% for wind and 8% for solar.			
Load Resource Balance				
	2020	2023	2026	2029
Total Capacity (MW)	36,153	35,202	34,919	34,835
Total Requirement (MW)	37,522	38,954	39,360	39,989
Capacity Surplus / (Deficit) (MW)	(1,369)	(3,752)	(4,441)	(5,154)

BPA'S 2018 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY (WHITE BOOK)[48]

The 2018 Pacific Northwest Loads and Resources Study ("White Book") is produced annually by the Bonneville Power Administration. The White Book presents a projection of loads and resource conditions over a 10-year period, 2020 through 2029 for the most recent publication. BPA's approach assumes retail loads and non-hydro resources availability are consistent with normal weather conditions, while hydro resources are modelled using 80-years of historical data. All planned additions and retirements in the region are reflected in the study. Major retirements include Boardman (2021), Centralia 1 (2020), Centralia 2 (2025), Colstrip 1 and 2 (2022), Valmy 1 (2022), and Valmy 2 (2026).

BPA examines both the region's energy balance and capacity position. BPA finds that there is enough energy available to the region, even in years with critically low hydro power availability. However, under those critical conditions the regional annual energy surplus is expected steadily decline from over 4,000 aMW today to 400 aMW in 2029. That resource balance finding holds only in situations where 100% of

[48] https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

uncommitted IPP generation is assumed to be available to Northwest utilities. BPA also tests cases where 50% and 0% of IPP generation is available and finds that in those sensitivities the region faces an energy deficit in 2026 and 2020 respectively.

Unlike energy, BPA finds that the Northwest faces a capacity shortage throughout the entirety of the study period. That result holds even in a case where BPA assumes that 100% of uncommitted IPP capacity can contribute to the region's load and resource balance. In that 100% IPP availability case, the region sees a 250 MW deficit in 2020, a figure that steadily increases to a nearly 5,000 MW deficit in 2029. The 2020 figure rises to 4,250 MW and the 2029 figure to 7,700 MW the 0% uncommitted IPP generation sensitivity.

Table 8: BPA White Book, Key Assumptions and Findings

Key Assumptions				
Region	PNW (ID, MT, OR, WA)			
Year released	2018			
Resources included	Resources as per utility IRPs; IPPs included			
Treatment of hydro	BPA internal Hourly (HOSS) model. Hydro peak contributions are calculated using a 120-hour sustained capacity methodology.			
Treatment of wind and solar	Wind and solar capacity not counted as firm			
Load Resource Balance				
	2020	2023	2026	2029
Total Capacity (MW)	39,133	37,490	36,773	36,649
Total Requirement (MW)	38,908	40,320	40,911	41,467
Capacity Surplus / (Deficit) (MW)	225	(2,831)	(4,138)	(4,818)

North American Reliability Corporation and Western Electricity Coordinating Council, 2018 Long-Term Reliability Assessment[49]

NERC publishes an annual assessment of reliability for each of its seven Regional Entities (REs), including an assessment of sub-regions within those entities. As part of that assessment, WECC reports a high-level assessment of the load and resource balance in the NWPP region. That balance is derived by looking at the load forecasts and plans of individual balancing authorities in the region and applying a probabilistic treatment of resource availability. The study finds that the NWPP-US region has 62 GW of capacity resources available in 2023, against 50 GW of peak demand. This balance is equivalent to a reserve margin of nearly 24%. The NERC/WECC study does, however, show that the region is trending towards tighter reserve margins and increased likelihood of unserved energy and loss-of-load.

The LTRA study has three key methodological differences with the studies noted above. First, the LTRA accounts for 2 GW of coal retirements in the region through 2028. In contrast, the 2019 E3 study, described below, has a similar geographic extent, but identifies 8 GW of coal retirements by 2030. Second, in developing the LTRA WECC applies deterministic assumptions about the availability of wind, solar and hydro resources. WECC develops probability distribution functions for both resource and peak loads but, for the purposes of the LTRA, reports median values. Finally, the LTRA examines the entire NWPP footprint, including Nevada. The result is that load-resource balance results reported in the LTRA are with respect to the NWPP region's overall summer peak load. This is an important difference because the reliability challenges identified in other regional studies are most acute in winter.

Table 9: NERC Long-Term Reliability Assessment, Key Assumptions and Findings

Key Assumptions

[49] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

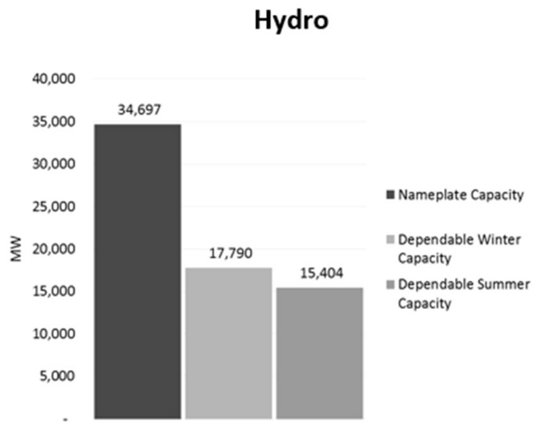
Region	WECC – NWPP – US (WA, OR, ID, NV, UT, MT ,WY, NV)			
Year released	2018			
Resources included	Existing and planned resources; IPPs included			
Treatment of hydro	Based on generation curve derived from historical generation			
Treatment of wind and solar	Expected hourly generation in peak hour			
Load Resource Balance				
	2020	2023	2026	2028
Total Capacity (MW)	61,652	61,850	62,898	62,822
Total Requirement (MW)	57,682	59,098	60,061	60,868
Capacity Surplus / (Deficit) (MW)	3,970	2,752	2,837	1,954

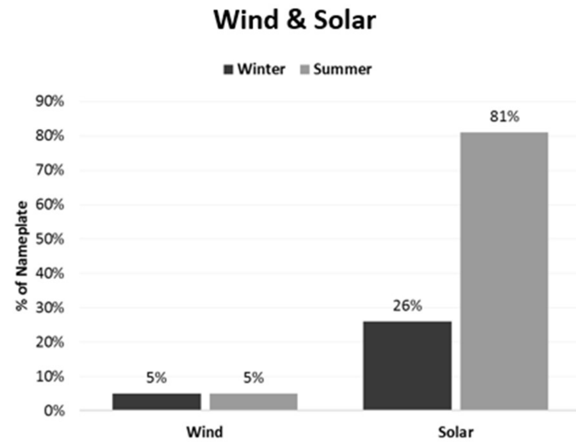
Portland Gas and Electric (PGE) and E3, Long-Term Assessment of the Load Resource Balance in the Pacific Northwest (2019)[50]

PGE and E3's 2018 report was a combination of a literature review and load-resource balance scenario development exercise. In this report, E3 reviewed reports from the NWPCC, BPA and PNUCC, summarizing the region's capacity position as reported by those entities. In addition, E3 developed a spreadsheet tool to recreate those reports key findings with a goal of being able to conduct additional sensitivities. That tool ended up borrowing many assumptions (e.g. hydro availability, variable renewables ELCCs) from the NWPCC Seventh Power Plan and the NWPCC Power Supply Adequacy Assessments.

[50] Available here

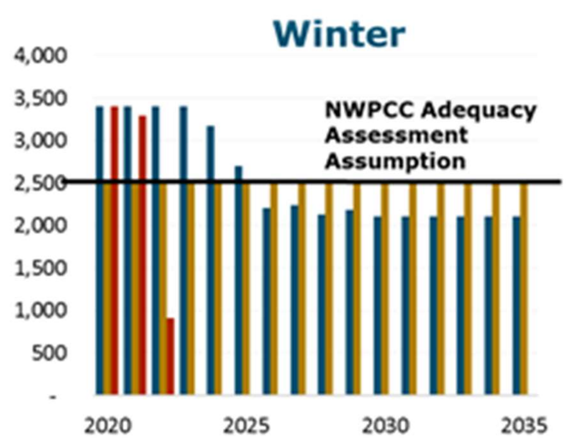
Figure 9: Hydro Availability (left) and ELCC's of Wind and Solar (right) Used by E3, Derived from the NWPCC Seventh Power Plan





Using the scenario tool, E3 developed Base Case, Low Need and High Need scenarios to test how varying key assumptions like load growth or import availability changes the Northwest's capacity position. A new contribution to the regional RA picture provided in this report is a more fine-grained analysis of the load-resource balance in the CAISO system. E3 concluded that there may be more import capability than assumed by the NWPCC in the near-term, but that this capability decreases in the early- to mid-2020s due to increasing winter peak loads and retirements of thermal power plants in California. This analysis was used to bound the import availabilities in the Low Need and High Need scenarios.

