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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2022-0245

SURREBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
January 2023

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SURREBUTTAL TESTIMONY

OF

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FILE NO. EA-2022-0245

Q. Please state your nam2022-0362e and business address.

A. Matt Michels, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Are you the same Matt Michels that filed Direct Testimony in this proceeding?

A. Yes, I am.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your Surrebuttal Testimony in this proceeding?

A. The purpose of my testimony is to respond to certain issues raised in the testimonies of Staff witnesses Brad Fortson, Shawn Lange, and Michael Stahlman.[1] Specifically, I will address the following key topics:

- Ameren Missouri's Integrated Resource Planning ("IRP") process is integral to its business planning and serves as the basis for its resource planning decisions. The importance of the IRP process to decision making and implementation is grounded in the Commission's IRP rules. It is not simply a modeling exercise, and it is critically important in order for the Company to serve its customers reliably and cost-effectively.

[1] Certain issues or points raised by these witnesses are also repeated or summarized in the testimony of Staff witness J Luebbert.

- Ameren Missouri's current IRP preferred resource plan ("PRP"), filed with the Commission in June 2022,[2] provides a firm basis for the need for the Boomtown Project specifically and the Company's planned portfolio transition, of which the Boomtown Project is the first part. Ameren Missouri's planned portfolio transition recognizes the challenges and risks associated with the necessity that it fundamentally shift its resource portfolio from one that is heavily reliant on coal-fired generation to one with much greater reliance on renewables. To accomplish this requires that our planning be more than just an academic exercise.
- The planned renewable resources in the Company's PRP, including the Boomtown Project, are expected to provide significant benefits to customers in terms of risk reduction and a more sustainable supply of electric energy during and beyond the planned transition as the Company also replaces dispatchable resources that ensure reliability.

Q. Do you have any schedules supporting your Surrebuttal Testimony?

A. Yes. I have two schedules attached to my testimony:

- Schedule MM-S1 – NERC's 2022 Summer Reliability Assessment
- Schedule MM-S2 – NERC's 2022 Long Term Reliability Assessment

[2] File No. EO-2022-0362

II. AMEREN MISSOURI'S IRP PROCESS IS INTEGRAL TO ITS BUSINESS PLANNING AND ITS ABILITY TO RELIABLY SERVE ITS CUSTOMERS

Q. Please describe the importance of the IRP process to Ameren Missouri and to its customers.

A. The IRP process is integral to the Company's business planning and essential to its ability to reliably serve its customers. It serves as the foundation for all resource planning decisions. The IRP process directly informs Ameren Missouri's strategic planning process as well as its annual and ongoing business planning process. It also serves as the basis for the Company's assessment of climate and environmental risks and mitigation efforts. Anything and everything that reflects the impacts and risks of resource-related decisions on the business and its customers can be traced back to the Company's IRP process, and it is the primary basis for implementing the resources called for by the Company's PRP.

Q. How does Staff witness Fortson portray the IRP process?

A. Staff witness Fortson appears to downplay the importance and rigor of the IRP process, characterizing it as primarily a "modeling exercise partially formalized by the Commission's Chapter 22 rules."[3] He goes on to suggest that the IRP process provides little recourse for concerns on the part of Staff or other parties with regard to a utility's assumptions, analysis, and plans. He expresses concern that utilities rely in large part on their IRP planning as a basis for supporting near-term resource investments and suggests that this is a recent development and cause for concern.

[3] Brad Fortson Rebuttal Testimony, p. 10, ll. 9 – 10.

Q. Do you agree with Staff witness Fortson's characterization of the role of the IRP process?

A. No. Staff witness Fortson's characterization of the IRP process runs counter to the significance of the IRP process as evidenced by a number of provisions of the Commission's IRP rules and by the history of reliance on the IRP process by the Commission, Staff, and other stakeholders with regard to resource implementation. The following rule provisions clearly indicate that a utility's IRP process is expected to be integral to its business planning and should be the primary basis for the implementation of the resources it needs to serve its customers reliably and cost-effectively:

- Each IRP filing must include a Resource Acquisition Strategy, which includes the PRP and an Implementation Plan for the subsequent three years (i.e., between triennial IRP filings). This clearly indicates an expectation that a utility will pursue the implementation of the near-term elements of its plan as well as steps toward implementation of longer-term elements.[4] That is precisely what we are doing in this case.
- Annual updates are intended to communicate, among other things, a utility's progress on implementing its resource acquisition strategy, including its PRP.[5]
- Utilities are required to notify the Commission of changes to its preferred plan, including specifically the requirement that it notify the Commission

[4] 20 CSR 4240-22.070(6)
[5] 20 CSR 4240-22.080(3)(A)3

of changes to its resource acquisition strategy and ensure that it is aligned with the utility's business plans.[6]

- Utilities are also required to certify in any cases brought before the Commission that any action requested that is affected by electric resource decisions is consistent with the utility's PRP.[7]

With regard to stakeholder opportunities to review and voice concerns regarding a utility's IRP, the Commission's rules provide ample opportunity for such concerns to be raised and addressed. The IRP rules provide Staff and other parties 1) an opportunity to review and comment on the utility's assumptions prior to completion of its integration and risk analysis,[8] 2) 150 days for review and discovery following the IRP filing,[9] 3) the filing of reports indicating any alleged deficiencies or concerns with the utility's filing (including concerns with any assumptions, analysis methods, or conclusions and suggested remedies),[9] and 4) 60 days to reach resolution on any issues identified, with such resolution filed with the Commission in a joint agreement if one can be reached.[10] And if agreement is not reached, the Commission has the power to hold a hearing after which it can order that deficiencies or concerns be remedied.[11]

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[6] 20 CSR 4240-22.080(12)
[7] 20 CSR 4240-22.080(18)
[8] 20 CSR 4240-22.080(5)
[9] 20 CSR 4240-22.080(7) (8)
[10] 20 CSR 4240-22.080(9)
[11] 20 CSR 4240-22.080(16)(D)

Q. How do you respond to Staff witness Fortson's assertion that utility reliance on the IRP process to support near-term resource implementation (including new generation investments) is a recent development and cause for concern?

A. This does not match my experience during the 14 years I have had responsibility for Ameren Missouri's IRP planning. One clear set of examples that contradicts this notion is the implementation of demand side programs under MEEIA.[12] Clear ties between the IRP process and approval of MEEIA programs have been established in practice and by rule. The MEEIA rules provide for the approval of programs by the Commission if they are consistent with the utility's PRP, along with certain policy and administrative conditions.[13] Decisions with respect to changes in generator retirement dates based on a utility's IRP are frequently used as the basis for resetting depreciation rates in rate review cases.[14] Investments in resources to comply with the Missouri RES[15] have routinely been part of utility PRPs and near-term implementation plans as have investments in environmental compliance measures. Rather than being concerned about utilities bringing forward projects and resource decisions that are consistent with the plans they file with the Commission, it should be recognized in a positive manner that such actions are consistent with the fact that the Commission has clearly indicated its expectation that utilities do exactly that.

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[12] Missouri Energy Efficiency Investment Act
[13] 20 CSR 4240-20.094(4)(I)3
[14] This often happens indirectly through a depreciation study, which relies significantly on retirement dates specified in the Company's most recent IRP filing.
[15] Renewable Energy Standard

Q. Are you saying that the IRP process and the PRP in particular should be the sole basis for justifying a specific project?

A. Not at all. Projects must be evaluated for their suitability and feasibility for implementation of a utility's resource acquisition strategy as indicated in its PRP, and changes in conditions since the time a utility adopted its PRP should be considered. This does not mean, however, that we should ignore the rigorous analysis and careful consideration of customer risks and benefits that are embodied in Ameren Missouri's IRP process and reflected in its PRP. If the IRP process were simply a modeling exercise as Staff witness Fortson suggests, I might agree that little or no weight should be attributed to its conclusions. But again, the IRP process is integral to Ameren Missouri's broader business planning and its ability to meet its customers' needs reliably and cost-effectively, and it necessarily reflects considerations that go beyond the basic modeling. It reflects a recognition of the real-world challenges and risks inherent in implementing a true resource acquisition strategy.

Q. Staff witness Fortson also notes that the Company characterizes its IRP filings and supporting analysis as "snapshot(s) in time" and that factors that influence planning and plans themselves can and do change.[16] Is that a fair basis on which to dismiss the importance of the IRP process and its use as the foundation for business planning decisions?

A. No, it is not. Staff witness Fortson quotes from the Company's analysis of transition risks filed in December 2021. That quote indeed indicates the Company's recognition that things can and do change, including the potential that resource needs could

[16] Brad Fortson Rebuttal Testimony, at p. 6.

be further accelerated. It is an indication of the thoughtful process used by the Company's management to carefully consider its decisions and to treat the IRP process as the strategic business planning and implementation process that it is intended to be, recognizing all the risks and uncertainties that are inherent in the planning and decision-making process, and not instead treating it just as a simple modeling exercise.

Q. Did Ameren Missouri file additional analysis of portfolio transition risk subsequent to its December 2021 filing?

A. Yes. As part of the Company's Notice of Change in PRP filed in June 2022, Ameren Missouri included a rigorous analysis of renewable transition risks performed by Roland Berger. Roland Berger's report was included with the filing, and the filing itself, including Roland Berger's report, is attached to my Direct Testimony in this case.[17] Roland Berger's analysis went far beyond what the Company had filed in December 2021, quantifying risks with respect to financing, project costs, and availability of viable projects over time.

Q. Does Staff witness Fortson, or any other Rebuttal witness, provide any discussion or analysis of the Company's June 2022 Notice of Change in PRP filing?

A. Oddly, no. Staff witness Fortson references the filing but offers no analysis of its assumptions or conclusions other than an observation that the preferred plan changed, which is obvious given that the June 2022 filing was a "Notice of Change in Preferred Resource Plan," coupled with an implication that the IRP process is not a suitable basis for supporting resource implementation. As a result, the substance of the Company's analysis in its June 2022 filing, including the robust risk analysis provided by Roland Berger, and

[17] See Schedule MM-D2 attached to my Direct Testimony.

the rationale for the Company's portfolio transition remain completely unchallenged, save the narrowly focused question of near-term need, which itself is based on a narrowly defined academic and theoretical approach to resource planning and implementation. As Company witness Wills' Surrebuttal Testimony describes, it is also based on an unduly narrow viewpoint on what "need" means.

Q. Has the Company changed its PRP since the time the application in this case was filed?

A. No. Ameren Missouri's current preferred resource plan was adopted by the Company's management and filed with the Commission in June 2022, just weeks prior to the filing of its application in this case. The analysis supporting adoption of the new PRP clearly demonstrated the costs, benefits and risks to customers of alternative paths for transitioning the Company's resource portfolio, indicating an advantage of hundreds of millions of dollars in present value revenue requirements ("PVRR") in favor of the Company's PRP.[18] Building the Boomtown Project and then steadily but thoughtfully adding more renewables in the coming years is squarely part of that PRP and mitigates the risks Roland Berger identified and quantified, as discussed in my Direct Testimony and Company witness Mike Granowski's Surrebuttal Testimony. It is difficult to imagine a more timely and conclusive analysis for purposes of supporting near-term resource decisions than a PRP filed less than a month before Ameren Missouri filed this case.

[18] Matt Michels Direct Testimony, at p. 20, l. 3.

III. AMEREN MISSOURI NEEDS TO ADD SIGNIFICANT ENERGY AND CAPACITY RESOURCES OVER THE NEXT 20 YEARS

Q. Did you address the need for the Boomtown Project in this case?

A. Yes. In my Direct Testimony, I described the need for energy and capacity over the Company's 20-year planning horizon. In doing so, I highlighted the need to consider more than just the numbers represented in a utility's capacity position. The capacity position is important, but it does not by itself account for all the considerations necessary to ensure proper planning and ensure that resources will be available to provide reliable and affordable service to customers across of range of conditions, including some that may happen in real time as we operate our fleet to serve our customers' needs.

Q. What is driving the need to go beyond the simple arithmetic of utility capacity positions?

A. The planning environment has seen a major shift in recent years, moving from one that is characterized by capacity surpluses and the predominance of dispatchable resources to one that is characterized by tight capacity supplies and increasing reliance on intermittent renewable energy resources that displace the need for fossil fuels. In the old environment, utilities could rely to some degree on the availability of underutilized resources owned and operated by other market participants to satisfy some degree of shortfall in resources in their own portfolio. Ameren Missouri has historically used a build threshold of at least 300 MW of capacity shortfall before including new generation resources in its plans. In the new environment, such reliance is extremely risky since the entire industry is transitioning its fleet and capacity surpluses have all but dried up.

Q. Has Ameren Missouri seen a similar shift in its own portfolio?

A. Yes. Historically, Ameren Missouri has been a net seller of energy into the MISO market, sometimes in excess of 10 million MWh annually and resulting in additional margins of tens of millions of dollars, which directly offset a portion of costs to customers. This annual energy surplus has been declining as the Company has planned for the retirement of coal units, and as I mentioned previously, Ameren Missouri expects to soon be in a net purchase position absent the addition of new energy generation resources. Enjoying a net sales position not only shields customers from the effects of market price spikes (i.e., it acts as a hedge against market exposure), but it also allows them to benefit from incremental revenues that reduce net energy costs in total.

With the retirement of the Meramec Energy Center (at the end of 2022) and the Rush Island Energy Center (by the end of 2025), Ameren Missouri is entering a period of tighter supply relative to demand in terms of both capacity and energy, with deficits in both capacity and energy looming in the absence of new resource additions.

Q. Have Ameren Missouri's customers realized benefits from the Company's historical long position?

A. Yes. Ameren Missouri and its customers have enjoyed the benefits of capacity and energy sufficient to meet their needs under a host of conditions, and the ability to sell capacity and energy into the MISO market in excess of what is purchased to meet customer needs has provided a significant revenue requirement offset for our customers.

Should we experience price spikes in the future, and there is no reason to believe we won't, our customers will be more exposed to the negative effects of such price spikes in the absence of the resource additions in our PRP and will be less likely to see the kinds of benefits they have enjoyed in the past. I provide additional examples of this later in my Surrebuttal Testimony.

Q. Has there been evidence to support the notion that the planning environment has seen the major shift you describe?

A. Absolutely. Staff witness Shawn Lange describes the results of MISO's capacity auction for planning year 2022-2023, noting that the capacity price in all load zones in MISO's North and Central regions was set to the cost of new entry ("CONE"). Simply stated, this means that there were not sufficient capacity resources bid into the auction to meet the demand and reserve requirements for those load zones.

Separately, NERC[19] issued its reliability assessment for the summer of 2022 in June of last year and stresses the following in its key findings: "System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of operator-initiated load shedding to maintain system reliability."[20]

This reliability assessment together with MISO's most recent capacity auction results clearly indicate that the electric industry has shifted to a new paradigm. At the same time, resource portfolios are increasingly characterized by higher levels of renewables, and with the tax incentives included in the Inflation Reduction Act ("IRA") that trend is expected to continue. MISO's Regional Resource Adequacy Report ("RRA") even states,

[19] North American Electric Reliability Corporation.
[20] Schedule MM-S1, NERC 2022 Summer Reliability Assessment, page 4.

"The (Net Scheduled Interchange) for the future system is projected to become more variable due to the increased penetration of renewables across MISO's neighbors."[21]

Q. How does the shift to this new paradigm change how utilities and the Commission should think about resource adequacy?

A. It changes the consideration of resource adequacy in three important ways. First, it requires a more rigorous consideration of reliability and resource adequacy over smaller timeframes. This includes looking at seasonal differences in demand and resource capabilities as well as more granular *hourly* and *sub-hourly* reliability analysis. The days of focusing solely on *annual* peak demand and expecting the required resources to be able to meet demand in all hours of the year are gone, yet this is the approach reflected in Staff's rebuttal case.

Second, it requires a recognition that consideration of reliability contributions of intermittent renewable resources is likely to change over time as operational experience is gained and analysis methods improve. This introduces some additional uncertainty that was not previously a significant factor in considering resource adequacy. Staff witness Lange describes in his Rebuttal Testimony the complexities involved in assessing the reliability implications of higher penetrations of renewable additions as noted by MISO in its RRA.

Third, it necessitates a more risk-focused view of resource planning to consider potential changes in resource needs and the risk associated with reliance on other market resources to meet demand. Without the benefit of the capacity surpluses MISO and other

[21] MISO November 2022 RRA, page 32; also Lange rebuttal testimony Attachment SEL-2, page 33; Net Scheduled Interchange is the net sum of all interchange schedules between MISO and neighboring Balancing Authorities.

markets previously enjoyed, there is little or no margin to absorb significant changes in resource needs, whether those needs be annual, daily, or hourly. Such changes could be driven by a number of factors, alone or in combination, that may include accelerated retirements due to environmental regulations or economic pressures, reductions in expected demand savings from energy efficiency, increases in demand due to electrification, extreme loads due to extreme weather, catastrophic loss of a major resource, increased onshoring of manufacturing, or other factors.

Q. Has NERC indicated a need to examine reliability more rigorously?

A. Yes. In NERC's 2022 Long Term Reliability Assessment, published in December 2022 and attached to my Surrebuttal Testimony as Schedule MM-S2, it recognized a need for additional consideration of specific issues affecting reliability. Specifically, NERC indicated a need to consider the following:[22]

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services;
- Include extreme weather scenarios in resource and system planning;
- Address IBR[23] performance and grid integration issues;
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons;
- Increase focus on DERs[24] as they are deployed at increasingly impactful levels

[22] *See* Schedule MM-S2, NERC 2022 Long Term Reliability Assessment, page 7.
[23] Inverter-based resources
[24] Distributed energy resources

- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure; and
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure.

Q. How is Ameren Missouri addressing NERC's recommended actions?

A. Ameren Missouri is focused on making a reliable and affordable transition from its "old fleet" to its "new fleet" as described in Company witness Ajay Arora's Surrebuttal Testimony. In short, this approach ensures that there is overlap of the development of the "new fleet" while retaining resources in the "old fleet" to ensure reliability during the transition (NERC's first recommendation listed above). Ameren Missouri also includes the following actions and considerations in its resource planning process:

- Consideration of extreme weather in accordance with the Commission's IRP rules[25]
- Consideration of the need for operational and system experience to assess the reliability contribution and integration needs of intermittent resources like wind and solar;
- Performing granular reliability analysis with the assistance of Astrape' Consulting and its SERVM model to examine hourly and sub-hourly resource needs that are not considered in a traditional capacity-focused assessment of resource needs;

[25] 20 CSR 4240-22.030(8)(B) and 20 CSR 4240-22.070(1)(D)

- Assessing a range of potential for customer-owned DER and the potential impacts of FERC Order 2222 and including multiple levels of DER adoption in the range of load forecasts generated for IRP analysis; and
- Inclusion of a range of potential electrification impacts in the range of IRP load forecasts.

Q. How is Ameren Missouri considering resource adequacy over smaller timeframes and the resource contributions of wind and solar resources?

A. Ameren Missouri is examining resource adequacy over smaller timeframes in two ways. First, the Company has incorporated MISO's new seasonal capacity construct for resource adequacy into its planning process. The Company first included a view of seasonal capacity in its analysis supporting its change in PRP filed last June. Since that time, FERC has approved MISO's seasonal construct, and MISO has released information for market participants regarding the seasonal accredited capacity ("SAC") for each generating unit, including new wind and solar resources, and the required planning reserve margin ("PRM") for each of the four seasons – summer, fall, winter, and spring. These values will be relied upon by market participants in preparing bid submittals for MISO's March 2023 planning resource auction, which will set capacity prices for each season for the 2023-2024 planning year. Ameren Missouri's planning has focused primarily on the summer and winter seasons to date, since those seasons are expected to drive resource needs.

Second, Ameren Missouri uses detailed hourly and sub-hourly modeling to assess reliability. This has largely been performed by Astrape' consulting with its SERVM model, which is also relied upon by various RTOs, including MISO. In short, the SERVM model examines reliability with robust consideration of uncertainty and volatility – generator outages, load variability, wind and solar output variability, and other factors.

Ameren Missouri's consideration of seasonal resource adequacy and granular reliability modeling are described in detail in my Direct Testimony in this case, including Schedule MM-D2.

Q. How does Ameren Missouri consider risk with respect to resource adequacy?

A. The main way risk is considered is through examination of different scenarios such as accelerated retirements and significant changes in demand. I provide examples later in my Surrebuttal Testimony.

Q. Have you updated your assessment of resource need to incorporate any changes?

A. Yes. I have updated the Company's capacity positions for winter and summer using the latest seasonal PRM and SAC values provided by MISO in December 2022 and prepared different scenarios to elaborate on the Company's consideration of risk. I have also updated energy positions and included scenarios for risk consideration.

Q. What is the primary benefit of renewable resources with respect to resource adequacy?

A. Renewable resources such and solar and wind are primarily energy resources, but also provide benefits in terms of capacity. For example, MISO has preliminarily determined that new wind resources will receive a capacity credit of 18% in the summer and 40% in the winter, while new solar resources will receive a capacity credit of 6% in the winter and 45% in the summer. While generation from renewable resources is expected to provide capacity benefits, the primary benefit of these resources is in providing low-cost, carbon-free energy throughout the year. I discuss in more detail the benefits of renewable resources later in my surrebuttal testimony.

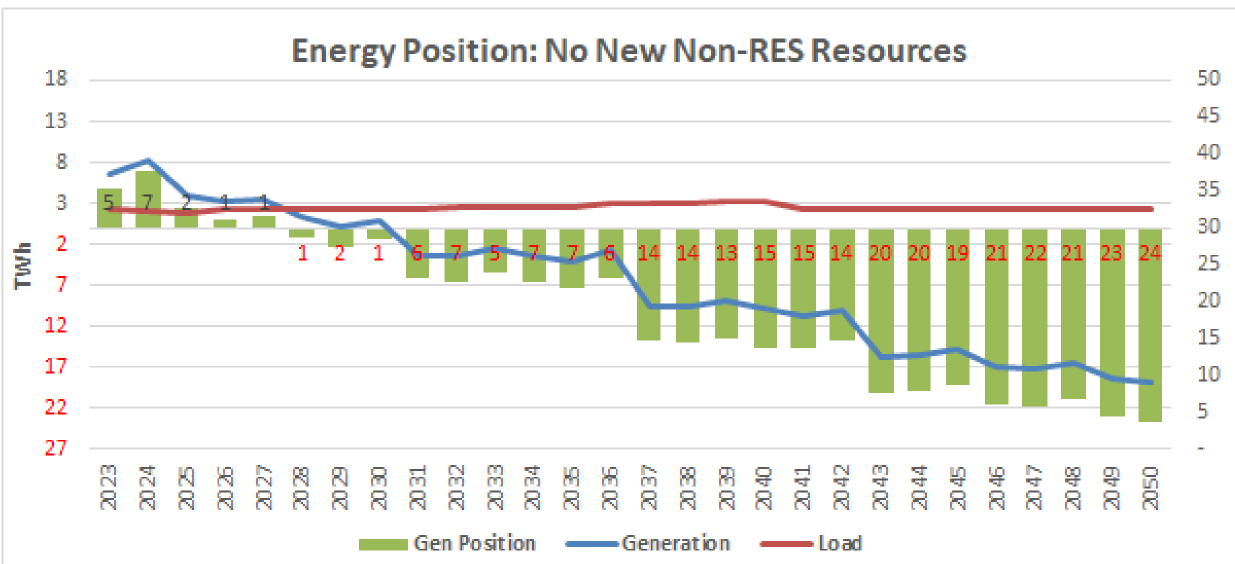
Q. Please discuss your approach to assessing energy needs.

A. Ameren Missouri's consideration of energy needs necessarily takes a long-term view. Over the next twenty years, Ameren Missouri expects to retire all of its coal-fired generation. The Meramec Energy Center was retired at the end of 2022, the Rush Island Energy Center will retire in the couple of years – no later than 2025, and the Sioux Energy Center is planned to be retired by the end of 2030. That will leave roughly 2,400 MW of coal-fired generation at the Labadie Energy Center, with retirement currently planned for two units in 2036 and the other two units in 2042. These coal-fired energy centers have historically provided roughly 70% of Ameren Missouri's electric generation, with another 20-25% from nuclear generation and the small remainder coming from a combination of renewables (including hydro, wind, and solar) and gas/oil peaking units. This means that large amounts of new energy generation will be needed, and low-cost, carbon-free resources will need to play a major role in providing that energy given the current and expected policy landscape and public and investor sentiment favoring such resources. This transition cannot be accomplished overnight, and Company witness Ajay Arora discusses in detail the practical considerations, and difficulties, of implementing a large, long-term renewable resource buildout.

Q. What does your analysis of long-term energy needs show?

A. The figure below shows annual normal[26] energy generation compared to normalized sales[27] with no new generating resources added other than the Huck Finn solar project, which is being added to meet the requirements of the Missouri RES. As should be expected, the shortfall in energy steadily grows as coal-fired resources are retired (in 2024-25, 2030, 2036, then 2042) and reaches 20 TWh in 2043, or about 60% of expected retail sales. In the near term, Ameren Missouri would go from a relatively strong annual net seller of energy in 2024 with a significant drop to becoming only a slight net seller in 2025-2027, then to a net purchaser of energy starting in 2028.[28]

Figure 1

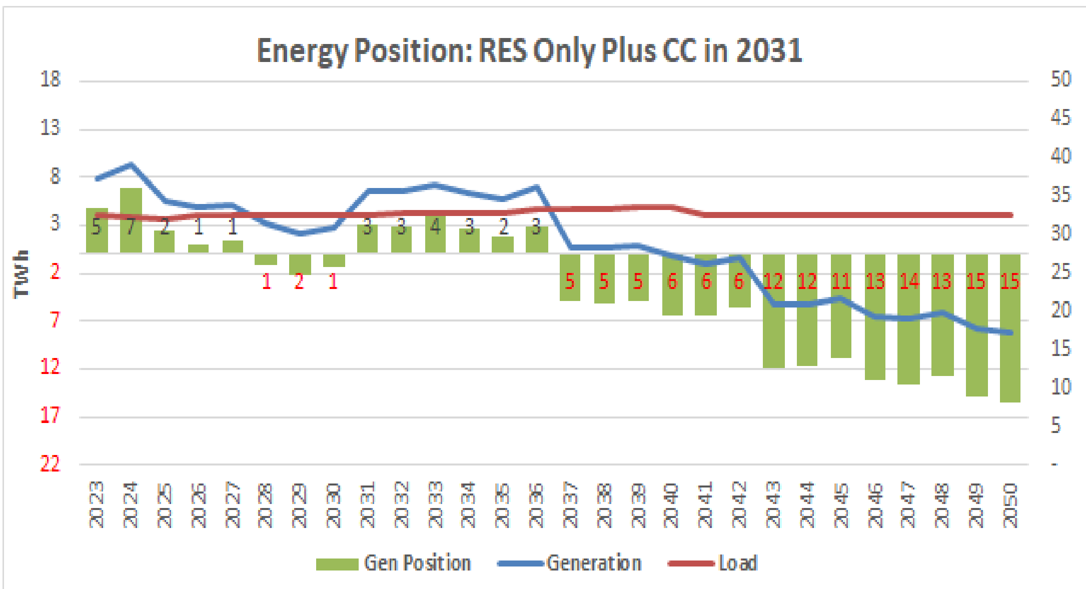


[26] "Normal," meaning without the unexpected loss of a major unit, or significant curtailment of generation (e.g., as was required in summer 2023 due to coal conservation), or other events or circumstances that can impact generation.
[27] *E.g.,* without considering the impact of extreme weather events.
[28] These numbers assume the Rush Island Energy Center continues as a system support resource throughout 2025 and then retires, but it may retire earlier – as early as 2024. Note that these numbers reflect approximately 2 million MWhs (2 TWhs) of generation from Rush Island in 2023 – 2025.

Q. Staff witnesses Fortson and Lange point out that Ameren Missouri's PRP includes the addition of 1,200 MW of natural gas combined cycle generation in 2031. How does that affect the Company's expected energy position in the absence of additional renewable resources?

A. First, it is important to note that, as Staff witness Lange acknowledges, the combined cycle gas addition in 2031 is primarily for capacity to ensure reliability. It is also expected to generate energy when market conditions warrant, but the amount of generation is dependent on those market conditions and may also be affected by other factors such as future environmental regulations. Based on the Company's modeling reflected in its June 2022 PRP analysis, the energy position including the 2031 combined cycle gas generation is shown in the figure below. It shows that Ameren Missouri would of course still be short energy from 2028-2030 prior to the combined cycle going into service. The Company would become a modest net seller of energy (on an annual basis) from the time the combined cycle begins operation in 2031 and continuing through 2036. Ameren Missouri would again become a net purchaser in 2037, first at about 5-6 TWh per year then increasing to 12 or more TWh per year starting in 2043. Again, this and other figures I present all assume normal generation and loads, but we all know that events or circumstances can arise that substantially reduce generation or increase load at times, as I discuss below, and as Company witness Arora discusses in his Surrebuttal Testimony. It is worth noting that the additional renewable generation added in the Company's current PRP (2,500 MW of solar and 2,000 MW of wind) would be expected to generate about 13 TWh annually based on assumed average capacity factors.[29] This would just meet the need for annual energy once all coal is retired and the 1,200 MW combined cycle generator is added, with a small amount of margin based on current assumptions for fuel and power prices, and loads.

Figure 2



Q. What kind of risks are inherent in the energy position shown above?

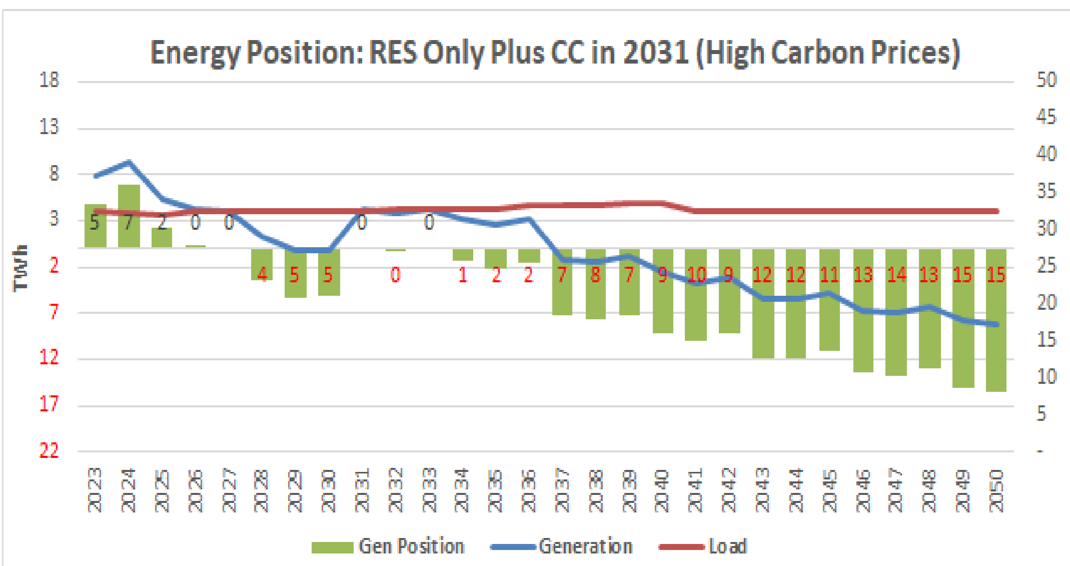
A. A number of risks are inherent in any energy position. Among these are risks associated with environmental regulations and market conditions that challenge the economics of remaining coal-fired resources (i.e., Labadie).[30] To put it simply, the energy position shown for 2037 in Figure 2 above would be representative of any year in which

[29] The amount of generation from future renewable resources could be lower, particularly for wind resources which are subject to greater risk of declining project quality over time, depending on build timing and site availability as described in Roland Berger's renewable transition risk assessment report included in Schedule MM-D2 attached to my direct testimony.
[30] Or before 2031, Sioux, since no one can say with certainty that Sioux's currently expected retirement date of 2030 will not change.

two Labadie units became unavailable to generate, and the energy position shown for 2043 would be representative of any year in which four Labadie units became unavailable.

Another specific risk is that of higher-than-expected carbon prices. Ameren Missouri uses a range of carbon price assumptions for its IRP analysis, as described in Schedule MM-D2 attached to my Direct Testimony. If we were to experience high carbon prices, generation from coal and gas resources would be reduced, and the energy position would appear as shown in Figure 3 below. As the figure shows, Ameren Missouri's annual energy position would be effectively flat to negative in every year starting in 2026 (and possibly 2025 if Rush Island is retired sooner than modeled). In no year would we expect Ameren Missouri to be a significant net seller of electric energy, and we would be increasingly and substantially short of meeting our customers' annual energy needs.

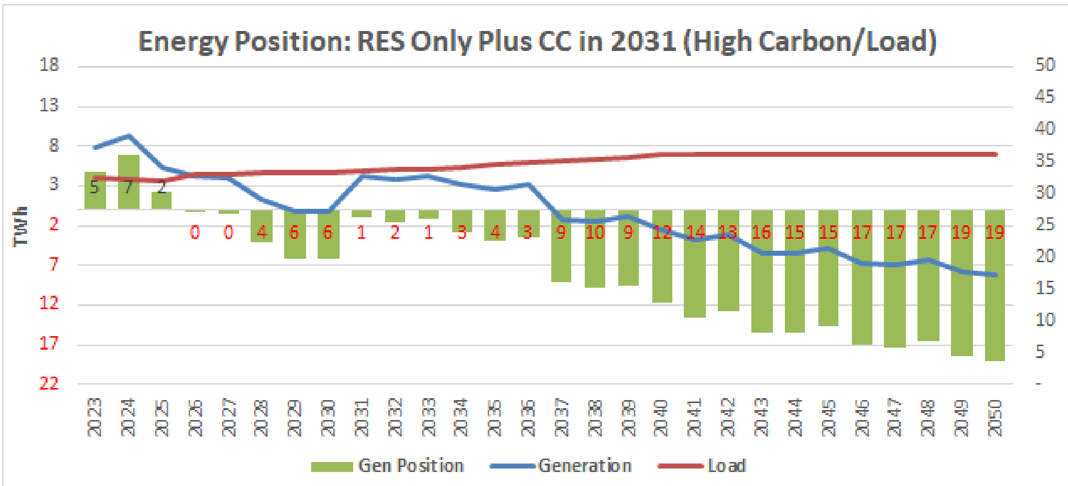
Figure 3



Ameren Missouri also evaluates a range of load forecasts as part of its IRP process to capture uncertainty in general economic conditions, the effects of customer adoption of DERs, and the contributions of efficient electrification. Figure 4 below shows Ameren

Missouri's energy position under high carbon prices and high load conditions. Under this scenario, expected energy shortfalls further increase, including a shortfall of 6 TWh by 2029.

Figure 4



Q. How much energy is the Boomtown Project expected to generate?

A. Approximately 350 thousand MWh annually. There is no doubt that Boomtown helps but is only a start, and we need to get started if we are to add, cumulatively, the renewable resources necessary to obtain the energy we need to reliably serve our customers.

Q. Ameren Missouri's June 2022 PRP change filing reflects another 1,200 MW of dispatchable generation in 2043. Won't that also provide energy to meet the future need?

A. That depends on what kind of resource is deployed in that timeframe. The need at that time is for dispatchable capacity to ensure reliability in the context of variable resources like wind and solar. What that resource will be remains to be determined and depends in part on the development of new generation technologies. How much energy that unspecified resource produces depends on the nature of the resource and market conditions at that time. If it is satisfied with storage resources, no additional energy will be produced. Regardless, we have need in the 20-year period before we get to 2043 that must be addressed.

Q. Is it possible that Ameren Missouri may not need the full amount of renewable resources shown in its PRP through 2040?

A. It is possible, but more so for renewable capacity that, under our PRP, we plan to add after 2030. There is much less chance that the renewable capacity additions our PRP calls for prior to 2030 will not be needed, and there is virtually no chance we won't need at least 150 MW of solar, which is the size of Boomtown. It is also possible that we may need more renewable resources than shown in our PRP. Regardless, we can and will adjust the mix of wind and solar we add throughout the planning horizon, including prior to 2030, as conditions change. That we cannot say for sure exactly how much we will eventually need, and when we will need it, simply highlights the importance of the flexibility that Ameren Missouri maintains as part of its IRP process. As conditions change – technology development, policy changes, market changes – the Company can adjust and refine its planning. Changing conditions will also likely include changes in the resource plans and implementation of other market participants, both in MISO and in neighboring regions. Staff's witnesses are right to point out that conditions can and do change. Rather than wait for such conditions to settle (and they *never* will), it is important that the Company take incremental steps to execute the transition of its portfolio based on the best information available, the consideration of risk and uncertainty, and the need to continue to maintain flexibility.

Q. If the Company is able to execute on its PRP, what does the energy position show?

A. Figure 5 below shows the Company's expected energy position for its PRP. This shows sufficient energy in every year and that Ameren Missouri would be expected to be a net seller of electric energy at levels roughly equivalent to what it has seen historically.

Figure 5

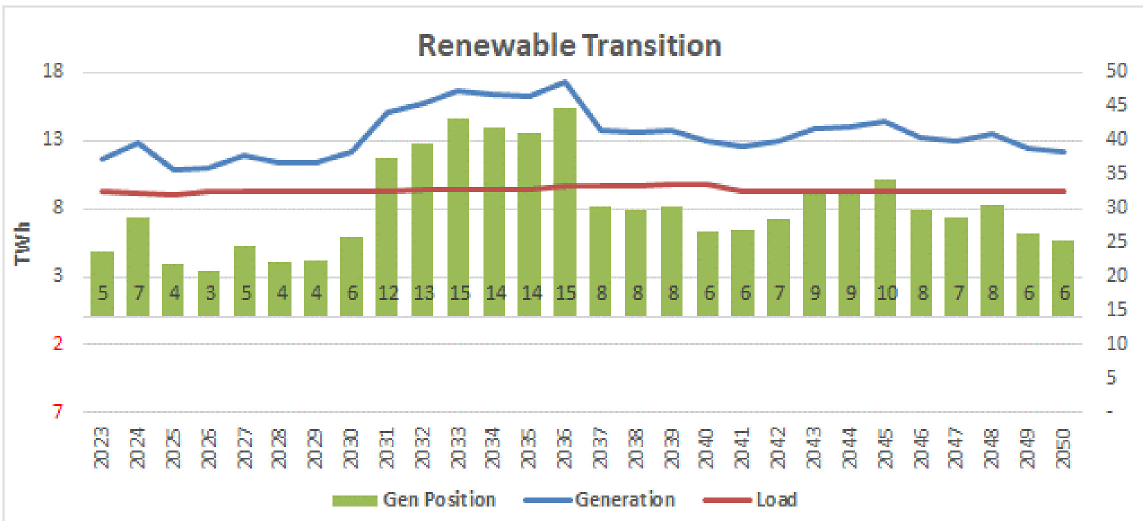
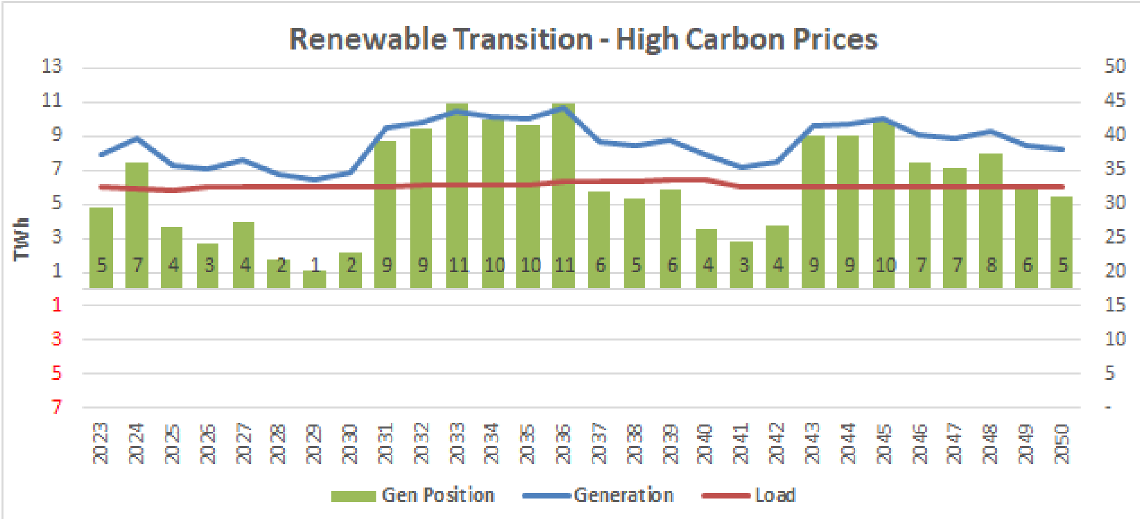


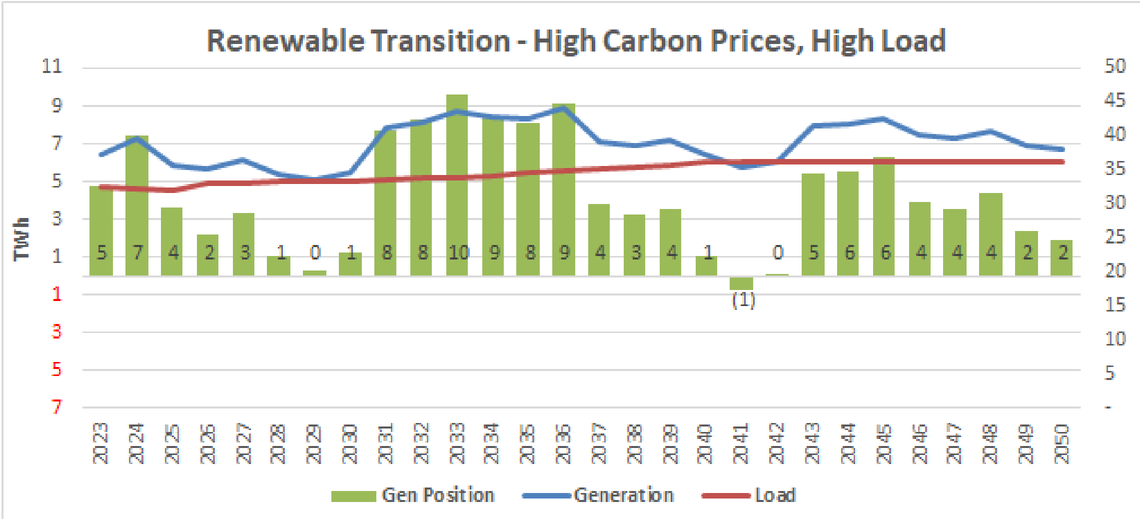
Figure 6 below shows the Company's energy position under a high carbon price scenario. As Figure 6 shows, the net energy sales position under high carbon prices would be reduced to 1-2 TWh in 2028-2030.