Figure 10: Winter and Summer CAISO Import Availability (MW) Scenarios



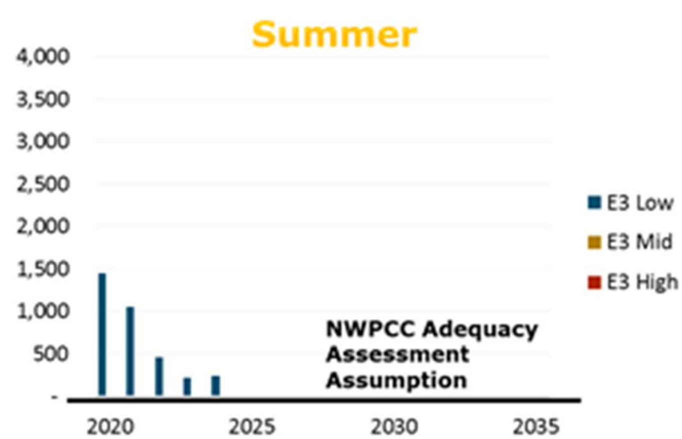


Table 10 summarizes the first year of capacity deficit in each of the scenarios E3 considered in this report. The key takeaway is that the region faces a near-term capacity challenge during winter, with potential challenges emerging in the summer in the mid-2020s.

Table 10: First Year of Capacity Shortfall, Winter and Summer

Scenario	Winter	Summer
Low Need Scenario	2026	2029
Base Case	2021	2026
High Need Scenario	2021	2023

Table 11: E3 Long-Term Assessment of the Load-Resource Balance in the Pacific Northwest: Key Assumptions and Findings

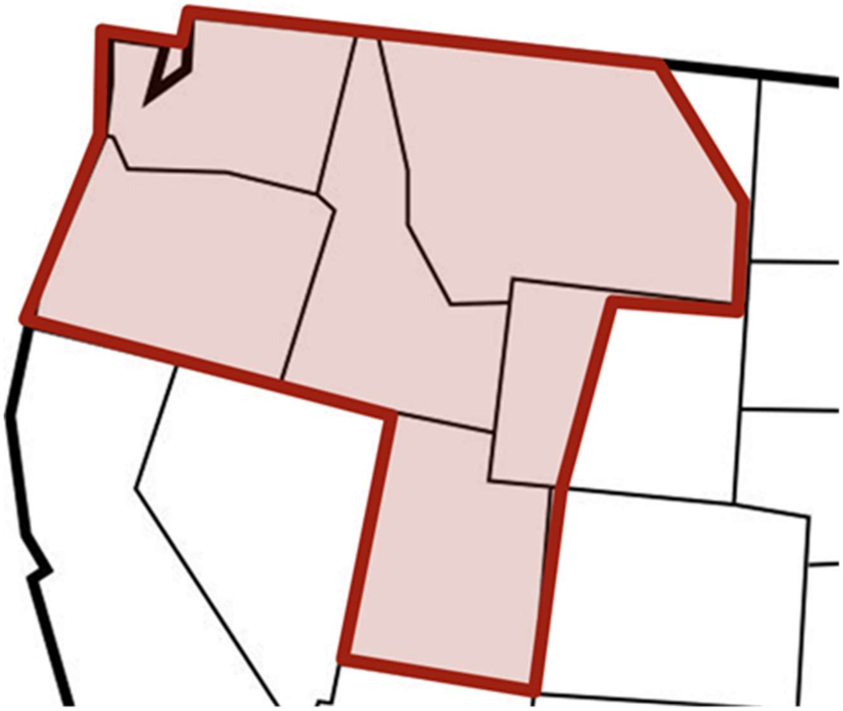
Key Assumptions				
Region	PNW (ID, MT, OR, WA)			
Year released	2018			
Resources included	Existing and planned resources; IPPs included			
Treatment of hydro	Benchmarked to NWPCC GENESYS			
Treatment of wind and solar	Benchmarked to NWPCC GENESYS			
Load Resource Balance				
	2020	2023	2026	2028
Total Capacity (GW)	40.2	40	41.2	42.7
Total Requirement (GW)	39.1	41	443	44.5
Capacity Surplus / (Deficit) (GW)	1.1	-1	-1.8	-2.2

E3, Resource Adequacy in the Pacific Northwest (2019)[51]

The E3 study *Resource Adequacy in the Pacific Northwest* was sponsored by Puget Sound Energy, the Public Generating Pool, Avista, and NorthWestern Energy. The study focuses on the challenges of ensuring resource adequacy in a deeply decarbonized electric system with high levels of renewable energy. Its geographic extent includes Washington, Oregon, Idaho, Utah, western Wyoming, and most of Montana (Figure 2), a combined region called the "Greater Northwest" in the study. The study uses E3's Renewable Energy Capacity Model (RECAP) to study resource adequacy needs under various scenarios in 2018, 2030 and 2050. RECAP simulates 70 years of historical hourly loads and hydro conditions, paired with weather matched wind and solar profiles, as well as historical rates of generator outages.

Figure 4: E3 Study Geography – The Greater Northwest

[51] https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf



2018 Resource Adequacy Results

The E3 Study finds that the region has insufficient capacity to meet a '1-in-10' year reliability standard of 2.4 hours LOLE in 2018. Put in terms of capacity, the study finds that the region requires 48 GW of effective capacity but only has 47 GW available. Full reliability statistics from the study for the Greater Northwest region are shown in Table 3. Of note, the E3 study finds that the planning reserve requirement (PRM) necessary to achieve a 2.4 hours per year LOLE target is 12%. That figure is lower than the PRM standard (typically 15%) many individual utilities in region use. This result holds because the E3 study accounts for more load and resource diversity across the entire Greater Northwest region (by considering the regional coincident peak).

Table 12**: Key Reliability Statistics from E3 Study**

Metric	Units	Value
Annual LOLP (%)	%	3.7%
Loss of Load Expectation (LOLE)	hrs/yr	6.5
Expected Unserved Energy (EUE)	MWh/yr	5,777

Normalized EUE	%	0.003%
1-in-2 Peak Load	GW	43
PRM Requirement	% of peak	12%
Total Effective Capacity Requirement	GW	48

RECAP's probabilistic simulation approach allows for a calculation of effective capacity by resource type in units of Effective Load Carrying Capacity. The E3 Study finds that the effective capacity contributions from wind and solar in 2018 are 7% and 12%, respectively. Those figures can rise to as high as 22% and 21% if wind and solar resources are broadly distributed across the region. The capacity contribution of wind and solar are limited because those resources are not consistently available during high load events in the Greater Northwest region, particularly very cold winter mornings and evenings. Table 2 reports the 2018 load and resource balance in the region, as well as the effective capacity percentage for each resource modelled.[8]

Table 3. 2018 Load and Resource Balance (E3 study)

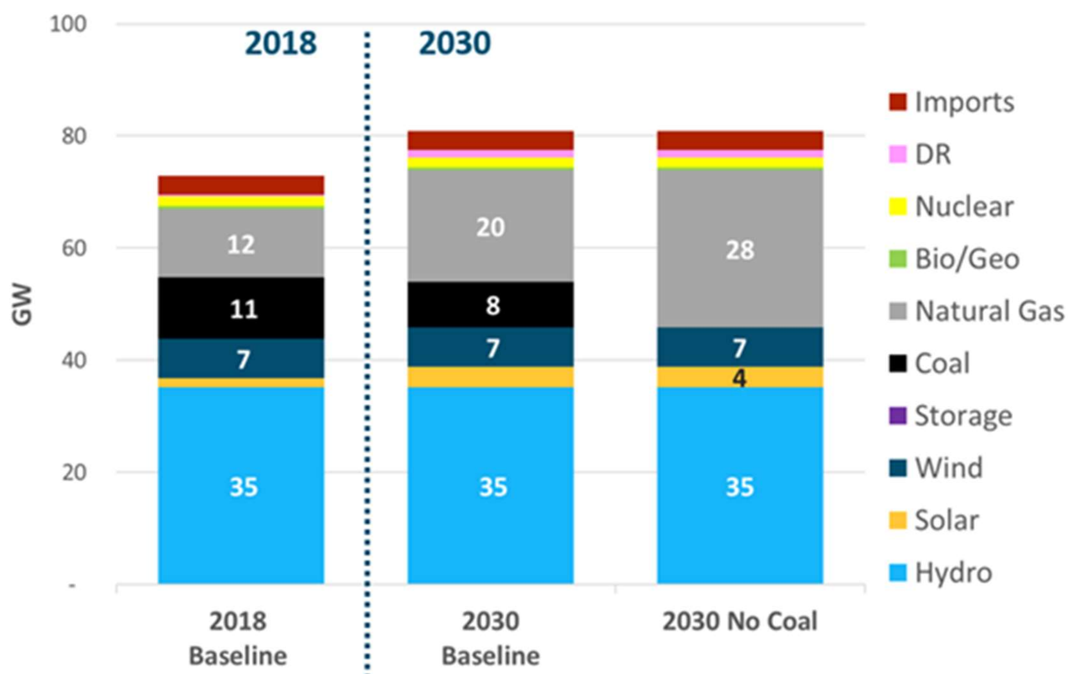
Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

2030 and 2050 Resource Adequacy Findings

The E3 study also includes an examination of the resource adequacy implications of a deeply decarbonized electric system in the Greater Northwest in 2030 and 2050. In both years, E3 examined the region's electric sector capacity requirements under different GHG emissions scenarios.

The E3 study found that in 2030 the region will need 8 GW of net new capacity, accounting for both load growth and planned coal retirements in the region. At the time of publication, this meant the region would need to add 730 MW of capacity per year to maintain resource adequacy. The capacity need rises to 16 GW new capacity—or 1450 MW/year—if all coal plants in the region are retired by 2030.

Figure 5. 2018 and 2030 generating capacity mix (E3 study)

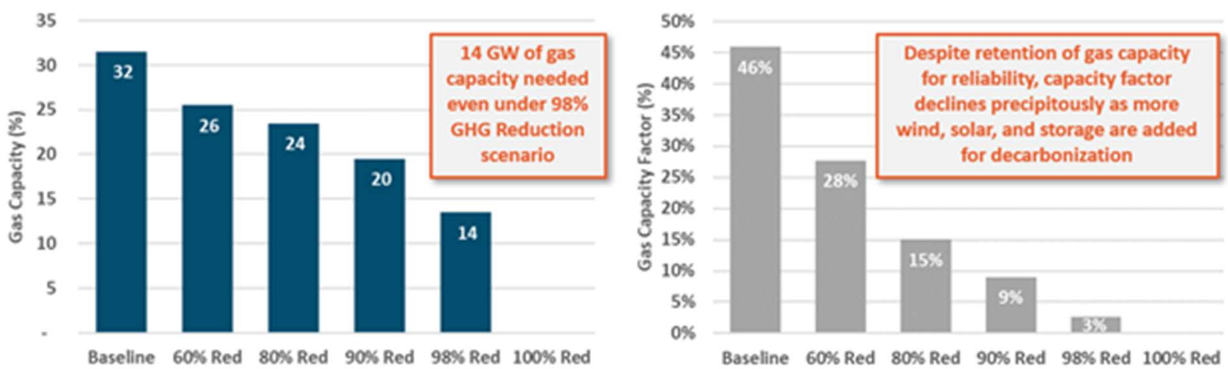


	2030 Baseline	2030 No Coal
GHG Free Generation (%)	61%	61%
Carbon (MMT CO2)	67	42
% GHG Reduction from 1990 Level	-12%*	31%

*Assumes 60% coal capacity factor

The E3 study continues by examining resource adequacy scenarios in 2050, considering electricity systems with between 60% and 100% GHG free generation. The 2050 results suggest that there is an ongoing need for firm capacity in the Greater Northwest and that gas power plants are the lowest cost means of providing this capacity. The region maintains 14 GW of rarely used gas capacity even in a scenario with a 99% GHG free electricity system.[9]

Figure 6. Natural gas capacity and capacity factors under various GHG reduction scenarios (E3 study)



E3 tested a scenario with zero GHG emissions in the electricity system and found that removing the final 1% of GHG emissions requires an additional $100 billion to $170 billion of additional investment. Those figures are equivalent to $11,000 and $16,000 per marginal ton of CO_2 abated. The reason for this large investment cost is that very high levels of wind, solar and storage capacity are needed to maintain reliability without firm resources.

Table 13: E3 Resource Adequacy in the Pacific Northwest: Key Assumptions and Findings

Key Assumptions	
Region	ID, MT, OR, UT, WA, Western WY
Year released	2019
Resources included	Existing and planned resources
Treatment of hydro	Stochastically selected from 80-year historical annual hydro data
Treatment of wind and solar	ELCC
Load Resource Balance	

	2018	…	2030	2050
Total Capacity (GW)	47.2	NA	52.9 (stipulated)	58.8 (stipulated)
Total Requirement (GW)	48.4	NA	52.9	58.8
Capacity Surplus / (Deficit) (GW)	-1.2	NA	8 GW to 16 GW new firm capacity needed	20 GW new firm capacity needed

Comparison of Key Assumptions and Conclusions

The studies outlined above each take different approaches to identifying and forecasting the Northwest's capacity position.

Analytical Approach

One high-level difference between studies is whether they take a stochastic or a deterministic approach to evaluate the region's capacity needs. Stochastic approaches, like those used in the E3 2019 and NWPCC Power Supply Assessment studies, simulate thousands of permutations of features like load, hydro, and renewable resource availability. By doing so, these analyses develop a distribution of load-resource balance hours, allowing for calculation of statistical reliability metrics and identification of metrics like effective load carrying capability. In contrast, deterministic methods sum resources available in the region, with various approaches to deem the capacity contribution of resources that are based on historical experience.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study[52]
Analytical Approach	Stochastic	Stochastic	Deterministic	Deterministic	Deterministic

Resource Adequacy Metrics

The E3 RECAP study and the NWPCC Power Supply Assessment both use statistical resource adequacy methods. Metrics like LOLE and LOLP capture the likelihood that the region's power system will be adequate across a range of plausible load and resource conditions. Studies that use a PRM-based reliability metric compare expected resource availability against peak loads plus a stipulated PRM. The derivation of those PRMs vary by study, ranging from summations of individual utility PRMs to figures developed from statistical studies.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study
Adequacy Metric	Annual LOLE of 2.4 hours/yr	Annual LOLP of 5%	PRM of 16%	Adjustment to available resources based on operating reserves and transmission losses	PRM of 19-20% (changes slightly for each year of the study)

[52] Note that WECC has the capabilities to conduct probabilistic modelling via a convolutional approach, but do not do so for the purposes of the NERC LTRA report.

Peak Load

A key determinant of a region's capacity position is its peak load. Each study approaches peak load calculations differently. Stochastic studies typically draw from historical records, with past levels of load escalated by a fixed annual peak-load growth figure, net of energy efficiency savings. Deterministic methods vary from applying a peak load growth rate to historical peaks to summing the peak load forecasts of individual utilities in the region. A final important consideration is whether a study reports coincident or non-coincident peak loads for member utilities. Studies that examine non-coincident peak loads may not fully capture the load and resource diversity available to the region, while studies that examine coincident peak load may overstate the ability of the region to capture resource diversity that is available.

Each study finds that both summer and winter peak loads in the region are growing. The summer load growth figures are notable and reflect increased adoption of air conditioning in the Northwest. While the region is likely to remain winter peaking for the foreseeable future, some studies do begin to identify potential loss of load hours during the summer as well.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study
Peak Load Calculation	CP of all participating utilities in base year followed by 0.7% annual post-EE load growth	Distribution of peak loads for 80 temperature year modeled in GENESYS	NCP of all participating utilities	BPA Load Forecasts	NCP of individual BAs aggregated by WECC

Thermal Resources, IPPs and market purchases

A substantial source of methodological variation across the studies reviewed is their treatment of independent power producers (IPPs). The NWPCC 2023 Assessment and E3 studies account for all the physical capacity, including IPPs, within their respective study footprints. PNUCC includes IPPs that have contracts but does not include uncommitted purchases from IPPs or other market purchases. In contrast, the BPA White Book includes both committed and uncommitted IPPs in its base case. However, BPA includes two sensitivities that examine the load-resource implications if only 50% and 0% of uncommitted IPP generation is available to the region.

Consistent with region-wide trends, a notable finding from many of these studies is that the amount of IPP generation in the region is expected to decline over time.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study
Treatment of IPPs	IPPs Included	IPPs Included	Non-contracted IPPs excluded	IPPs Included	IPPs Included

Hydro Capacity

Hydro power plays a central role in the Northwest energy system. Hydro resources are the single largest source of both energy and capacity in the region. However, assessing the capacity contribution of hydro resources is not a simple exercise and methods vary across the studies. The challenges of assessing hydro capacity contributions range from annual variation in rainfall and snowpack to non-energy constraints on the system. The result is that dependable capacity contribution of the Northwest hydro system for reliability is different from that system's physical one-hour peak capacity. Because of that, each of these studies use a sustained peak capacity figure, with values ranging from 10 to 120 hours. These sustained peaking capacities lead to hydro system capacity contributions that are 60% or lower than system nameplate.

A key driver for each study is the 'Water Year' assumed for hydro conditions. The term 'Water Year' refers to the water availability in a historical year. Deterministic studies typically examine a Critical Water Year, meaning a past year with limited water availability, for reliability purposes, with the two most commonly used years being 1937 and 2001. Stochastic studies typically draw water availability profiles randomly from the historical record, matching permutations of both low- and high-water years with low- and high- resource availability and load conditions.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study
Hydro Capacity	Stochastically selected from 80-year historical annual hydro data	A wide range of hydro conditions modeled in GENESYS	8th percentile based on average water	BPA internal Hourly Operating and Scheduling Simulator (HOSS) model	Based on expected generation curve derived from historical generation

Capacity Contribution of Variable Energy Resources

Like hydro, calculating the capacity contribution variable energy resources like wind and solar is a complicated exercise. A common approach in deterministic studies is to identify the share of name-plate capacity that those resources generate during historical peak load hours and apply that share as a planning assumption going forward. A more data intensive, but state-of-the-art, approach is to calculate the effective load carrying capacity of variable renewables. ELCCs are equal to the additional load that can be met by an incremental generator while maintaining the same system reliability. An ELCC is calculated on a marginal basis, with capacity contributions typically falling as a function of the cumulative installed capacity of any one resource. ELCC figures are sensitive to interactions between different portfolios of resources. All else equal, ELCC's for bundles of resources (e.g. solar + storage) will be higher than the ELCC of an individual resource.

Assumption	E3 Study	NWPCC 2023 Assessment	PNUCC Study 2019	BPA White Book 2018	WECC/NERC Study
Renewables Capacity	ELCC endogenously calculated in RECAP	ELCC endogenously calculated in GENESYS	5%	Renewables are not counted as firm capacity	Based on expected hourly generation profiles in

					peak hour

Appendix D: IRP review

Summary

An important component of the NWPP resource adequacy assessment is acquiring an understanding of the current resource planning methods and assumptions used by the member utilities in their integrated resource planning process. A prospective future resource adequacy program will need to be designed with current regional planning practices in mind. Doing so will ensure that a regional resource adequacy framework is well suited to support the Northwest's ongoing electric system transformation.