Figure 6



If high loads are also included in the energy position, the result is the chart in Figure 7 below. This chart shows that under these assumptions, we would expect to just meet customer energy needs in 2029, with a small buffer of 1 TWh in 2028 and 2030. Beyond 2030, we would expect a 1 TWh energy shortfall in 2041. While there is sufficient time to reevaluate expected conditions and adjust plans accordingly to address potential issues as far in the future as 2041, the nearer term needs could not be met absent the renewable resources in our PRP, and options to address any shortfall absent these resources could be limited, to the extent sufficient options are available at all.

Figure 7



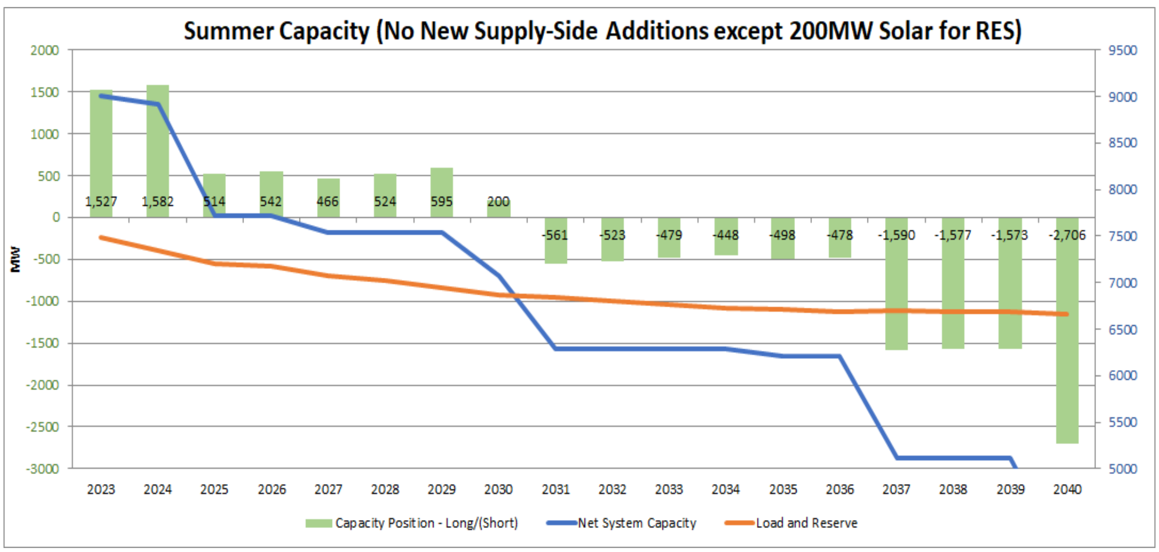
The revenues from net energy sales accrue to customers, either through base rates or through the Fuel Adjustment Clause ("FAC"). This benefit is included in the PVRR results I described in my Direct Testimony, which shows that the Company's PRP (aka, Renewable Transition) **results in lower costs to customers by more than $600 million** compared to a plan in which the vast majority of renewable additions are delayed. The table highlighting this difference is included later in my Surrebuttal Testimony as Table 1.

It is important to note that the PVRR results shown do not reflect the value of extended and expanded tax credits, which Roland Berger estimated to be $339 million, as shown in Schedule MM-D2 attached to my Direct Testimony. This estimate was based on provisions of the previously considered Build Back Better Act and does not reflect certain provisions of the IRA such as bonus tax credits for projects, like Boomtown, located in statutorily defined "Energy Communities." That these credits in fact are available beyond the period assumed in our June 2020 Preferred Resource Plan filing makes adding renewables according to that plan instead of taking Staff's approach *even more favorable* for our customers; i.e., the PRP is even better for our customers compared to the wait-and-see approach that we had presented in our direct case, before the Inflation Reduction Act had become law.

Q. You mentioned that you have also updated summer and winter capacity positions. What do those show?

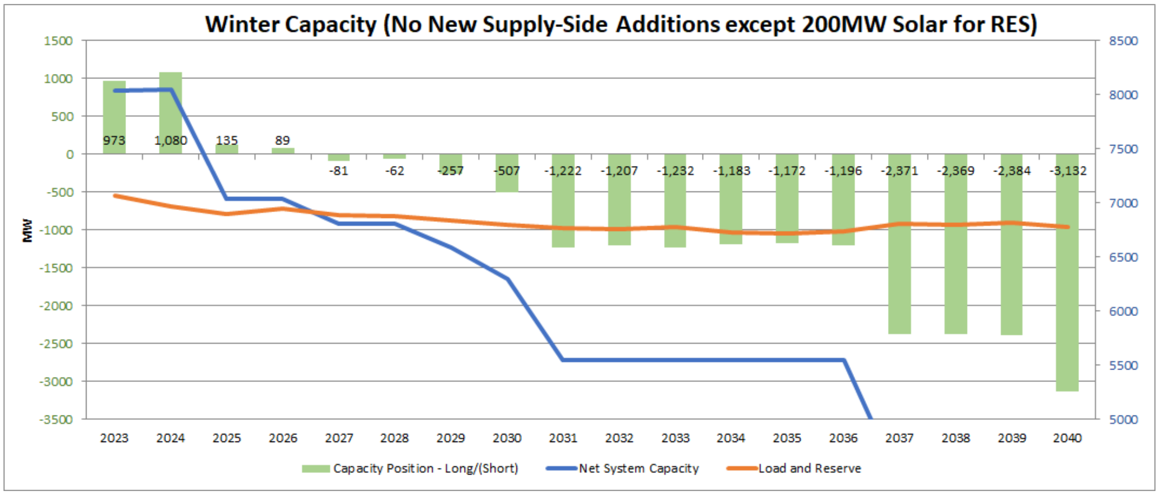
A. Figures 8 and 9 below show the winter and summer capacity positions with no new resources other than 200 MW of solar added for compliance with the Missouri RES (i.e., the Huck Finn Project).[31] These capacity positions reflect the latest information from MISO regarding the values for PRM and SAC for the Company's resources for each season.

Figure 8



[31] The Huck Finn Project CCN Application is pending in File No. EA-2022-0244.

Figure 9



The summer capacity position shows a need starting in 2031. The winter capacity position shows a need starting in 2027. If we look at the capacity positions for Ameren Missouri's PRP, we see Figures 10 and 11 below. Note that the winter season tends to be the driver for capacity needs. This is due in significant part to fuel constraints for simple cycle gas-fired resources, for which purchasing firm gas transportation tends to be prohibitively expensive. This is manifest primarily in a higher PRM for winter (25.4%) than for summer (7.4%).

The winter capacity position drops precipitously in 2025 (as noted, this could occur in 2024) as a result of the impending retirement of the Rush Island Energy Center. After that, steady additions of renewable resources, primarily wind, help to maintain sufficient capacity to meet load and reserve margin requirements. The expected capacity surplus grows as storage resources are added in 2034-2037 in advance of the retirement of two Labadie units at the end of 2036. There is a capacity deficit in 2040 after the retirement of the remaining Illinois CTGs (Venice having been shown to be retired in 2029).

Figure 10

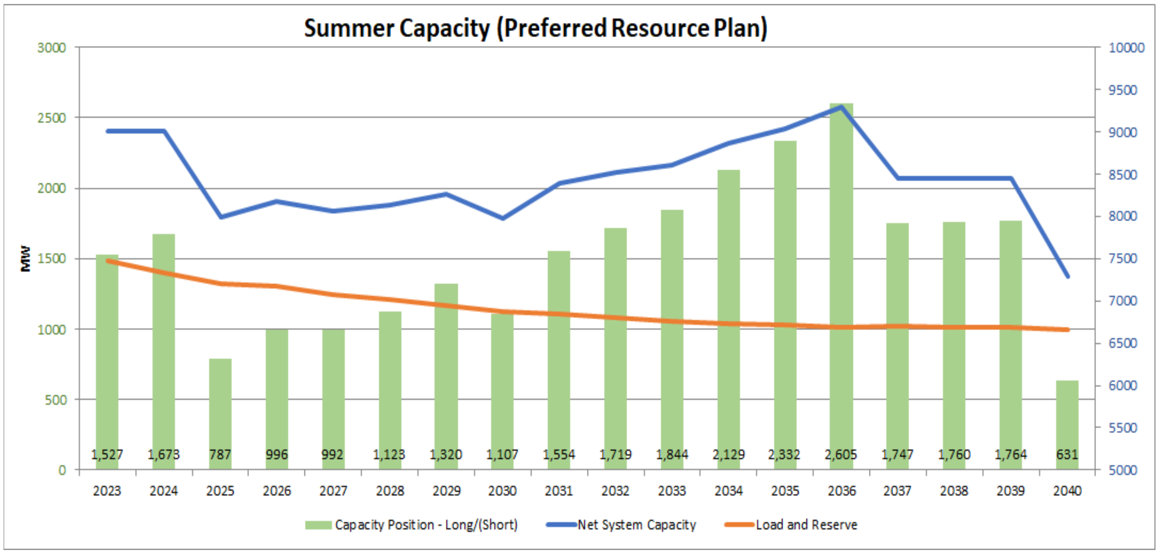
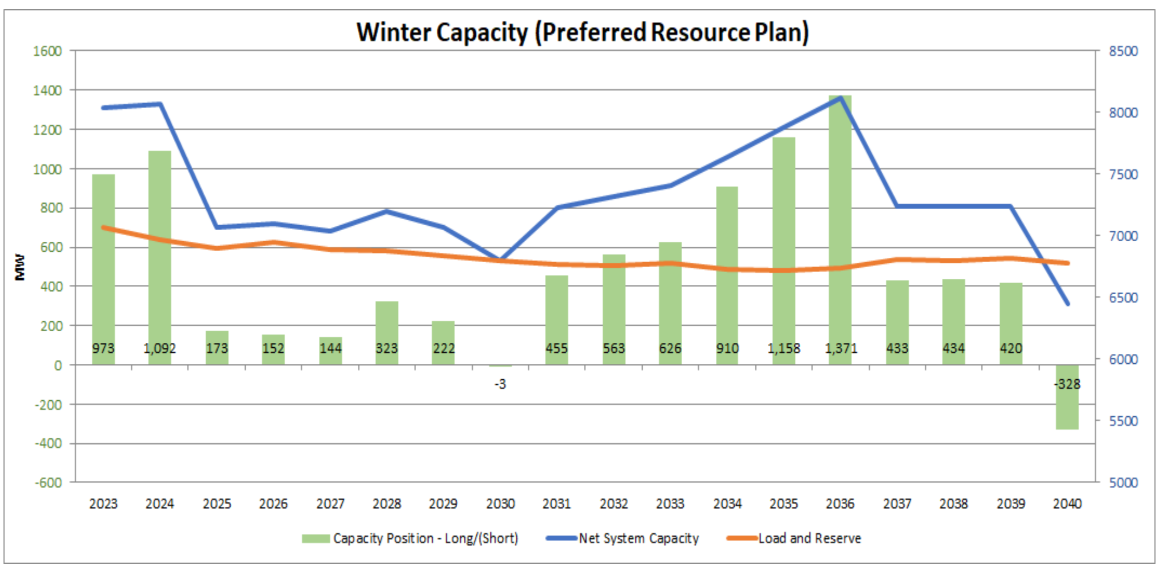


Figure 11



Q. Staff witness Fortson quotes from one of Ameren Missouri's filings, indicating that the Company does not expect to have a capacity need for 15 years (from the time of the quoted filing).[32] Why are the capacity positions above showing an earlier capacity need?

A. Staff witness Fortson is quoting from the Company's Transition Risk Analysis filed in December 2021. The preferred plan at that time reflected retirement of the Rush Island Energy Center in 2039 as well as continued operation of Ameren Missouri's Illinois CTGs through the entire planning horizon. The Company filed its updated PRP in June 2022 to reflect retirement of Rush Island by the end of 2025, the retirement of Venice by the end of 2029, and the retirement of its other Illinois CTGs by 2040. These changes involved the accelerated retirement of about 3,000 MW of generating capacity. This is demonstrative of exactly the kinds of risks inherent in real world capacity planning. Staff simply ignored these changes in the Company's PRP.

At the same time, significant changes were being made in our consideration of MISO's new seasonal capacity construct, which resulted in updated values for both the PRM and capacity accreditation and a newly placed emphasis on winter season capacity as I described above.

[32] Brad Fortson Rebuttal Testimony, at page 6.

Q. Staff witness Lange discusses the Illinois Climate and Equitable Jobs Act ("CEJA") and the Rush Island retirement in his rebuttal testimony, remarking that the Company indicated it had performed no analysis of the impact of the Boomtown project on these issues. How do you respond?

A. Both questions are framed backwards. CEJA and the retirement of Rush Island directly impact the Company's energy and capacity outlook, as I have described in detail previously in my Surrebuttal Testimony. Implementation of the Boomtown Project would not have an effect on either the implementation of the requirements of CEJA or the retirement of Rush Island, but both of those realities influence the energy and capacity needs, as I have reflected in the analysis included in both my Direct and Surrebuttal Testimonies, that can be met by the Company's PRP, and in part by Boomtown.

Q. Staff witness Stahlman expresses concern about the location of the Boomtown project in Illinois, suggesting that this creates risks associated with potential changes in state energy policy or a change in RTO by Ameren Missouri. Are these significant risks?

A. No. While it is theoretically possible that the Illinois General Assembly could pass legislation negatively affecting solar resources, there is no reason to believe that it would do so. In fact, given the political sentiment underlying the CEJA, the idea that the state of Illinois is going to pass legislation that undermines solar energy generation in the state appears far-fetched. Illinois has clearly indicated through its policy decisions that it favors renewable resources over fossil-fueled resources.

With respect to the potential for Ameren Missouri to leave MISO, while the potential exists for Ameren Missouri to exit MISO at some time in the future, it must be recognized that this is not seen as probable, as evidenced in the Commission's Fourth Order Modifying 2012 Report and Order in File No. EO-2011-0128, which was issued just six months ago. In this Order, the Commission granted the joint motion "to extend authorization for Ameren Missouri to participate in MISO indefinitely rather than for a fixed term," based on "(t)he movants (belief) this revision would be appropriate given the substantial benefits Ameren Missouri receives from its membership in MISO, as well as the high financial costs Ameren Missouri would face if it were to leave MISO."[33]

Q. Does adding the gas combined cycle unit in 2031 obviate the need for other resources?

A. No. As demonstrated in my discussion of energy needs, renewable resources are needed to meet the Company's energy needs, but they also provide capacity benefits. The winter capacity position reflects total capacity benefits from wind and solar resources of 771 MW, including 126 MW of capacity credit for solar resources. Both renewable resources and dispatchable resources are needed to meet customers' energy and reliability needs in an affordable and sustainable manner over the planning horizon.

Q. Staff witness Lange mentions Ameren Missouri's consideration of oil-fired backup for certain simple cycle CTGs.[34] How do those affect the consideration of resource needs?

A. This is where consideration of granular reliability analysis comes into play. The modeling performed by Astrape' (as discussed in Schedule MM-D2 attached to my Direct Testimony) showed that additional reliability resources may be needed to achieve target reliability metrics even with the addition of planned renewables and the 1,200 MW

[33] Fourth Order Modifying 2012 Report and Order, File No. EO-2011-0128, p. 1-2.
[34] Shawn Lange Rebuttal Testimony, at p. 9.

combined cycle generator. Ameren Missouri's June 2022 PRP change filing (again, completely ignored by the Staff) noted that such projects were among those being considered to address potential reliability gaps. Beyond that, should one or more of these projects be implemented, I would expect them to make a contribution to winter resource capacity but provide no other significant benefits in terms of capacity or energy. As I have discussed in my Direct Testimony and Surrebuttal Testimony, long-term *energy* needs are the primary driver of the renewable transition. As noted, adding oil backup to those simple cycle CTGs does not address those needs in any meaningful way at all.

Q. Does it make sense to carry a greater level of capacity than is required by MISO?

A. I believe it does when various risks and realities are considered. First, it must be recognized that the PRM is a minimum requirement. It should not in any way be viewed as a cap. It would be virtually impossible to try to exactly match capacity resources to capacity needs, and as the capacity positions charts for summer and winter above show, resource needs will be different in different seasons.

Second, capacity additions are "lumpy" by nature. It would be virtually impossible to try to exactly match capacity resources to capacity needs, and as the capacity position charts for summer and winter in Figures 8-11 above show, resource needs will be different in different seasons.

Third, even if resources could be exactly matched to need, waiting until the exact moment it is needed to add the resource or resources carries inherent risk that things may not go as planned. As mentioned previously, demand could change rapidly, resources could be retired or constrained sooner than planned, or loads could be higher than expected, including if the planned savings from demand-side programs fall short.

Fourth, and perhaps most relevant to this case, resources may be added to satisfy an energy need. As I mentioned before, renewable resources are primarily energy resources. They provide low-cost, carbon-free energy that is not subject to fuel price variability, because the "fuel" is free.

Q. Has Ameren Missouri previously added resources to address long-term needs?

A. Yes. Ameren Missouri has implemented MEEIA programs for a decade, during which time the Company and its customers have enjoyed the benefits of surplus capacity and energy. The deployment of demand-side resources pursuant to MEEIA recognizes real world considerations. Most notably, demand side resources are best implemented over a long time and before a resource need (from a pure, just-in-time capacity position planning standpoint) is imminent. Doing so over the last decade has put Ameren Missouri and its customers in a far better position from a reliability standpoint than if the Company had waited and tried to more precisely align the timing of deployment of demand-side resources with an imminent and strictly PRM-based capacity need.

Q. Is the deployment of renewable resources similar to the deployment of demand side resources?

A. Yes, in several ways. Renewable energy resource projects are typically on the order of hundreds of megawatts rather than a thousand megawatts or more. You can see that based on the 200 MW Huck Finn project the parties in File No. EA-2022-0244 just agreed should be granted a CCN, the 150 MW project proposed here, and on Ameren

Missouri's other recently added utility-scale renewable energy resources, which range in nominal capacity from 300 to 400 MW. One of such projects by itself does not necessarily "solve" a specific need; it is the portfolio of projects taken together that does so.

Demand side programs under MEEIA typically provide annual incremental demand savings on the order of 100-200 MW as well. Another similarity is the consideration of lost opportunities. Demand side programs are often designed to incentivize customers to make more energy efficient choices for appliances and applications that may have a life of ten years or more. If a less energy efficient choice is made, that opportunity is lost for a significant time. Similarly, the opportunity to build or acquire a renewable project at a favorable location may not be available later. This is important from at least a couple of perspectives, including locating resources where the wind or solar conditions are favorable, where transmission interconnection costs are minimized, and locating resources across a broad region to obtain a measure of geographical diversity can be leveraged since the sun does not shine and the wind does not blow at the same time or with the same intensity in all places at once. This is not to say that renewable resources and demand side resources are exactly the same or involve exactly the same considerations. Rather, it is simply important to recognize the specific characteristics and constraints of resource implementation for each resource type.

Q. Does continuous implementation of renewable resources result in an unfair advantage for renewable resources compared to demand side resources? Said another way, does the Company's approach to renewable resource implementation represented in its PRP result in demand side resources not being considered on an equivalent basis with supply side resources?

A. No, not at all. If anything, it results in both renewables and demand side resources being considered on a *more* equivalent basis. With both demand side resources and renewable resources, there is a substantial danger that if you don't start, you will never get where you need to be.

Q. Staff witness Lange suggests that Ameren Missouri is not coordinating appropriately with MISO and other market participants to address issues that may arise as renewable penetration reaches high levels. Is Staff witness Lange correct?

A. No. This assertion is plain wrong. Staff witness Lange is quoting from MISO's RRA, which indicates that more coordination between MISO, members and states could enable reliable addition of up to 50% renewables in MISO. The truth is, MISO is far from this point today, and the steps that might be needed to ensure reliable addition of renewables at that level are continuing to be identified. Ameren Missouri and project developers are coordinating appropriately with MISO through MISO's generator interconnection process, and Ameren Missouri actively participates in MISO's long-range planning efforts that will help to identify and address the kinds of issues that will need to be addressed to achieve high levels of renewable resources. Ameren Missouri's plan to add renewable resources steadily over time will help to ensure we gain the incremental insights we need as it transitions its generation portfolio.

Q. Did Staff produce any analysis of risks associated with Ameren Missouri's energy and capacity needs?

A. No.

Q. Did Staff produce any substantial critique of the Company's consideration of risks associated with assessing and planning for energy and capacity needs?

A. No. Staff's assessment of the Company's consideration of energy and capacity needs appears to be superficial, dated and based on a risk-free view of the planning environment.

Q. How would you contrast Ameren Missouri's view of capacity planning with that of Staff's witnesses in this case?

A. I think it comes down to two differences in philosophy. First, Staff appears to be concerned with adding resources too early, whereas the Company is concerned with adding resources too late. Importantly, the Company has an obligation to ensure safe, reliable, and cost-effective service to its customers, regardless of the circumstances and how they might change, and while Staff does not bear this obligation themselves, they do have a duty to assist the Commission in ensuring that utilities subject to the Commission's regulation satisfy this obligation. Second, Staff appears to be focused on utilities' incentives to add rate base, whereas the Company is focused on ensuring reliable, affordable, and sustainable electric supply for its customers, appropriately accounting for real world risks and constraints and recognizing what Staff clearly knows – that plans can be changed as conditions change and better information is available. To put it even more simply, Ameren Missouri prefers to have the flexibility to slow down or change course to being in the position of wishing we had done more or moved faster, only to find ourselves in trouble, whether that trouble manifests itself in literally being unable to serve our customers when we need to, or unable to do so absent incurring massive cost to purchase power in the market at extremely high prices as we have seen other utilities have to do.

IV. RENEWABLE RESOURCES PROVIDE SIGNIFICANT RISK MITIGATION BENEFITS

Q. What are the risk mitigation benefits of adding renewable energy resources steadily over time as set forth in the Company's PRP?

A. There are several, as also discussed in detail in Company witness Arora's Surrebuttal Testimony. First, they fulfill a long-term energy need for customers. Waiting to deploy renewable resources could result in falling short of meeting energy needs or requiring the rapid deployment of less beneficial resources, particularly if viable projects are limited, transmission constraints cause delays or higher costs, or financing rates are higher due to delaying transition from fossil fuels.

Second, renewable projects are expected to benefit from lucrative tax credits made available by federal law. The IRA expanded and extended tax credits for renewable projects, including making production tax credits ("PTC") available to solar projects.

Third, adding renewable resources provides a hedge against various market risks. This includes risks associated with power prices, carbon prices and fuel prices. The Company's IRP analysis demonstrates the benefits to customers of deploying renewable resources steadily over time. Table 1 below shows that the substantial benefits to customers of steady renewable energy resource deployment would further increase under a high carbon price regime. Likewise, higher prices for natural gas (and coal to the extent it is still in use) drive power prices higher and provide greater revenue and risk mitigation benefits for renewable resources.

Table 1

PVRR and PVRR Differences ($MM)	0%	50%	50% <<<Probabilities	
	No CO_2 Price	Low CO_2 Price	High CO_2 Price	Prob. Wtd.
Renewable Transition	77,181	78,116	79,933	79,024
Renewables for Capacity Need	77,307	78,502	80,811	79,656
Difference (Proposed vs. Capacity Need)	(126)	(386)	(878)	(632)

Q. Can you elaborate on the benefits of renewable resources as a hedge against fuel price risks?

A. Yes. Renewable resources are characterized by moderate capital costs, modest non-fuel operating and maintenance costs, and zero fuel costs. Once built or acquired, the costs of the resource are known and relatively stable. In fact, the fixed asset costs of renewables decline over time as the assets depreciate. Adding the benefits of federal tax credits significantly mitigates or offsets those costs. With no fuel costs, any production from renewable resources results in revenues from the market. In periods of high fuel costs (e.g., gas or coal), market prices will tend to increase as well while the "fuel" for renewable resources remains free.

Q. Can you provide an example of how solar generation can help to mitigate price volatility risk?

A. Yes. Table 2 below shows the peak days for each summer and winter month from 2019 through 2021. For each peak day, it shows what the net energy position (generation minus load) would have been had the Meramec and Rush Island coal units not been available to generate, thus simulating a future state in which those units have been retired, which will in fact be a reality as early as next year. Note that in every instance, net energy would have been negative. That is, Ameren Missouri would have had to purchase more energy than it generated to serve native load.

Also shown for each peak day is the actual measured solar irradiance, or global horizontal irradiance ("GHI"), in watts per meter squared (w/m^2), along with its ratio compared to the highest daily GHI for that month and that year. Note that for 11 of the 18 months shown, solar irradiance is at or above 80% of its daily maximum for the month, and in four of the nine winter months shown, solar irradiance is at or above 40% of its daily maximum for the year.

Table 2 also shows the on-peak and average power prices (LMP) for each peak day and the approximate cost to purchase to cover the energy shortfall at the average LMP. This shows that four of the 18 peak days would have been expected to result in added costs of over a million dollars, with the peak day in February 2021 (during winter storm Uri) seeing a cost of over $9 million on that day alone. Such events may, and often do, last for multiple days. Company witness Arora also provides an actual example from the Christmas weekend winter storm just last month in his Surrebuttal Testimony.

Finally, the table shows the estimated amount of electric energy Boomtown would have produced had it been available on these days and the savings it would have produced at the on-peak LMP. It shows that the Boomtown Project would have been expected to produce tens of thousands of dollars in benefits on most of the peak days and over a hundred thousand dollars on the peak day in August 2021.

Table 2

Peak Day Net Energy, Solar Irradiance and LMP

Date	Net Energy (excl. Mer/RI) (MWh)	Global Horizontal Irradiance (W/m^2)	% Of Month High GHI	% Of Year High GHI	On-Peak LMP ($/MWh)	Average LMP ($/MWh)	Estimated Cost ($000)	Approx. Solar Gen. (MWh)	Estimated Solar Savings ($000)
01/30/19	(19,597)	3939	100%	47%	62.32	54.29	1,064	870	54
02/08/19	(14,616)	4325	92%	51%	28.17	26.19	383	955	27
06/05/19	(1,688)	7840	96%	93%	26.90	24.16	41	1,731	47
07/19/19	(19,655)	8002	95%	95%	40.76	33.87	666	1,766	72
08/12/19	(17,938)	3613	45%	43%	31.00	26.62	478	798	25
12/16/19	(13,826)	281	9%	3%	25.00	23.24	321	62	2
01/20/20	(19,331)	1445	46%	16%	28.00	26.15	505	319	9
02/14/20	(12,193)	4702	87%	53%	24.25	23.02	281	1,038	25
06/26/20	(33,860)	7842	88%	88%	25.61	21.55	730	1,731	44
07/09/20	(16,160)	7910	94%	89%	40.41	32.79	530	1,746	71
08/10/20	(13,392)	7121	91%	80%	38.28	31.38	420	1,572	60
12/25/20	(28,948)	1548	47%	17%	32.55	29.18	845	342	11
01/28/21	(36,177)	3893	100%	44%	26.73	25.41	919	859	23
02/15/21	(67,905)	2461	50%	28%	167.83	142.44	9,672	543	91
06/18/21	(52,823)	7982	91%	90%	44.72	37.49	1,980	1,762	79
07/29/21	(50,880)	5720	68%	65%	50.92	43.75	2,226	1,263	64
08/25/21	(27,348)	6859	87%	78%	69.21	57.04	1,560	1,514	105
12/07/21	(10,843)	658	21%	7%	61.21	52.95	574	145	9

Q. Are you suggesting that such benefits should be a primary basis for deploying renewable resources?

A. No. As I described previously, the main driver of the need for the Boomtown project and other renewable resources is to meet customer energy needs. The analysis shown above simply provides an indication of the kind of benefits Boomtown and other renewable projects can deliver during peak demand or extreme conditions. And even though a solar facility like Boomtown obviously will deliver more energy in the summer, solar energy generation in the winter is not as poor as Staff's Rebuttal Testimony suggests.

Q. You mentioned previously that Ameren Missouri and its customers have historically enjoyed benefits of the Company's capacity length. Can you provide an example of such benefits?

A. Yes. In MISO's 2015 planning resource auction, capacity prices in Zone 4 experienced significant separation from the rest of MISO, clearing at $150/MW-day compared to $3.48/MW-day in Zone 5 (which encompasses MISO's area in Missouri). Ameren Missouri was able to purchase capacity resources to meet its shortfall in Zone 5 at the lower price while selling the same amount of generation in Illinois at the higher Zone

4 price, resulting in net cost savings to customers of $27 million. As Staff witness Lange discusses in his Rebuttal Testimony, capacity prices in MISO went to CONE in the 2022-2023 auction. While Ameren's Illinois regulated utility customers were exposed to those high prices, Ameren Missouri's customers were shielded from the impacts of those high prices by the Company's portfolio of capacity resources and actually benefited economically as a result of Ameren Missouri's capacity length.

Q. Has Ameren Missouri described in detail its consideration of the risk mitigation value of renewable resources?

A. Yes. The Company has done this first in its 2020 IRP, then in its June 2022 PRP change filing, and finally in the Direct Testimony of Company witness Arora in this case. The discussion in the two IRP documents I mentioned is included in Schedules MM-D4 and MM-D2, respectively, which were both attached to my Direct Testimony in this case. Company witness Arora further elaborates on the Company's consideration of risks and mitigation in his surrebuttal testimony.

Q. Staff witness Stahlman asserts that Ameren Missouri's addition of renewable resources does not necessarily result in Ameren Missouri's customers being served by cleaner generating sources.[35] Do you agree?

A. No. Staff witness Stahlman takes a narrow view of what it means to serve customers with renewable resources based on their operation the MISO market (i.e., all generation is sold into the market, and all energy used to serve load is purchased from the market). While this is a true and accurate representation of how the MISO market operates, it does not capture the full picture of the customers' relationship to the Company's resource

[35] Michael Stahlman Rebuttal Testimony, at p. 2.

mix. Ameren Missouri's customers pay rates that reflect the prudent costs of the resources owned and operated by Ameren Missouri, and they realize the benefits of the revenues generated by those resources in the MISO market, either through reflecting them in base rates or through the FAC. Even if one takes the narrow view that customers are served by a "slice" of the total energy produced by generators in MISO, *any* increase in renewable generation will result in the displacement of dispatchable generation (almost certainly fossil generation, and at the very least partly fossil generation) somewhere in the MISO market. This necessarily means that the total energy produced in MISO will be "cleaner" and that the share purchased to serve Ameren Missouri customers will be "cleaner" as well. Company witness Wills discusses this in his Surrebuttal Testimony as well.

V. CONCLUSION

Q. Please summarize the key points of your surrebuttal testimony.

A. Ameren Missouri's IRP process is integral to its business planning and implementation. It is not just a modeling exercise, and the Commission recognizes this through its IRP rules and practices. Based on the Company's most recent IRP analysis, which was completed and filed with the Commission just weeks before this case was filed, Ameren Missouri will need to add significant levels of energy resources to replace other generators, primarily coal-fired, that are expected to be retired during that time. Based on that same analysis, Ameren Missouri has determined that renewable resources are best suited to provide significant amounts of low-cost, carbon-free energy to customers in the long term and that executing on the Company's PRP by adding renewable resources steadily over time will provide significant risk mitigation and economic benefits to customers compared to waiting and attempting to add thousands of megawatts of renewable resources in a very short timeframe. In addition to satisfying long-term energy needs, renewable resources also provide important market risk mitigation. To ensure the Company is able to meet its customers' long-term electric energy needs, including under circumstances that may unfold differently than expected, the Company's portfolio transition must begin now.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

SCHEDULE MM-S1

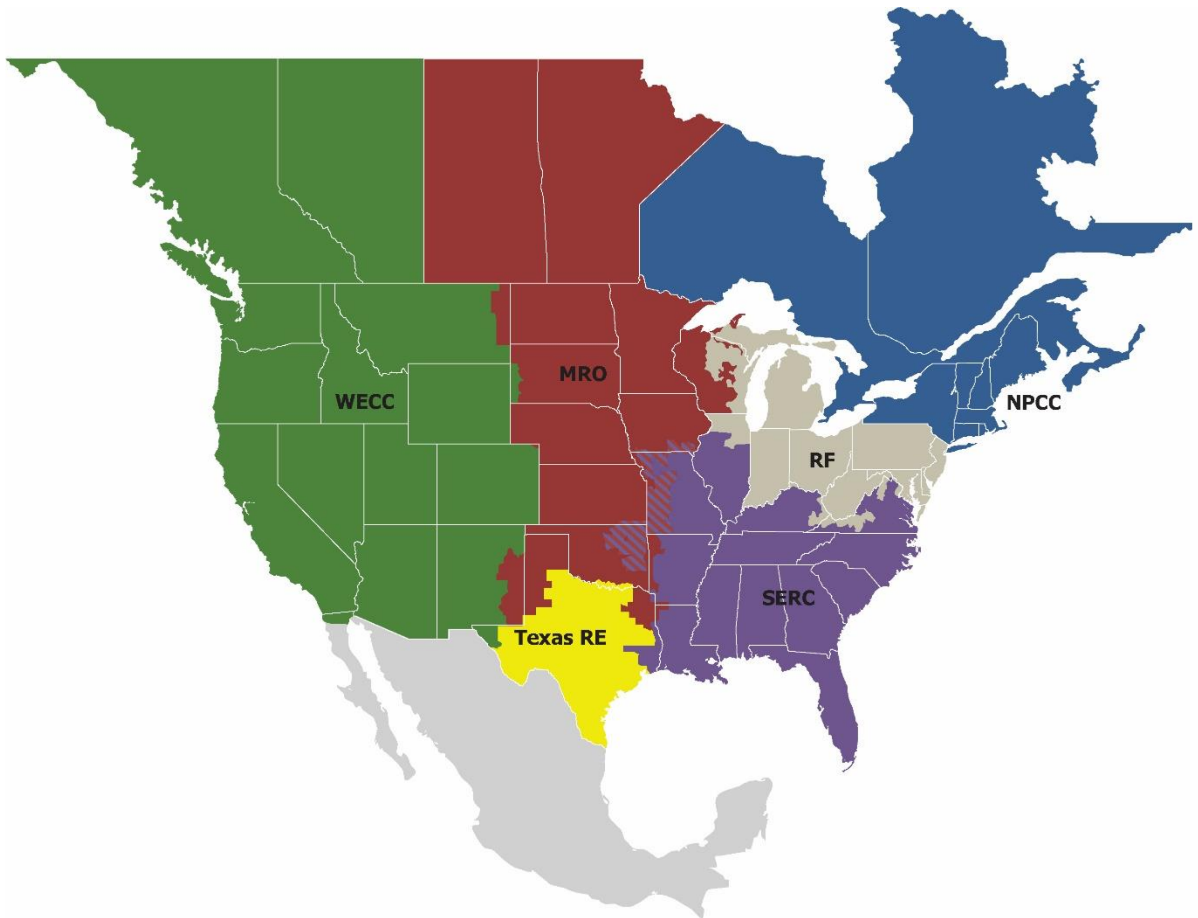
Table of Contents

Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes as well as highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

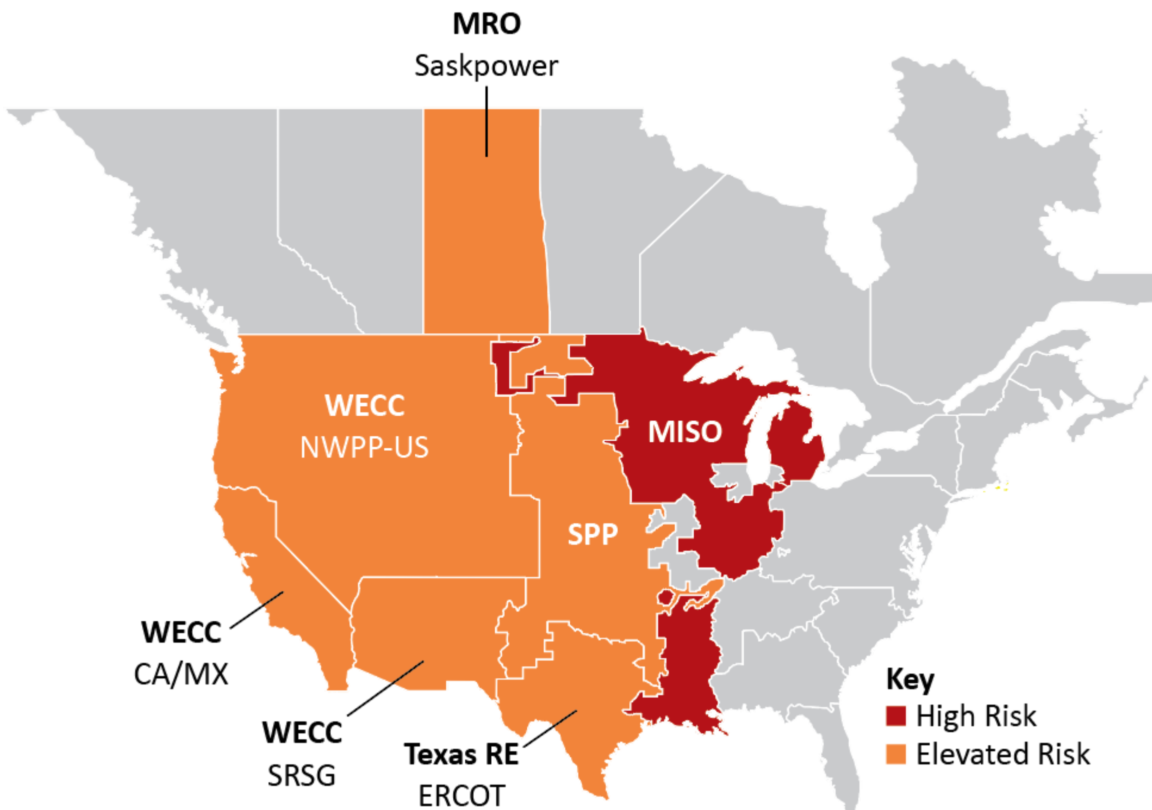


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.
- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.
- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

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- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see Figure 2). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

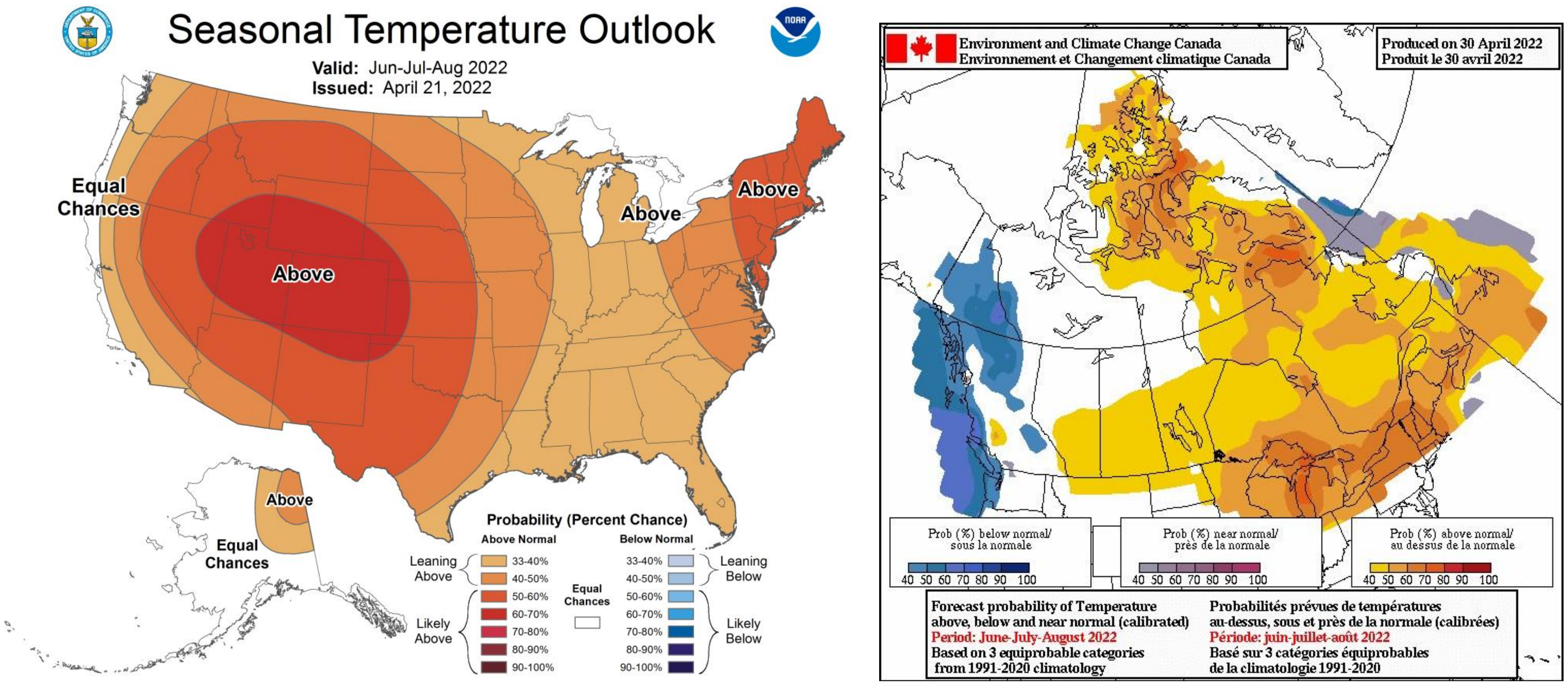

Figure 2: United States and Canada Summer Temperature Outlook[2]

[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

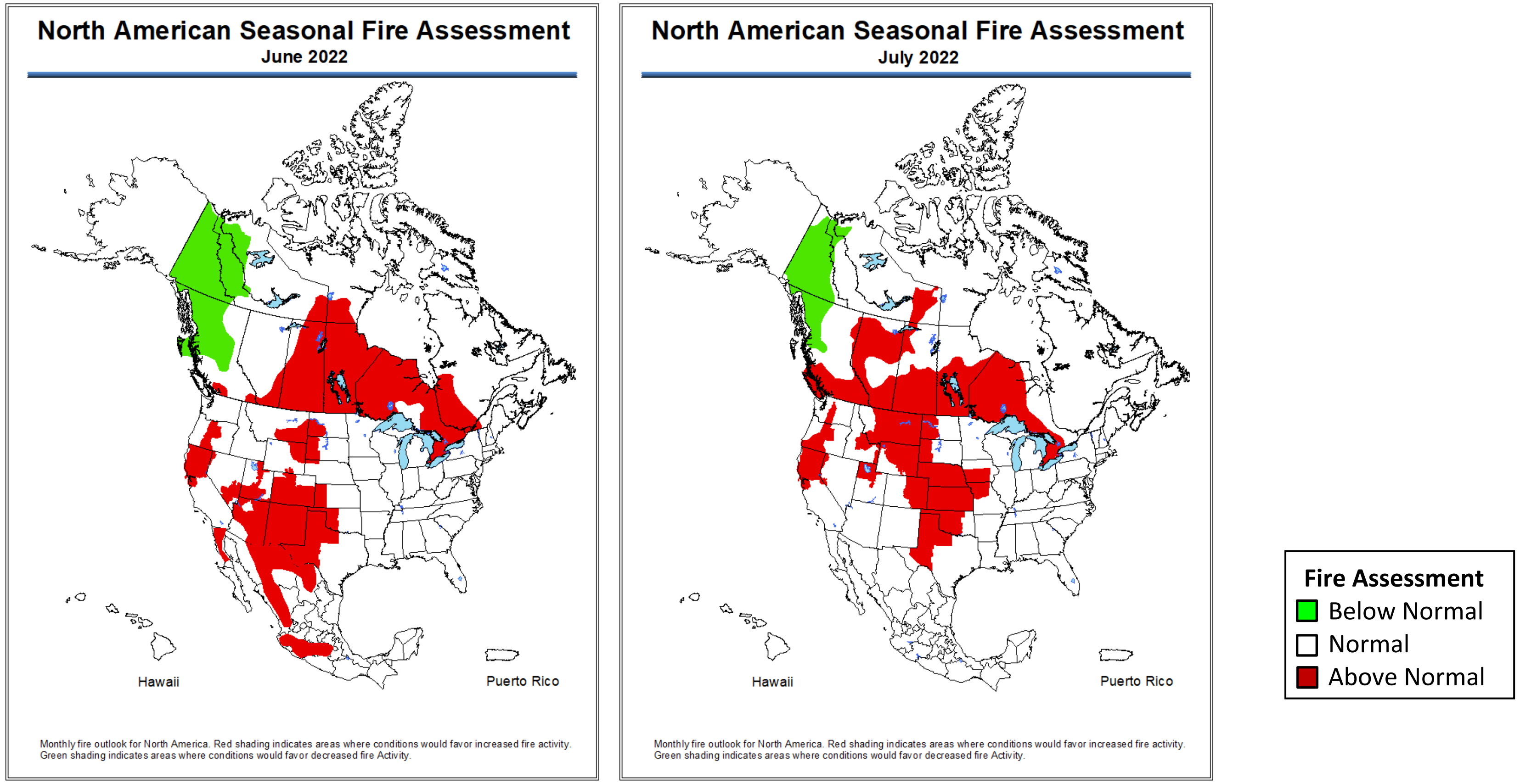

Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

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[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation

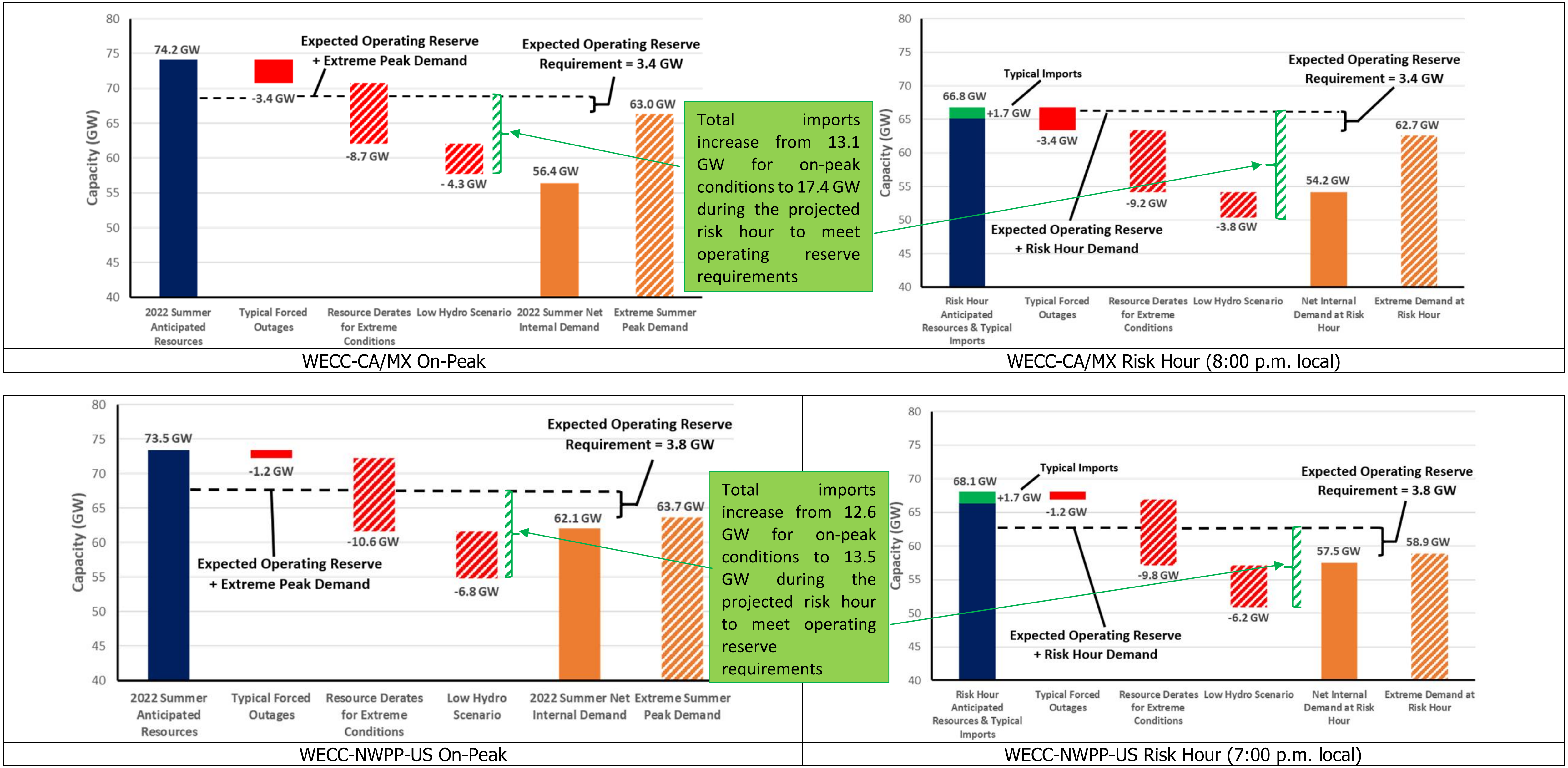
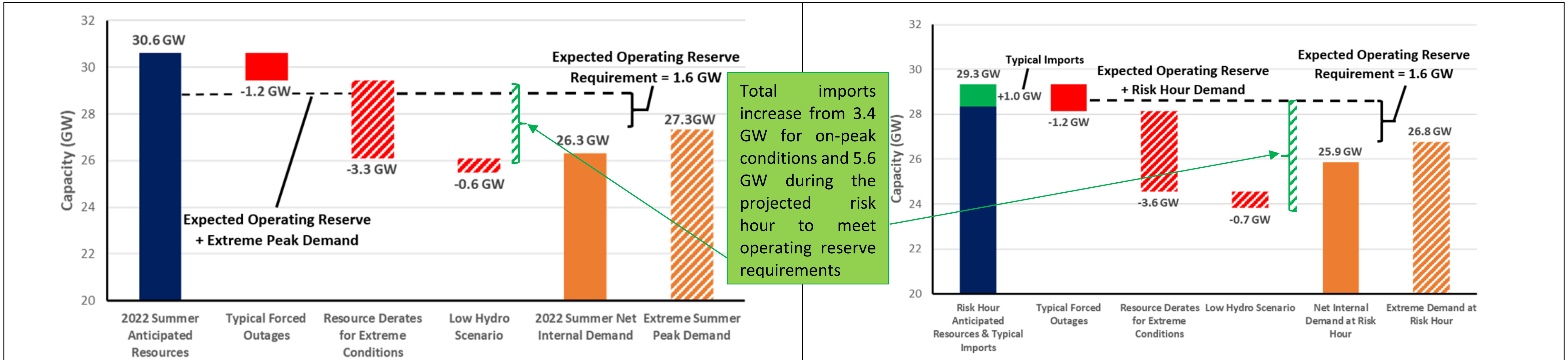


Figure 4: Risk Scenarios for WECC U.S. Assessment Areas



WECC-SRSG On-Peak	WECC-SRSG Risk Hour (7:00 p.m. local)

Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy necessary to meet extreme peak demands. Table 2 describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

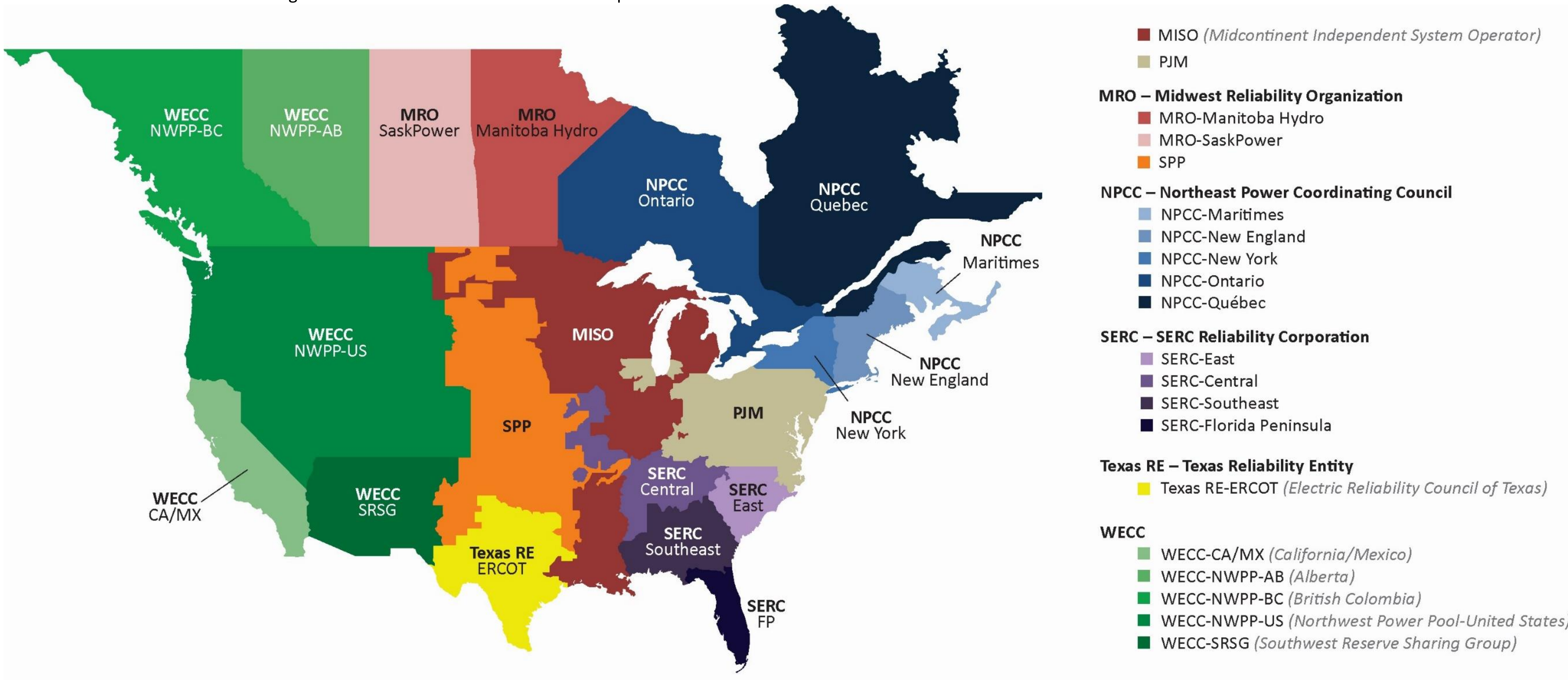
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like these are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



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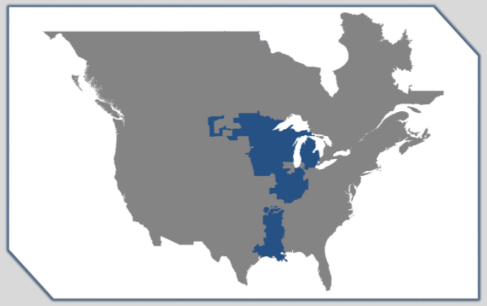
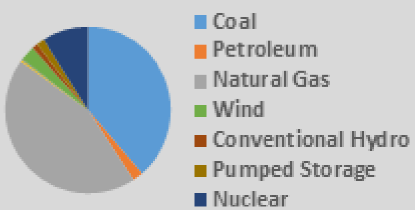


MISO

MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



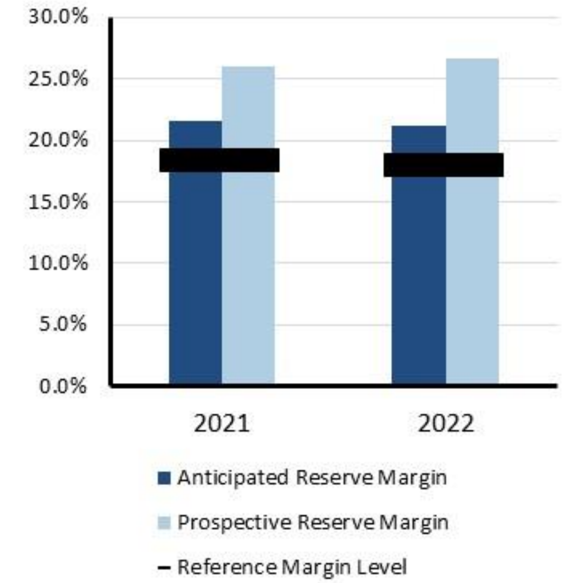
Highlights

- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

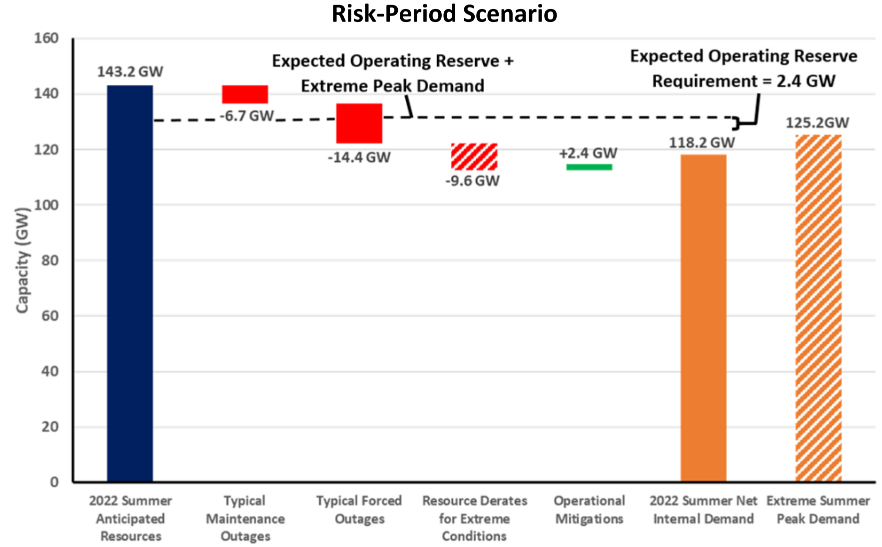
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

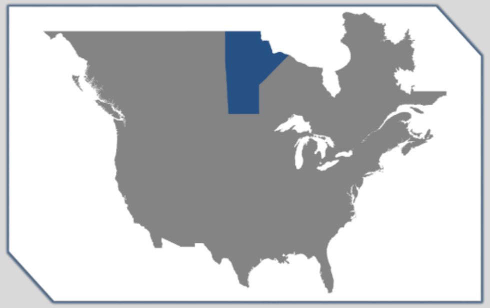
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum of last five years of outages

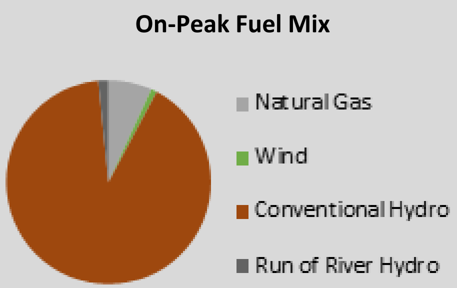
Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

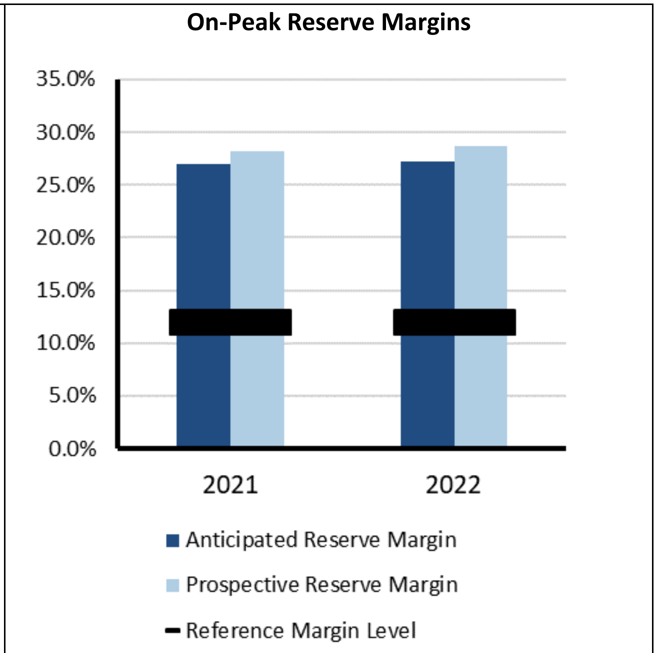


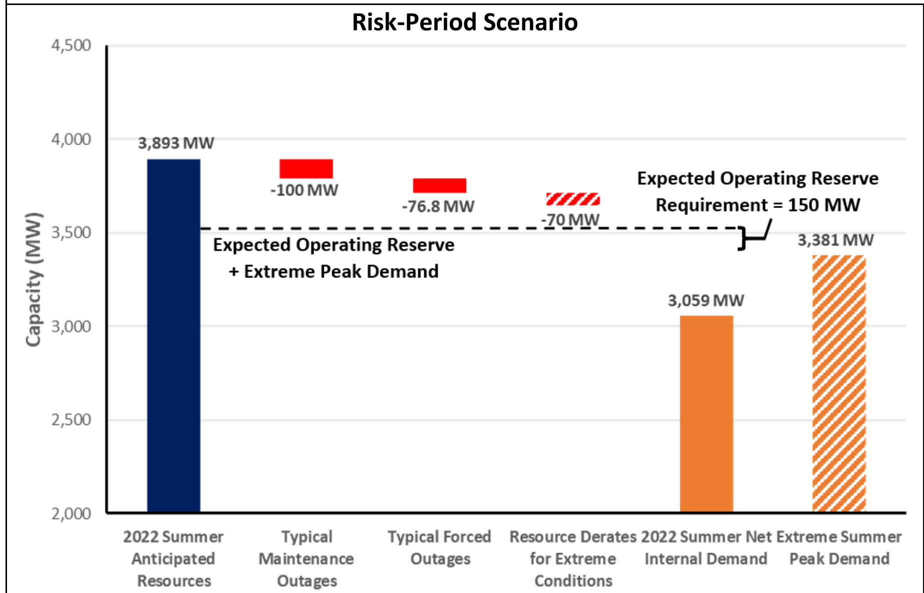
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description (See Data Concepts and Assumptions)

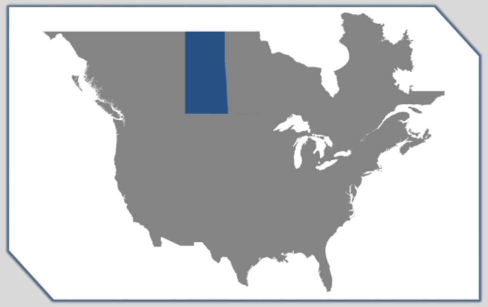
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates

SCHEDULE MM-S1



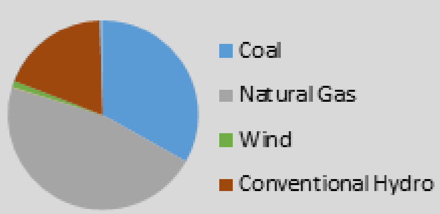
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

On-Peak Fuel Mix



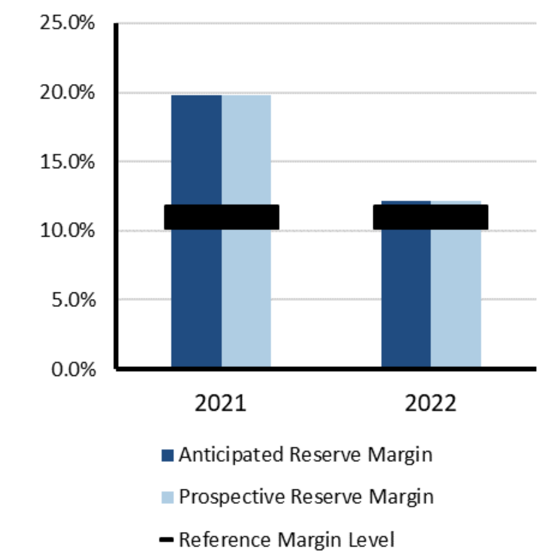
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

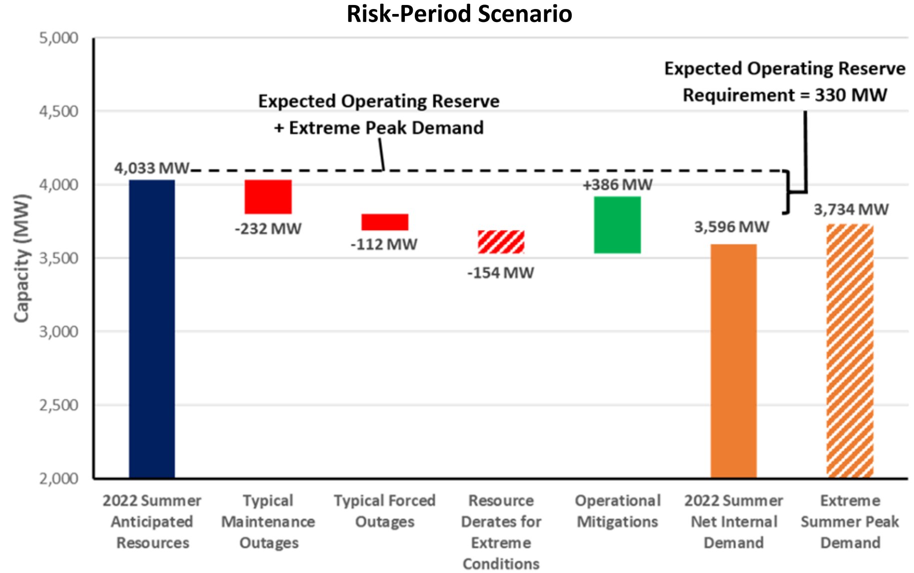
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

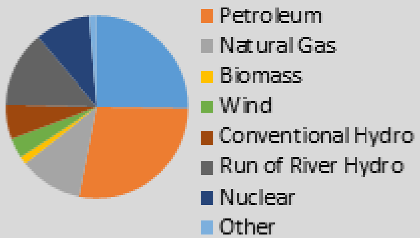
Forced Outages: Estimated by using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the Northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

On-Peak Fuel Mix



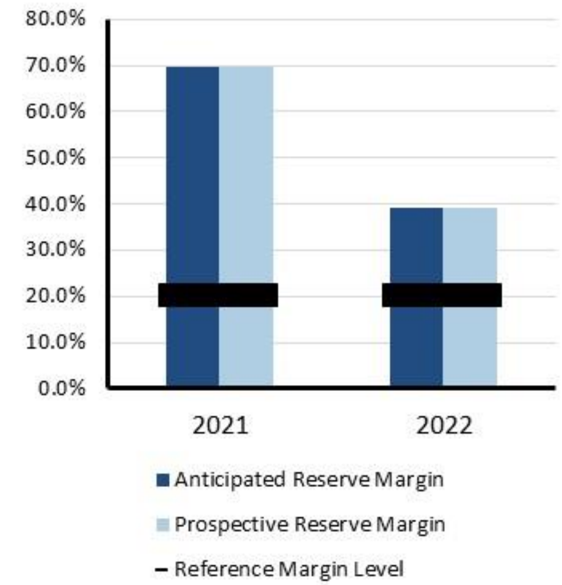
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

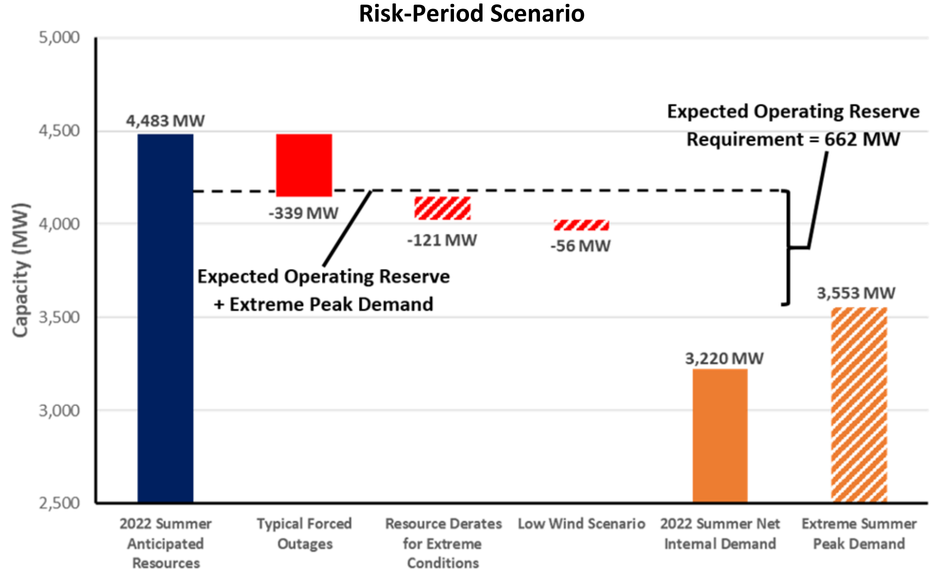
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (99/1) extreme demand forecast

Outages: Based on historical operating experience

Extreme Derates: Based on historical data for ambient temperature thermal de-rates

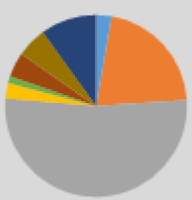
Low Wind Scenario: A low-likelihood scenario resulting in no wind resources

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

On-Peak Fuel Mix



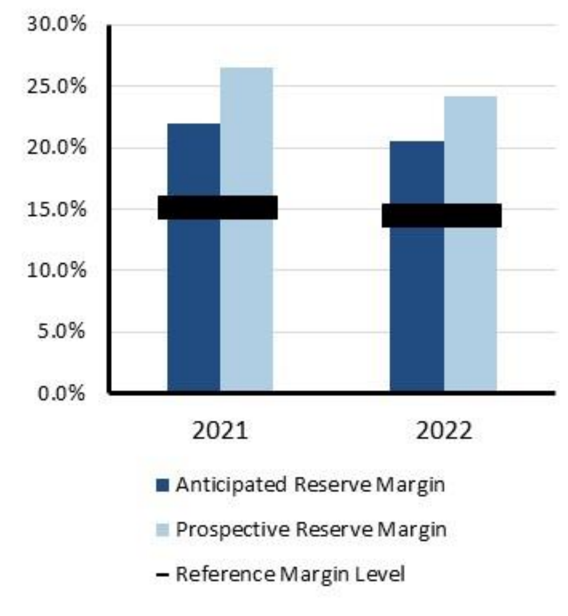
Highlights

- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.

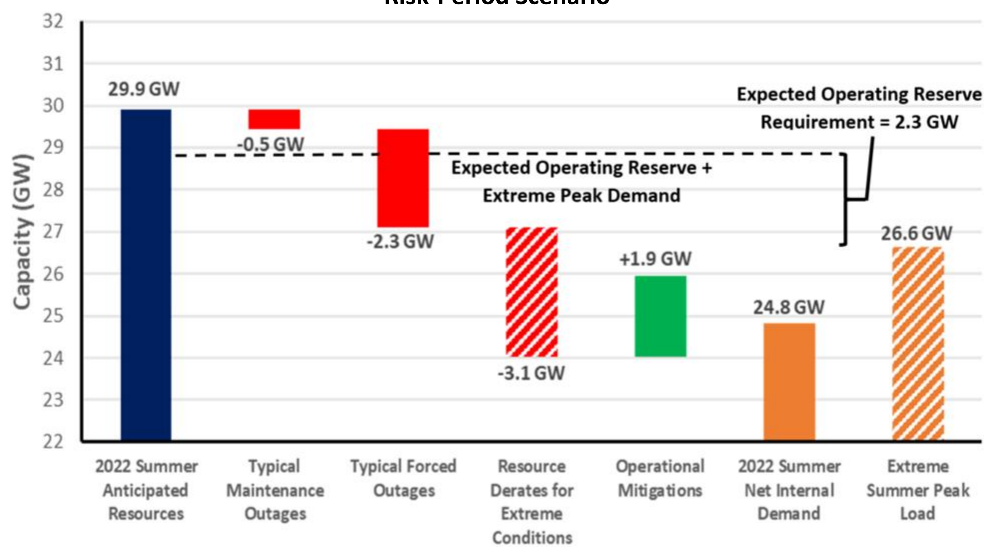
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

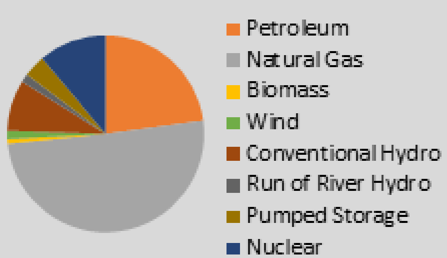
Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

SCHEDULE MM-S1

NPCC-New York

The New York Independent System Operator (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%."

On-Peak Fuel Mix



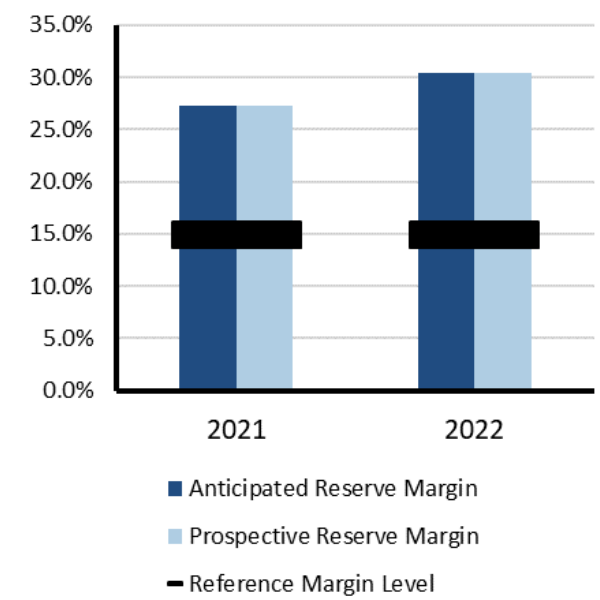
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.

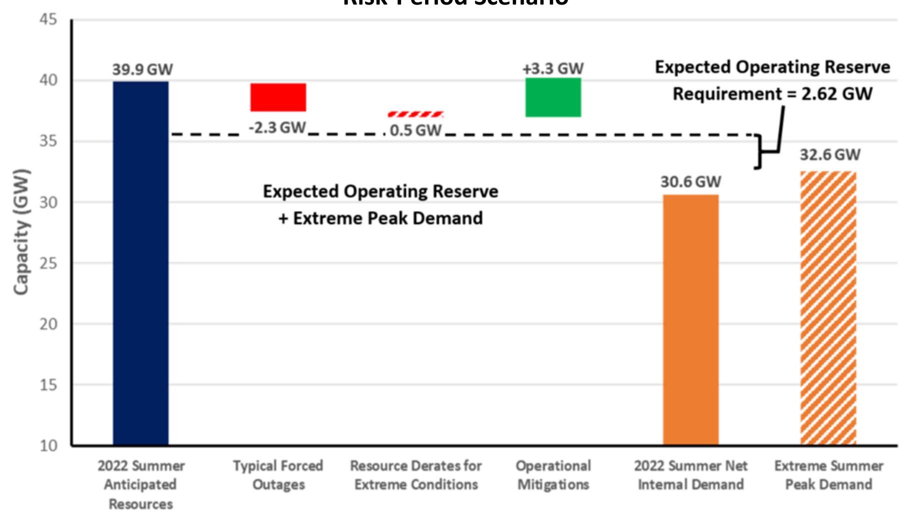
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Forced Outages: Based on historical 5-year averages

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

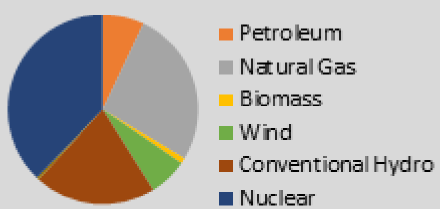
SCHEDULE MM-S1

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

On-Peak Fuel Mix



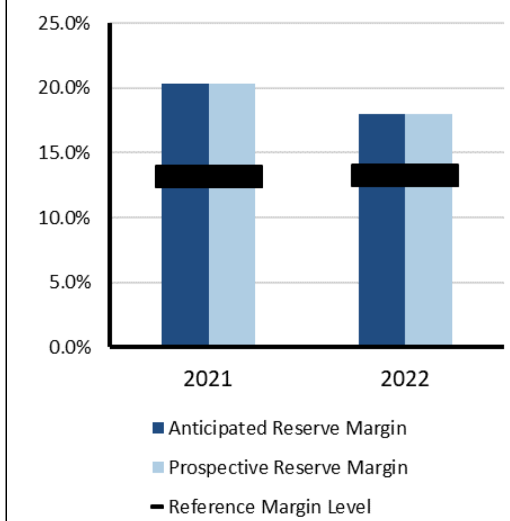
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

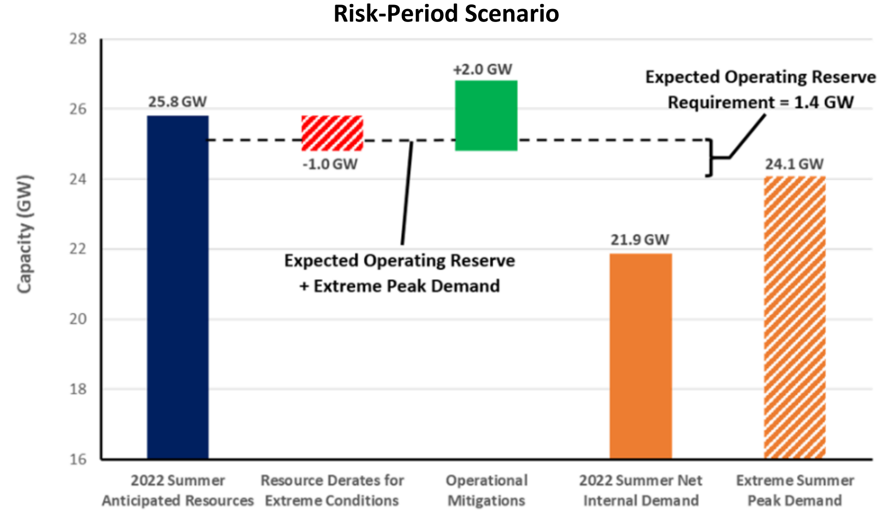
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

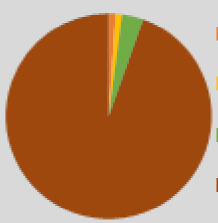
Operational Mitigations: Imports anticipated from neighbors during emergencies

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



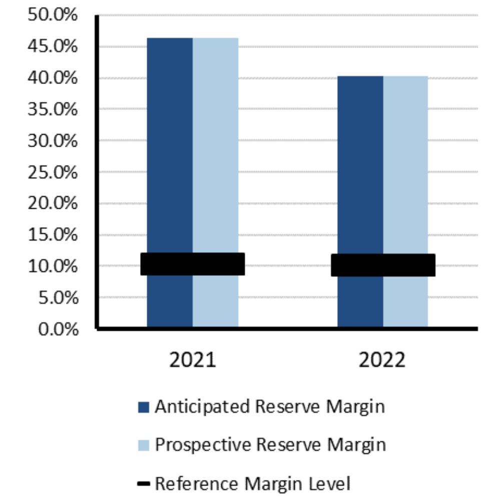
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

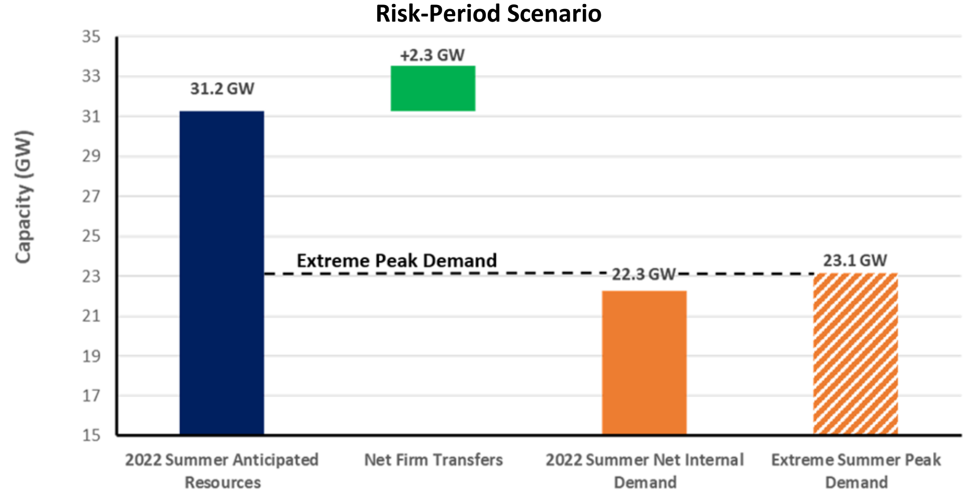
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