1. *Integrated resource planning is more than a resource adequacy program*

An important consideration is that a resource adequacy program does not replace utilities' integrated resource planning efforts or the adequacy assessment component of the integrated resource plan (IRP). This is due to many factors, including:

- **Planning timeframe differences**. Utility IRPs typically look out 10 to 20 years, while resource adequacy programs tend to focus on a 1 to 3 year timeframe. The longer planning horizon of IRPs is important for assessing long lead time resources and to articulate the utility's pathway through the ever-changing power system landscape. For example, a utility may examine a wider range of future load pathways in the IRP than an adequacy program, or use different assumptions about the impact of climate change on loads and resources. However, if a resource adequacy program extends further than 3 years, it may overlap more with IRPs and IRP action plans.

- **Non-adequacy requirements.** IRPs incorporate a multitude of local policy and regulatory directives regarding environmental standards, resiliency goals, conservation potential, energy affordability, customer equity, avoided cost determination, and other critical issues. A resource adequacy program does not address these utility and state specific non-adequacy requirements.

- **Utilities may use multiple planning standards.** Utilities may continue using one or more planning standards they have established for their individual utility's resource characteristics and IRP approach. A utility that volunteers to participate in a resource adequacy program will also be compelled to demonstrate their adequacy based on that program's specific metrics.

A well-designed resource adequacy program could supplement and inform utilities' IRP processes. For instance, resource adequacy program considerations may be incorporated into the short-term IRP action plans required by many State Commissions. In turn, methodologies and assumptions evaluated in an IRP may also help inform the critical requirements of a successful resource adequacy program.

2. *Key takeaways*

- **Each utility approaches resource planning uniquely.** IRPs are the product of a process that is influenced by a utility's regulators, stakeholders, staff, resource portfolio, and other factors. This makes IRPs a tailored product for the utility. Due to the specificity of each utility's IRP, it may be difficult to compare certain components of multiple utilities' IRPs to another.

- **The changing power system is driving the need to review and consider a resource adequacy program.** As large coal units retire, and additional wind, solar, and other carbon-free resources are added to the generation mix, it is increasingly important to understand power system adequacy on a broad, regional level. Understanding the commonalities and differences in the individual utility resource planning processes can help inform the status of the region's resource position.

- **A resource adequacy program brings common, comparable, methods.** Using set methodologies will provide visibility into aggregated resource positions and quantify regional resource adequacy. Additionally, planning on a regional level allows for more efficient resource evaluation (e.g. resource diversity benefits) and a lower aggregated peak load (coincident vs. non-coincident peaks).

3. Open questions

In the course of researching regional IRPs, NWPP members identified several open questions. Some of these questions are addressed in more detail elsewhere in this report and some will not be answered until the RA program moves further into its design stages. The open questions asked thus far include:

- What is the resource adequacy program timeframe? Longer timeframes will overlap more with IRPs.
- Are consumer-owned and investor-owned utility planning approaches compatible?
- Are NERC obligations considered in a resource adequacy program?
- Are different states' approaches to planning compatible with the resource adequacy program?
- Will the resource adequacy program help the region achieve greenhouse gas emission reductions?
- How will a regional resource adequacy program address fuel supply risks?
- How will a resource adequacy program evaluate new resources?
- How is the involvement of stakeholders and regulators envisioned?
- How often will the resource adequacy program requirements and methodology be updated? Will the metrics and approach need to change over time as the mix of resources evolves further?
- How will a resource adequacy program consider the need for transmission and gas transport?
- How does spot market usage fit into the resource adequacy program?
- How will energy efficiency, demand response, and other demand side resources fit into the resource adequacy program? Will these be factored into the demand forecasts? Or in another way?

4. Project overview

This document draws from IRPs and survey data from 16 utilities in the Northwest (including BC Hydro), among other sources. It has been compiled to provide a sense of how utilities in the region conduct long range planning today, with a focus on resource adequacy. The remaining sections include:

- The evolving western power system
- Utility IRP adequacy assessment methods
- Power system resources
- Load forecasts and methods

- Utility IRP load/resource positions
- State level IRP requirements

The graphics/observations based on the survey and utility IRPs are an interpretation of the data. At times the results were difficult to definitively categorize, and not all utilities answered every question. The Northwest Power Pool website has the survey/results, and utility IRPs are accessible online.

The evolving western power system

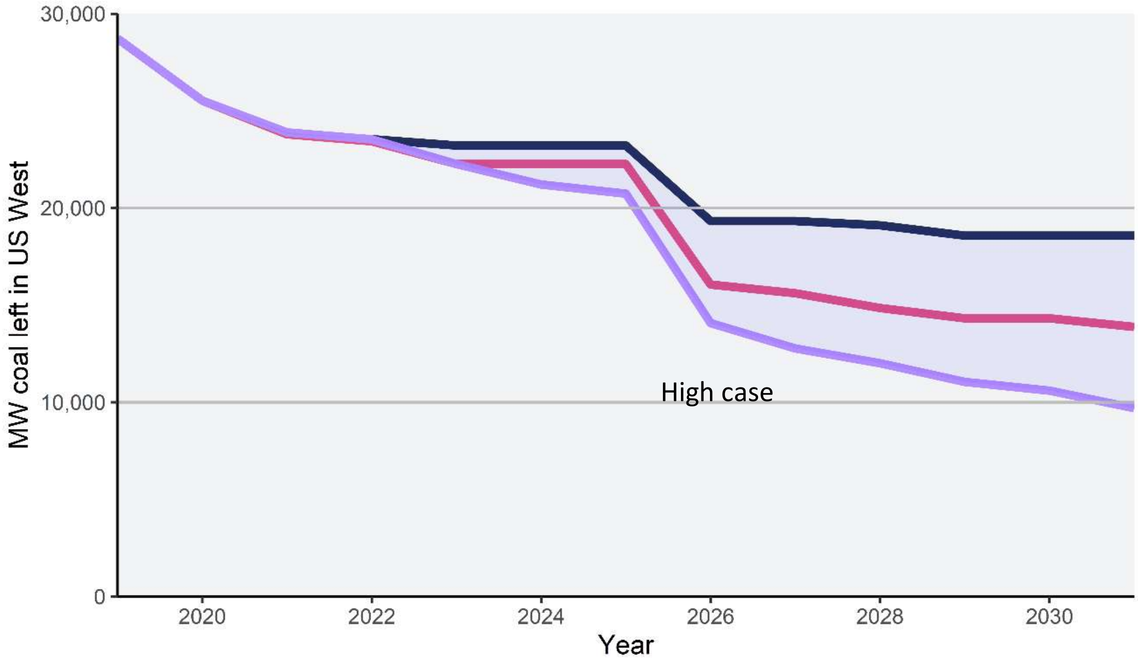
Largely as part of the effort to recognize climate change and pollution, two central forces are reshaping the western power system: thermal plant retirements and state policies ushering in new renewables/carbon-free resources. This section discusses both at a high level.

Thermal retirements

Across the Western Interconnection, thermal units, especially coal units, are retiring. The figure below shows three cases for coal retirements in the US Western Interconnection.

- The reference case includes coal units that have announced a retirement date (e.g. Centralia)
- The mid case includes units that (subjectively) have a higher retirement risk (e.g. the San Juan units that are potentially being sold to an investment firm)
- The high case is built off utilities' IRP high retirement scenarios

Figure 11 – Reference, mid, and high case coal retirement scenarios - US Western Interconnection



Observations

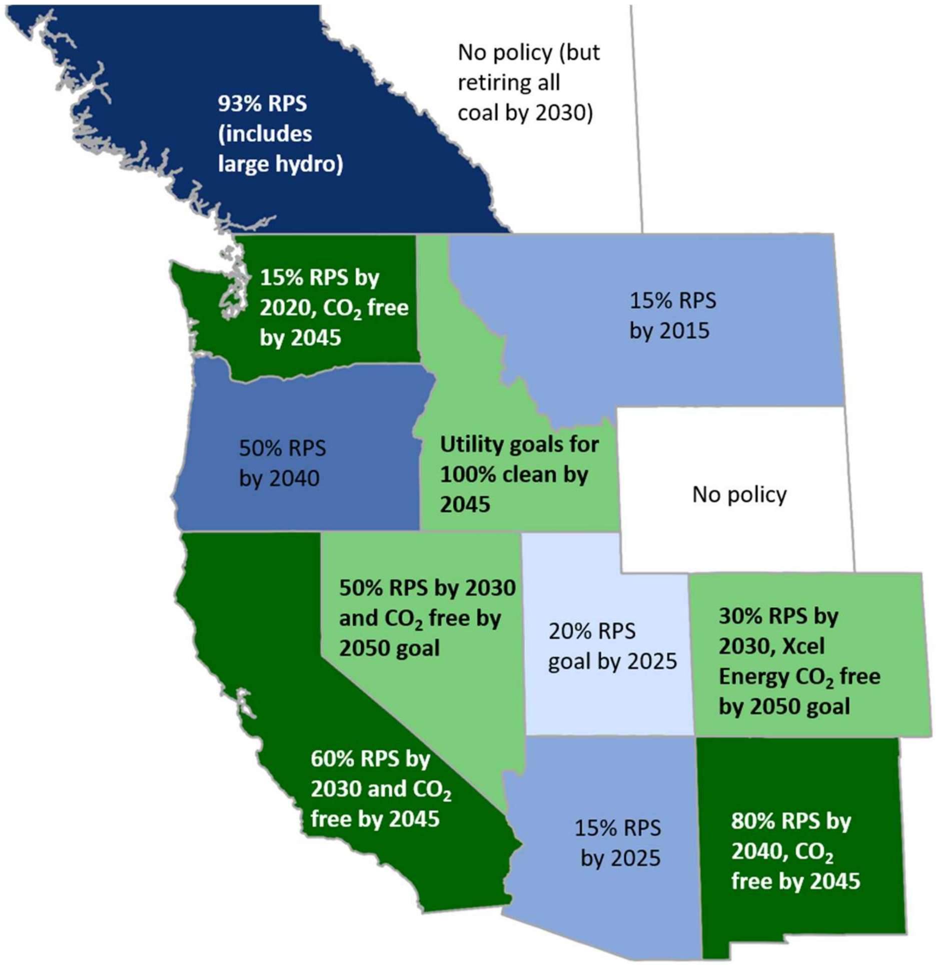
- The pace of coal retirements has been accelerating in recent years. The range of US retirements (~10,000 MW to ~19,000 MW through 2030) may increase in the upcoming years
- The figure does not include replacement power for the retiring coal units. Utilities are actively planning how to maintain system adequacy without these resources
- The figure above does not include Alberta. Alberta has around 6,000 MW of coal in its footprint retiring by 2030 (some of these units are already mothballed). There are tentative plans to replace or convert these units with gas fired generation
- These retirements are in addition to planned non-coal retirements across the West. In California, the Diablo Canyon nuclear units and once-through-cooling gas units are retiring. These retirements tally over 9,000 MW from 2019 through 2029, although there are plans to repower some of those units.

Renewable portfolio standards and carbon free targets

Utilities are subject to many policies and regulations at the local, state/province, and federal level. The map below illustrates, at a high level, electric utility renewable portfolio standards/goals and carbon free/neutral standards/goals in the Western Interconnection (not including northern Mexico).

- In **blue** are areas with renewable portfolio standards/goals; darker colors for higher standards
- In **green** are areas with CO_2 free/neutral standards/goals. Dark green denotes a state level standard, light green is used for state level goals, or where the majority of load is served by utilities with CO_2 free/neutral standards/goals

Map 1 – High level RPS and carbon free/neutral goals in the West



Observations

- Renewable portfolio standards increase regularly. For example, the Oregon RPS for large utilities was 25% by year 2025 until 2016, when it was increased to 50% by 2040
- The state CO_2 free or neutral targets are relatively new – the first was signed into law in California in September 2018. In 2019 three more states (NM, NV, WA) passed similar legislation
- The map also does not show carbon pricing programs that are active in California, British Columbia, and Alberta (although the Alberta tax is currently in flux)

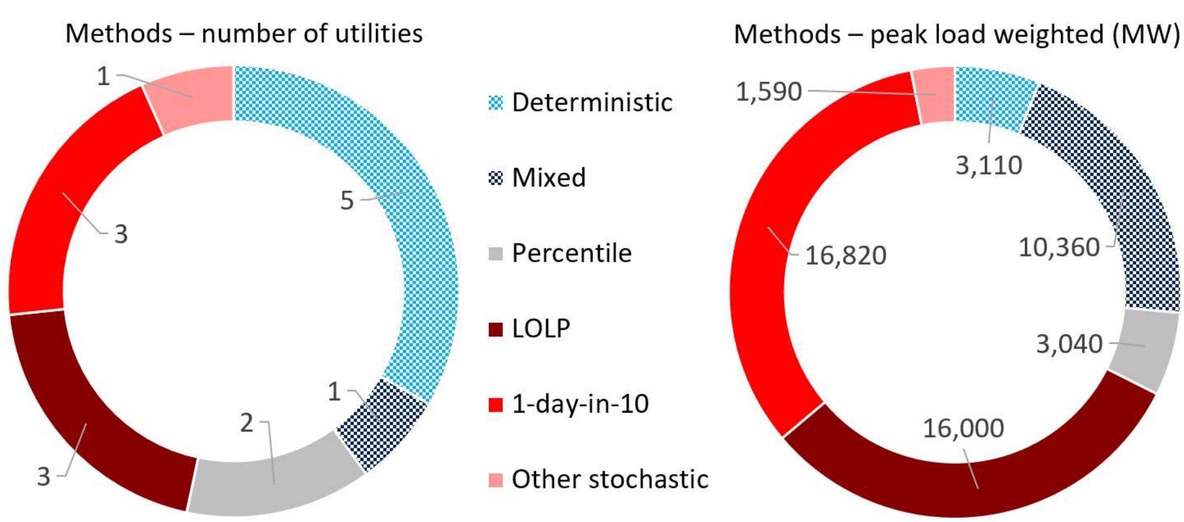
Utility IRP adequacy assessment methods

There are various overarching approaches to evaluating a utility's need for power as a component of an IRP. These approaches set the stage for how utilities conduct their planning. For example, a stochastic approach that may also require more granular data for planning. This section focuses on the methods used for assessing resource adequacy and for determining the need for power.

Resource adequacy assessments in planning

To assess the need for resources, utilities employ a variety of methods for examining adequacy in their long-term planning. The figure below lumps the methods into six bins. Utilities shown in a red hue utilize a stochastic analysis. Utilities with a patterned blue hue use deterministic methods (fixed assumptions). The percentile method is shown in gray. The circle on the left shows the number of surveyed utilities using each method. On the right the same data are weighted by utility peak load.

Figure 12 – Adequacy planning methods differ by utility



Example of approaches used for resource adequacy assessments

- Loss-of-load probability (LOLP), often using a 5% standard

- 1-day-in-10, often calculated via loss-of-load hours, loss-of-load expectation, expected unserved energy, or a combination of those metrics
- Deterministic methods, for example load/resource planning with 1937 or 2001 water
- Percentile method, where a utility models loads and resources to create a 5th or 10th percentile most stressful event and examines how the system performs under those conditions

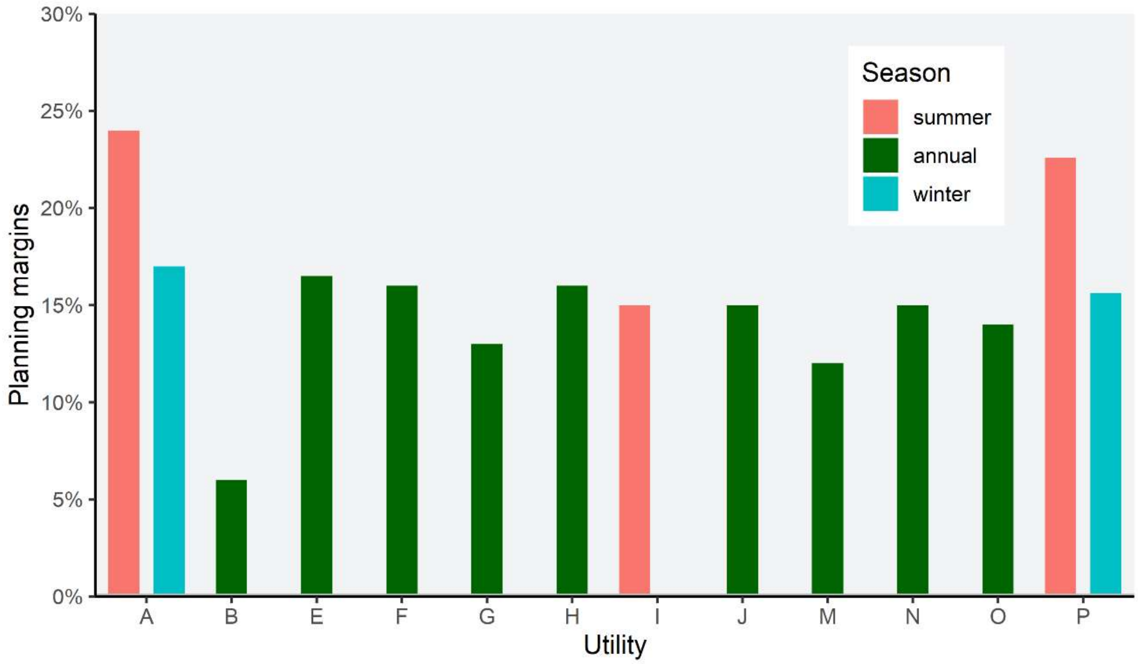
Observations

- Utilities performing deterministic or percentile planning tend to be public utilities. These utilities' primary resource is hydropower (owned or via BPA), and many are focused on energy adequacy
- Most utilities using stochastic approaches are investor owned utilities. These utilities have a diverse portfolio of resources and are more focused on capacity rather than energy needs

Planning margins

Planning margins are used by some utilities to guide the need for resources. For example, a utility may ensure that resources exceed load plus a 16% planning margin. Other utilities do not use planning margins, they rely on other methods, and have to back-calculate the values when asked. For those who use margins, they can account for various factors, including load and resources variations.