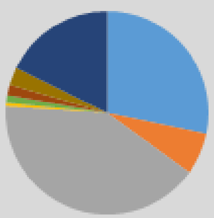
Net Firm Transfers: Imports anticipated from neighbors during emergencies

PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



Highlights

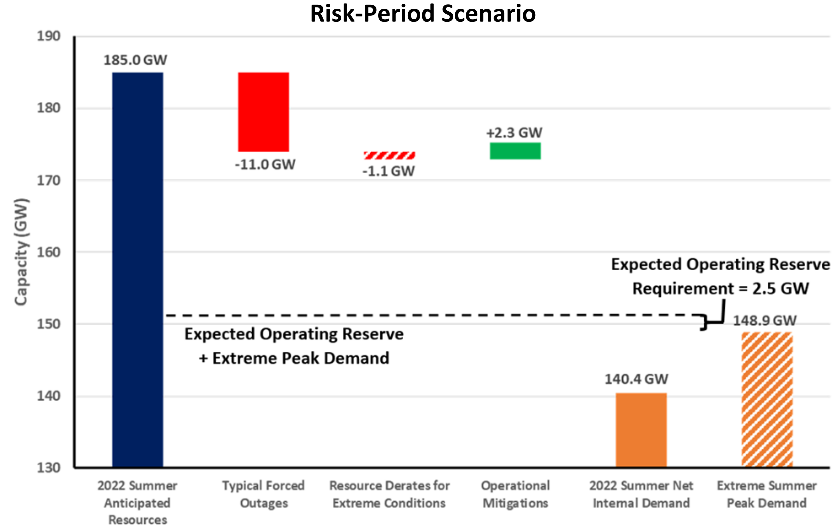
- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

On-Peak Reserve Margins

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.3 GW based on operational/emergency procedures

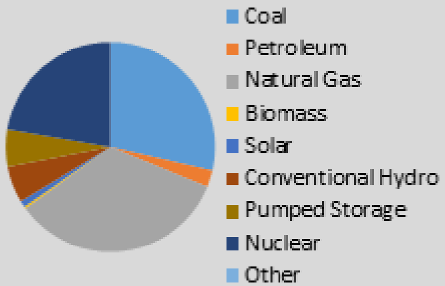
SERC-East

SERC-East is a summer-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

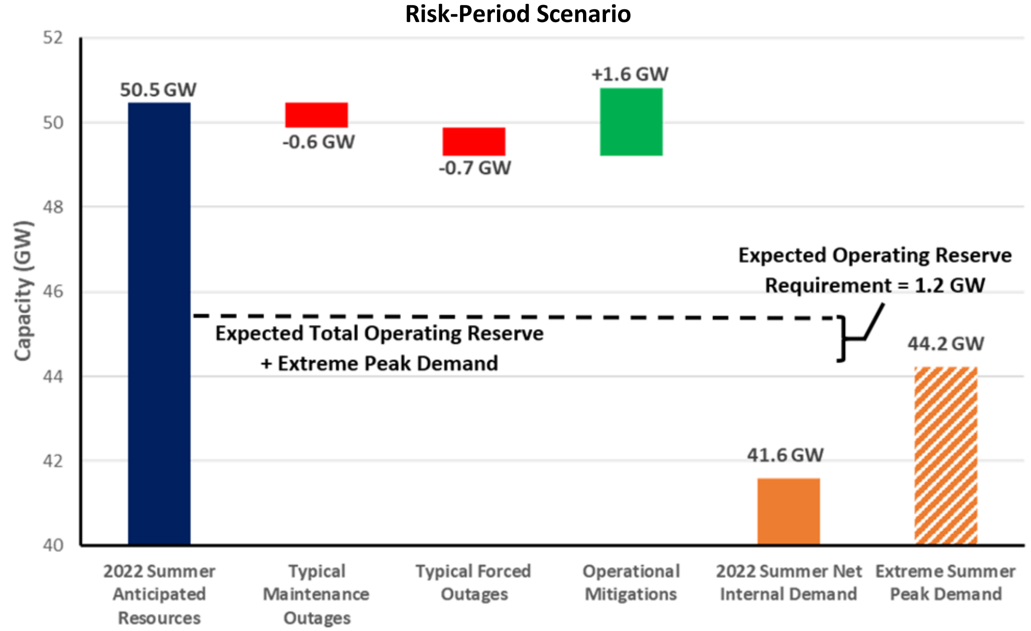
- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures

SCHEDULE MM-S1

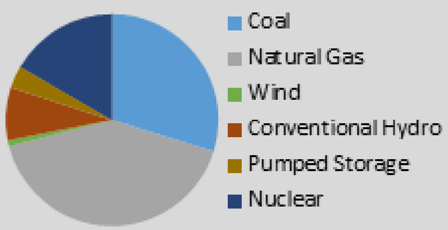
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee, portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC-Central is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



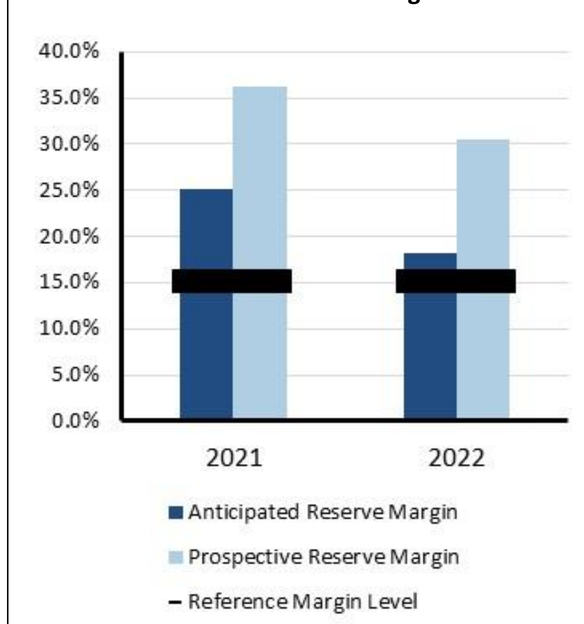
Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

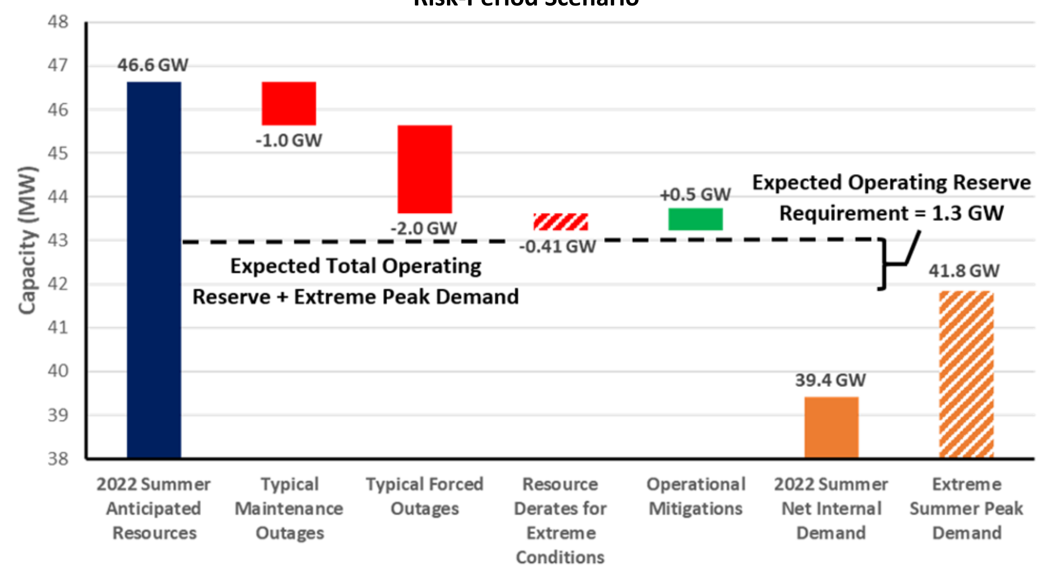
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

SCHEDULE MM-S1

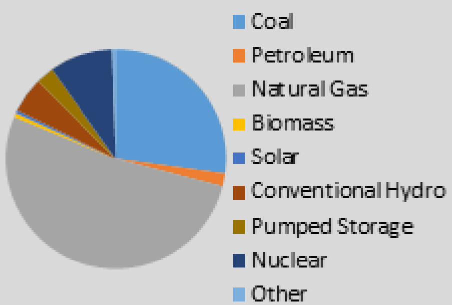
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC Regional Entiey. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



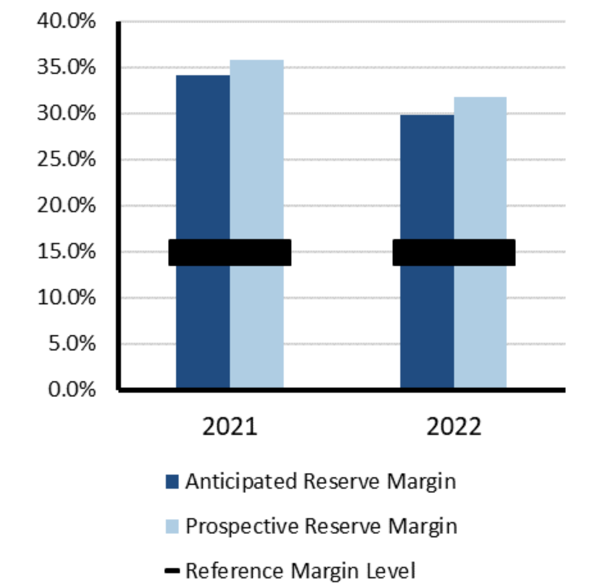
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

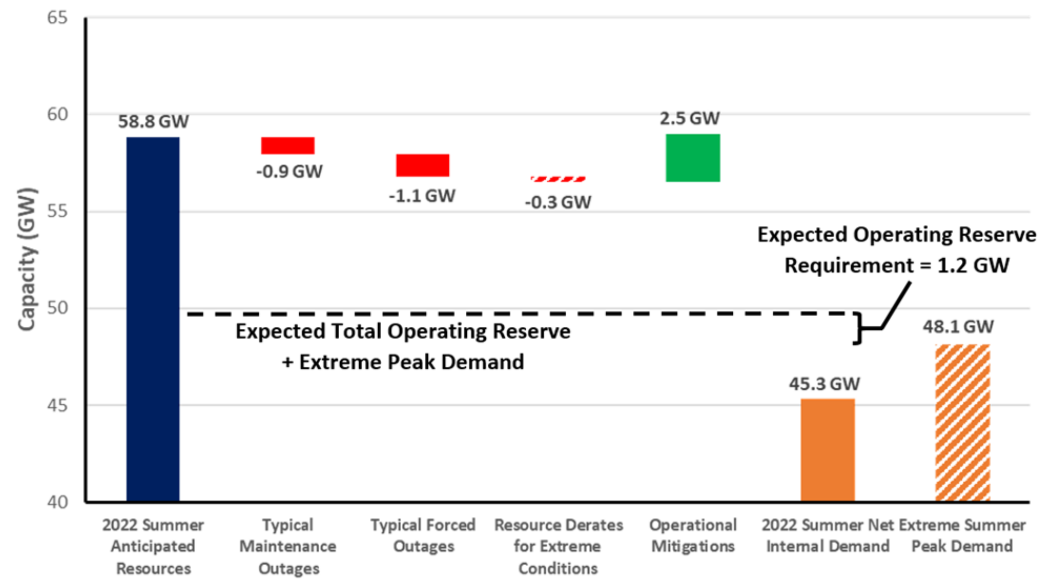
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures

SCHEDULE MM-S1

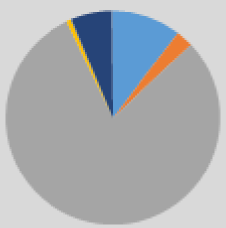
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



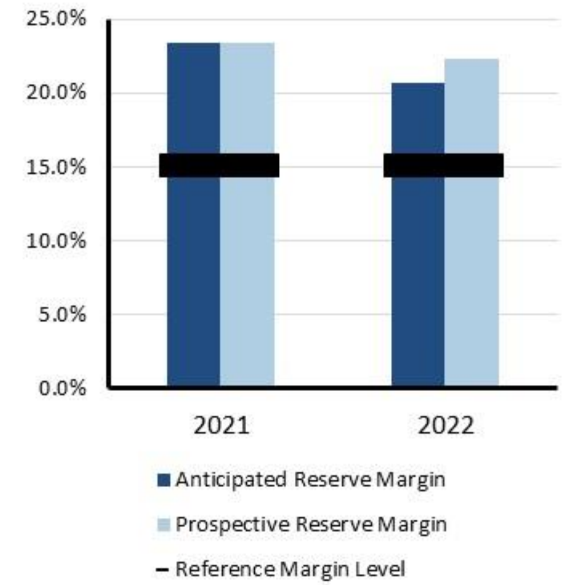
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

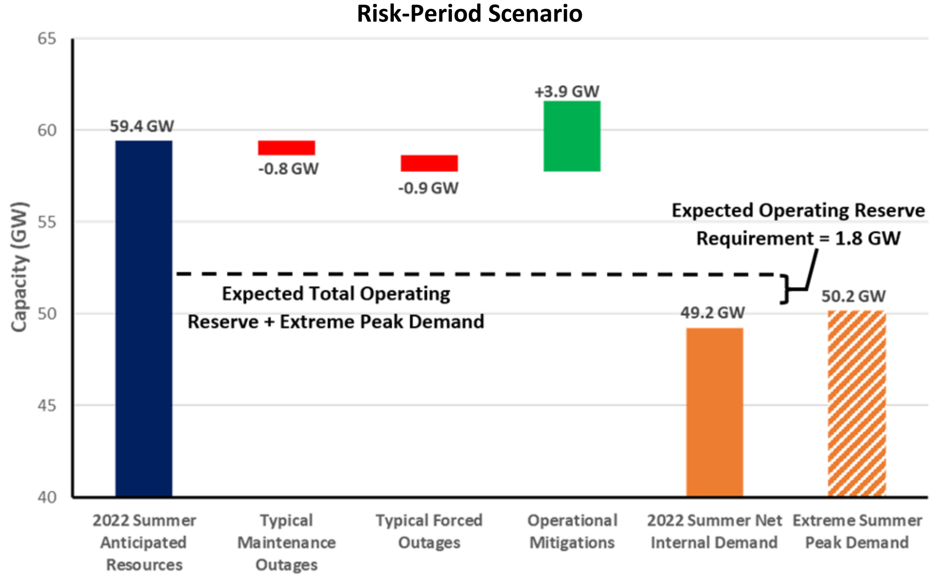
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

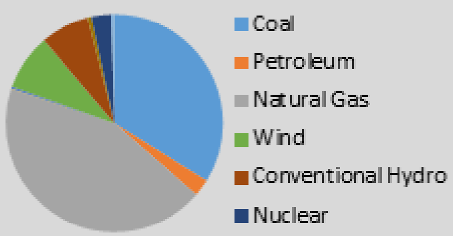
SCHEDULE MM-S1

SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

On-Peak Fuel Mix



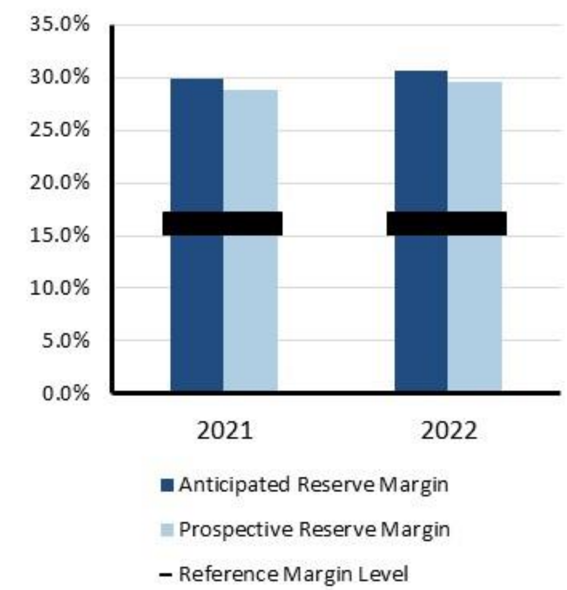
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

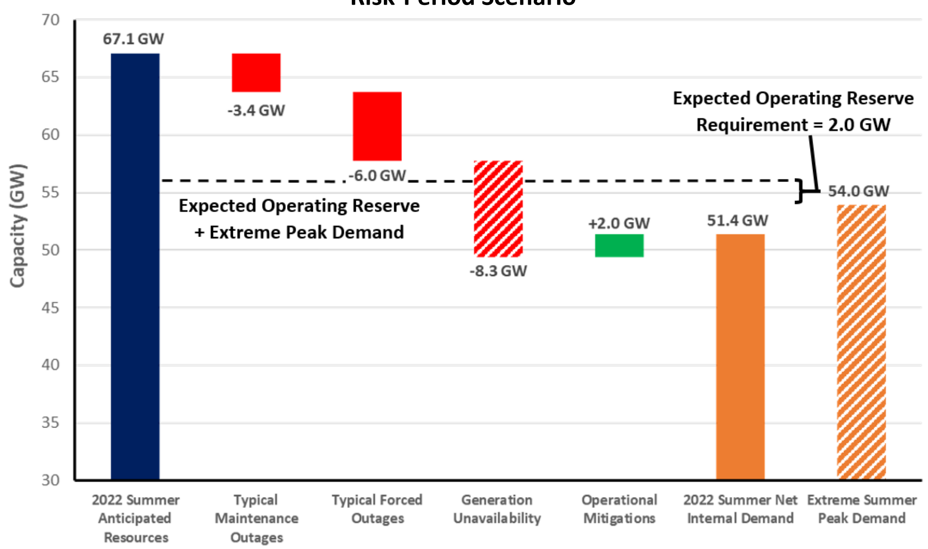
Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

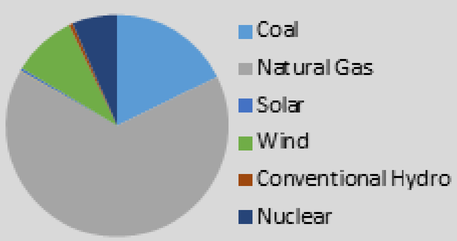
Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is a summer-peaking Regional Entity that covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,000 generation units, and serves more than 26 million customers. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Regional Entity.

On-Peak Fuel Mix



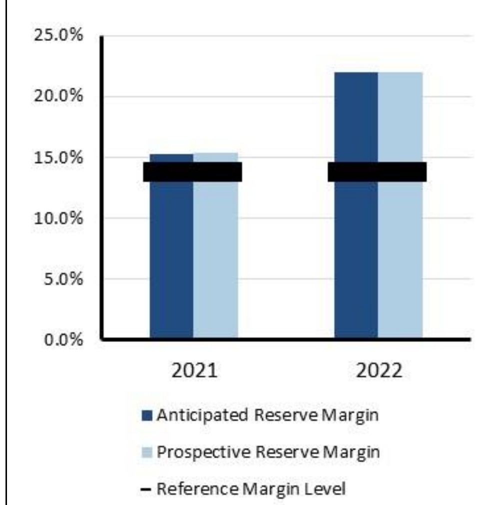
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

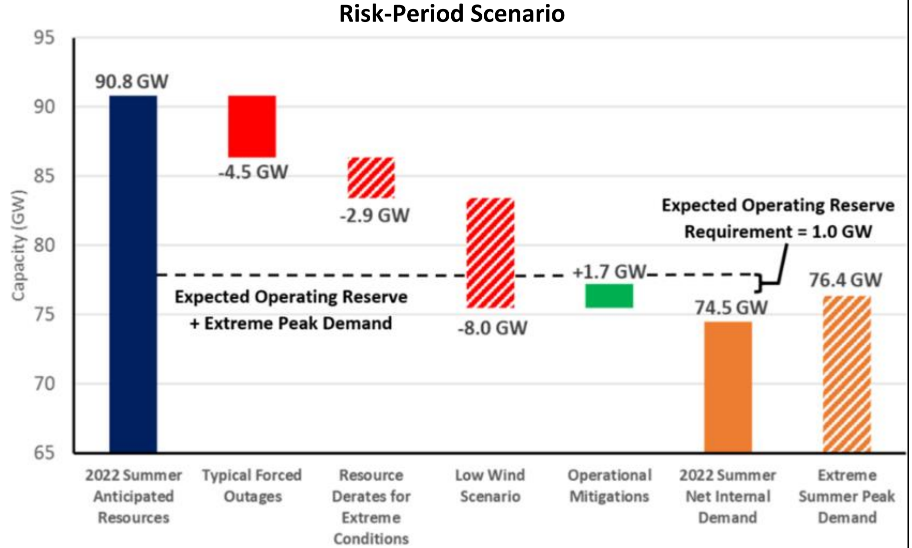
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

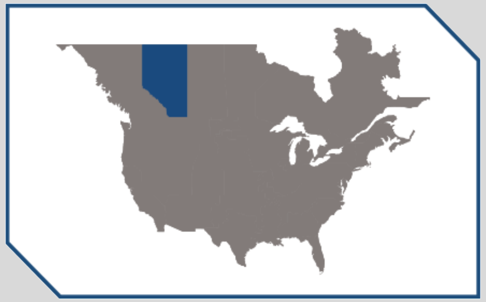
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



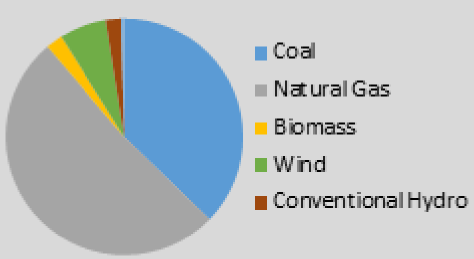
WECC-NWPP-AB

WECC-NWPP-AB (Alberta) is an assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



Highlights

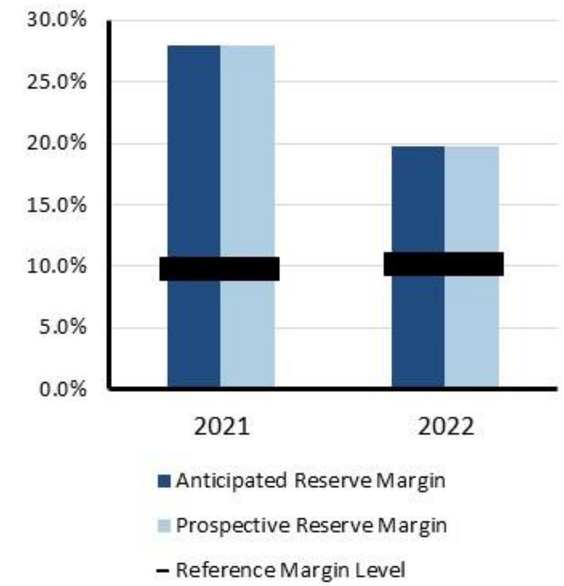
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

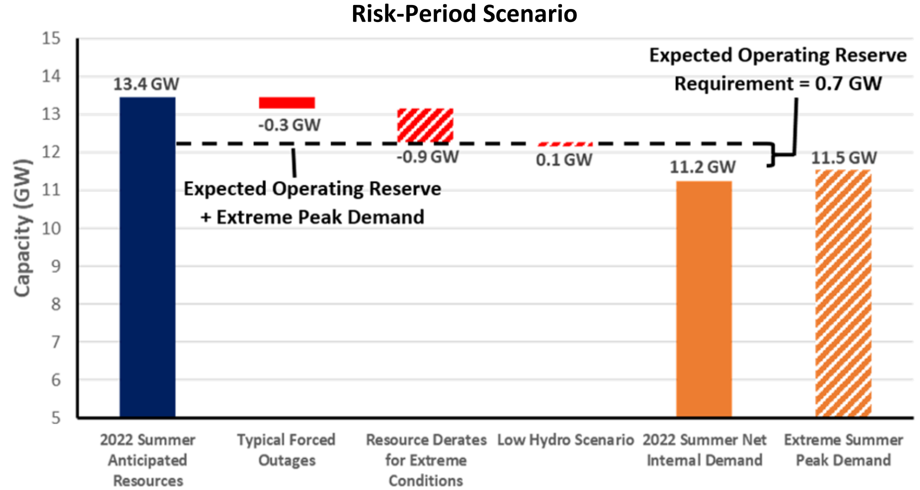
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

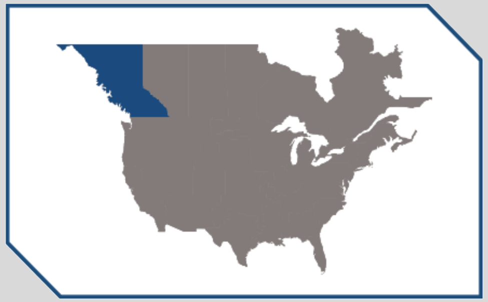
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



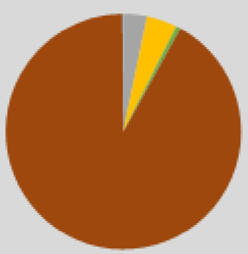
WECC-NWPP-BC

WECC-NWPP-BC (British Columbia) is an assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



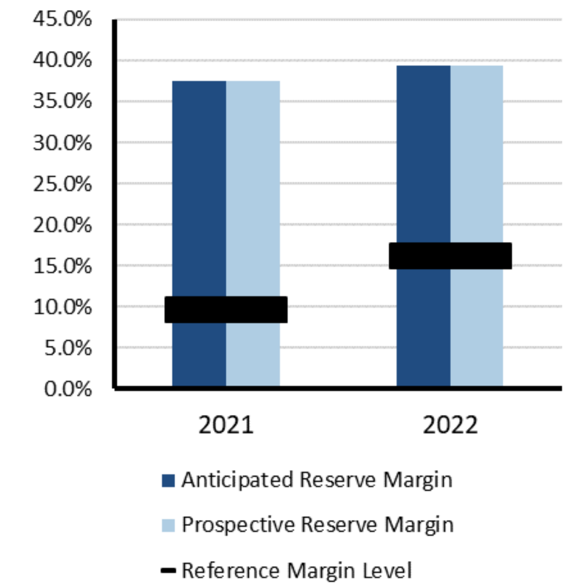
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

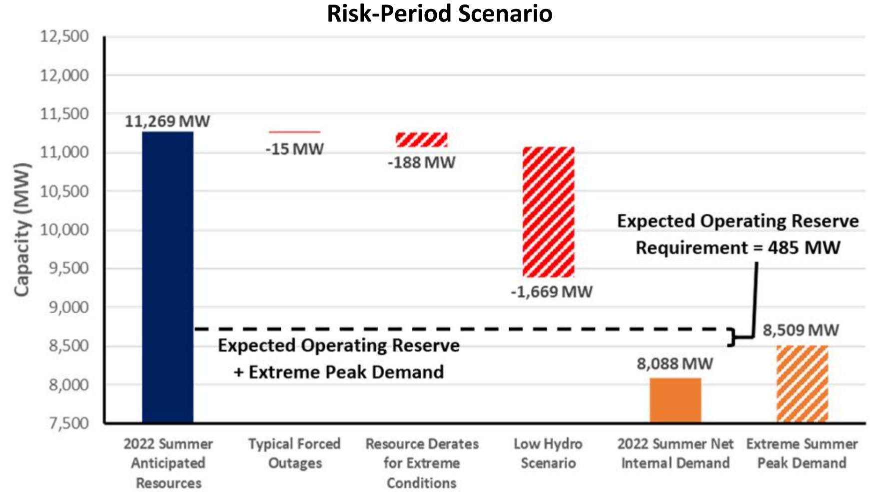
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

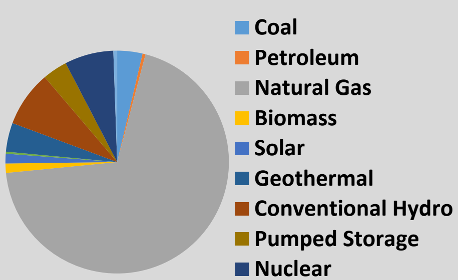
WECC-CA/MX

WECC-CA/MX (California-Mexico) is an assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorizes, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



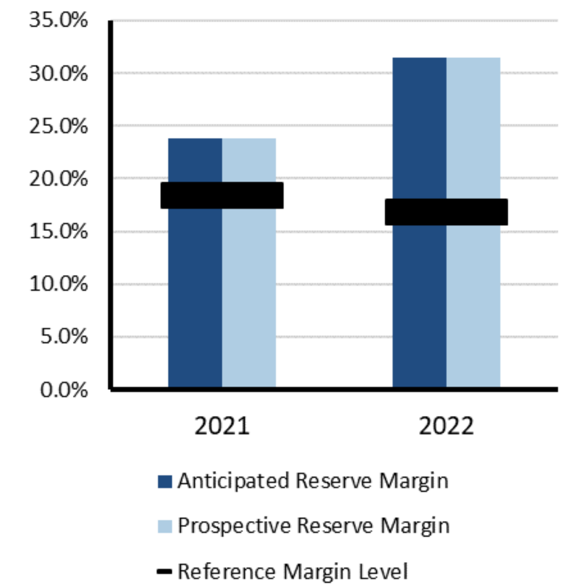
Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

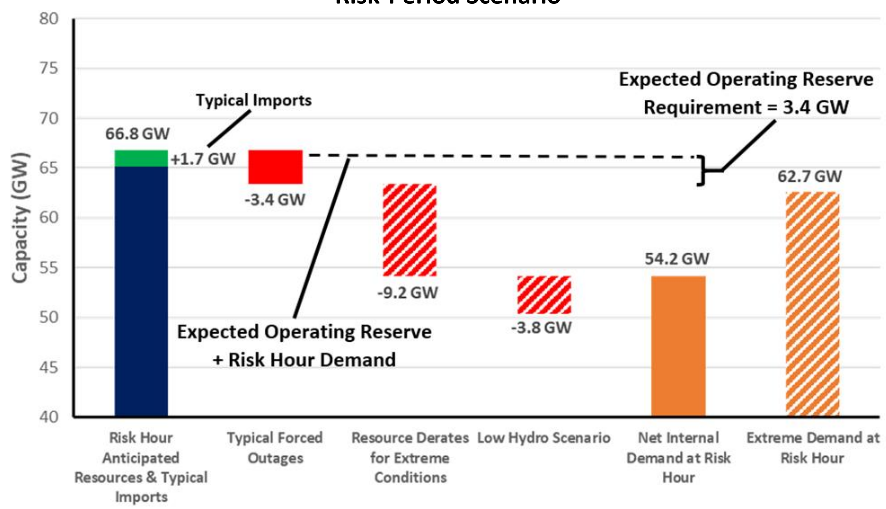
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

SCHEDULE MM-S1

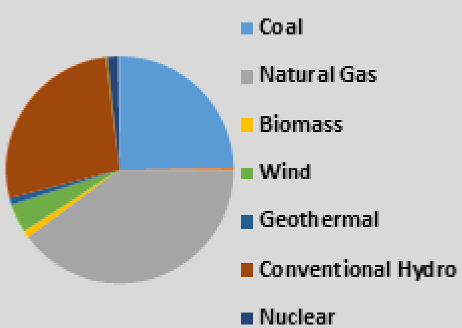
WECC-NWPP-US

WECC-NWPP-US (Northwest Power Pool) is an assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



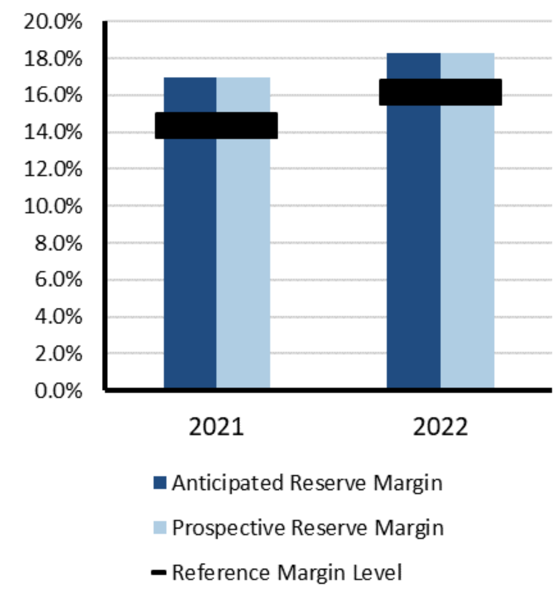
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

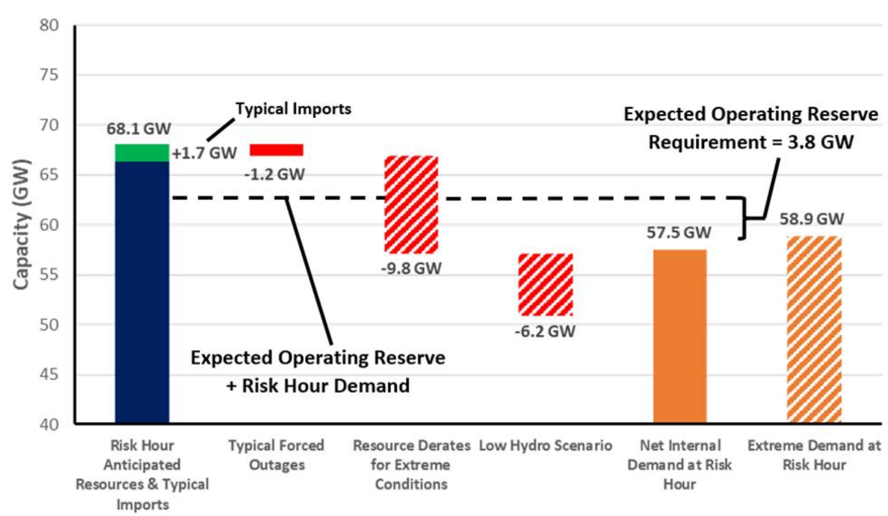
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

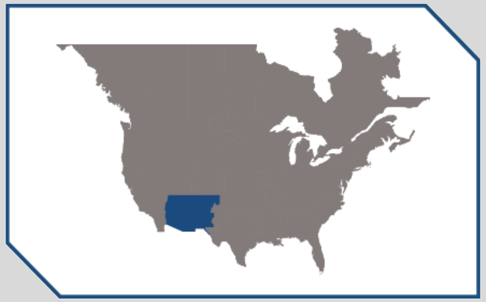
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

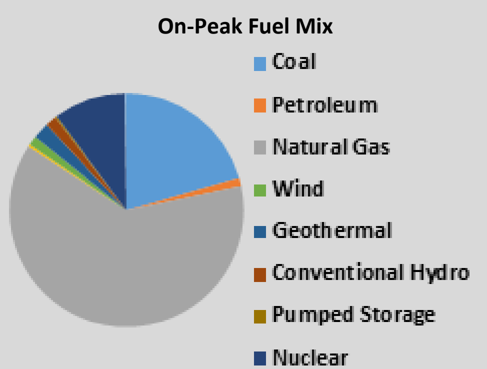


WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is an assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the Northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

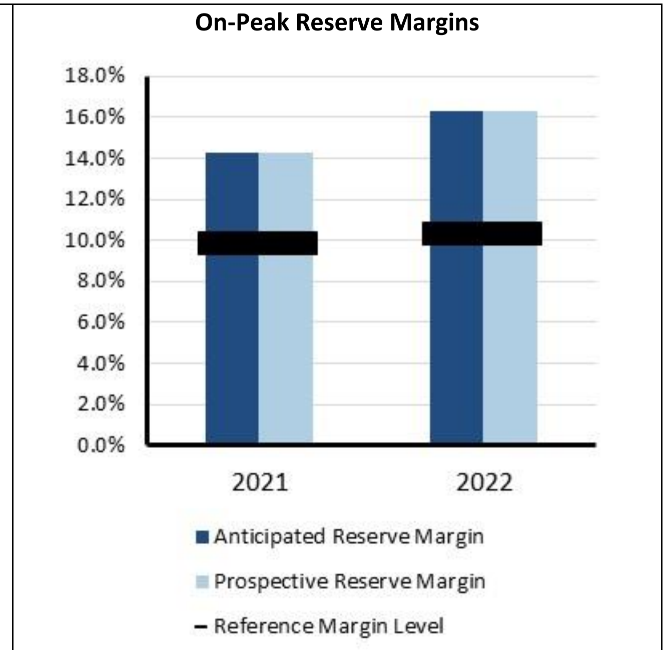


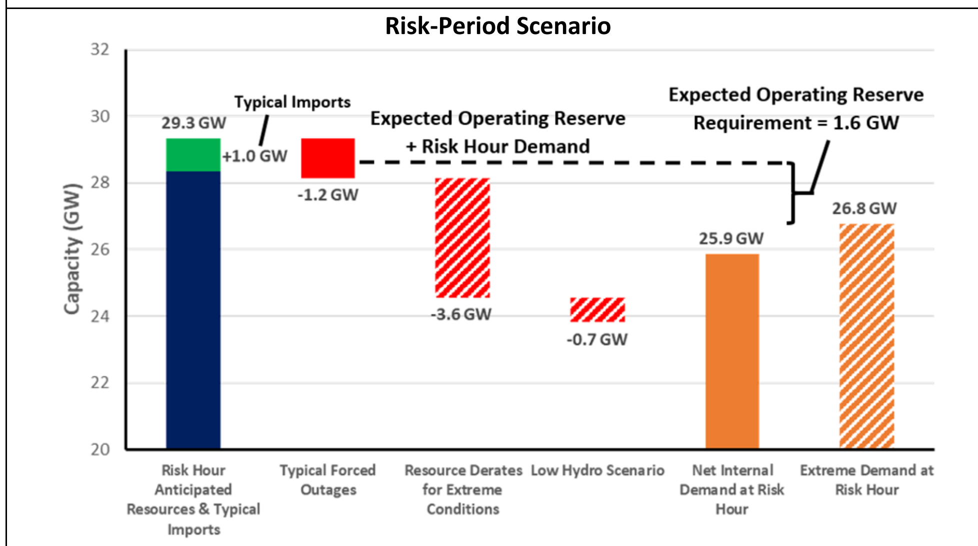
Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

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Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2021 Long-Term Reliability Assessment* data has been used for most of this 2022 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[7] or total internal demand for the summer and winter of each year.[8]
• Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[7] *Glossary of Terms* used in NERC Reliability Standards
[8] The summer season represents June–September and the winter season represents December–February.
[9] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[10] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[11] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022 summer as shown in **Figure 9**.

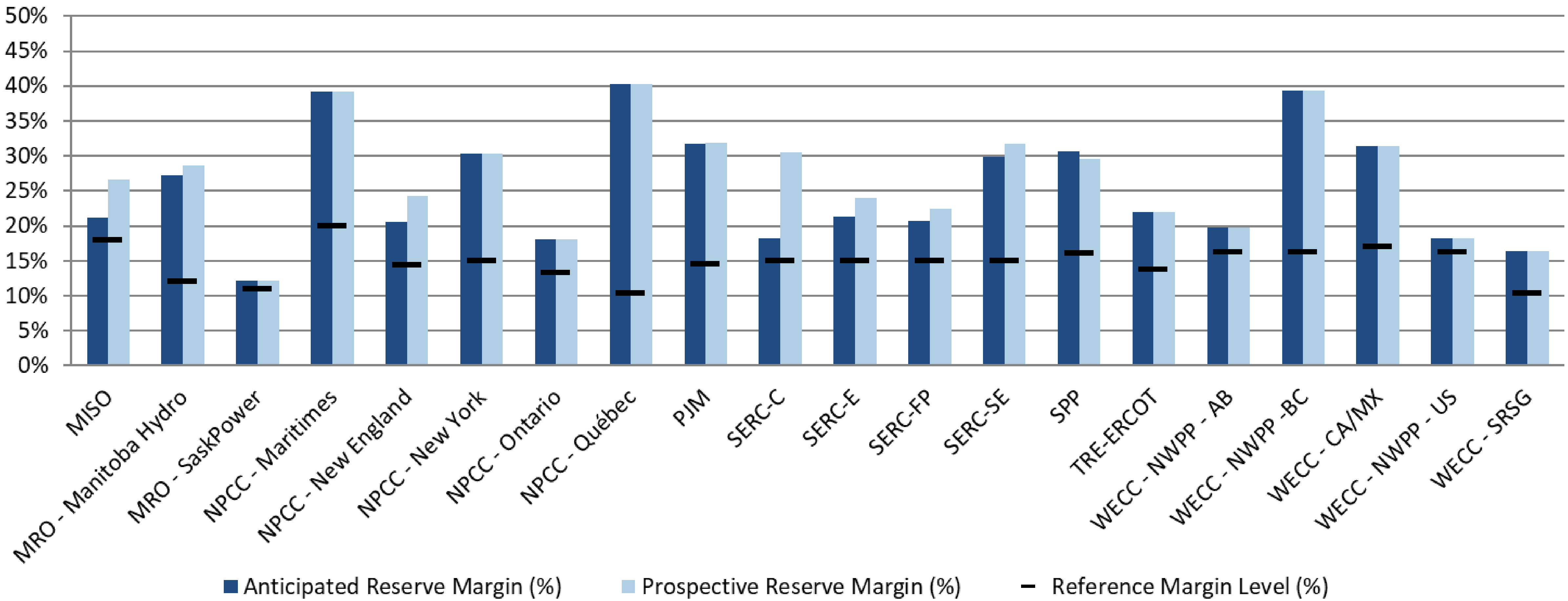

Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[11] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

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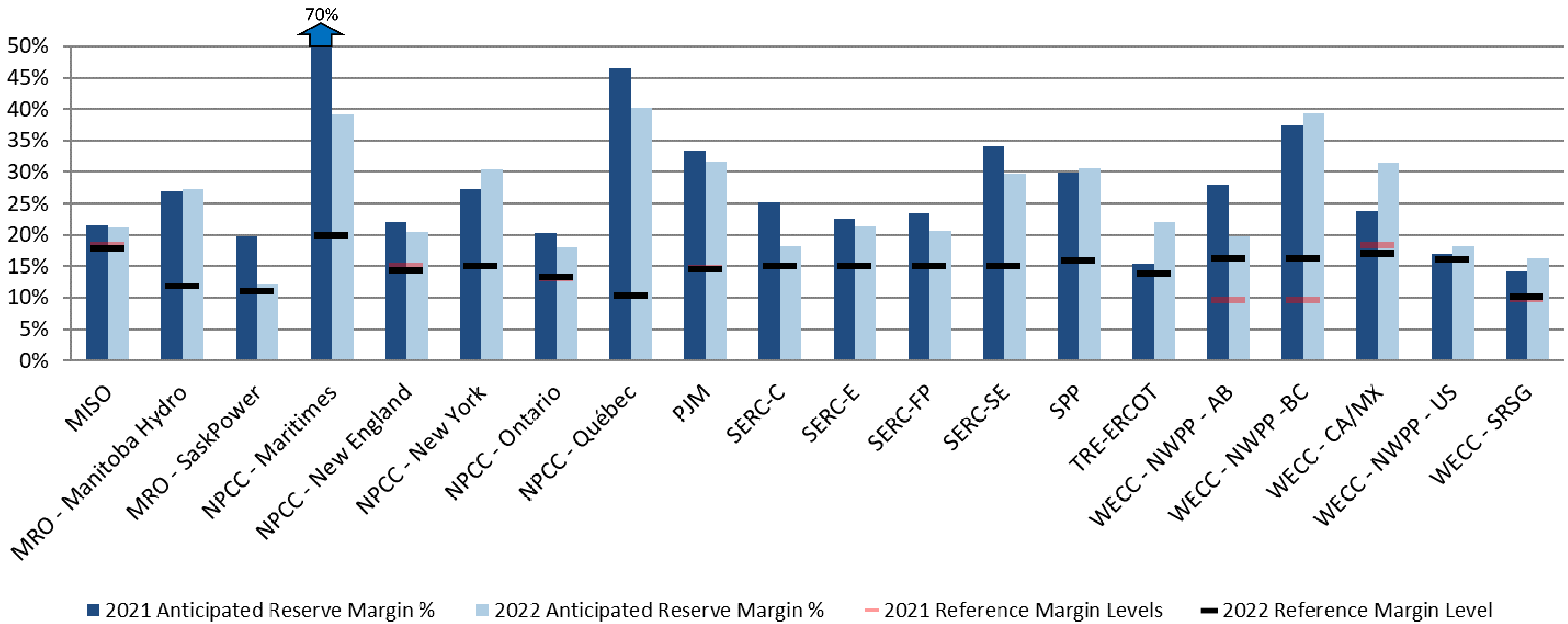
Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 11**.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

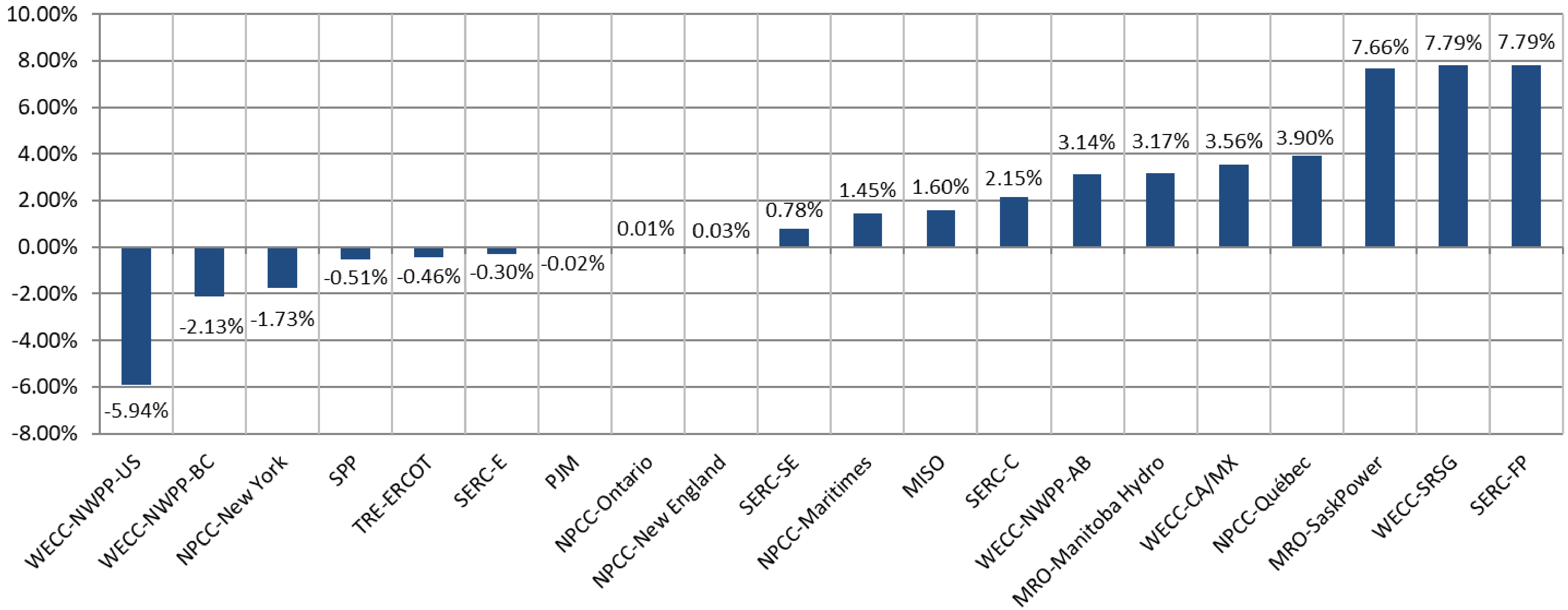


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

[12] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

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NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022 Long-Term Reliability Assessment

December 2022

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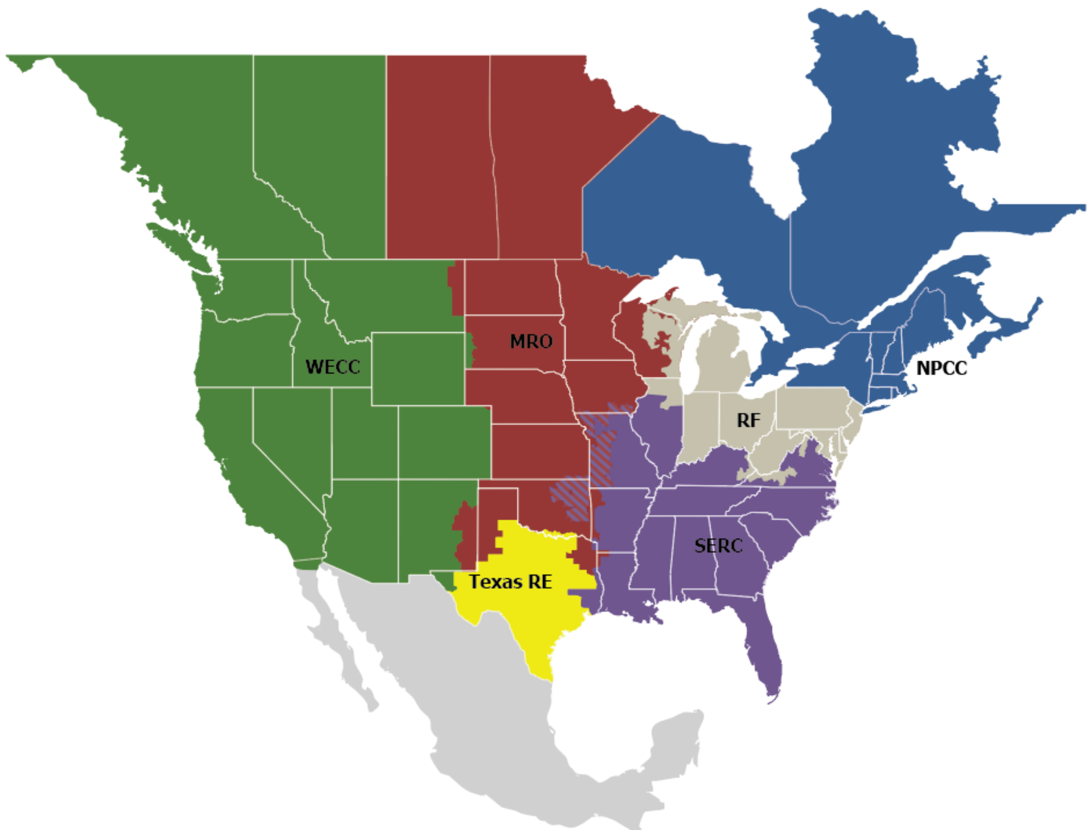
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

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About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area (see **Regional Assessments**) basis to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee, at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2022 about known system changes with updates incorporated prior to publication. This *2022 LTRA* assessment period includes projections for 2023–2032; however, some figures and tables examine data and information for the 2022 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

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Assumptions

In this *2022 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2022. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

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Executive Summary

Introduction

This *2022 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. This *2022 LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

The findings in this 2022 LTRA are vitally important to understand the reliability risks to the North American BPS as it is currently planned and as it is being shaped by government policies, regulations, consumer preferences, and economic factors. Energy systems and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee—and design for—their future states. This report contains future energy sufficiency metrics that serve as guideposts for the reliability of the North American electric grid on its current trajectory. It also describes the relevant trends that are propelling the grid's transformation and have the potential to alter the ability of the BPS to service the energy needs of communities and industries in North America.

Projected Area Supply Shortfalls

The **Resource Capacity and Energy Risk Assessment** section of this report identifies potential electricity supply shortfalls under normal and more severe conditions. NERC's assessment assumes the latest demand forecasts, resource levels, and area transfer commitments as well as accounts for expected generator retirements, resource additions, and demand-side resources.

High Risk Areas[7]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, areas shown in red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10 year load-loss metric during periods of the assessment horizon. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. The following is a summary of the high-risk areas (details are discussed in later sections of this *2022 LTRA*):

- **In the Midcontinent Independent System Operator (MISO)** area, the previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.
- **NPCC-Ontario** also continues to project a reserve margin shortfall in 2025 and beyond. The capacity deficit of 1,700 MW is driven by generation retirements and lengthy planned outages at nuclear units undergoing refurbishment.
- Resource additions in the **California/Mexico (CA/MX) part of WECC** are alleviating capacity risks, but energy risks persist. Planned reserve margins meet annual reserve margin targets for the duration of the 10-year horizon. However, overall variability in both the resource mix and demand profile contributes to shortfall risk periods, mainly in summer months around sunset, when expected supplies are not sufficient to meet the demand.

Elevated Risk Areas[8]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme weather impacts the system by increasing electricity demand and forcing generation and other resources off-line. While a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, **long-duration weather events increase the risk of electricity supply shortfalls**.

In many parts of North America, peak electricity demand is increasing, and forecasting demand and its response to extreme temperatures and abnormal weather is increasingly uncertain. Electrification and distributed energy resource (DER) trends can be expected to further contribute to demand growth and sensitivity to weather patterns. Specifically, electrification of residential heating requires the system to serve especially high demand on especially cold days.

[7] An assessment area is deemed to be "high risk" by failing to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1 day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[8] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

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Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

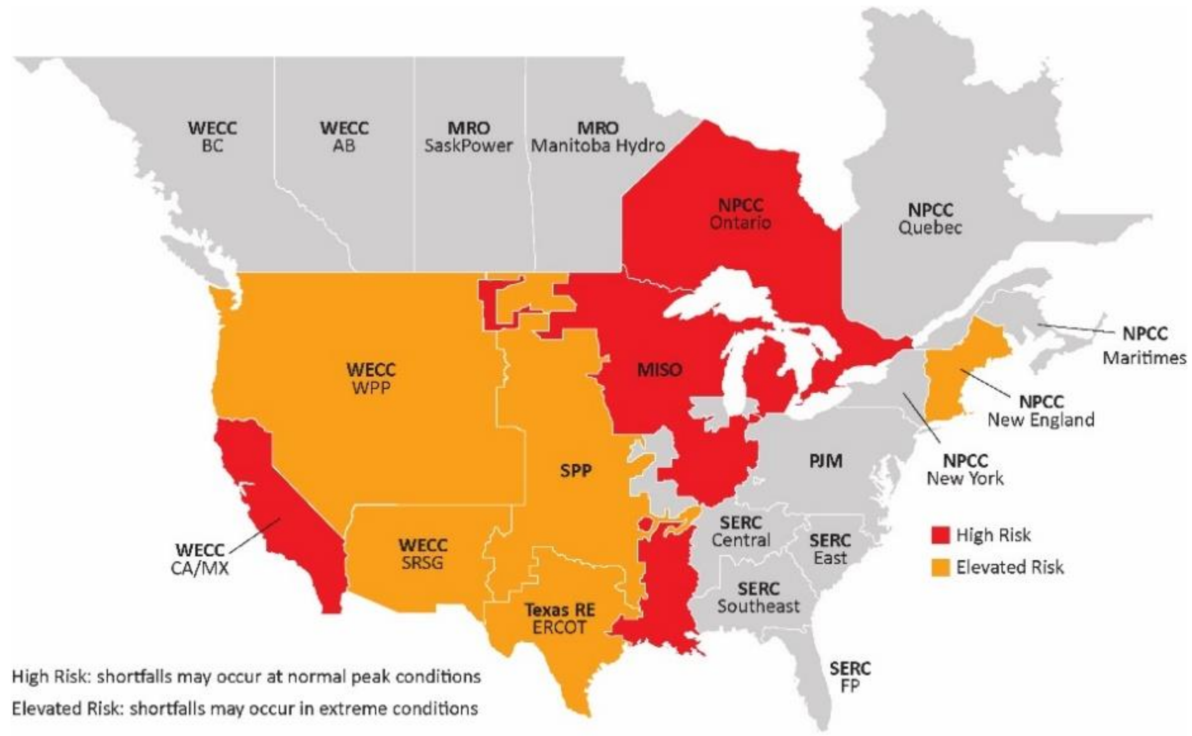

Figure 1: Risk Area Summary 2023–2027

Areas in orange (elevated risk) in Figure 1 meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- All three assessment areas in the **U.S. West—CA/MX, Western Power Pool (WPP), and the Southwest Reserve Sharing Group (SRSG)—**have increasing demand and resource mix variability. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.
- Reliability during extreme winter weather remains a concern in **Texas**. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. A high number of forced outages of the thermal and wind generation fleet have been an issue in severe winter weather. Improved generator availability resulting from winter preparedness programs and reforms implemented by Texas regulators, ERCOT, and Generator Owners since February 2021 are expected to reduce the risk that electricity supplies will be insufficient during a severe winter storm.
- **SPP** is exposed to energy risks in ways that are similar to both Texas and the U.S. West. Severe weather in SPP is likely to cause high generator outages and poses a risk to natural gas fuel supplies. In addition, the penetration of wind generation makes the resource mix variable and exposed to insufficient energy during low wind periods.
- In **New England**, limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions to generators. Liquefied natural gas facilities and sufficient generators with stored backup fuels are critical to electric reliability.

Continuing Resource Mix Changes and Implications for Reliability

This *2022 LTRA* contains the latest industry projections for generation and other resources, including DR, DERs, and the resulting **Continuing Resource Mix Changes and Implications for Reliability** found at this link. Highlights of these trends and the implications for reliability include the following:

- **Reliable Interconnection of Inverter-Based Resources:** Reliably integrating inverter-based resources (IBR), which include most solar and wind generation, onto the grid is paramount. Over 70% of the new generation in development for connecting to the BPS over the next 10 years is solar, wind, and hybrid (a generating source combined with a battery).
- **Accommodating Large Amounts of Distributed Energy Resources:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Solar photovoltaic (PV) DERs are projected to reach over 80 GW by the end of this 10-year assessment, a 25% increase in projection since the *2021 LTRA*; a total of 12 assessment areas project to double the amount of DERs in their areas by 2032.

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- **Managing the Pace of Generation Retirements:** As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.
- **Maintaining Essential Reliability Services:** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.[9] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services. As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

Trends and Implications for Reliability

Demand Trends and Implications as well as Transmission Development Trends and Implications found at these links affect long-term reliability and the sufficiency of electricity supplies. Several key insights emerge from the latest industry data:

- **Peak Demand and Energy Growth:** Projected growth rates of electricity peak demand and energy in North America are increasing for the first time in recent years. Government policies for the adoption of electric vehicles (EVs) and other energy transition programs have the potential to significantly influence demand. Demand-side management programs, including conservation, EE, and DR continue to offset demand and contribute to load management. Where rapid transition is proposed, early alignment and coordination on energy and infrastructure are needed.
- **Insufficient Transmission for Large Power Transfers:** Transmission development projections remain near the averages of the past five NERC LTRAs. There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the *2021 LTRA* projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources.
- **Emerging Electrification Challenges:** Several emerging issues and trends have the potential to impact future long-term projections of demand and resources. In addition to EV and electrification issues, cryptocurrency mining may have a notable impact on demand and resources in some areas. Resource development may be significantly altered by supply chain issues and differ from projections used in this *2022 LTRA*. Notable emerging issues and their potential implications are discussed in this report.

Conclusions and Recommendations

The energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues. General actions for industry and policymakers to address the reliability risks described in this *2022 LTRA* include the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services
- Include extreme weather scenarios in resource and system planning
- Address IBR performance and grid integration issues
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure

Specific *LTRA* recommendations are provided on the following page and in the appropriate sections of this report.

[9] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

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Reducing the Risk of Insufficient Energy

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios for resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. In areas with a high dependence on VERs and natural-gas-fired generation, Prospective Reserve Margins (PRM) are not sufficient for measuring resource adequacy:

- Industry and regulators should conduct all-hours energy availability analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs.
- The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons.
- State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
- Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.
- Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections.

Planning and Adapting for IBRs and DERs

IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused a sudden loss of generation resources over wide areas in some cases. As areas become more reliant on IBRs for their electricity generation, it is critically important to reduce risks from IBR performance issues. Likewise, explosive growth in DERs underscores the need to incorporate them into system planning:

- The ERO and Industry should take steps to ensure that IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document to address IBR performance issues that illustrates current and future work to mitigate emerging risks in this area.[10] Regulators, industry-standards-setting organizations, trade forums, and manufacturers each have a role to play to address IBR performance issues.
- Industry should increase its focus on the technical needs for the BPS to reliably operate with increased amounts of DERs. Growth promises both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures

Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure:

- ERO and Industry planners should enhance guidelines for assessing and reducing risks through system and resource planning studies and develop appropriate Reliability Standards requirements to ensure corrective actions are put in place.
- Regulators and other energy stakeholders must also take steps to promote coordination on interdependencies. The forum convened by the North American Energy Standards Board is one such important action that should be broadly supported.[11]

[10] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf
[11] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

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Capacity and Energy Assessment

Resource Capacity and Energy Risk Assessment

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk:

- Comparing the margin between projected resources and peak demand, or reserve margin, to a reference margin level (RML) that represents the accepted level of risk based on a probability-based loss of load analysis
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over *all* hours to identify high risk periods and energy constraints. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial Probabilistic Assessment (ProbA) are used to identify risk levels. LOLH greater than two hours and EUE greater than 0.2% of total energy is considered high risk for the purposes of this LTRA.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Supplemental tables and figures throughout this *LTRA* as well as assessment area dashboards (see **Regional Assessments**) provide resource capacity and energy risk assessment results for all areas.

Finding: Parts of the North American BPS face resource capacity or energy risks as early as the summer of 2023 (**Figure 1**). Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

Future Capacity Shortfall in MISO

Anticipated reserves fall below the RML in the MISO assessment area beginning in the summer of 2023—one year earlier than reported in the *2021 LTRA* and two years earlier than reported in the *2020 LTRA*. Resources below the RML indicate that the area lacks adequate resources to limit load loss events to less than 1-day-in-10 years, an established resource planning criterion. The 1,300 MW shortfall that is projected for next summer follows the retirement of 5,900 MW of coal-fired and natural gas generation since 2021. Anticipated resources for the 2023 summer include 6,600 MW of planned (Tier 1) resources made up of 56% solar, 37% natural gas, and 7% wind. MISO's anticipated reserve margins (ARM) and PRMs for the next five years are in **Figure 2**.

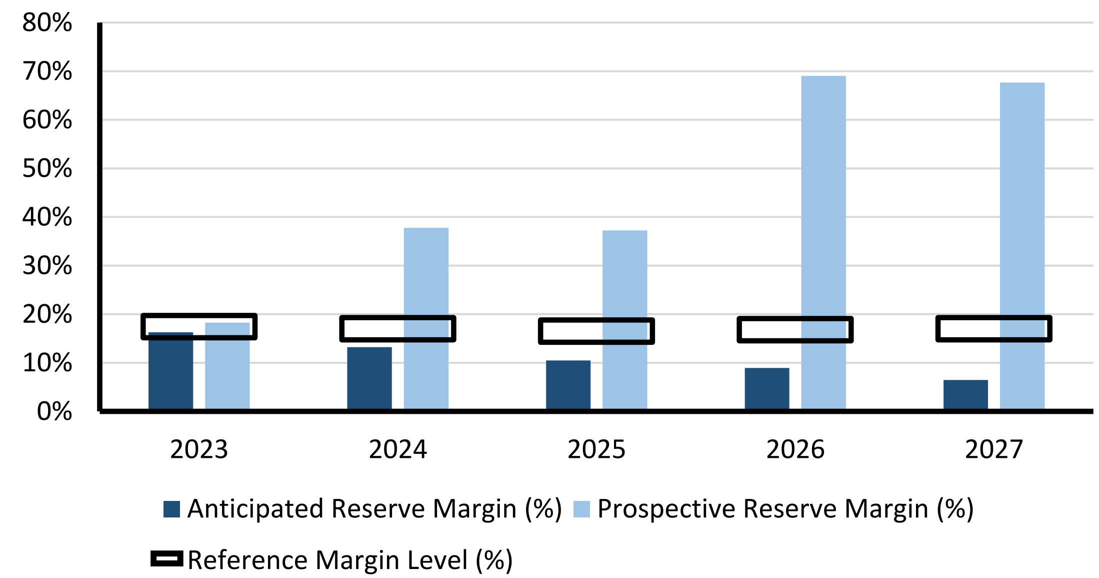

Figure 2: MISO Five-Year Projected Reserves (ARM and PRM)

Future Energy Risks in MISO

Results of the biennial ProbA conducted as part of this year's *LTRA* (2022 ProbA) confirm LOLH for 2024 are expected to increase from less than 0.1 hours per year to approaching one hour per year. Most risk occurs in June through August, corresponding to the months during which demand in MISO peaks. The ProbA also reveals risk periods in September and October when seasonal planned outages overlap with high demand. Another risk period is associated with winter, when extreme cold temperatures can push demand higher than normal in the morning and evening hours.

Future Capacity Shortfall in NPCC-Ontario

The ARMs in NPCC-Ontario fall below the RML in 2025 and beyond (see **Figure 3**). Anticipated shortfalls of about 1,700 MW are forecast for 2025 and 2026. As reported in the *2021 LTRA*, the main drivers for Ontario's projected shortfall are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026. If approval is received from the Canadian Nuclear Safety Commission, this extension would reduce the potential capacity shortfall

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in 2026 described in the *2021 LTRA*. The ARM in **Figure 3** is calculated with an assumed retirement of Pickering units in late 2026.

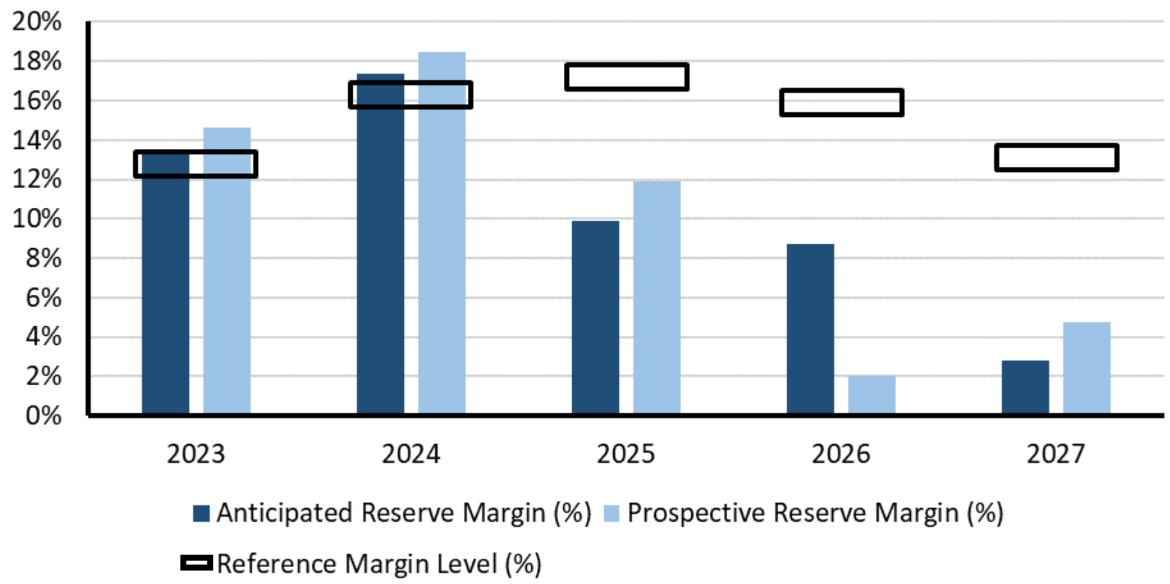

Figure 3: NPCC-Ontario Five-year Projected Reserves (ARM and PRM)

In order to address these emerging resource adequacy needs, the Independent Electricity System Operator's (IESO) established a Resource Adequacy Framework in 2021 to provide a flexible and cost-effective approach for competitively securing resources.[12] The Resource Adequacy Framework sets out a multi-pronged approach to cumulatively address needs over varying time frames with the annual acquisition report specifying the mechanisms and targets that will be used to meet the needs. In addition to supporting the Pickering Nuclear Generating Station extension, Ontario's Ministry of Energy also directed the IESO to obtain 4,000 MW of new capacity through three separate procurements. The IESO also announced new energy efficiency programs targeting needs in 2025–2027.

Energy Risks in U.S. Western Interconnection

Throughout the U.S. assessment areas in WECC, both demand and resource variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years despite having adequate capacity for the peak demand hour.

Energy Risks in WECC-CA/MX

Resource additions in WECC-CA/MX are alleviating capacity risks, but energy risks persist. In the *2021 LTRA*, a capacity shortfall was projected beginning in 2026. Now the ARM in 2026 has risen to over 22% and is above the RML throughout the 2023–2027 period (see **Figure 4**). This indicates that the anticipated resources are sufficient to meet peak demand of a normal summer. However, the area remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Heat events spanning a wide area that reduce the availability of electricity imports into California are likely to continue to raise concerns and be an area of risk that could induce energy shortfalls in the near term.

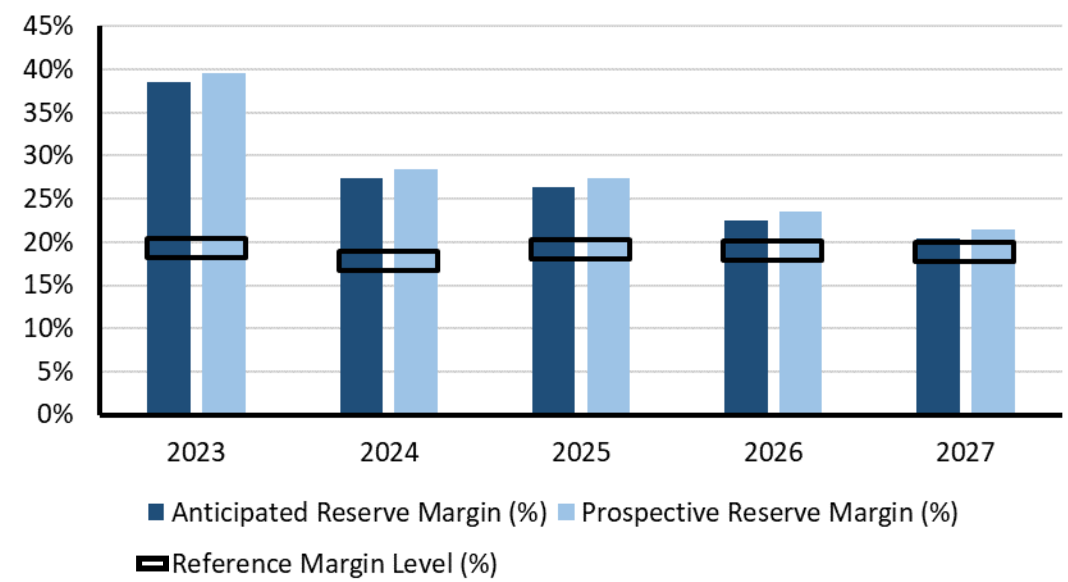

Figure 4: WECC-CA/MX Five-Year Projected Reserves (ARM and PRM)

12 https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework

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Added capacity in California has resulted in improved ProbA metrics and reduced energy risks; however, calculated load loss hours and unserved energy risks remain high. Since the 2020 ProbA, LOLH for 2024 has decreased from 56 hours per year to less than 1 hour per year, but projections for 2026 increase to nearly 10 hours per year. **Figure 5** shows a summary of CA/MX monthly energy shortfall risks for 2024 from the ProbA. Risk periods are spread across the months of July–September, coinciding with some of the warmest temperatures and potentially volatile electricity demand. Output from solar begins to fall off earlier in the day during the late summer months as well, and hydro output is lower from seasonal water flow patterns.

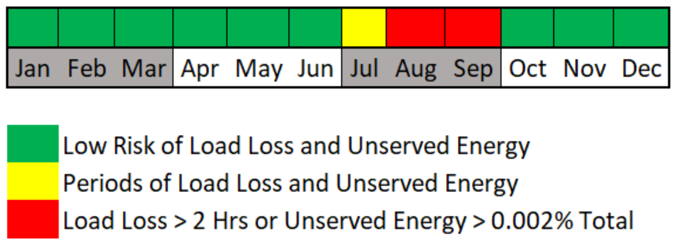

Figure 5: 2024 Monthly Energy Risk Summary for WECC-CA/MX

Examining the projected resource performance for the full 24 hours of the day that the peak risk hour occurs demonstrates the drivers of the energy risk in California. The bars in **Figure 6** show the variation in capacity resource output over the day. Each curve represents a demand forecast that ranges from a normal year forecast (e.g., Demand 50 indicates levels are equally likely to be above or below the actual demand on that day) to an extreme year forecast with higher demand levels that are unlikely to be exceeded by actual demand (e.g., Demand 05 indicates that statistically only 5 in 100 years are likely to have a day in which actual demand exceeds this forecast). As solar decreases as sunset approaches, the total of all available resources can fall short of the demand, especially for the higher demand levels represented in the load forecast. Imports are limited and cannot satisfy the increased demand levels in the CA/MX area, resulting in significant EUE.

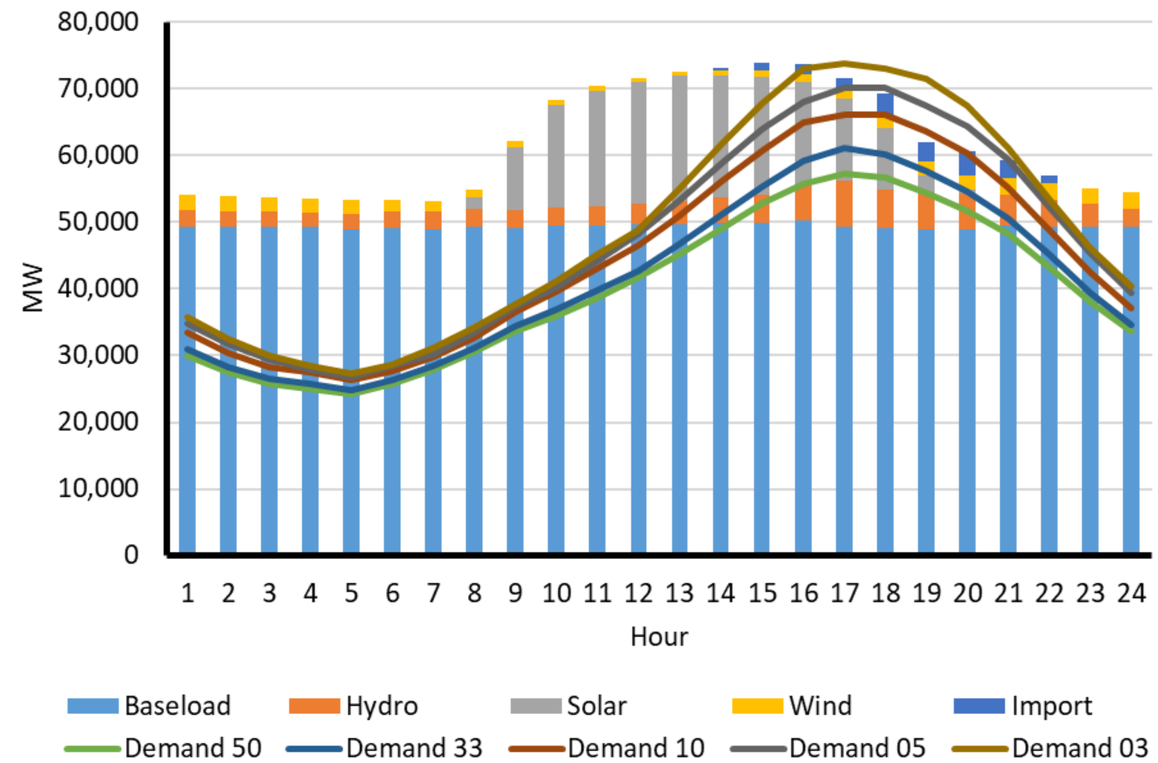

Figure 6: Hourly Demand and Resources for 2024 Summer Peak in WECC-CA/MX

Energy Risks in WECC-SRSG and WECC-WPP

Assessment areas in the U.S. Southwest and Northwest are also projecting summer periods of energy shortfall risks in the next five years. Risk months for WECC-SRSG and WECC-WPP are summarized in **Figure 7** and **Figure 8**. These areas have an increasingly variable generation resource mix and peak summer demand profile. Like CA/MX, late summer periods in the Southwest have the greatest risk of energy shortfalls due to the hot temperatures and potential for volatile electricity demand along with drop-off in solar that begins to occur earlier each day. In the Northwest, risk is spread across all summer months; this is driven primarily by declining on-peak capacity as coal-fired generators retire and less generation capacity is in the interconnection queue to replace it. ProbA results indicate that the risk of energy shortfall is increasing from 2024 to 2026 study years in both assessment areas.

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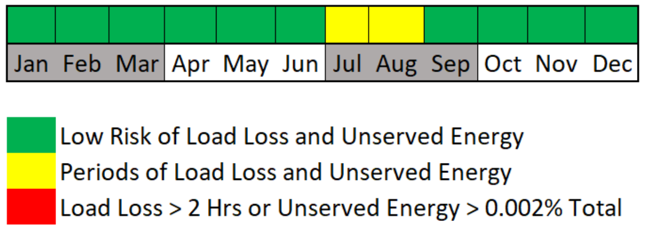

Figure 7: 2026 Monthly Energy Risk Summary for WECC-SRSG

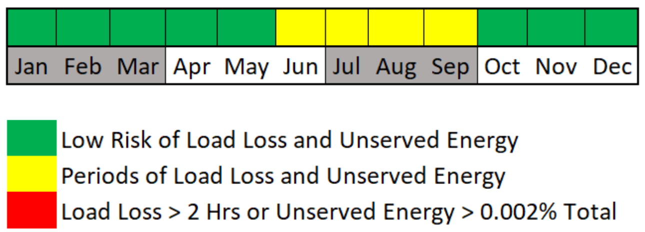

Figure 8: 2026 Monthly Energy Risk Summary for WECC-WPP

ERCOT Energy Risks

Generation resources, primarily solar and wind, continue to be added to the grid in Texas in large quantities, increasing on-peak planning reserve margins but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation.

The summer on-peak ARM is projected to stay above the RML of 13.75% through 2027 (see **Figure 9**). The ARM increases significantly for the summers of 2023 and 2024 due to the expected addition of over 22,000 MW of summer Tier 1 capacity, most of which is solar.

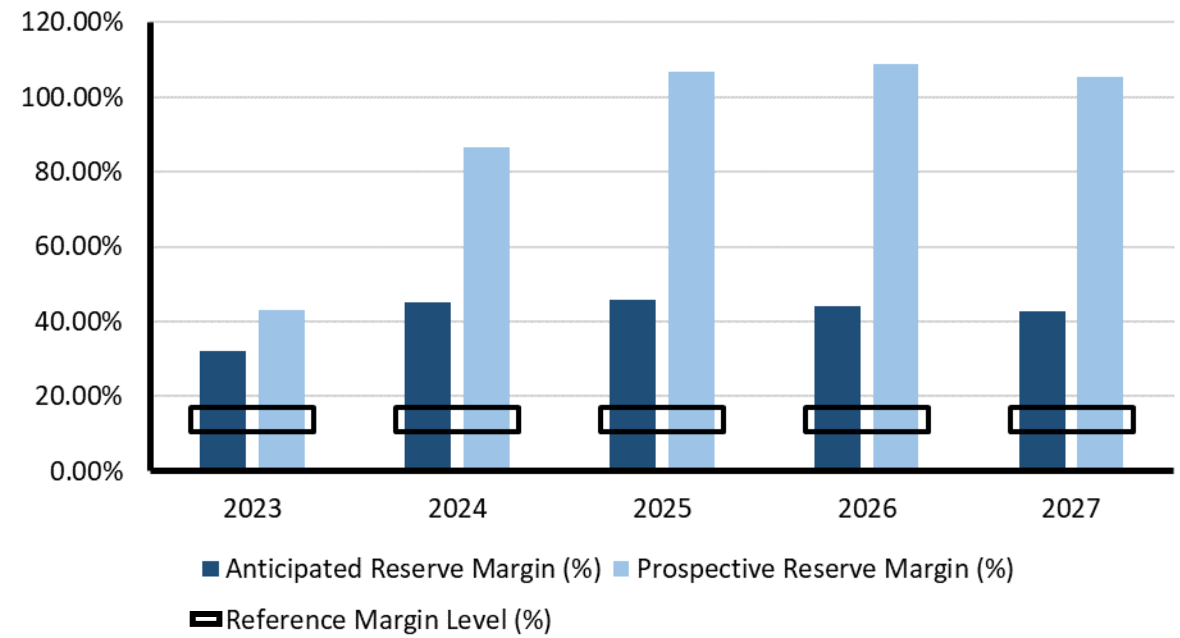

Figure 9: Texas RE-ERCOT Five-Year Projected Reserves (ARM and PRM)

The growing penetration of solar in ERCOT is increasing the risk of tight operating reserves during hours after the daily peak load hour when planning reserve margins are measured. Like California, this issue is most acute for the summer season when solar generation ramps down during the early evening hours while load is still relatively high. Studies by ERCOT show that the highest risk of energy emergencies occurs during summer months from early afternoon through early evening hours, peaking during the 7:00–8:00 p.m. hour. See **Texas RE-ERCOT** in the assessment area pages. ERCOT's summer LOLH and EUE are relatively small; however, these results are contingent upon completion of nearly 20 GW of Tier 1 solar resources by 2024.

Finding: Parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020–2021 U.S. Western area heat wave and the South Central Winter Storm Uri in 2021.