Figure 13 – Wide range of planning margins (includes operating reserves)



Observations

- Utilities reported a wide range of planning margins in the survey responses, from 6% to nearly 25% including operating reserves
- Some utilities have different margins in the summer and winter, others use one annual value
- Comparing across planning margins is tricky since they can vary due to assumptions
    + e.g. a utility may include forced outages in a planning margin, or exclude forced outages and account for them elsewhere (which would lead to a lower margin)

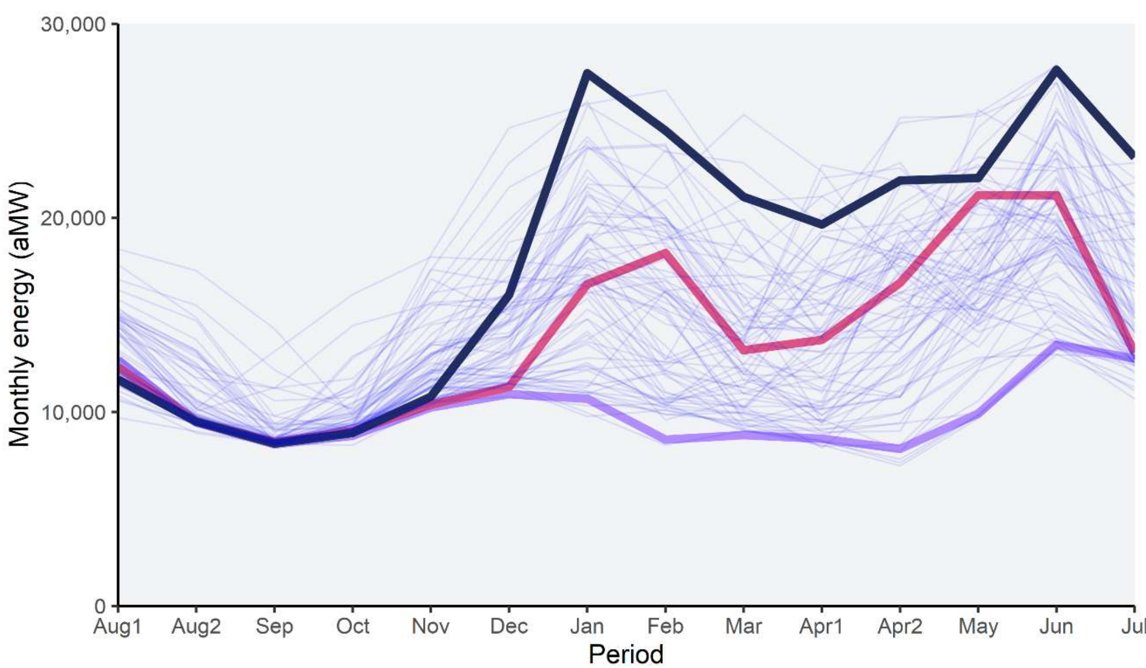
Power system resources

Utilities depend on a wide range of resources to meet load, every second of the year. Resources are evaluated to determine how they provide energy, peak capacity, and more. This section discusses how utilities assess various resources, and at times, reports the resulting values.

Hydropower energy and peak variation

Hydropower is the largest power resource in the Northwest. However, the US portion of the system has limited storage. As a result, there are large annual variations in how much hydropower is available for meeting energy and peak needs. The survey asked utilities to quantify how they vary hydrological conditions in their power planning. The graph below shows 80 different water years from the regional historical record to give an idea of how large the variations can be.

Figure 14 – US Northwest hydro power variability (80 water years, 1937 (blue) 1958 (red) 1974 (Navy))



Example of approaches used to quantify hydropower in planning

- Most utilities use a multiyear hydropower assessment. For example, a utility would use 80 different water years as an input to a stochastic model. The model then cycles though the years to simulate a range of possible conditions
- Some utilities use a deterministic approach. This may involve using a specific water year (e.g. 1937 or 2001), or creating a synthetic year or generation profile (e.g. 8^{th} percentile hydro conditions)

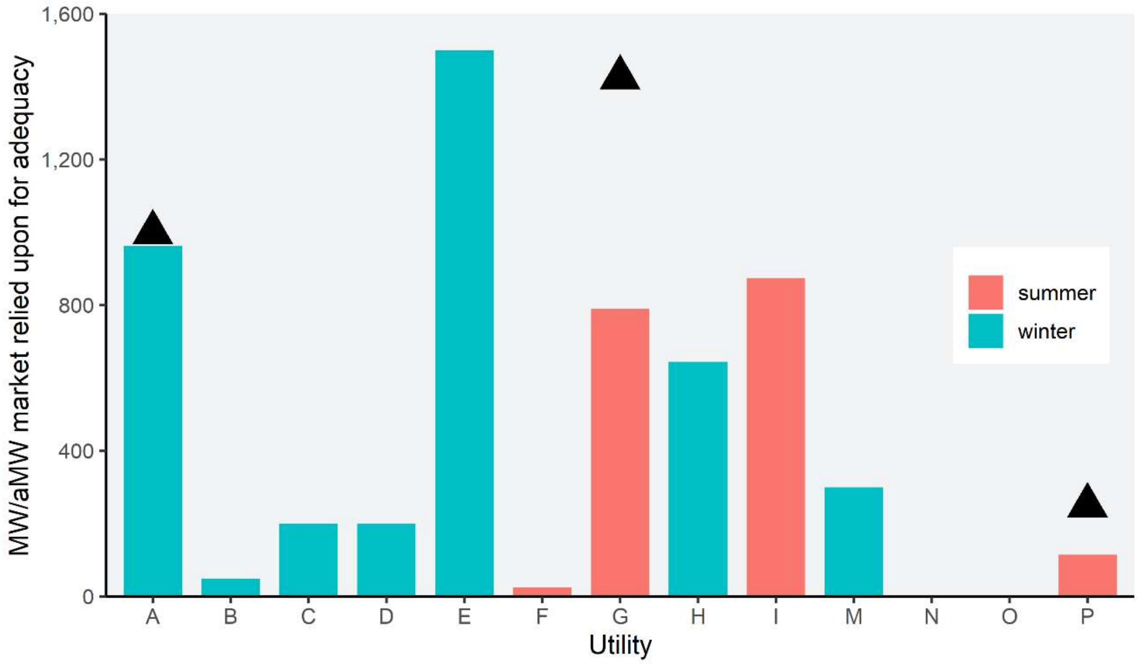
Observations

- Hydropower generation in the Northwest varies annually
- Most utilities include low water conditions in their adequacy assessments either by sampling a wide range of years or by focusing on low water conditions

Utility wholesale power market reliance

In addition to owned and contracted generating resources, utilities often rely on wholesale market power purchases for resource adequacy needs. The graph below shows the depth and amount of wholesale market purchases the surveyed utilities expect to utilize in their long-term planning. Some utilities may still be inadequate following market purchases (barring no additional actions). Wholesale market purchase limitations rise from a bevy of factors, including the expectation that market resources may not be available, and/or individual utility planning risk profiles.

Figure 15 – Market reliance varies in 2025



Note: the height of the bars in this figure depicts the amount of market purchases each of the utilities surveyed by PNUCC plan to rely on to serve their peak loads. The color of the bar indicates weather the utility in question is summer or winter peaking. The black triangles denote the amount of market purchases that utilities have assessed is available relative to their planned purchases.

Example of approaches used to create market assumptions

- Internal or consultant studies of existing planning work (e.g. NWPCC's Adequacy Assessment)
- Internal or consultant studies based on modeling (e.g. using AURORA)
- Discussions with trading staff

Observations

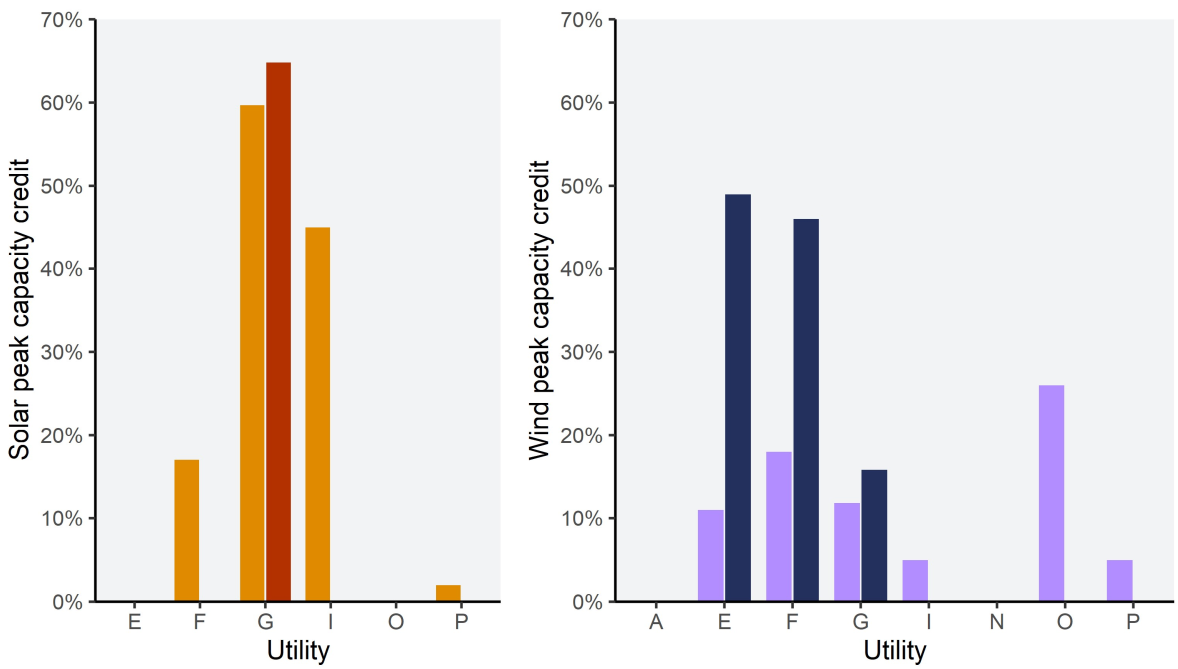
- It is difficult to compare utility market reliance values side-by-side for various reasons, including:
    + Some utilities are seeking short-term capacity from the market. Others are seeking energy products from the market (e.g. a full month of high load hour purchases)
    + Some utilities categorize market in their IRP as short term (e.g. day-ahead) purchases only. Others use a more expanded definition of market that includes monthly or yearly transactions