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Extreme Winter Weather Risks in Texas

Though typical winters in Texas are mild and pose little risk of energy shortfalls, extreme winter weather similar to Winter Storm Uri in February 2021 are likely to challenge grid operators to maintain reliability in the near-term. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. This is in contrast to the relative stability of ERCOT's summer peak demand, which does not vary by more than a few percentage points between an average year and an extremely hot year. With such demand variability, long-range weather and demand forecasting becomes more important to ensuring sufficient resources are available and ready to operate.

In winter, demand in Texas peaks during cold early morning hours before ERCOT's vast solar resources are producing electrical output. Demand must be met primarily with the fleet of thermal and wind generators. In Texas and other parts of the South that do not experience harsh winters each year, high forced outages of the thermal and wind generation fleet has been a common issue when extreme weather events have led to energy emergencies, causing generator component freezing, fuel supply disruption to natural gas and coal-fired plants, and wind generator protection cut-outs.[13] ERCOT's analysis for the 2022 ProbA included forced outage risk modeling for extreme winter conditions, and most risk of load loss occurs in winter, not summer, months. A summary of monthly energy risk is in Figure 10.

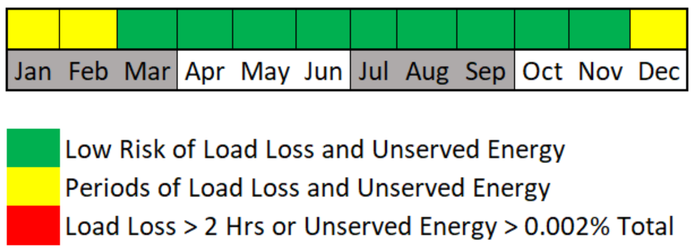

Figure 10: 2024 and 2026 Monthly Energy Risk Summary for ERCOT

These winter energy risks in the ProbA results are significantly influenced generator outage modeling like the effects from Winter Storm Uri. Since February 2021, Texas regulators, ERCOT, and Generator Owners have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. The ProbA results do not consider these changes and are likely to be pessimistic for similar extreme weather as a result.

Energy Risks in NPCC-New England

Studies performed by NPCC and ISO New England have identified energy risks for the area. Although there is sufficient capacity to meet the resource adequacy criterion, a previously identified and persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. See the NPCC New England assessment area pages.

Energy Risks in SPP

While the SPP PRM shows a significant amount of capacity, ARMs do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the SPP assessment area pages.

Recommendation for Reducing Resource Capacity and Energy Risk

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios in resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. Industry and regulators should conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs. In areas with high dependence on VERs and natural-gas-fired generation, PRMs are not sufficient for measuring resource adequacy.

The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons. State and provincial regulators and ISO/ RTO) should have mechanisms they can employ to prevent retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.

[13] See the findings and recommendations of the Joint FERC/NERC/Regional Entity inquiry into the February 2021 cold weather event: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

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Resource Mix Changes

Finding: The vast amounts of wind, solar, and now hybrid generation resources in interconnection processes will enable continued transition in the generation resource mix as traditional resources retire. VERs (resources with output dependent upon weather and hourly conditions) will increase and the fleet of thermal resources will shrink and have less fuel diversity.

The addition of VERs (primarily wind and solar) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Maintaining reliability will require the pace of change to be carefully managed by industry and regulators and steps to be taken to ensure that essential reliability services (ERS) continue to be provided as generators retire.

Generation Resource Mix in 2022

Figure 11 shows the fuel mix composition of all generation resources connected to the North American BPS in 2022. The installed resource mix (left) is based on the design ratings of the generators. On-peak resource capacity (right), in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. The wind on-peak capacity contribution ranges from a low of 10% of installed capacity in Saskatchewan to 26.2% in ERCOT. Solar on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect solar contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments web page provide on-peak capacity contributions of existing wind and solar resources in each assessment area.[14]

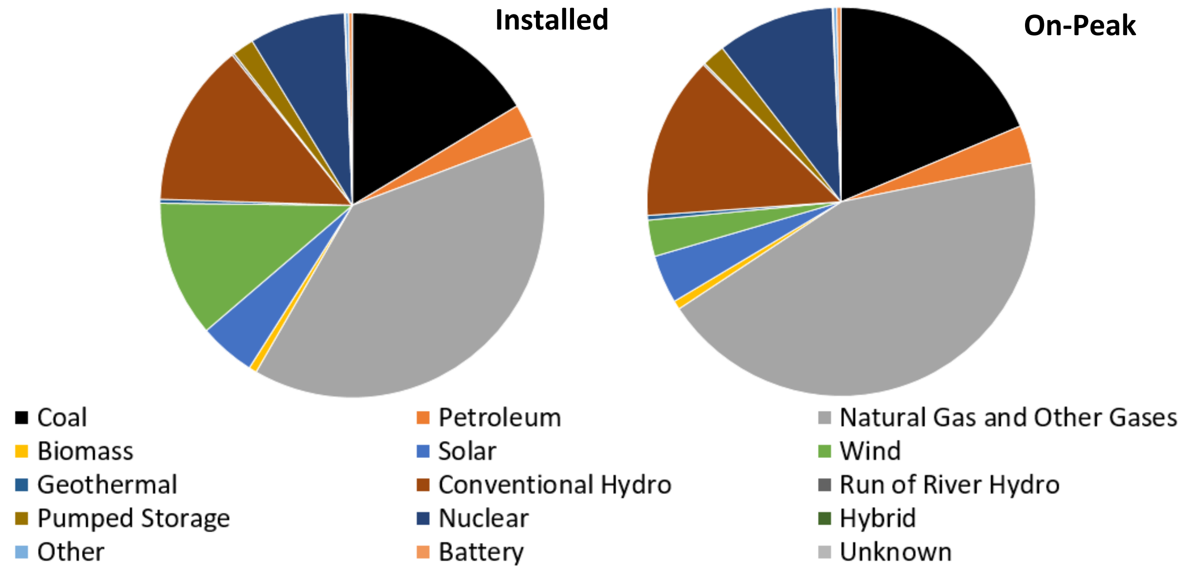

Figure 11: 2022 BPS Generation Capacity by Fuel Type

Total on-peak capacity by generation type is summarized in Table 1 below. The capacity of several traditional baseload generation fuel-types is in decline. Since the *2021 LTRA*, coal-fired generation has fallen by 17 GW and nuclear generation has fallen by 2 GW.

Table 1: 2022 Capacity at Peak Demand

Type	Capacity (GW)	Change since 2021 (GW)
Natural Gas	477	+14
Coal	202	-18
Nuclear	106	-2
Solar and Wind	70	+19
All others	189	+2
Contributions at hour of peak demand. VER (solar, wind, and some hydro) typically count less than installed nameplate capacity.		

[14] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

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Capacity Additions

New generation is added to the BPS through area interconnection planning processes. Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in **Figure 12**. See supplemental tables for greater detail by fuel type.

In general, Tier 1 resources are in final stages for connection while Tier 2 resources are further from completion and some may, in fact, not be completed. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

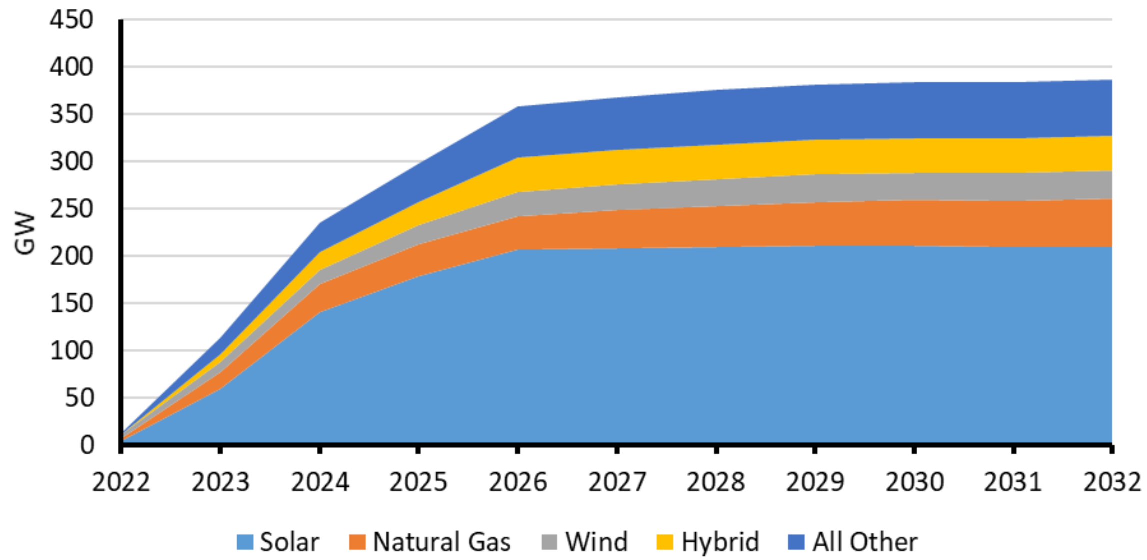

Figure 12: Tier 1 and 2 Planned Resources Projected Through 2032

Solar and wind capacity, both existing and planned, vary widely by area. **Figure 13** and **Figure 14** show current solar and wind installed capacities and capacity in the planning process through 2032 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (e.g., a wind or solar farm) are connecting to the grid in parts of North America, and many more projects are in BPS planning processes. A complete listing for all assessment areas is available in the supplemental tables.

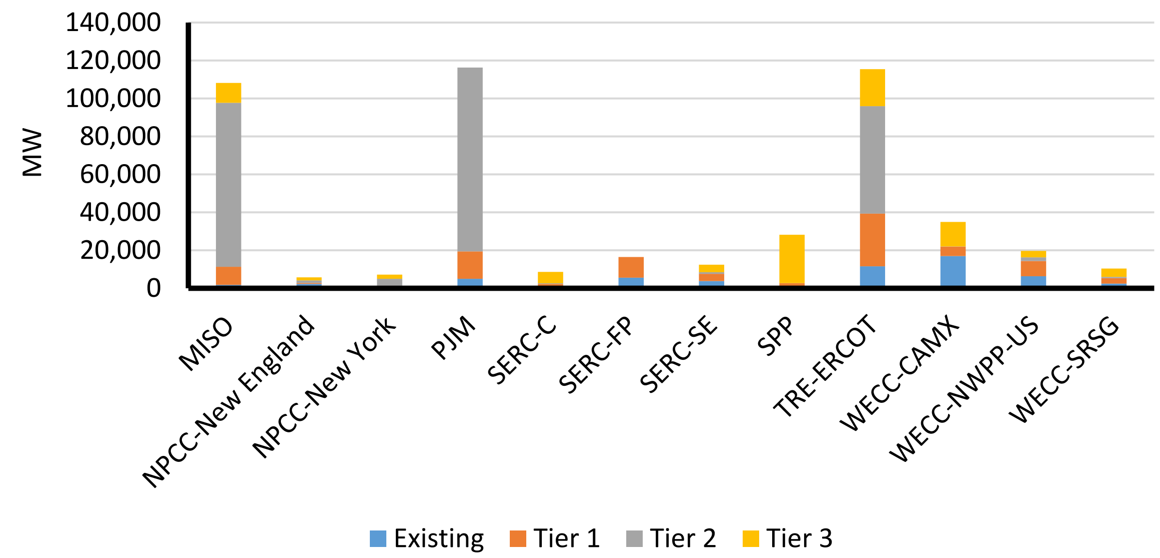

Figure 13: Solar Capacity Planned and Existing

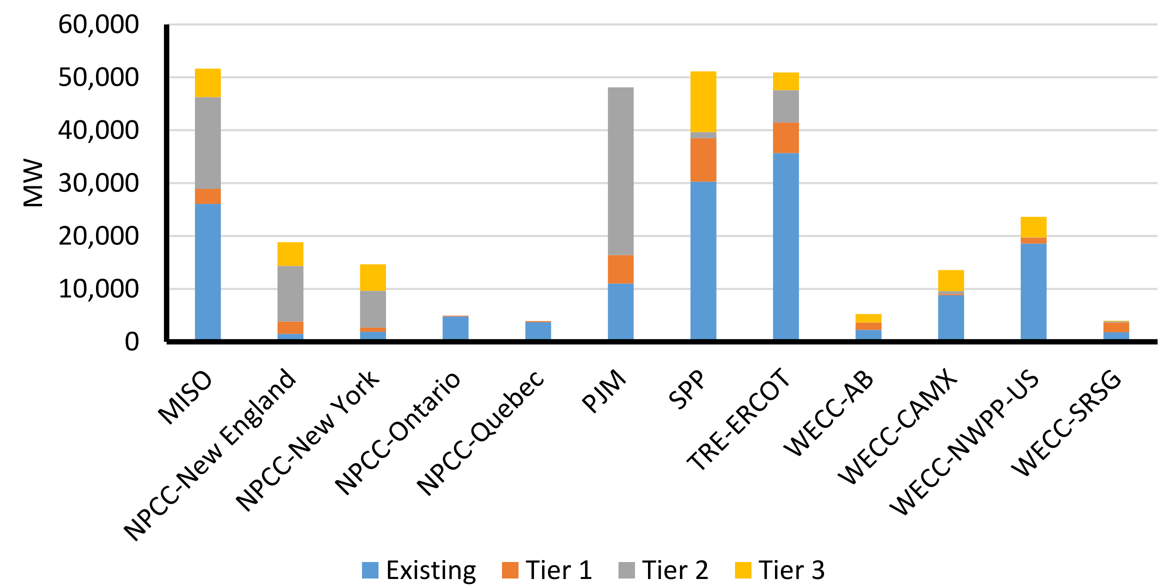

Figure 14: Wind Capacity Planned and Existing

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Solar Distributed Energy Resource Growth

Behind the meter (BTM) solar PV generators are solar resources connected directly to the distribution system, such as residential rooftop solar systems. Rapid growth of BTM solar PV continues with cumulative levels expected to reach over 80 GW by the end of this 10-year assessment period (an increase of 25% since publication of the *2021 LTRA*). BTM solar PV generators, like grid-connected solar, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours and may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. Supplemental tables show the current and projected BTM solar PV by area.

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. The resource mix changes as these retirements are coinciding with the addition of new generation of different types with different capacity characteristics. **Figure 15** shows how the current resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2032 if confirmed retirements occur and all projected Tier 1 resources are added. Across the entire BPS, the on-peak capacity contribution of solar and wind will grow modestly from the current 7% to 12%. The change in specific Interconnections varies. ERCOT and the Western Interconnection are projected to have more significant increases in the share of on-peak generation that is coming from VERs while the Eastern Interconnection and Québec Interconnection would change little in the 10-year period.

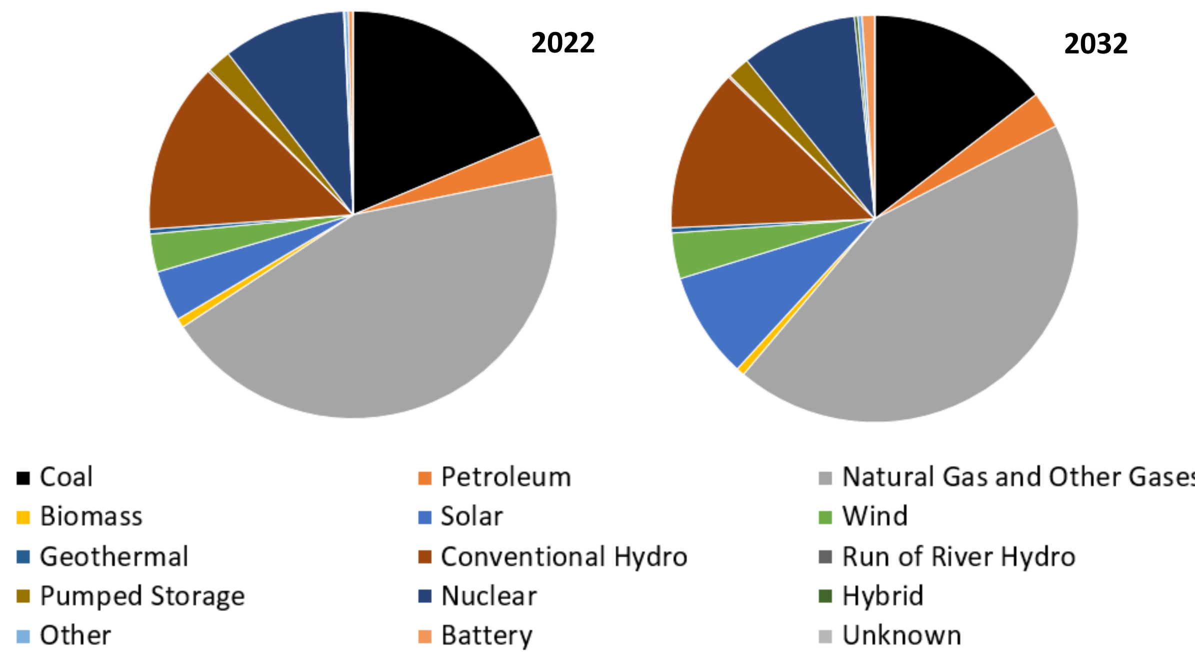

Figure 15: 2022–2032 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or integrated resource planning process in vertically-integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Additional retirements beyond what is reported as confirmed in this *2022 LTRA* are expected. Often Generator Owners announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. **Figure 16** shows the total capacity of confirmed and announced as well as unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next five years.[15]

[15] Confirmed generator retirements are reported to NERC by each assessment area in the LTRA development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

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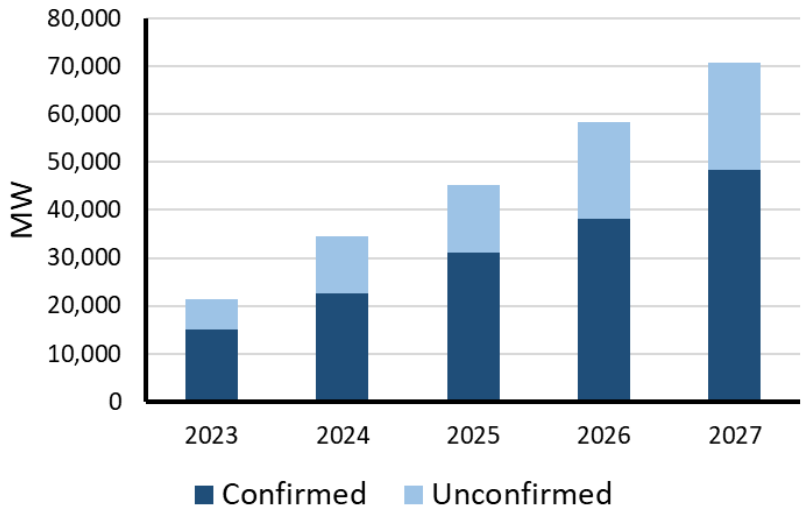

Figure 16: Projected Generation Retirement Capacity Through 2027

Throughout this *2022 LTRA*, all confirmed generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. In some risk areas identified in the **Resource Capacity and Energy Risk Assessment** section of this *2022 LTRA*, the announced, unconfirmed generator retirements are likely to exacerbate currently-projected energy shortfalls. **Figure 17** shows a comparison of the 2027 (Year 5) ARMs for the assessment areas at risk of shortfall as well as the potential 2027 reserve margins for a scenario with both confirmed and announced generator retirements. In MISO, where 10.2 GW of generation is expected to retire by 2027, another 5.4 GW of generation capacity is at risk of retirement based on retirement plan announcements. Loss of this additional capacity could lower the reserve margins from 6.5% in the current year to below 2% for the 2027 capacity assessment. The Maritimes provinces in Canada could also face a capacity shortfall if 550 MW of unconfirmed retirements were to exit the system without replacement resources.

In SPP, Texas RE-ERCOT, CA/MX, WPP, and SRSG, where energy limitations are contributing to projected load-loss risk in the **Resource Capacity and Energy Risk Assessment** section of this LTRA, additional thermal generator retirements could also be detrimental to reliability. Loss of these traditional baseload resources would lead to a more variable generation resource mix unless they are replaced by resources that are dispatchable, flexible, and able to counter variations in generation and demand. Consequently, the risk of insufficient energy and loss-of-load during periods of high demand and low resource output will rise.

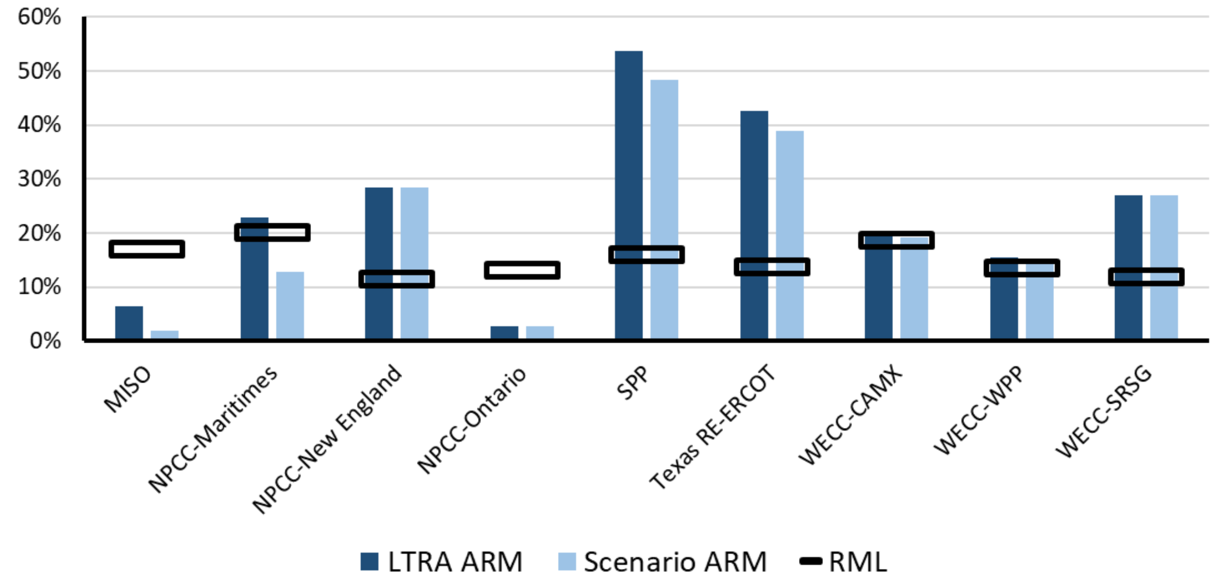

Figure 17: Year 2027 Reserve Margins Including a Scenario with Announced/Unconfirmed Retirements

These scenarios illustrate the potential impacts that significant generation retirements can have on resource adequacy, and they underscore the important role of ISO/RTO and integrated system planning processes that are necessary to maintain reliability.

Reliability Implications

The addition of variable resources, primarily wind and solar, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Important reliability implications include the following:

- **Flexible Resources:** In order to maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, some operators are seeing the need to have more system ramping capability. As more solar and wind generation is added,

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additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.[16] Maintaining ERSs is critically important, and resources must be made available in the long-range resource portfolio as part of the planning process; market and other mechanisms need to be in place to deliver resources with ERS-capabilities to the operators.

- **Fuel-related Risks to Electricity Generation (Fuel Assurance):** Natural gas for electricity generation is an essential fuel that bridges the rapid development of VERs. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[17] Disruptions to the fuel delivery can result from adverse events that may occur, such as line breaks, well freeze-offs, and/or storage facility outages. The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Furthermore, additional pipeline infrastructure is needed to reliably serve electric load.
- **Inverter-based Resources:** IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as the summer of 2022.[18] A common thread with these events is the lack of IBR ride-through capability causing a minor system disturbance to become a major disturbance. To address systemic issues with IBRs, NERC continues to urge industry's adoption of the recommended practices set forth in NERC guidelines even as NERC begins the process of developing mandatory Reliability Standards based on those guidelines. High priority items include incorporating electromagnetic transient modeling into the NERC Reliability Standards and developing a comprehensive ride-through requirement that focuses specifically on generator protections and controls.
- **BES Protective Relay Systems:** The changing resource mix presents unique risks and challenges to the vast network of protective relay systems that are critical to the safe and reliable operation of the Bulk Electric System (BES). Protection systems are meticulously planned and maintained to rapidly respond to dynamic grid conditions in a coordinated manner that isolates faults from spreading throughout the system and minimizes risks to grid equipment and personnel. With more IBRs and fewer synchronous generators on the grid, there is growing concern in the industry that protection systems will no longer function properly during system faults without redesign. Unlike synchronous generators, which produce high currents with unbalanced characteristics during faults that enable existing protections systems to function properly due to their physical properties, IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation. Protection engineers need to have better tools to analyze periods of low synchronous generation and ensure protection systems will still function properly.
- **Tools and Models for Assessing Capacity and Energy Risks:** Planners and operators are updating processes, tools, and techniques to keep pace with the changing resource mix. The explosive growth of battery and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, battery duration, and battery operating mode. Additionally, resource planners and wholesale market designers in most areas with growing wind and solar resources are considering or developing new processes for assigning the contribution of resources to meeting demand. Some are investigating the use of effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods should address the risks and shortcomings in present modeling described in this report. Specifically, the statistical representation of capacity that has variable and uncertain fuel can

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[16] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf
[17] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
[18] See *May/June 2021 Odessa Disturbance Report*, *June-August 2021 CAISO Solar PV Disturbance Report*, and other relevant IBR event reports here: https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

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be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and highly reliable. Finally, planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure that the industry is ready to take actions needed to preserve the reliable operation of the BPS for many potential system conditions. Traditional models and approaches rooted in a loss-of-load expectation of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand distributions appear to be ill-suited for describing the extremes of a changing weather patterns.

- **Essential Reliability Services:** Conventional units, such as coal and nuclear power plants, provide frequency support services as a function of their large spinning mass and governor control settings, along with voltage regulation. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. The reliability of the BPS depends on the operating characteristics of the replacement resources. Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the BPS to have resources not only with the capability to respond to frequency and voltage changes, but to actively provide those services.[19]

Recommendations for Reducing Risks as the Resource Mix Changes

In addition to the recommendations found elsewhere in the report, the following will reduce risks that can occur during the resource mix transition:

- Resource planners and policymakers must give careful attention to the pace of change in the resource mix and update capacity and energy risk studies, including all-hours probabilistic analysis, with accurate resource projections.
- The ERO and Industry should take steps to ensure IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document for addressing inverter-based resource performance issues that illustrates current and future work to mitigate emerging risks in this area.[20] Regulators, industry standards-setting organizations, trade forums, and manufacturers also have a role to play addressing IBR performance issues.
- Industry should increase its focus on technical needs for reliably operating with increased amounts of DER. Growth promises both opportunity and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role to BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.
- Industry, regulators, and energy stakeholders must urgently act to solve reliability challenges arising from interdependent natural gas and electricity infrastructure. For industry, this entails enhancing guidelines for assessing and reducing risks and developing appropriate Reliability Standards requirements to ensure corrective actions are put in place. Regulators and other energy stakeholders must also take steps. The forum convened by the North American Energy Standards Board is an example of one such important action.[21]

[19] Essential reliability services are measured periodically using evaluations developed by the Essential Reliability Service Task Force: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERSTF%20Framework%20Report%20-%20Final.pdf Forward-looking frequency response evaluations are conducted every three years and included in the Long-Term Reliability Assessment. Historical evaluations are reported in the State of Reliability report: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf

[20] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

[21] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

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Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth rates in North America are both increasing. The 10-year summer and winter peak demand growth projections show the largest percentage increase in recent years. Electrification and projections for growth in EV over the 10-year horizon are a component of the demand and energy estimates provided by each assessment area. Growth rate increases in winter peak demand are being influenced by electrification of space-heating systems. Summer peak demand growth rates are lower compared to winter; growth in DERs and some EE contributing to lower summer demand growth. See the Figure 18 for seasonal peak demand growth over the current and prior assessment periods and Figure 19 for net energy growth. Area demand growth rates are provided in the supplemental tables, and more information is available in the Regional Assessments pages.

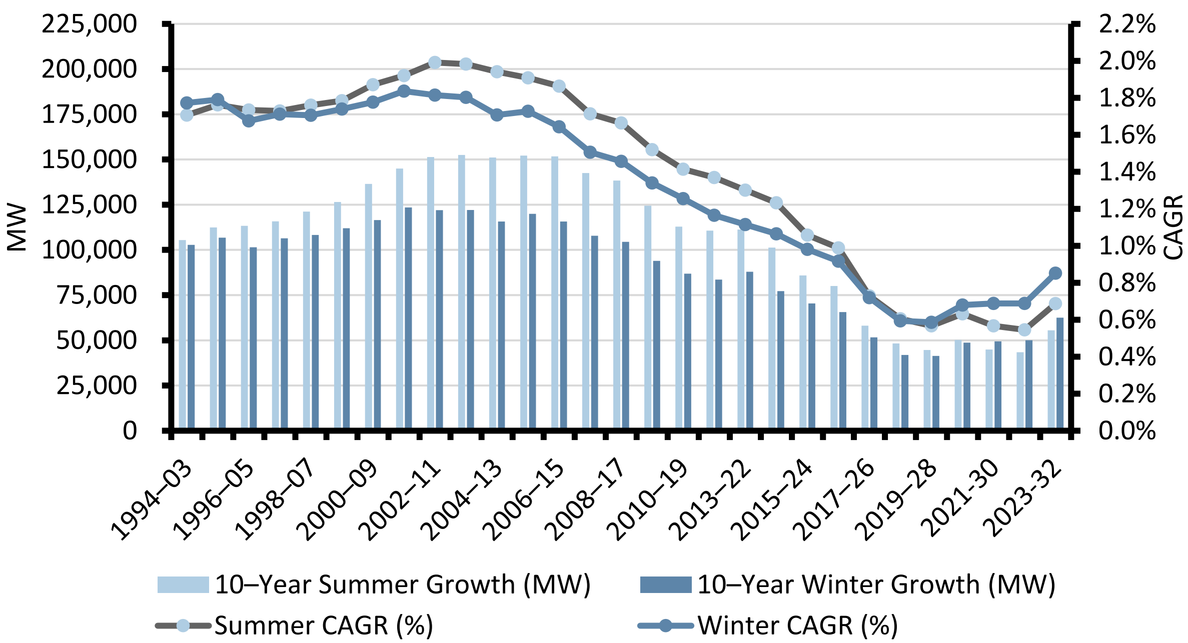

Figure 18: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

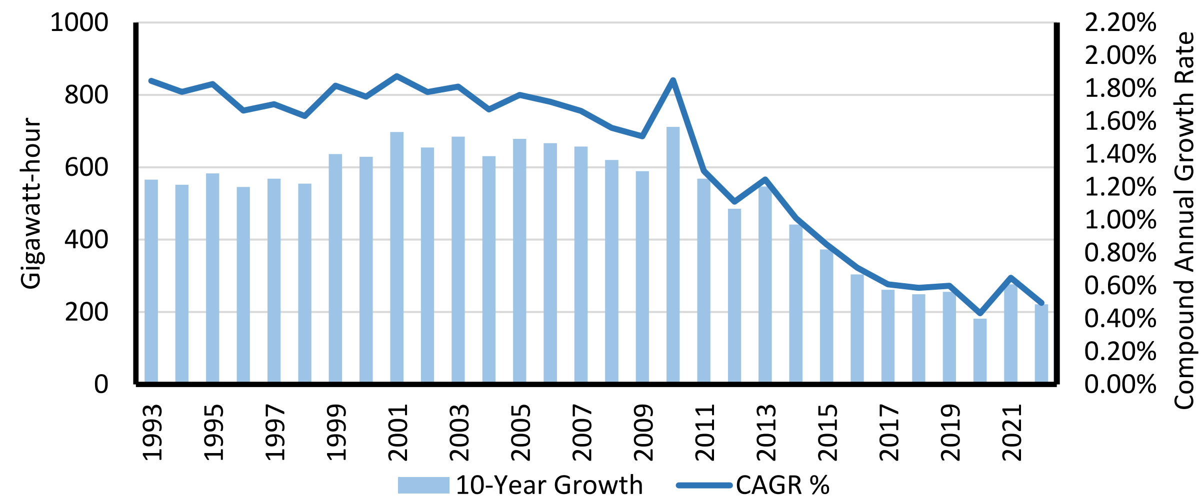

Figure 19: The 10-Year Net Energy to Load Growth and Rate Projection Trends

Demand-Side Management

Conservation, EE, and DR programs contribute to an assessment area's ability to manage load. DR describes a number of load-reducing programs that are available to system operators under specific conditions. NERC collects forecasts of the amount in MW that is expected to respond when called upon to reduce peak load for each assessment area. Figure 20 shows the total system DR forecasted to be available for the first and fifth year's summer and winter peaks (Year 1 and Year 5) from each of the past five LTRAs.

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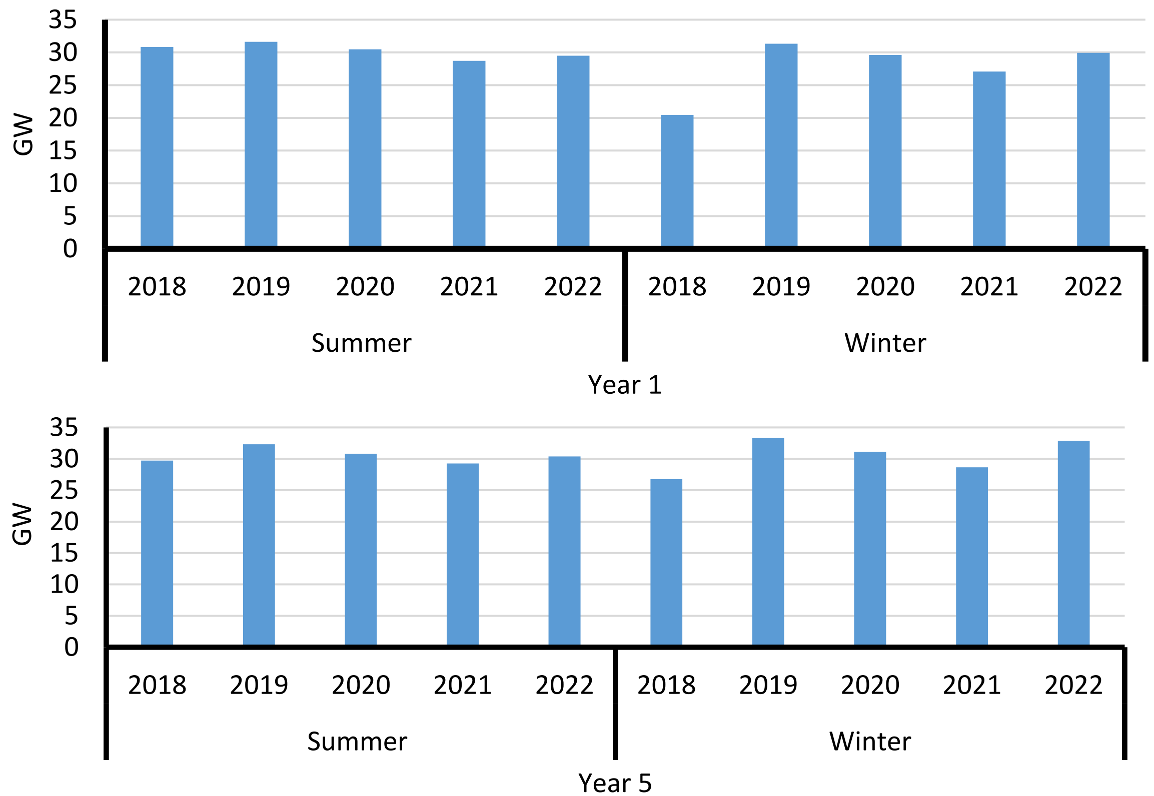

Figure 20: Demand Response Available in Year 1 and Year 5 of 2018–2022 LTRA

Reliability Implications

Demand projections are influenced by a variety of factors, including the economy, energy policies, technology development, and consumer preferences. Projections are increasing in complexity with more uncertainty in the impacts of the changing resource and demand characteristics, especially with their variability. DR, EE, BTM generation, energy storage, electrification and consumer behavior all impact the demand and energy projections. To ensure reliability, grid and resource planners must manage short- and long-term load forecasts to account for this complexity and uncertainty.

Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Such changes have wide-ranging implications to how the grid and resources are planned and operated.

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Transmission Development Trends and Implications

Trends

There is relatively little change in cumulative miles of BPS transmission under construction or in planning for the next 10-year horizon; however, projects for renewable integration are increasing. The current cumulative level of 15,495 miles of transmission (>100 kV) in construction or stages of development for the next 10-years (Figure 21) is running near averages of the past five years.

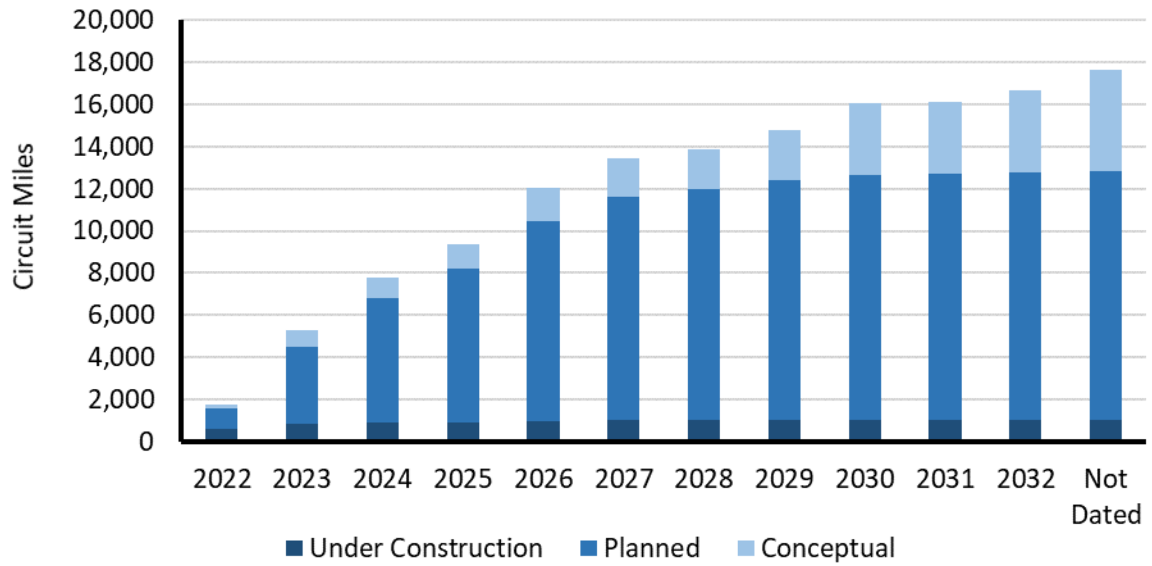

Figure 21: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. Figure 22 shows the percentage of future transmission circuit miles by primary driver. Most project miles are initiated to support grid reliability. Projects under construction or in planning to integrate renewables have grown from 1,589 miles reported in the *2021 LTRA* to 2,376 miles currently.

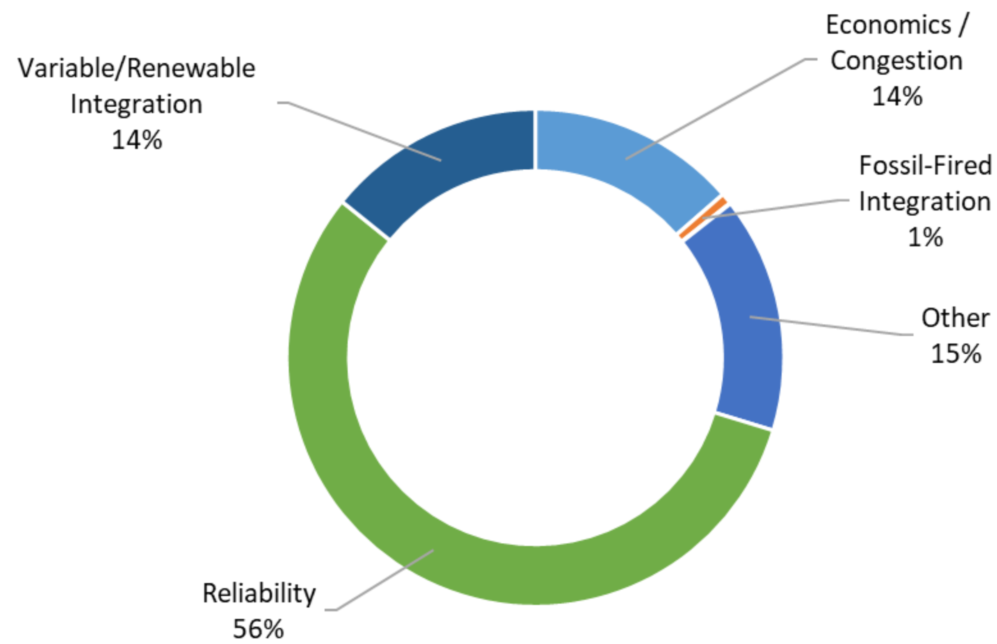

Figure 22: Future Transmission Circuit Miles by Primary Driver

Reliability Implications

Decarbonization goals must be developed with due consideration for transmission needs. Meeting the siting and grid development needs for new generation involves transmission development. Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves.

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Emerging Issues

In developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS in the next 10-years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Electrification and Electric Vehicle Growth

Government policies for the adoption of EVs and other energy transition programs have the potential to significantly influence future demand and energy needs. For example, estimates from the California Energy Commission staff of the added electrical load from plug-in EV charging by 2030, under the state's zero-emission vehicle targets, indicate an additional 5,500 MW of demand at midnight and 4,600 MW of demand at 10:00 a.m. on a typical weekday. This is an increase of 25 and 20%, respectively at those times.[22] State and local policies for transitioning appliances and heating systems can also affect projections of electricity demand and daily load shapes, and these policies also have many ramifications for infrastructures other than the BPS. Industry demand forecasters have differing methods for projecting how EV adoption will impact future demand and many have not directly applied government policy targets to demand forecasts.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections. Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT and their stakeholders and Texas regulators are working on resolving various policy, market, operational, and planning issues associated with interconnecting these large flexible loads and potentially using them as reliability resources.

Supply Chain and Other Factors Affecting Projections

Projections of future resources and transmission in this *LTRA* are based on industry data from the interconnection queues, representing only some of the myriad factors that will ultimately determine when and what gets completed. For resources to materialize and connect to the grid, substantial supply chain, planning, and commissioning processes must be completed. Timing is only an estimate, and some projects can be expected to be withdrawn from the interconnection process by developers. Having ample generating capacity in the interconnection queues to replace the nearly 60 GW of confirmed generation retirements projected over the 10-year assessment period (already a low indicator of future retirements) does not provide assurance that new capacity will be connected and available to meet future resource needs.

6 GHz Frequency Band Interference

The ability of grid owners and operators to monitor and control BPS equipment and respond to grid events may impact future changes in the allocation of the frequency spectrum, constituting an emerging risk to BPS reliability. Growth in demand for wireless connectivity and the need to improve rural internet connectivity prompted the U.S. Federal Communications Commission (FCC) to issue a ruling in 2020 and propose further access changes that impact frequencies that was once restricted to licensed users, including many electric grid owners and operators.

Recent changes to U.S. communications regulations and pending future rules are increasing the risk that electric grid owners and operators will experience harmful interference on communications channels that are important for the reliable operation of the BPS. In April 2020, the FCC issued a report and order that partially opened spectrum in the 6 GHz band for unlicensed use.[23] Prior to this ruling, the 6 GHz band was restricted to use by an array of industries responsible for critical infrastructure, such as electric, natural gas and water utilities, railroads, and wireless carriers as well as by public safety and law enforcement officials. Electric utilities in the United States use communications systems operating in this frequency band as primary or alternate means for monitoring and controlling BPS equipment (via SCADA systems) and for voice communications with operators and field personnel. Subsequently, the FCC gave notice of further proposed rulemaking to fully open the 6 GHz band to unlicensed users with the removal of current restrictions on mobile device outdoor usage. Many electric grid owners and operators that use the 6 GHz band are anticipating impacts to their communications networks and are developing mitigation plans. Following an initial review and an industry survey conducted by a task force established by the NERC RSTC, NERC has identified that many grid operators continue to use the 6 GHz band for their critical communications and many have not identified remediation plans to mitigate potential interference impacts.[24] Because of the expected growth of users in the 6GHz band and potential for increased interference, NERC is taking action to determine the level of impact that the regulation changes have on BPS reliability and develop mitigation to reduce the risks.

[22] See, for example, California Energy Commission Revised Staff Report *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment*: https://efiling.energy.ca.gov/getdocument.aspx?tn=238032
[23] https://www.fcc.gov/document/fcc-opens-6-ghz-band-wi-fi-and-other-unlicensed-uses-0
[24] https://www.nerc.com/comm/RSTC/6GHTZF/6GHZ%20Communication%20Network%20Extent%20of%20Condition%20White%20Paper.pdf

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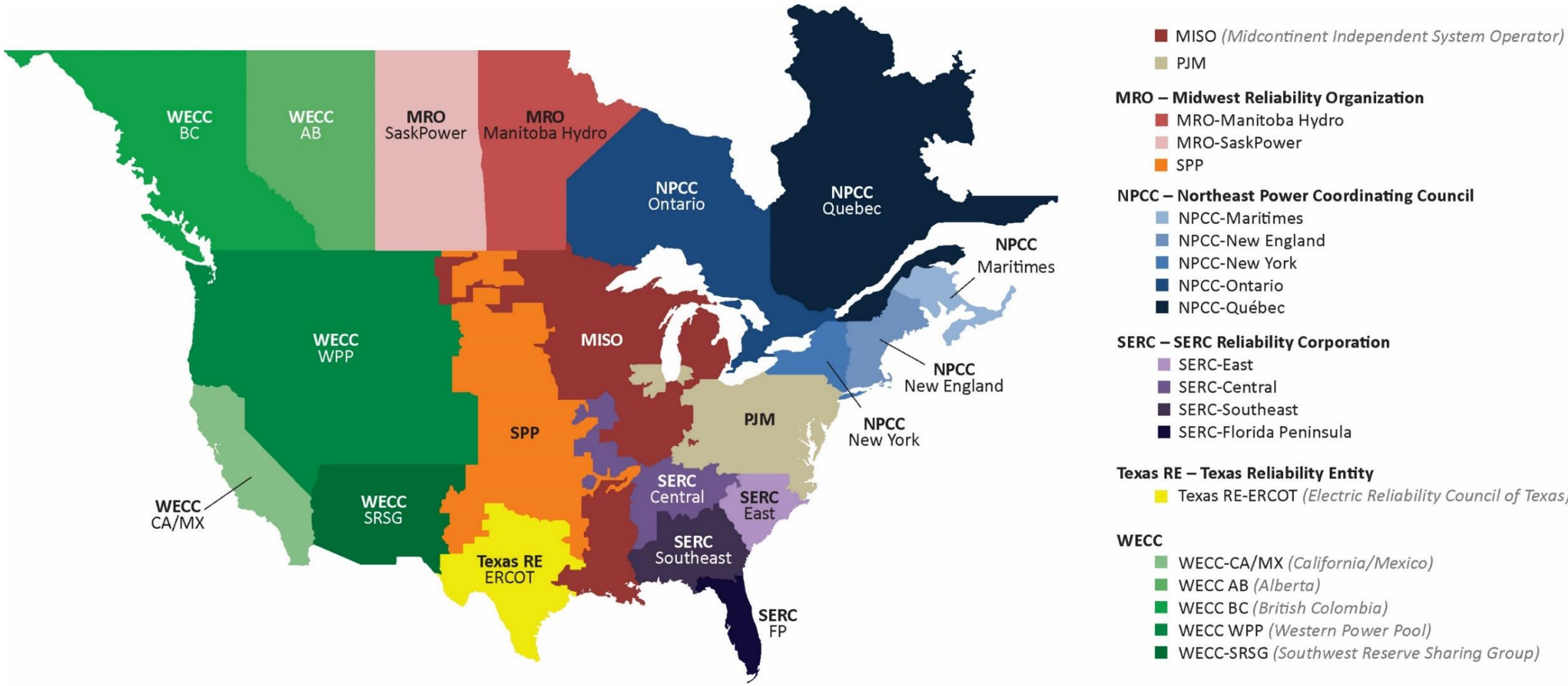
Regional Assessments

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. In addition, NERC published additional *2022 LTRA* assessment area data in supplemental tables on the Reliability Assessments web page.[25] The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



[25] See the NERC Reliability Assessments page here: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

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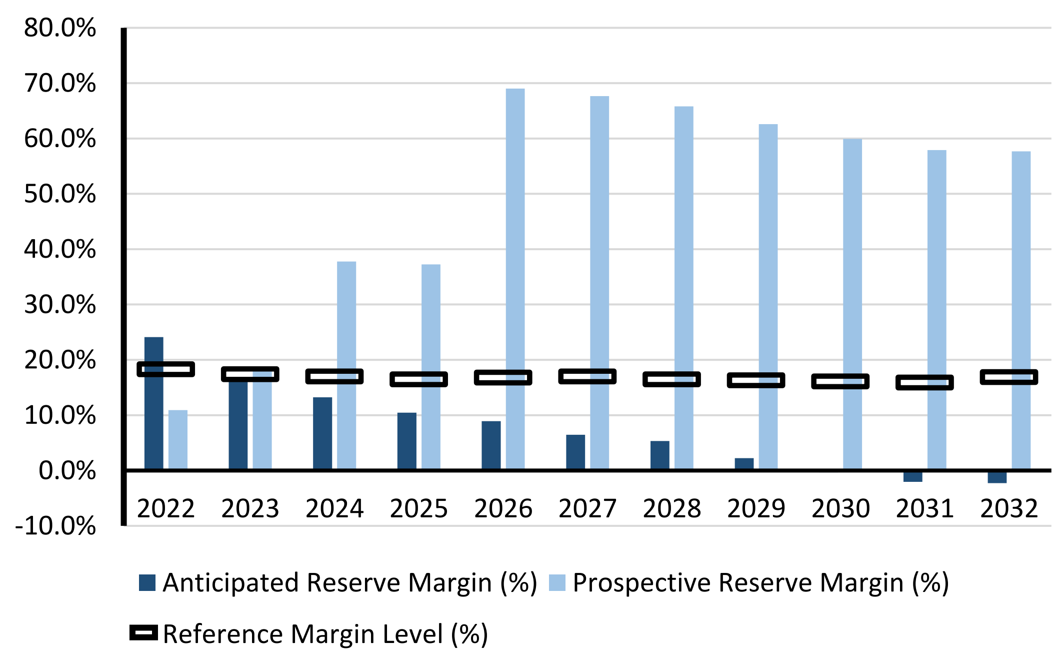
MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

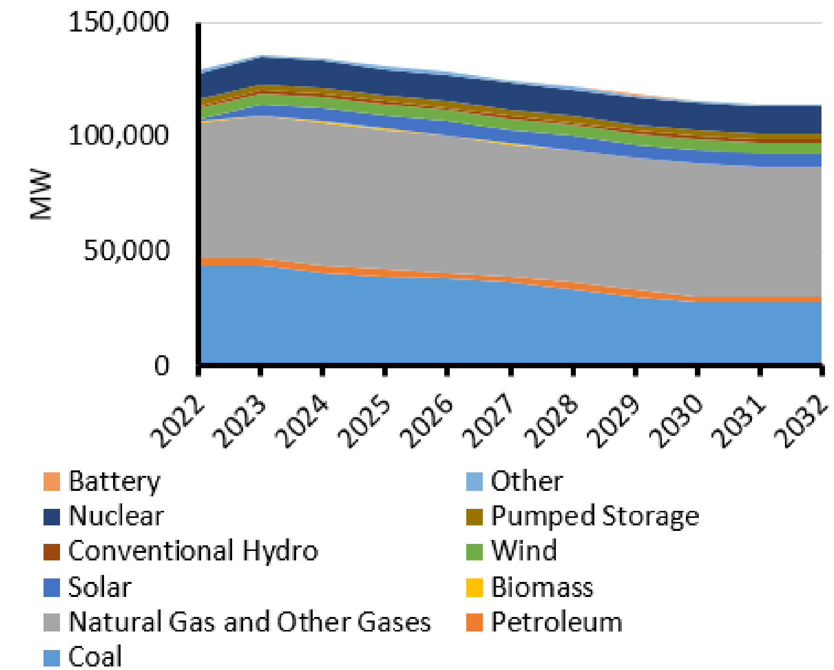
MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	124,950	126,091	126,212	126,298	126,631	126,965	127,240	127,652	128,320	128,317
Demand Response	6,158	6,189	6,116	6,130	6,131	6,051	6,052	6,054	6,050	6,017
Net Internal Demand	118,792	119,902	120,096	120,168	120,500	120,914	121,188	121,599	122,269	122,300
Additions: Tier 1	6,605	8,253	8,311	8,311	8,311	8,311	8,311	8,311	8,311	8,311
Additions: Tier 2	2,322	30,796	35,517	76,576	78,071	78,096	78,096	78,096	78,096	78,096
Additions: Tier 3	2,193	3,504	5,501	6,055	8,581	9,331	10,538	11,621	12,226	12,409
Net Firm Capacity Transfers	1,593	1,598	767	767	663	593	598	493	493	155
Existing-Certain and Net Firm Transfers	131,538	127,506	124,353	122,572	119,986	119,034	115,593	112,865	111,440	111,204
Anticipated Reserve Margin (%)	16.3%	13.2%	10.5%	8.9%	6.5%	5.3%	2.2%	-0.3%	-2.1%	-2.3%
Prospective Reserve Margin (%)	18.2%	38.9%	40.0%	72.6%	71.3%	69.9%	66.7%	63.9%	61.8%	61.6%
Reference Margin Level (%)	17.4%	17.0%	16.5%	16.8%	17.0%	16.5%	16.3%	16.1%	15.9%	16.9%



Planning Reserve Margins



Existing and Tier 1 Resources

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MISO

Highlights

- MISO is facing resource shortfalls across this entire assessment period. Since the *2021 LTRA*, 5,900 MW of generation has retired (mostly coal-fired generators) and 1,700 MW of new generation has been added (approximately 700 MW natural-gas-fired, 400 MW Solar, 100 MW wind, and 300 MW pumped storage. In the summer of 2023, MISO's capacity shortfall is projected to be 1,395 MW even after adding over 6.5 GW of new generation with signed interconnection agreements. More additions from the planning queue are not likely to be completed in sufficient quantity to make up for the capacity shortfall.
- MISO's Reliability Imperative Initiative is designed to lead the shared responsibility that utilities, states, and MISO have in addressing the ongoing generation fleet changes and the challenges of more frequent extreme weather events.

MISO Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	44,102	40,951	39,159	38,066	36,351	33,846	30,415	28,133	28,133	28,133
Petroleum	2,800	2,800	2,707	2,707	2,697	2,697	2,697	2,524	2,451	2,451
Natural Gas	62,087	62,514	61,096	59,606	57,647	57,647	57,644	57,521	56,310	56,310
Biomass	375	375	375	375	304	273	273	240	240	240
Solar	4,753	5,852	5,829	5,828	5,828	5,827	5,827	5,826	5,826	5,826
Wind	4,645	4,689	4,741	4,739	4,730	4,682	4,670	4,660	4,654	4,654
Conventional Hydro	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,280	1,280
Pumped Storage	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617
Nuclear	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711
Other	1,280	1,280	1,257	1,224	1,224	1,224	1,224	1,224	1,224	1,224
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	135,805	134,224	130,927	128,308	124,544	121,959	118,513	115,891	114,465	114,465

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MISO Assessment

Planning Reserve Margins
MISO is projecting a decrease from last year's reserve margins with planned reserves falling below reference margin levels beginning in 2023. The reserve decline is driven mainly by lower capacity contribution from weather dependent new generation additions that are replacing retiring units with higher contributions. Increasing demand projections also contribute to lower reserve margins. Increased coordination and continued action with MISO members will be critical to ensuring resource adequacy into the future. In most of the MISO area, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Seasonal resource assessments evaluate unit availability, outage rates, and forecasted load varies across all four seasons. MISO has also initiated a change to a seasonal capacity construct that promotes energy adequacy by evaluating how each resource and resource type helps to serve load at periods of peak risk in each season.

Probabilistic Assessment
In the Base Case results, most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. The winter also experiences a small amount LOLH when cold temperatures push demand higher than normal.

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss of load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase

The ProbA analyzes all hours of the year; whereas, the LTRA is only looking at 10-year summer/winter peak forecasts. As a result, the ProbA provides more insight into intra-yearly system risks that may occur during non-peak periods, and the LTRA highlights longer-term resource adequacy planning concerns.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	14.3	193.6	68.8
EUE (ppm)	0.02	0.304	0.108
LOLH (Hours per Year)	0.085	0.808	0.393
Operable On-peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA results for comparison

For the 2022 ProbA Risk Scenario, MISO is investigating how the risk changes as a result of modeling seasonal average, rather than annual average, outage rates along with correlated cold weather outages.

Demand
The peak demand forecast increased from last year by approximately 1.1 GW, largely due to a rebound from COVID-related decline. The five-year regional demand growth remained stable at a relatively flat 0.2%. It is unclear how electrification of transportation and other sectors will drive future growth, but anticipated electrification is considered in the MISO Transmission Expansion Plan (MTEP) process.

Demand Side Management
DR programs continue to play an important role in providing capacity. While DR projections are shown to be decreasing over this assessment period, this trend may change following the 2022 resource auction, OMS-Survey, and in the transition to seasonal capacity auctions.

Distributed Energy Resources
MISO estimates that there is a total of 860 MW of installed solar PV distribution resource capacity. While DERs are anticipated to play a larger role into the future, MISO is still working with stakeholders on adequate methods for aggregating, reporting, and allowing DER participation in MISO markets.

Generation
Since the *2021 LTRA*, MISO has retired 5,000 MW of generation and added 1,700 MW of new generation for a net change of 3,300 MW (on-peak capacity).

The MISO generator interconnection queue continues to show steadily increasing levels of VERs, including battery storage and hybrid resources, in the future generation fleet mix. Currently 300 MW

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of grid-connected batteries are installed with another 15 GW in the interconnection planning queue and 16 GW of hybrid battery-renewable generation in queue. This transition of the generation fleet, along with the observed impacts from extreme weather events, such as Hurricane Laura in 2020 and Winter Storm Uri in February 2021, continue to stress the importance of the MISO Resource Adequacy construct. Appropriate planning and operating signals must be sent to prompt investment (or system enhancements) when needed to ensure that the BPS continues to perform reliably.

Capacity Transfers

Net firm transfers with neighboring areas declined from the prior *LTRA* and continue to decline as reported in this year's *LTRA*; for the summer of 2023, firm transfer commitments have fallen by nearly 25%. Non-firm transfers have played a critical role in maintaining reliability during extreme weather events. A growing reliance on non-firm imports increases the risk of energy emergencies when external transfer assistance is not available.

Transmission

Approved transmission projects increased since the *2021 LTRA*. In the latest MTEP (MTEP21), 33% of projects are classified as "reliability" projects that are needed to maintain system reliability in accordance with NERC Reliability Standards. Another 47% are for replacing aging equipment, and the remaining 20% are for the integration of new resources and to accommodate load growth. In addition, MISO's Long Range Transmission Plan introduced a $10.3 billion transmission project portfolio in the upper-Midwest that was appended to MTEP21 transmission projects in summer of 2022. These lines are expected to support 53 GW of renewable energy and provide $23–52 billion in benefits to MISO utilities.

Reliability Issues

MISO's planning, markets and operations continue to evolve in response to the changing resource fleet and the increased frequency of extreme weather events. Managing the increasing uncertainty is a key component of the market redefinition effort and includes transitioning to a seasonal resource adequacy construct, reforming accreditation, and enhancing scarcity pricing to better align system needs and capabilities during tight operating conditions. The seasonal resource adequacy construct has been filed at FERC and will be effective in September 2022 ahead of the 2023/2024 Planning Resource Auction. MISO is awaiting FERC approval of the updated tariff provisions.

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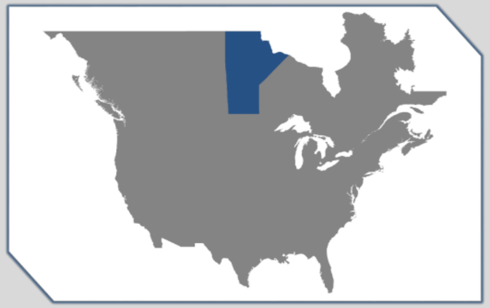
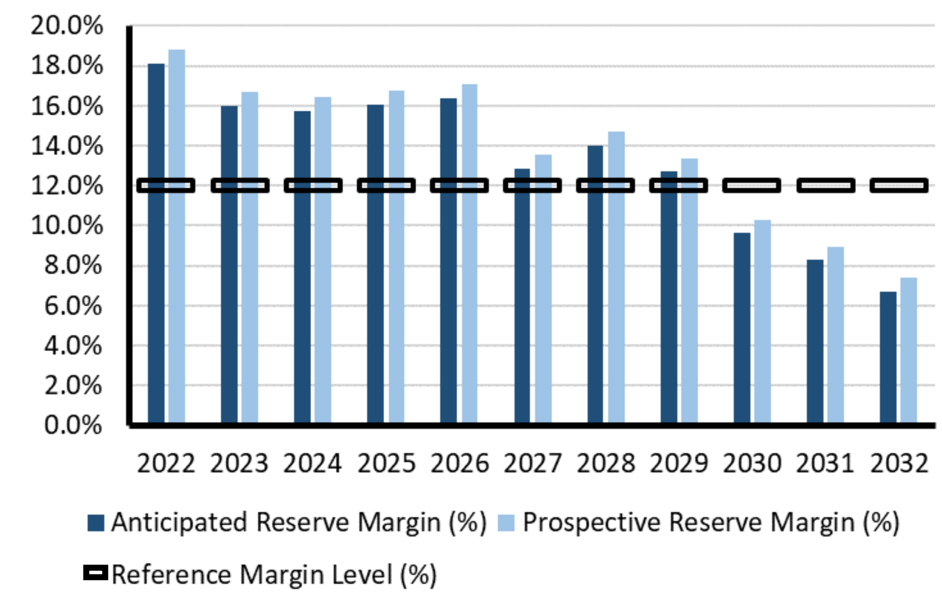


MRO-Manitoba Hydro

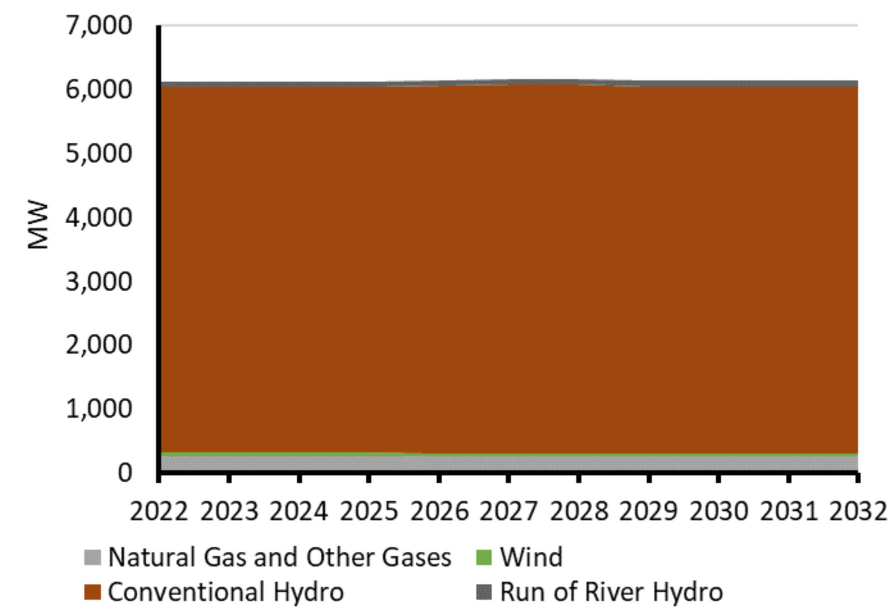
Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada.

Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	4,622	4,628	4,638	4,650	4,844	4,862	4,894	4,945	5,008	5,080
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,622	4,628	4,638	4,650	4,844	4,862	4,894	4,945	5,008	5,080
Additions: Tier 1	279	279	279	331	340	340	337	337	337	337
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-622	-627	-587	-587	-542	-466	-471	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,083	5,078	5,103	5,082	5,127	5,203	5,179	5,086	5,086	5,086
Anticipated Reserve Margin (%)	16.0%	15.8%	16.0%	16.4%	12.9%	14.0%	12.7%	9.6%	8.3%	6.7%
Prospective Reserve Margin (%)	16.7%	16.5%	16.7%	17.1%	13.5%	14.7%	13.4%	10.3%	8.9%	7.4%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- MRO-Manitoba Hydro ARM is above the RML throughout the first five-years of this assessment period.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for the winter of 2022/2023.
- The Manitoba Hydro system is not currently experiencing the large additions of wind and solar generation or thermal generation retirements as seen in some other assessment areas. The predominately hydro nature of the system is not expected to change during this assessment period.

MRO-Manitoba Hydro Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	52	52	31	31	31	31	31	31
Conventional Hydro	5,706	5,706	5,706	5,758	5,767	5,767	5,745	5,745	5,745	5,745
Run-of-River Hydro	83	83	83	83	83	83	83	83	83	83
Total MW	6,119	6,119	6,119	6,150	6,159	6,159	6,137	6,137	6,137	6,137

SCHEDULE MM-S2

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM does not fall below the RML of 12% during the first five years of this assessment period. Lower reserve margins in the second half of this assessment period compared to the *2021 LTRA* are due to demand growth. No Tier 2 resources have been assumed to come into service during this assessment period. No resource adequacy issues are anticipated during the first five years of this assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

As the operator of a predominately hydro system, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis on an at least weekly basis as required to manage near-term to season-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessments

Every two years, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2022. The probabilistic assessment was supportive of a 12% RML for the Manitoba system being sufficient to provide a loss of load expectation of less than 1-day-in-10 years under the study assumptions.

Probabilistic Assessment

The LOLH and EUE indices calculated for 2024 increase slightly as compared to the results obtained in 2020 assessment mainly due to some improvements in the model and larger forecast reserve margins.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	3.383	28.64	7.23
EUE (ppm)	0.133	1.141	0.287
LOLH (Hours per Year)	0.004	0.036	0.007
Operable On-peak Margin	N/A	13.5%	13.5%

* Provides the 2020 ProbA results for comparison

Demand

Manitoba Hydro is projecting modest electricity load growth over the next five years. Factors considered in load growth projections include economic activity, EV adoption, and demand side management (DSM) programs in Manitoba operated by Efficiency Manitoba. The EV load forecast in Manitoba now assumes Canadian federal targets of zero emission vehicles reaching 10% of light-duty passenger vehicles sales by 2025, 30% by 2030, and 100% by 2040. Over this assessment period, Manitoba Hydro projects the total internal demand growth to increase at a compound annual growth rate (CAGR) of 0.56% for summer and 1.06% for winter.

Demand-Side Management

Manitoba Hydro does not have any DSM resources that are considered as controllable and dispatchable DR. There have been no modifications to the methods for controllable and dispatchable DR programs since the *2021 LTRA*.

Distributed Energy Resources

There is a potential for increased solar DER resources in the latter half of this assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system.

Generation

All seven hydro units at the Keeyask Generating Station (630 MW net addition) are anticipated to be in commercial operation for the winter of 2022/2023. The completion of all seven units will improve resource adequacy for the remainder of this assessment period. Manitoba is not currently experiencing large additions of wind and solar resources being seen in other areas, so emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years.

Energy Storage

Additions of energy storage resources in the next 10 years are not anticipated at this time.

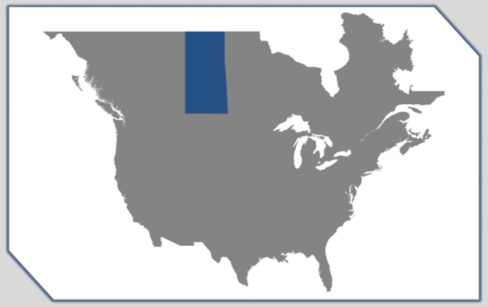
Capacity Transfers

A capacity transfer of 190/215 MW from Manitoba to Saskatchewan beginning June 1, 2022, will tend to increase east to west flow on the Manitoba–Saskatchewan interface. The 230 kV/ 390 MVA Birtle to Tantallon line, which will help facilitate this and other capacity transfers to Saskatchewan, was placed in service in March 2021.

SCHEDULE MM-S2

Transmission

The Manitoba to Minnesota Transmission Project, a major new 500 kV interconnection, was placed into service on June 1, 2020, and provides for alternative supply from the MISO market during drought conditions and improves the resilience of Manitoba Hydro's system to extreme events, including drought. Manitoba Hydro currently has 86 miles of transmission under construction and 58 miles of planned transmission during the 10-year assessment period.



MRO-SaskPower

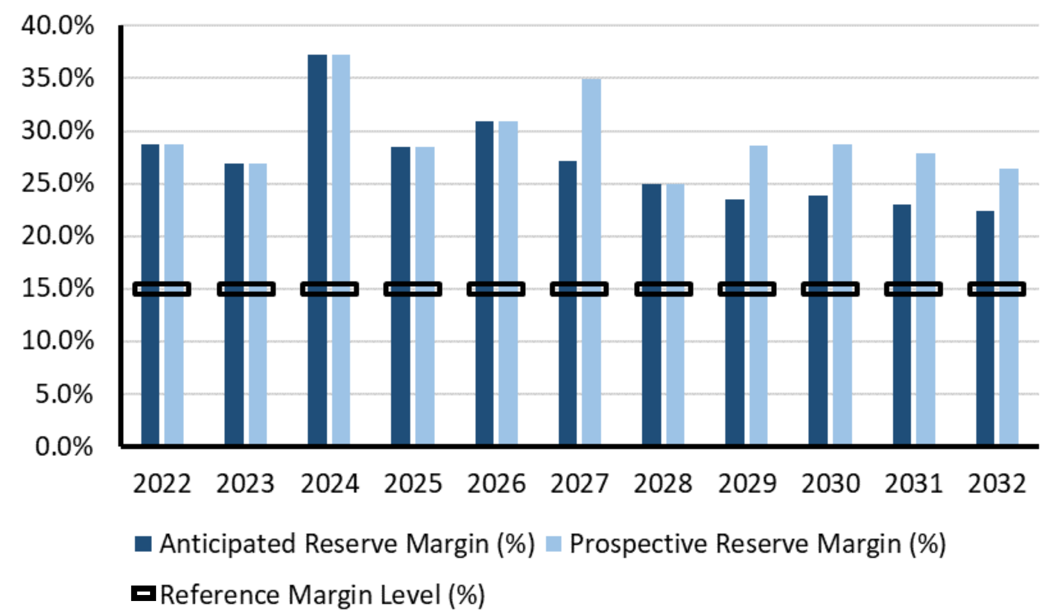
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

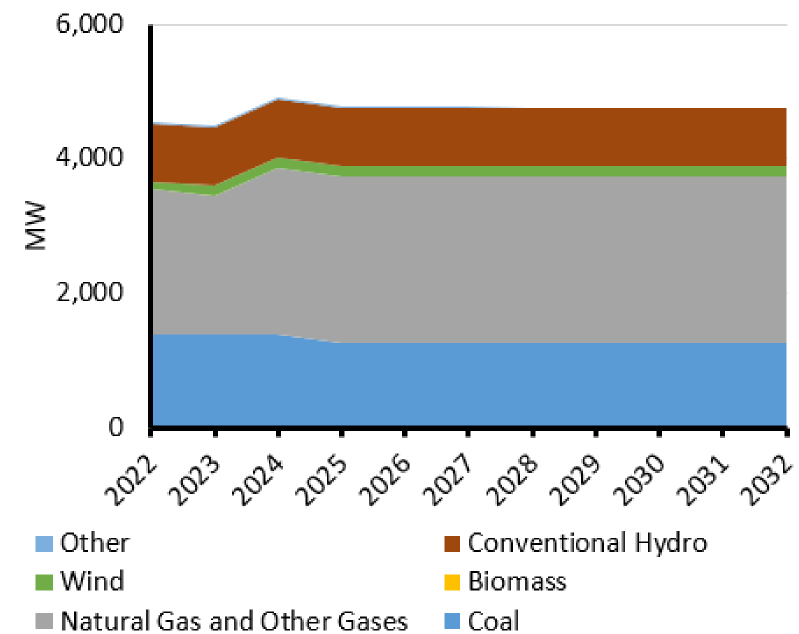
SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	3,804	3,827	3,916	3,940	3,999	4,056	4,101	4,128	4,156	4,178
Demand Response	67	67	67	67	67	67	67	67	67	67
Net Internal Demand	3,737	3,760	3,849	3,873	3,932	3,989	4,034	4,061	4,089	4,111
Additions: Tier 1	40	461	506	506	506	506	506	506	506	506
Additions: Tier 2	0	0	0	0	303	303	561	1,453	1,453	1,453
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	290	290	290	290	290	290	290	290
Existing-Certain and Net Firm Transfers	4,701	4,699	4,438	4,563	4,495	4,478	4,478	4,525	4,526	4,526
Anticipated Reserve Margin (%)	26.9%	37.2%	28.4%	30.9%	27.2%	24.9%	23.5%	23.9%	23.1%	22.4%
Prospective Reserve Margin (%)	26.9%	37.2%	28.4%	30.9%	34.9%	25.0%	28.6%	28.7%	27.8%	26.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- MRO-SaskPower's ARM is above the RML (15%) throughout this assessment period.
- SaskPower is adding approximately 760 MW of new generation within the next five years, including a 200 MW installed capacity wind generation facility and a 377 MW natural gas facility. Confirmed retirements in the area total approximately 340 MW.
- A long-term firm capacity transfer of 190 MW from Manitoba to Saskatchewan began in 2022.

MRO-SaskPower Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,390	1,390	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Natural Gas	2,053	2,473	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	164	164	164	164	164	162	162	162	162	162
Conventional Hydro	862	862	862	862	862	862	862	862	862	862
Other	22	22	22	22	17	1	1	1	1	1
Total MW	4,492	4,913	4,778	4,778	4,773	4,755	4,755	4,755	4,755	4,755

SCHEDULE MM-S2

MRO-SaskPower Assessment

Saskatchewan uses a criterion of 15% as the Reference Reserve Margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and available DR for each year. Saskatchewan's ARM ranges from approximately 20–37% and does not fall below the RML.

Probabilistic Assessment

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for this assessment period. The major contribution to the EUE is due to some of the Saskatchewan's hydroelectric units requiring extended maintenances through winter peak season for the life extension and upgrade of associated components. The planned maintenance on the hydro units is segregated to minimize adverse impact on the system reliability.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	26.5	169.5	117.0
EUE (ppm)	1.1	6.5	4.4
LOLH (Hours per Year)	0.3	1.4	0.9
Operable On-peak Margin	22.8%	23.1%	24.6%

* Provides the 2020 ProbA results for comparison

Saskatchewan's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 1.0% with a range from 0.5–2.3% throughout this assessment period.

Saskatchewan is adding approximately 761 MW of generation under Tier 1 category within the next five years, including a 200 MW wind generation facility, two utility-scale solar projects (10 MW each), and the expansion of two existing natural gas facilities as well as two new natural gas facilities for a total of 687 MW. The remaining capacity (74 MW) is projected to be carbon neutral and waste heat recovery projects.

Under Tier 2, over 1,462 MW of new generation is projected in this assessment period. This includes six natural gas facilities. The natural gas generation is a proxy holder for any new generation needed beyond the medium-term (>5 years), but a portion of this capacity is anticipated to be covered through deploying renewables, carbon neutral, and low emission generation projects.

A total of approximately 343 MW is confirmed for retirements. This includes 139 MW of coal generation, 41 MW of natural gas, 21 MW of heat recovery facilities, 22 MW of wind facilities and 25 MW of hydro import contract. Unconfirmed retirements of approximately over 1,400 MW is also expected in this assessment period. This includes approximately 1,200 MW of coal generation that will be phased out by the end of 2029. Generating resources being planned as Tier 2 and Tier 3 will replace the retired units before retirements, so Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Saskatchewan's EE and energy conservation programs include incentive-based and education programs that focus on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy and demand during peak hours. Energy provided from EE and DSM programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. Saskatchewan's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 67 MW, with a 12-minute event response time. Other programs are in place that provide access to additional curtailable load that require up to two hours notification time.

Saskatchewan has interconnection agreements with Manitoba Hydro, Southwest Power Pool, and Alberta Electric System Operator. Saskatchewan currently has contracts in place for firm capacity transfers for up to 290 MW from Manitoba Hydro within this assessment period.

Approximately 80 km of 230 kV transmission line is under construction phase, and several other transmission projects (approximately 650 circuit km) are under the planning and conceptual phase in the 5–10-year planning horizon. These projects are driven by load growth, new generation additions and reliability needs. Saskatchewan also has its first Battery Energy Storage System, a 20 MW/20MWh facility under-construction.

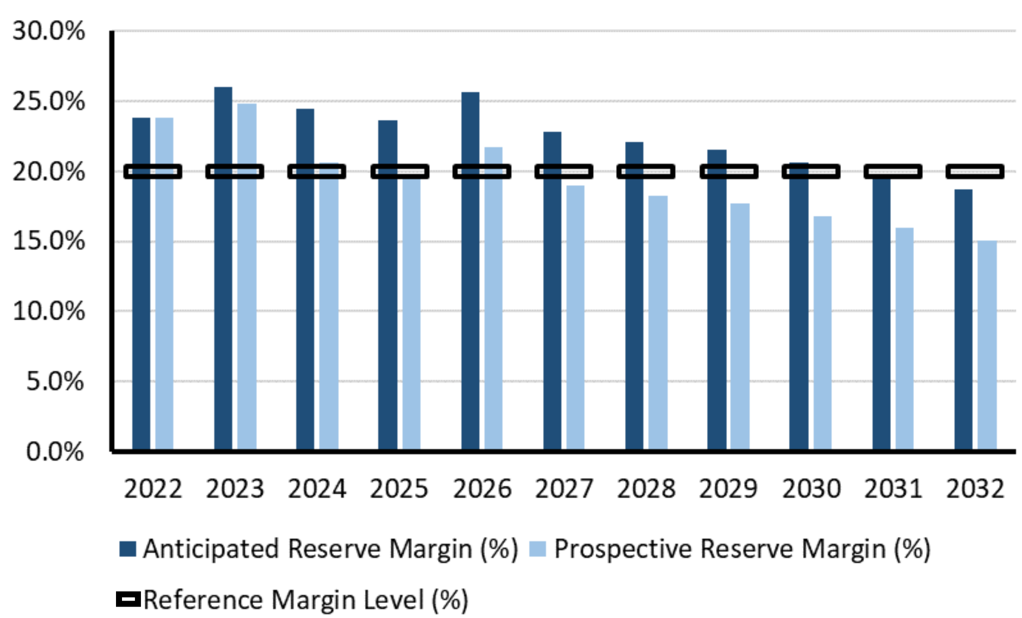
SaskPower performs transmission planning studies, including the annual transmission planning assessment and other applicable periodic studies to meet NERC requirements, system impact studies for new load/generation interconnections, generation retirements, transmission service request studies, area adequacy studies, and other special studies as required to identify potential system issues. Mitigations are identified as part of these studies and included in the system development plan to ensure system performance requirements are met.

NPCC-Maritimes

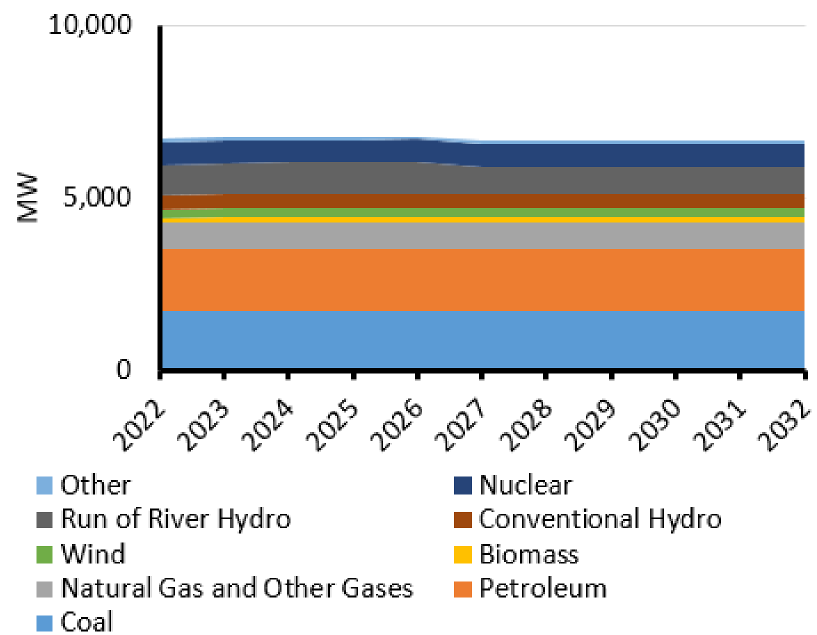
The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	5,636	5,727	5,750	5,772	5,805	5,840	5,862	5,905	5,945	5,994
Demand Response	302	320	333	337	336	335	335	334	333	333
Net Internal Demand	5,334	5,406	5,417	5,435	5,469	5,504	5,528	5,571	5,611	5,661
Additions: Tier 1	14	39	39	39	39	39	39	39	39	39
Additions: Tier 2	0	254	254	254	254	254	254	254	254	254
Additions: Tier 3	5	21	177	237	487	554	754	804	804	804
Net Firm Capacity Transfers	81	63	31	153	153	153	153	153	153	153
Existing-Certain and Net Firm Transfers	6,709	6,691	6,659	6,789	6,679	6,679	6,679	6,679	6,679	6,682
Anticipated Reserve Margin (%)	26.1%	24.5%	23.7%	25.6%	22.8%	22.1%	21.5%	20.6%	19.7%	18.7%
Prospective Reserve Margin (%)	24.8%	20.6%	19.8%	21.7%	19.0%	18.2%	17.7%	16.8%	16.0%	15.0%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- The Maritimes Area peak loads are expected to increase by 9.7% during summer and by 6.3% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 1.2% during the 10-year assessment period for an average growth of 0.1% per year.
- The Maritimes Link, an undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador, began service in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides for a 150 MW firm capacity import to NS. Due to short-term maintenance outages and the ongoing commissioning work on the HVDC transmission link from Labrador to Newfoundland, a 150 MW (nameplate) coal-fired unit will be retained in NS, if needed, to provide firm capacity and maintain an adequate planning reserve margin for the upcoming winter 2022-2023. The unconfirmed retirement of this coal unit is shown in 2023 in this assessment. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area.