- Since these assumptions vary by utility, in aggregate, it is difficult to tell if IRP market assumptions paint an accurate picture of how much market power is available

Other renewables peak capacity contribution

As additional wind and solar resources are added to the mix, it is important to take into account their ability to provide energy, peak capacity, and other values. The survey asked utilities how much peak capacity credit they attribute to wind, solar, and other non-hydro renewable resources in IRPs, and the methods used to calculate those values. The figure below shows the estimated peak contribution of solar and wind power on the margin (how much peak need is met by the next nameplate megawatt).

Figure 16 – Expected solar and wind peak contributions vary



Example of approaches used to calculate peak capacity credit

- Effective load carrying capability
- Other stochastic assessment methods
- Percentile exceedance (e.g. historical occurrence on peak at the 10th percentile)

Observations

- Location matters. In the figure above, the higher peak capacity wind resources are in Montana or Wyoming
- The existing utility portfolio influences peak value
    + There tends to be diminishing marginal returns to resource peak value
    + Systems with storage may see higher peak values from new resources
- Summer peaking utilities tend to see more value from solar power than winter peaking utilities
- The survey did not ask if utilities' use ELCC saturation curves
- Not all utilities reported solar and wind peak capacity values. This varied, in part, on if the utility has solar and wind in their existing resource portfolio, and if the utility has a resource or capacity need

Other resources and resource questions

5. Energy efficiency

The survey did not delve into much detail about existing and future energy efficiency programs in utility planning. That said, from reading utility IRPs, discussions with utility staff, past success in meeting the Northwest Power and Conservation Council's Power Plan targets, and observing minimal load growth in the Northwest over the past few decades, utilities in the Northwest have, and plan to continue, to acquire energy efficiency at a high level.

6. Thermal power resources

For thermal resource, most utilities employed one of the following methods to assess peak availability:

- Nameplate capacity used for peak capacity
- Net dependable capacity calculated which includes seasonality and other de-rates
- Forced outages modeled stochastically

- Effective load carrying capability methodology

7. Demand response

Out of the 16 utilities surveyed, four indicated (non-pilot) active demand response programs. The largest amount of demand response was from summer season programs (irrigation and air-conditioning). Most utilities indicated they were starting to examine demand response more intensely going forward.

8. Transmission planning

The survey asked utilities how transmission or other deliverability constraints are accounted for. Responses varied by utility. At a high level:

- Some utilities do not expressly consider transmission in their IRP planning
- Some utilities include transmission costs in their future resource costs

- A few utilities limit their available market purchases due to transmission constraints
- A few utilities include transmission as a potential resource option
- One utility noted they are developing a model to advise on what future transmission paths are optimal to contract with or construct

- One utility noted they take transmission outages into consideration

9. Natural gas fuel constraints

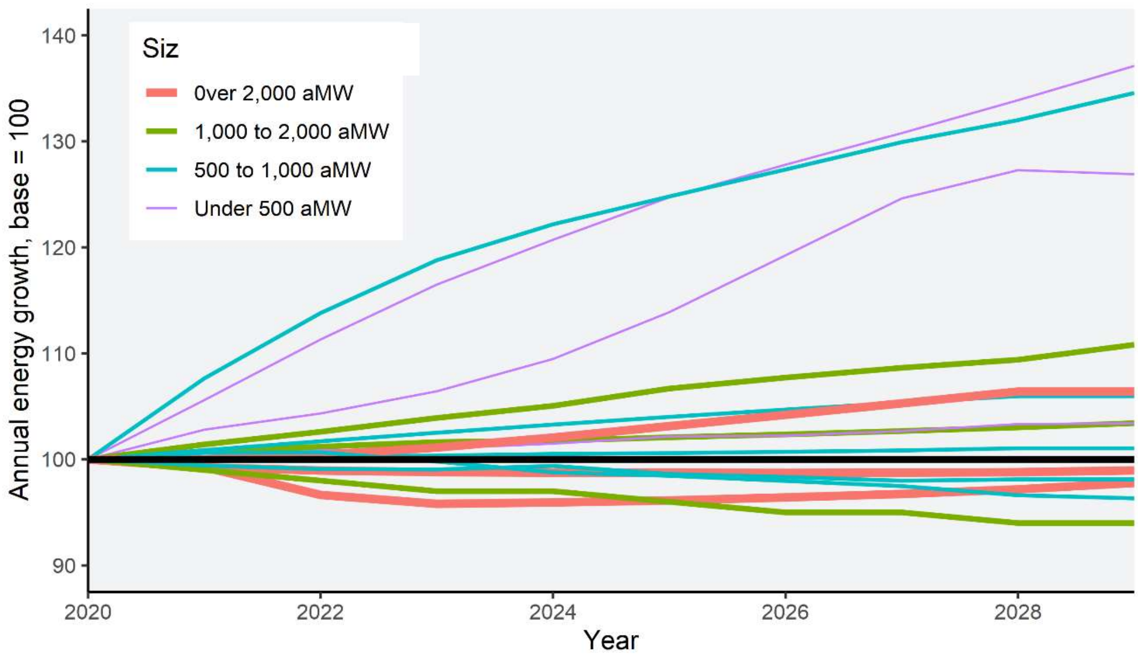
Most utilities surveyed did not consider natural gas fuel constraints as part of their planning. Many did factor in forced outages, which could be adjusted to account for fuel limitations. A few utilities ensure that their gas units have firm pipeline transportation or backup fuel.

Load forecasts and methods

Loads are half of the picture in regard to resource adequacy. This section examines various utility load forecasts and catalogues the various methods used to create them.

The survey asked utilities to report the load growth in their current load forecasts and what method they are using to create them. The figure below shows select normalized annual energy load forecasts. Larger utilities are shown in thicker lines, smaller utilities in thinner lines.

Figure 17- The most aggressive expected growth comes from smaller utilities



Example of approaches used for load forecasting

- The majority of utilities use a mostly econometric forecasting model
- One utility surveyed uses a mostly end-use model
- Some utilities rely on end-use models for residential load forecasts and econometric for other sectors

Observations

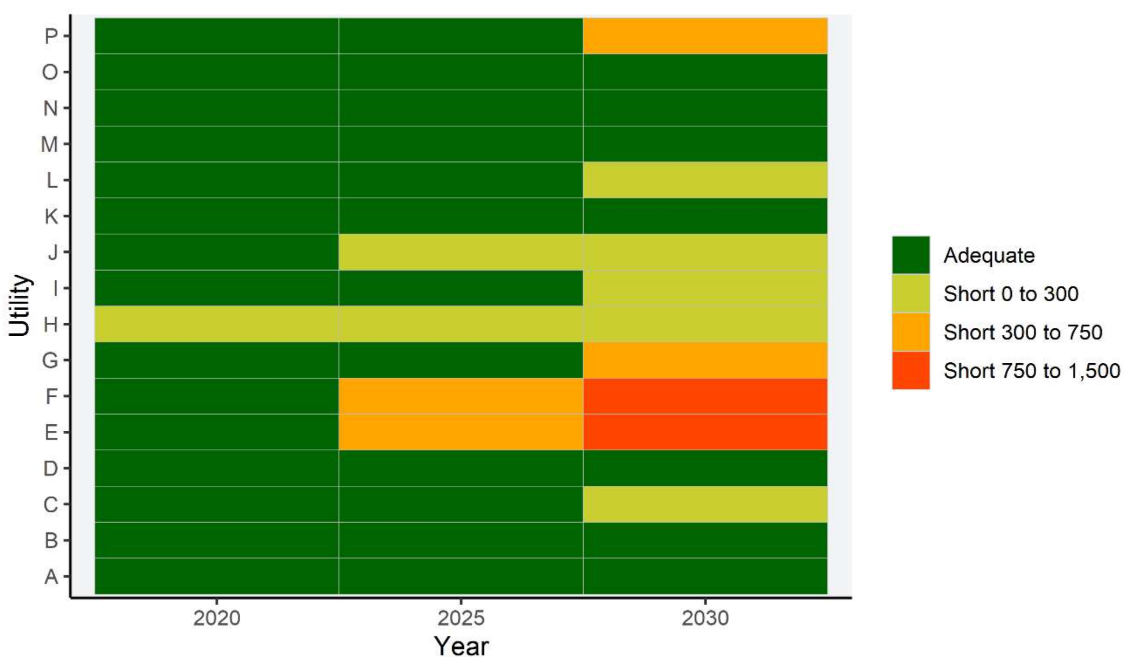
- Utility load growth rates vary, with smaller utilities forecasting more aggressive load growth in percentage terms (likely due to potential large new industrial customers)
- This survey did not investigate if there was a connection between load growth rates and forecasting approach (econometric, end-use, or other)
- Looking at aggregated regional historical loads (not pictured) there has been minimal load growth in the past decade (there are utilities who are growing, and others experiencing a reduction in demand)

Utility IRP load/resource positions

With resources evaluated and loads forecasted, utilities assess their load/resource position and determine if there is a resource need. Assessments vary by utility and methodology.

Utilities were asked to quantify their load/resource position in year 2020, 2025, and 2030. The figure below illustrates this assuming utilities can purchase power from the market as they see fit, have acquired energy efficiency, but have not acquired any new generating resources. These resource positions are not comparable from one utility to the next due to different base assumptions.

Figure 18 – Utility load/resource position (market power available, no new dispatchable resources)



Observations

- Many utilities have a need to acquire resources, starting most pointedly in the early tomid 2020's
- It is difficult to compare these results utility-to-utility for a number of reasons, including:

+ Different planning metrics and standards can lead to different results
+ Some utilities focus on capacity adequacy, others on energy adequacy
+ Peak needs surpluses are not necessarily coincident by time or season. As a result, you cannot sum the values in the figure above to create a regional picture
+ Different planning assumptions (beyond metrics and standards) make comparisons challenging. For example, two utilities could own a portion of the same wind farm but assess its on-peak capacity credit differently

- If utilities acquire their preferred portfolio of resources, they are all adequate in the long run

State level IRP requirements

In review of the different state resource planning requirements there are areas of commonality. The actual planning elements for each state vary but most states have some common minimum requirements including completion of a conservation potential study, and the evaluation of demand response resources, environmental costs, and distributed generation technologies. Identifying and evaluating risks is another common element, including market fundamentals and price forecasts. Most states also require a transmission assessment to be included in the filed resource plan. Finally, several states use the IRP process to help determine avoided costs for PURPA contracts.

For the states included in this NWPP Resource Adequacy evaluation utilities file IRPs on regular intervals with the majority requiring filings every two years. Current legislation commonly requires utilities to develop 10 to 20 year least cost integrated resource plans with shorter action plans (commonly two to five years). Newly passed legislation in some states will require a shorter 10-year resource plan to meet new emission reduction requirements.

For investor owned utilities, state Commissions review the filing and acknowledge that the IRP complies with state standards and guidelines. Acknowledgement is not pre-approval for future rate making decisions. All states require an open public process where commission staff and other stakeholder groups can provide input into the investor owned utility planning process and allow written comments to be submitted after utility IRP filings.

For consumer owned utilities, the governing bodies have more discretion, but most consumer owned utilities follow the same legislation with modified rules that are applicable to the consumer owned utility governance model.

Appendix E: Deliverability, Transmission and Fuel Supply

Resource adequacy programs are designed to enable sharing of planning reserves among load serving entities. However, the total quantity of capacity in the region is not the only consideration for maintaining reliability. RA programs must also consider the deliverability of capacity and fuel across their electric and gas transmission systems.

Transmission

Deliverability challenges following from transmission constraints have led most regional RA programs in the United States to adopt zonal or local capacity requirements, in addition to requirements for their total system need. Zonal capacity approaches typically allocate RA requirements at relatively broad geographies (e.g. states or utility service territories), while local approaches do so at more narrow geographies (e.g. load pockets). In both cases, a key determination of sub-regional RA requirements is a transmission study. Transmission studies examine contingencies, typically modelled during a peak load hour, to determine to what degree deliverability of resources could be affected. Such studies can substantially shift the set of resource options available to a sub-region for capacity planning purposes. For instance, LSEs in Michigan must procure 95% of their capacity obligations from within their zone given transmission constraints to the state from the rest of MISO. Similarly, California conducts an N-1-1 study during peak conditions to determine the deliverability of capacity resources to load pockets in the state. This approach serves as the basis for a local resource adequacy requirement in California.

Given the geographic scope of the Northwest, both its size and terrain, it is very likely that transmission constraints will implicate the design of a regional RA program. In 2019, NWPP began to study this issue, examining the implications of the region's shifting resource mix on the region's transmission system over 5- to 10-year time horizons.

NWPP found that over a 5-year planning horizon the available transmission capacity in the region is sufficient to deliver quantities of renewable energy expected over that timeframe. In the longer term, NWPP found that transmission system upgrades will be needed to address the large regional load and resource imbalances described in the main body of this report. NWPP notes that its US region faces large amounts of coal retirements and posits that the transmission system may operate differently if the replacement locations for these resources are in a combination of wind (e.g. Montana and Wyoming) and solar (e.g. Utah and Wyoming) rich areas.

NWPP's results also suggest that one major transmission addition will be needed in the coming to serve growing summer peak loads in the Northwest. The report notes that additional upgrades may be needed to export power from Montana and Idaho to load centers in Oregon and Washington, but that additional study is needed to fully characterize those needs.

Gas Deliverability

The Northwest natural gas transmission and storage system delivers power to buildings, industry and electric generation. Natural gas generation capacity in the Northwest may expand following both existing and announced coal retirements. Building or contracting with natural gas generators with firm gas transportation service is one potential strategy entities in a regional RA program could use to meet their capacity obligations.

Firm gas transportation means that a customer has a reservation on a gas system that can be called upon at any point in the year. Non-firm gas transportation customers can have their service interrupted when gas systems reach their capacity limits. The role of firm versus non-firm fuel varies across jurisdictions that have resource adequacy programs. A common practice is to apply a non-performance charge for resources that are committed to provide capacity but do not do so in the operational timeframe. These charges tend to be punitive in nature and so encourage generators to procure firm gas service or a back-up fuel. A subset of jurisdictions also incorporate forced outages into their qualification of resources, the result of which is typically incorporated into those jurisdictions PRM.

Recent Studies of Gas Deliverability in the Northwest

Several recent studies have examined the sufficiency of the Northwest's gas system during peak load and contingency events. They include:

- *The 2018 Pacific Northwest Gas Market Outlook*, Northwest Gas Association 2018
- *Western Interconnection Gas Interface Study*, Wood MacKenzie and E3 2018
- *The Northwest Gas Landscape – Looking Forward*, The Power and Natural Gas Planning Taskforce 2015

2018 Pacific Northwest Gas Market Outlook, **Northwest Gas Association 2018**[53]

The Northwest Gas Association (NWGA) produces an annual report that forecasts the Northwest's available gas system, delivery and storage capability and demands. The 2018 report found that the region has more than enough gas supply available to serve annual energy demands, but that it is near capacity for peak planning purposes. NWGA forecasts an uptick in demand from the electric generation sector in the early 2020s as a result of coal-retirements in the region. That increased electric generation, combined with forecasted growth in peak building heating demands, will mean that peak day demands will continue to approach the region's gas delivery and storage capacity, even with the addition of planned pipeline projects. Indeed, the NWGA notes that the region's gas delivery and storage system was recently strained due to a combination of delivery infrastructure contingencies and a late-season cold-snap.

Western Interconnection Gas Interface Study, Wood Mackenzie, E3 and Argonne National Laboratory 2018[54]

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[53] https://www.nwga.org/wp-content/uploads/2019/05/Outlook2018_AllPages.pdf

The Western Interconnection Gas Interface Study was commissioned by WECC to examine the interactions of the Western United States' gas and electric systems. The motivation for this study was to evaluate the deliverability of gas for electric generation in the face of coal retirements and increased deployment of variable energy resources. The study examines different gas system contingencies like pipeline ruptures, compressor station failures or gas supply freeze-offs and explores their impact on electric reliability. The report's key finding is that the western gas system is resilient against gas disruptions across most of its geographies and the maintaining gas infrastructure will be important to ensuring a reliable electric system with high levels of renewables.

The Northwest Gas Landscape – Looking Forward, The Power and Natural Gas Planning Taskforce 2015[55]

This report is a collaboration of the NWGA and PNUCC. It examines the implications large new gas users in Northwest for the region's gas deliverability. Potential large new users include new industrial facilities, new electric generators, LNG export facilities and LNG facilities used for regional transportation fuels. These new users would have the option to elect for either firm- or non-firm gas delivery service. All else being equal, if more of those users opt for firm service, there will be less non-firm gas delivery service available to existing customers. The report discusses several options to increase the capacity of the region's gas delivery system including new pipelines, new storage, recall agreements, demand-side management and biogas.

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[54] https://www.wecc.org/Administrative/Gas-Electric%20Interface%20Study%20Public%20-%202018%20July.pdf

[55] https://www.nwga.org/wp-content/uploads/2015/07/Northwest-gas-inf-FINAL-Jul-2015-v21.pdf