NPCC-Maritimes Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695
Petroleum	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	129	129	129	129	129	129	129	129	129	129
Wind	250	275	275	275	275	275	275	275	275	275
Conventional Hydro	410	410	410	410	410	410	410	410	410	413
Run-of-River Hydro	902	902	902	902	792	792	792	792	792	792
Nuclear	663	663	663	671	671	671	671	671	671	671
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,743	6,768	6,768	6,776	6,666	6,666	6,666	6,666	6,666	6,669

SCHEDULE MM-S2

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference RML used for the Maritimes area is 20%. The ARM during the winter period ranges from 19–25% and ranges from 70–87% during the summer period for the 10-years of this *LTRA* study.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

The ARM level during off-peak season for the Maritimes area ranges between 70–87%. During off peak hours, the Maritimes area has surplus generation available to meet the energy needs, so there are no constraints with converting the capacity to energy during these times.

Probabilistic Assessments (ProbA and Other Studies)[26]

The two Balancing Authorities (BA) within the Maritimes area, as members of NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments, which provides an evaluation of generation resource and transmission system adequacy; this will be necessary to meet projected seasonal peak demands and operating reserves.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	1.125	1.838	3.869
EUE (ppm)	0.039	0.06	0.138
LOLH (Hours per Year)	0.023	0.023	0.071
Operable On-peak Margin	16.7%	25%	22.9%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With the Forecast Capacity Resources declining slightly, a slight increase in estimated LOLH and EUE is observed between the two assessments. The Maritimes Area is winter peaking and EUE risk occurs during the winter months. The estimated EUE is negligible.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area; thus, the peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of New Brunswick and Nova Scotia, which are historically highly coincidental (typically between 97% and 99%). Therefore, demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas, and the aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The Maritimes area peak loads are expected to increase by 9.7% during summer and by 6.3% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1.03% in summer and 0.69% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 1.2% during the 10-year assessment period for an average growth of 0.1% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs with smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway; however, no specific annual demand and energy saving targets currently exist. During the 10-year assessment period in Maritimes, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 23 MW to 186 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 550 MW. [27]

Distributed Energy Resources

The DER installed capacity in Nova Scotia is approximately 235 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar. Based on a loss of load expectation (LOLE) analysis, the existing wind resources are assumed to have an ELCC of 18% and BTM solar is assumed to have an ELCC of 0%. The Maritimes area has shown embedded BTM solar PV projections of 70 MW in 2022 rising to 327 MW by 2032. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives that include municipal and provincial incentive programs mainly in Nova Scotia and Prince Edward Island. There is no capacity contribution from solar generation due to the timing of area's system peak (the winter period).

[26] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

[27] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

SCHEDULE MM-S2

Generation

There are no new confirmed retirements in the *2022 LTRA* as compared to the *2021 LTRA*.

New Brunswick Power's 2020 Integrated Resource Plan assumes extending 28 MW of diesel-fired generation and 290 MW of natural-gas-fired generation, starting in 2025 and 2026 respectively. New Brunswick plans to add a Tier 1 community-owned wind project of 20 MW nameplate capacity in 2023. In New Brunswick, unconfirmed retirements include a hydro facility of 4 MW at the end of its service life pending regulatory approval and a 98 MW power purchase agreement contract.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 350 MW phased-in from 2024/2025 with an ELCC of 10%. These projects are part of the provincial rate base procurement being undertaken by the procurement administrator appointed under the Electricity Act, assumed to represent 350 MW of additional wind. Tier 2 resources include a 200 MW battery resource and the conversion of a 150 MW coal unit to natural gas in late 2024. Tier 3 resources in Nova Scotia include natural gas additions (combustion turbines) of 150 MW in 2026 and 550 MW from 2027–2031 as well as new wind generation with a nameplate capacity of 435 MW phased in from 2025–2029. In addition, this assessment includes an expected firm import of 85 MW from the province of Newfoundland and Labrador starting in late 2023.

Small amounts of new solar generation capacity (Tier 2) of up to 31 MW are expected to be installed in Prince Edward Island in the 2022/2023 time frame. The island also plans to add (Tier 3) 50 MW of thermal capacity in 2026 as well as wind resources of 30 MW (late 2023) and 40 MW (2025–2026). Northern Main Independent System Administrator projects new solar additions (Tier 1–3) of approximately 117 MW name plate capacity during this LTRA study period.

New Brunswick derates its wind capacity using a calculated year-round equivalent capacity of 22%. Nova Scotia and Prince Edward Island derate wind capacity to 18% and 15%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub-areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

Nova Scotia plans to add a 200 MW (4-hour duration) Tier 2 battery resource in late 2024. Pilot projects and internal studies are underway to further understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by New Brunswick Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks; these analyses are in a preliminary stage. The value of energy storage options is expected to increase as the technology improves and as New Brunswick's smart grid network develops. These studies would be evaluated further as the economics around these options become viable.

Capacity Transfers

Probabilistic studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

Construction of a 475 MW +/-200 kV high voltage direct current (HVDC) undersea cable link (Maritime Link) between Newfoundland and Nova Scotia was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides for a 150 MW firm capacity import to Nova Scotia. Due to short-term maintenance outages and the ongoing commissioning work on the HVDC transmission link from Labrador to Newfoundland, a 150 MW (nameplate) coal-fired unit will be retained in NS, if needed, to provide firm capacity and maintain an adequate planning reserve margin for the upcoming winter of 2022/2023. The unconfirmed retirement of this coal unit is shown in 2023 in this assessment. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the Southeastern New Brunswick area. There are currently no planned or under construction transmission projects.

Reliability Issues

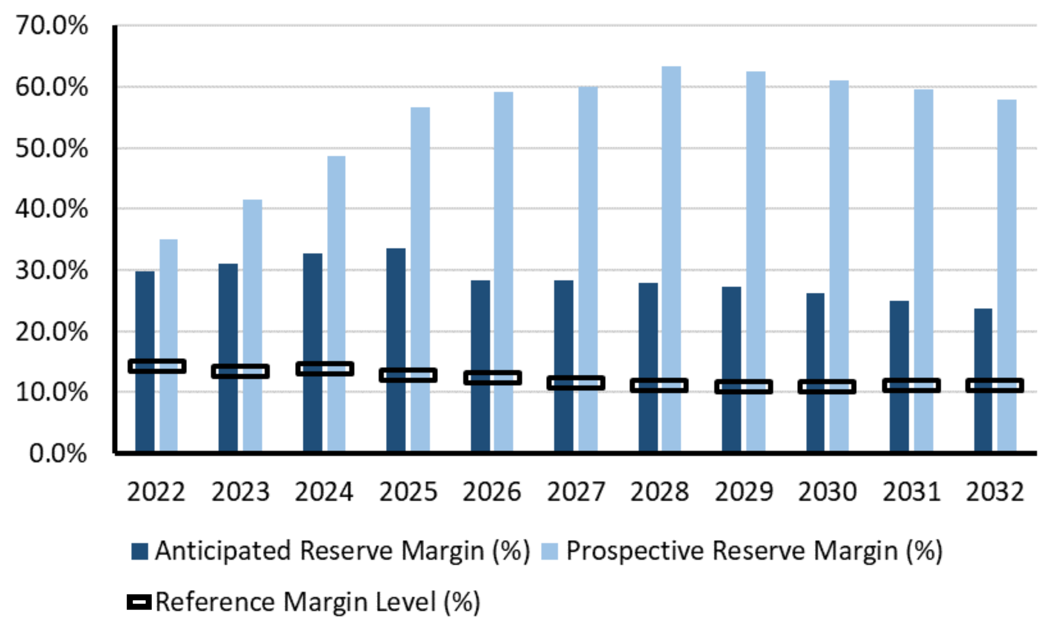
There are no known resource adequacy issues that affect the Maritimes area reliability that are unique to the Maritimes area. The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/natural gas, tie benefits, and biomass with no one type feeding more than about 28% of the total capacity in the area. Although there is not a high degree of reliance upon any one type or source of fuel, supply chain issues may affect fuel procurement; the situation is being monitored. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during this assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions.

NPCC-New England

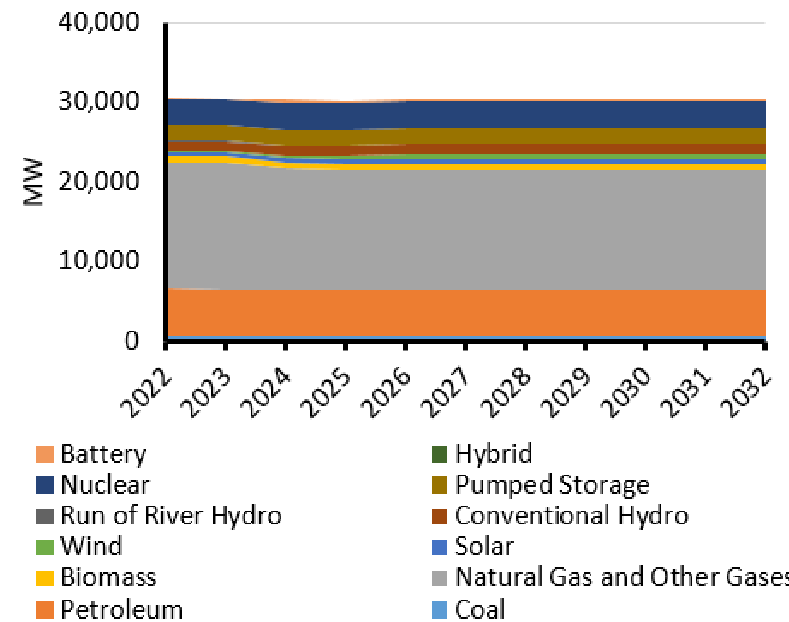
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	24,633	24,600	24,579	24,592	24,631	24,722	24,869	25,071	25,322	25,576
Demand Response	592	678	765	765	765	765	765	765	765	765
Net Internal Demand	24,041	23,922	23,814	23,827	23,866	23,957	24,104	24,306	24,557	24,811
Additions: Tier 1	247	1,520	1,738	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additions: Tier 2	1,666	2,941	4,601	6,451	6,720	7,634	7,634	7,634	7,634	7,634
Additions: Tier 3	776	1,976	3,468	4,528	5,240	5,612	5,984	5,984	5,984	5,984
Net Firm Capacity Transfers	1,059	1,487	1,504	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	31,249	30,245	30,087	28,640	28,679	28,697	28,711	28,721	28,728	28,735
Anticipated Reserve Margin (%)	31.0%	32.8%	33.6%	28.4%	28.4%	27.9%	27.2%	26.2%	24.9%	23.7%
Prospective Reserve Margin (%)	41.5%	48.7%	56.6%	59.1%	60.1%	63.4%	62.5%	61.1%	59.5%	57.9%
Reference Margin Level (%)	13.5%	14.0%	12.9%	12.5%	11.5%	11.2%	11.0%	11.0%	11.2%	11.2%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- New England is forecast to have adequate generating capacity and a robust bulk transmission system to meet the peak seasonal forecast demands for electricity through the 10-year LTRA assessment period; however, ISO-NE has identified energy adequacy risks for the area.
- The overall system is transitioning to lower generator emissions with the development of renewable and clean energy resources. Beyond the *2022 LTRA* assessment horizon, additional imports of Canadian hydro-electricity, offshore wind, and new technologies (e.g., longer duration energy storage) will likely continue the trend toward a cleaner, albeit more complex power system.
- ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.

NPCC-New England Fuel Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Coal	636	636	636	636	636	636	636	636	636	636
Petroleum	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829
Natural Gas	15,813	15,067	15,067	15,067	15,067	15,067	15,067	15,067	15,067	15,067
Biomass	998	992	992	992	992	992	992	992	992	992
Solar	355	476	476	476	476	476	476	476	476	476
Wind	204	359	577	793	793	793	793	793	793	793
Conventional Hydro	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168
Run-of-River Hydro	154	154	154	154	154	154	154	154	154	154
Pumped Storage	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889
Nuclear	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346
Hybrid	29	29	29	29	29	29	29	29	29	29
Battery	29	354	354	354	354	354	354	354	354	354
Total MW	30,450	30,300	30,518	30,734	30,734	30,734	30,734	30,734	30,734	30,734

SCHEDULE MM-S2

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's annual RML is based on the capacity needed to meet the ISO-NE and NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The needed capacity, referred to as the installed capacity requirement (ICR), varies from year to year depending on projected system conditions (e.g., demand, generation, transmissions, capacity imports). The ICR is calculated on an annual basis and covers four years into the future. The latest calculations result in an RML of 13.5% in 2023, 14.0% in 2024, and 12.9% in 2025 as expressed in terms of the 50/50 peak demand forecast published in May 2021. For the years beyond the forward capacity market (FCM) time frame, this assessment uses the reserve margins associated with the representative ICR calculated in 2022 for 2026 through 2031. These margins range between 11.0% (2030) to 12.5% (2026). ISO-NE assumes 11.2% reserve margin for years beyond 2031 for study purposes.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

ISO-NE's probabilistic and deterministic study results indicate that there are sufficient capacity resources to meet forecasts of summer and winter peak as well as energy demands during this 10-year assessment period. However, a previously identified/standing concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure.

In 2018, ISO-NE initiated its Energy Assessment process, with the development of a 21-day forecast of projected system energy availability. Forecasts of weather, transmission topology, generation capability (including intermittent renewable resources), fuel inventories, known outages, pipeline constraints, and projected imports/exports all factor into a 21-day simulation of New England's energy production capability. Depending on the severity, projected energy deficiencies can trigger energy alerts or energy emergencies that are disseminated to market participants and federal and state regulators. This early notification of potential energy shortages should initiate actions by market participants as necessary to firm up their fuel supplies or replenish inventories in order to enhance supply-side capability.

Due to the importance of these type of studies, especially as the resource mix continues to transition to rely more on renewable resources, ISO-NE has undertaken several new projects to develop more enhanced deterministic and probabilistic energy-security analyses across varying time horizons. In addition, ISO-NE, with stakeholder input, is working on near- and long-term market improvements to expand the existing suite of energy and ancillary services that will cost effectively address uncertainties in firm electric energy production due to extreme weather or supply-chain limitations. All of these activities should directly enhance overall BES energy-security.

Probabilistic Assessments (ProbA and Other Studies)[28]

ISO-NE conducts various probabilistic resource adequacy (LOLE based) assessments annually to identify regional capacity resource needs and to comply with the annual NPCC area resource adequacy review requirements. In addition, ISO-NE participates in the NPCC ProbA studies to meet the biannual LTRA assessment requirements. In the transmission assessment domain, revisions to the ISO planning processes now reflect FERC Order 1000 requirements, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with other neighboring systems will continue, which can help state policymakers in New England achieve their objectives of accessing a greater diversity of resources from neighboring power systems.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	58.62	0.139	0.016
EUE (ppm)	0.471	0.001	0.00
LOLH (Hours per Year)	0.095	0.00	0.00
Operable On-peak Margin	9.8%	32.6%	27.8%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With comparable estimated Forecast Reserve Margins, a slight decrease in LOLH and EUE for 2024 was observed. The New York area is summer peaking and the EUE risk occurs during the summer months, however the EUE values are negligible.

[28] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

SCHEDULE MM-S2

Demand

Over the 10-year planning horizon, the forecast net internal summer peak demand increases by 770 MW from 24,041 MW in 2023 to 24,811 MW in 2032. The corresponding net internal winter peak demand increases by 3,233 MW from 19,498 MW in 2023/2024 to 22,731 MW in 2032/2033. Net energy for load is forecast to grow by 18,590 GWh from 125,236 GWh in 2023 to 143,826 GWh in 2032. Over this assessment period, ISO-NE projects the total internal demand growth to increase at a CAGR of 0.42% for summer and 1.95% for winter.

The forecast for EE and conservation during the forecast summer peak ranges from 2,288 MW in 2023 to 3,106 MW in 2032.

New England has 903 MW (3,146 MW nameplate) of BTM solar PV; this is forecast to grow to 1,120 MW (6,555 MW nameplate) by 2032. The BTM solar PV peak load reduction values are calculated as a percentage of ac nameplate. On-peak contributions decrease from 28.7% of nameplate in 2022 to about 17.0% in 2032. The percentages reflect diminishing solar PV production as the time of the system peak shifts later in the day, a phenomenon associated with increased BTM solar PV on the system.

Demand Side Management

New England has 592 MW of controllable and dispatchable DR resources in 2023 and the amount will grow to 765 MW by 2032. The area also has over 3,327 MW (2023) of passive demand side management resources consisting of EE and distributed generation that participate in the regional capacity market. This amount is assumed to increase to 4,226 MW by the end of the LTRA assessment period.

Distributed Energy Resources

There are approximately 1,100 MW (nameplate rating) of smaller than 5 MW each of settlement-only generating resources that do not participate in the ISO-NE capacity market.

Generation

Needed capacity and operating reserves are procured through the wholesale markets. Studies of expected system conditions show that developing new resources near load centers, particularly in NEMA/Boston and SEMA/RI, would provide the greatest reliability benefit. To the extent that new economic resources are developed that can help balance supply with demand, the system would require fewer transmission/distribution upgrades, less ancillary services, and exhibit less congestion and losses, helping the BPS perform more flexibly and reliably.

The regional reliance on natural-gas-fired generation continues and is still exposed to the lack of firm natural gas pipeline transportation entitlement and uncertain liquefied natural gas deliveries. Gas sector infrastructure contingencies can become reliability risks during any time of the year. ISO-NE and interregional organizations have assessed these risks in a number of energy-security studies, and ISO-NE has taken a number of actions, including revising OP-21 to include a 21-day energy forecast, to improve the overall reliable and efficient operation of the system. The solution includes development of renewable resources with energy storage; imports from neighboring areas; fast-start and flexible ramping resources; and continued investment in EE measures within both the electricity and gas sectors.

Future environmental regulations, public policies, and economic considerations will affect the operation of existing resources and the mix of new resources. As oil- and coal-fired generators retire, the new supply resources are expected to be predominantly renewable sources of energy, notably wind and solar. Federal and state policies and initiatives will continue to affect the planning process, such as those promoting EE, solar PV, and wind resources. Public policies restricting carbon emissions will be a limiting factor for energy production by fossil-fueled generating units.

Energy Storage

ISO-NE currently has over 1,800 MW of pumped storage hydro units and 30 MW of battery storage resources. The amount of battery storage resources is expected to grow over the next several years. There are approximately 5,600 MW of Tier 2 and 3 stand-alone battery projects currently in the queue, which are anticipated to go commercial by 2025. Another 500 MW of projects in the queue are co-located, primarily with solar PV resources.

Capacity Transfers (Reliance on Assistance)

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE takes into account the transfer capability with these BAs to assure that their limits do not impact regional resource adequacy. ISO-NE’s FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE’s capacity imports are assumed to range from 1,115 MW to 1,504 MW during the 2022–2025 summer period. Year 2025 is the end of the current FCM capacity supply obligations, and no assumptions are made regarding the availability of imports beyond it. The ISO has assigned import capacity values of zero to the remainder of the LTRA years. In addition, there are no firm exports identified over the 10-year LTRA horizon.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of inverter-based resources, and changes to mandatory planning criteria promulgated by NERC, NPCC, and stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the power system is expected to continue to improve as a result of approximately $1.3 billion of planned transmission upgrades over the next 10 years, much of which is still in the siting process or under construction. Generator retirements, the integration of many distributed and grid-level resources, the use of inverter-based technologies, and issues rising from minimum-load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy. Transmission assessments and resultant plans are currently being developed throughout the area to meet these future system needs. ISO-NE currently has 74 miles of transmission under construction and 433 miles of planned transmission during the 10-year assessment period.

Reliability Issues

New England's bulk electric power grid is transitioning to a system with a growing number of renewable and clean energy resources as well as DERs. The lack of observability and controllability of VERs and DERs is now being addressed to realize the full benefits of energy storage, micro-grids, and smart grid technologies. The rapid implementation of revised interconnection standards for distributed resources is vital for ensuring overall system reliability and facilitating the economic development of IBRs.

Global, regional, and local supply chains are currently impacting the residential and commercial sectors. Those same issues can have reliability impacts across the overall-interconnected energy industry. To some extent, New England has already experienced this situation in the form of fuel availability challenges during winter. ISO-NE has been a key player at the national level in promoting BES reliability through the sharing of lessons-learned and best-practices as well as initiating the performance of more detailed and in-depth BES energy assessments.

Just-in-time delivery of a generator's input fuel source—whether natural gas, wind, or solar—is creating opportunities for the electricity supply-side industry to develop long-term energy storage solutions. Energy storage has been accomplished within the oil and natural gas industries and is now the next major hurdle on the electric industry horizon.

SCHEDULE MM-S2

NPCC-New York

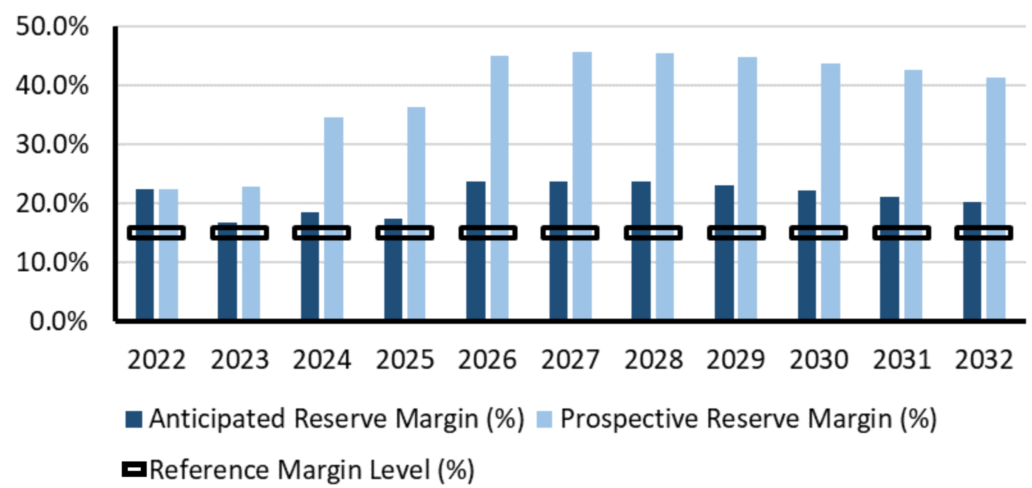
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this LTRA, the established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.

Demand, Resources, and Reserve Margins (MW)

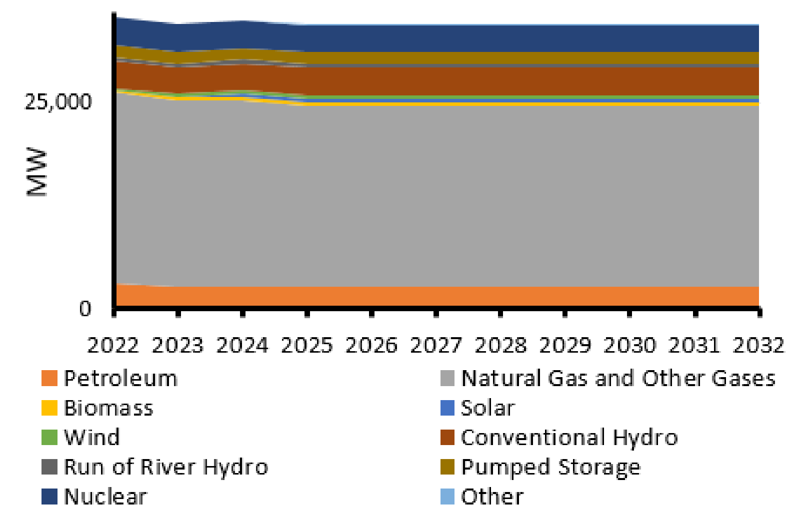
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	32,018	31,778	31,505	31,339	31,292	31,317	31,468	31,684	31,946	32,214
Demand Response	813	813	813	813	813	813	813	813	813	813
Net Internal Demand	31,206	30,966	30,693	30,527	30,480	30,505	30,656	30,872	31,134	31,402
Additions: Tier 1	163	648	685	685	685	685	685	685	685	685
Additions: Tier 2	1,916	4,996	5,841	6,538	6,658	6,658	6,658	6,658	6,658	6,658
Additions: Tier 3	1,369	3,060	3,968	4,870	5,046	5,046	5,046	5,046	5,046	5,046
Net Firm Capacity Transfers	1,776	1,602	1,485	3,188	3,188	3,188	3,188	3,188	3,188	3,188
Existing-Certain and Net Firm Transfers	36,212	36,038	35,321	37,024	37,024	37,024	37,024	37,024	37,024	37,024
Anticipated Reserve Margin (%)*	16.6%	18.5%	17.3%	23.5%	23.7%	23.6%	23.0%	22.1%	21.1%	20.1%
Prospective Reserve Margin (%)	22.3%	34.2%	35.9%	44.5%	45.1%	45.0%	44.3%	43.3%	42.1%	40.9%
Reference Margin Level (%)**	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Wind, solar, and run-of river summer-certain capacities are derated by 85%, 58%, and 54%, respectively, for the summer period.

**The LTRA RML is 15% and it is used for the purpose of the LTRA; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%. All values in the IRM calculation are based upon full installed capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- Clean energy policies, such as the 2019 Climate Leadership and Community Protection Act, are reshaping the New York grid in unprecedented ways. NYISO has established new market rules that advance the state's clean energy policies. Wholesale electricity markets are open to significant investments in wind, solar, and battery storage.
- Reliability margins are shrinking. Generators needed for reliability are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.
- A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. These attributes are critical to a dynamic and reliable future grid. With a high penetration of renewable intermittent resources, dispatchable and emissions-free resources as well as long-duration storage resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping needs.
- The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Clean energy conversion is a key underlying element of electrification policies. New York is projected to become winter peaking in future decades due to electrification, primarily via heat pumps and EVs.
- New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

NPCC-New York Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Petroleum*	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636
Natural Gas*	22,710	22,710	22,111	22,111	22,111	22,111	22,111	22,111	22,111	22,111
Biomass	326	326	326	326	326	326	326	326	326	326
Solar	93	513	551	551	551	551	551	551	551	551
Wind	329	394	394	394	394	394	394	394	394	394
Conventional Hydro	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313
Run-of-River Hydro	440	440	440	440	440	440	440	440	440	440
Pumped Storage	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Nuclear	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341
Battery	40	40	40	40	40	40	40	40	40	40
Total MW	34,637	35,122	34,560	34,560	34,560	34,560	34,560	34,560	34,560	34,560

* Most petroleum and natural-gas-fired generation in the NPCC-New York assessment area is capable of operating using either fuel (i.e., dual-fueled units). For purposes of this table, generators are assigned to the category that corresponds to their primary fuel.

SCHEDULE MM-S2

NPCC-New York Assessment

Planning Reserve Margins

There is no long-term reserve margin criterion in New York. For the LTRA, an RML of 15% is applied by NERC (when none is provided by an assessment area) for the purpose of evaluating on-peak capacity. The ARMs and PRMs in this LTRA are above 15% RML throughout the 10-year assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 days/year probability of unplanned load loss.

NYISO also provides significant support to the NYSRC, which conducts an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion. The IRM for the 2022/2023 capability year is 19.6% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15–20.7%. Additionally, NYISO performs an annual study to identify the minimum locational minimum installed capacity requirements (LCRs) for the upcoming capability year. In 2018, FERC accepted proposed revisions for determining LCRs; the new methodology uses an economic optimization algorithm to minimize the total cost of capacity for the New York balancing area. The NYISO establishes statewide and Locational ICAP requirements for the LSEs.

Energy Assessment, Including Non-Peak Hour Risk

The New York Climate Leadership and Community Protection Act (CLCPA) include the following targets for specific years:

- **2025:** 6,000 MW of distributed solar PV (10,000 MW by 2030)
- **2030:** 3,000 MW of battery storage
- **2030:** 70% renewable energy
- **2035:** 9,000 MW of offshore wind
- **2040:** 100% zero-emissions electricity
- **2050:** 85% reduction in greenhouse gas emissions

With a high penetration of renewable intermittent resources, dispatchable, emissions-free, and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is the greatest. Three major processes for considering energy risks are as follows:

***Energy Assessment Operations Planning* Considerations**

NPCC Grid Operations performs or assists in performing energy assessments, including, but are not limited to, a fuel and energy security study and ongoing assessments, a study assessing potential impacts related to extreme weather possibilities, and weekly analysis based on the results of reporting by generation resources through the NYISO's Generator and Fuel Emissions reporting data portal. NYISO also performs an internal energy analysis at least weekly based on data and information reported by supply resources through the NYISO Generator and Fuel Emissions reporting system. Resources provide data and information on an annual, weekly, and as-needed basis while considering system operating conditions. This analysis has the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security.

Energy Assessment Reliability Planning Process Considerations

NPCC and the NYSRC planning criteria require assessment of extreme system conditions that have a low probability of occurrence, such as peak load conditions that result from extreme weather (i.e., 90th percentile peak load forecast) and the loss of fuel (natural gas) supply under normal weather peak conditions. For the extreme system condition due to loss of fuel supply, this assessment assumes a winter peak value with all NYCA natural-gas-only units unavailable and with reductions in the capacity of dual-fuel units. These extreme system condition evaluations include both steady state and dynamics N-1 assessments.

For the resource adequacy evaluations, NYISO uses the GE Multi-Area Reliability Simulation (MARS), which employs a probabilistic method (sequential Monte Carlo) to determine reliability indices for the New York BPS and also for establishing its annual IRM. There are several types of randomly occurring events that are taken into consideration, such as the forced outages of generating units, the forced outages of transmission capacity, and deviations from forecasted loads. Once all of this analysis is completed, MARS calculates the annual reliability indices (LOLE in days/year, LOLH in hours/year, loss of energy expectation (in MWh/year) for the replication.

SCHEDULE MM-S2

This analysis occurs concurrently across all load levels; MARS combines them in a weighted sum to get a single value for each replication.

The MARS simulations do not take into consideration potential reliability impacts due to unit commitment and dispatch, ramp rate constraints, and other production cost modeling techniques or impacts due to sub-zonal constraints on the transmission system.

Energy Assessment Economic Planning Process Considerations

Production cost models used by NYISO include constraint and contingency definitions that are consistent with NYISO's Reliability Planning Process. The production cost models used also incorporate market and operating criteria, such as contingency and operating reserves. While the studies performed with the model do not explicitly assess Regional Entity criteria, they do provide an outlook of future challenges that might occur while sustaining them. An example is hours/MWh of energy deficiency and reserve deficiency conditions. Additionally, because energy assessments implicitly require the evaluation of energy (MWh not MW), production cost models are useful as they model 8,760 hours per year of a multiple-year time horizon.

The currently in progress *2021–2040 System & Resource Outlook* (the Outlook), which is conducted by the NYISO in collaboration with stakeholders and state agencies, provides a comprehensive overview of the potential resource development over the next 20 years and the resultant transmission constraints throughout New York as well as highlights opportunities for transmission investment driven by economics and public policy. Together with the NYISO's publication of the *2021–2030 Comprehensive Reliability Plan* (CRP), the Outlook will provide a full power system outlook to stakeholders, developers, and policymakers.

Probabilistic Assessments (ProbA and Other Studies)[29]

NYISO performs probabilistic assessments with GE's MARS as part of its reliability planning processes as well as to determine annual IRM and LCRs. Improving capacity accreditation is in progress to value resources in the capacity market based on their duration and marginal impact upon meeting NYSRC resource adequacy requirements. NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. The NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, usually based on the latest available RNA/CRP results and assumptions. NYSRC reliability rules have recently included a requirement defining the NYISO's obligation to deliver a *Long-Term Resource Adequacy Assessment Report* every reliability needs assessment report (RNA) year as well as an annual update in the non-RNA years ("intervening year"). Results of the 2022 ProbA are tabulated below.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	6.837	0.091	0.059
EUE (ppm)	0.046	0.001	0.00
LOLH (Hours per Year)	0.029	0.00	0.00
Operable On-peak Margin	11.3%	11.6%	16.7%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With comparable estimated Forecast Reserve Margins, a slight decrease in LOLH and EUE for 2024 was observed. The New York area is summer peaking and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Demand

The energy and peak load forecasts are based upon end-use models that incorporate projections of economic drivers as well as end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. The forecast of BTM solar PV-related reductions in summer peak assumes that the New York balancing area peak currently occurs at 4:00 p.m. or 5:00 p.m., Eastern, in July or August. The hour of the summer peak varies and is assumed to shift slightly later into the evening over the forecast horizon. The forecast of BTM solar PV-related reductions to the winter peak is zero because the sun sets before the assumed peak hour of 6:00 p.m., Eastern, in January. The baseline forecast includes upward adjustments for increased usage of EVs and other electrification as well as downward adjustments for the impacts of EE trends, DERs, and BTM solar PV. The impacts of net electricity consumption of all energy storage units are added to the baseline energy forecast and the peak-reducing impacts of BTM energy storage units are deducted from the baseline peak forecasts.

[29] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

SCHEDULE MM-S2

In 2019, NYISO performed a *Climate Impact Study Phase I: Long-Term Load Impact Study* and the results of the study identified a clear upward trend in temperatures throughout the state. These trended weather conditions are incorporated within the end-use models and are reflected in the baseline and percentile forecasts. The NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

Over this assessment period, NYISO projects the total internal demand growth to increase at a CAGR of 0.07% for summer and 2.36% for winter. The 10-year annual average energy (+0.22%) and summer peak demand (+0.39%) growth rates are higher than last year. The forecasted increase in peak demand is attributed in part to EV charging during the system peak hour and the electrification of non-weather sensitive appliances (i.e., conversion of cooking, water heating, and other end-uses from fossil-fuel based systems to electric systems). The higher forecasted growth in energy usage can be attributed primarily to the increasing impacts of EV usage, space heating electrification, and electrification of other end uses. The winter peak forecast has also increased for these same reasons. New York is projected to become winter peaking in future decades due to electrification primarily via heat pumps and EVs.

Over the course of the forecast horizon, significant load-reducing impacts occur due to EE initiatives and the growth of distributed behind-the-meter energy resources, such as solar PV. These impacts result primarily from New York State's energy policies and programs. The relative BTM solar impact on peak load declines over time as the New York balancing area summer peak is expected to shift further into the evening.

The economic and behavioral changes stemming from the COVID-19 pandemic changed 2020 and 2021 load levels and load shapes relative to a typical year. The impact on total energy consumption in 2020 was significant. In 2021, impacts on total load were much smaller than in 2020. Throughout the pandemic, the largest load reductions have consistently been in New York City (Zone J), being an urban area with a large share of commercial load. With the exception of New York City, which continues to see somewhat lower than expected energy and peak levels, the load recovery from the COVID-19 pandemic is largely complete throughout the state.

Demand-Side Management

The NYISO's resource planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance. The NYISO will develop market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increases in response to the state's climate and clean energy policies. Many of New York utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed, and significant impacts on demand are included in the load forecast. There were no major changes in the DR accounting methods or assumptions since the *2021 LTRA.* The *2021 LTRA* reported 1,199.1 MW of DR participating in NYISO's DR programs for the summer capability period. For the *2022 LTRA*, the DR participation for the summer capability period has decreased slightly to 1,169.8 MW. There are currently 200 MW of DR participating in ancillary services programs that provide either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO is currently implementing a three- to five-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. On the markets side, the DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. As a next step, the NYISO will develop market concepts to encourage the participation of flexible load that will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. These efforts will add new means by which resources can participate in NYISO's markets as well as enhance existing participation models. On a similar theme, NYISO is developing market participation rules for wholesale market generation resources co-located with storage. As part of this effort, NYISO has identified two potential participation models for such resources: the Co-Located Storage Model and the Hybrid Storage Model.

SCHEDULE MM-S2

Generation
The most recent Reliability Planning Process (2022/2023 RPP) started with its *2022 RNA* and targets 2022 Q4 for completion. The study period for the RNA is 2026–2032. The 2022 RNA Base Cases future system assumptions reflect the following information:

- Approximately 2,100 MW (nameplate) proposed projects were included, mostly wind and solar.
- Approximately 1,800 MW generation assumed deactivated, including those impacted by the Peaker Rule. The generators are also reflected in the LTRA spreadsheet as either confirmed deactivations (for those units indicating plans to deactivate in order to comply with the rule), or with zero capacity during the ozone season (May–September) and with applicable capacity value during non-ozone period.

Additionally, the NYISO's interconnection process contains an unprecedented number of proposed projects in various stages of development.

Energy Storage
Storage resources help to fill in voids created by reduced output from renewable resources; however, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. The Hybrid Co-Located Model is now implemented to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. The Hybrid Storage Resources model is in development to allow multiple technologies at the same point of interconnection participate in the market as a single resource. Additionally, the resource adequacy simulation tools (e.g., GE's MARS) used in planning and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging as well as temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers
The models used for the NYISO reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a Base Case assumption.

Transmission
New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources from upstate to downstate load centers where demand is greatest. Currently, 1,635 miles of transmission line projects are planned over the 10-year assessment period total.

The *2022 RNA* (targeting 2022 Q4 for completion) includes the following:

- Local Transmission Owner plans designated as firm in the applicable *NYISO Gold Book*
- The NYPA/National Grid's Northern New York Priority Transmission Project (under the New York State Accelerated Renewable Energy Growth and Community Benefit Act, which seeks to accelerate siting and construction of large-scale clean energy projects
- The 1,250 MW Champlain-Hudson Power Express HVDC Line from Hydro Québec to New York City
- The Western NY Public Policy Transmission Project (the Empire State Line Proposal), which is being developed by NextEra Energy Transmission New York, Inc.
- The AC Public Policy Transmission Project (ACPPTP) consisting of two transmission projects in the Mohawk and Hudson Valleys selected by the NYISO Board of Directors in 2019

Planning for new transmission to support offshore wind is underway. A new Public Policy Transmission Planning Process is in progress (not yet included in the reliability planning models) that will include projects to support offshore wind development.

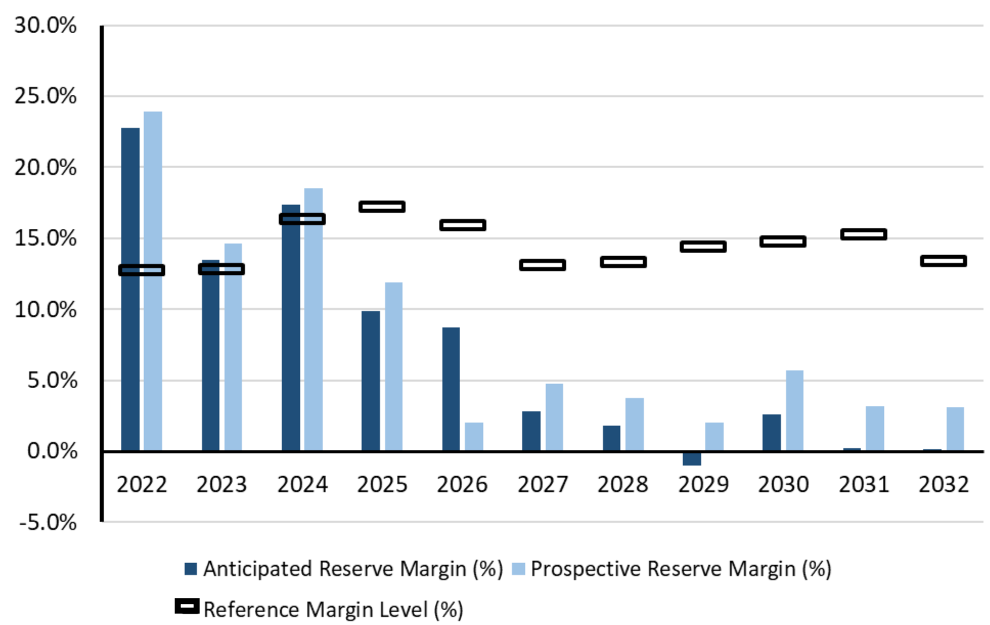
SCHEDULE MM-S2

NPCC-Ontario

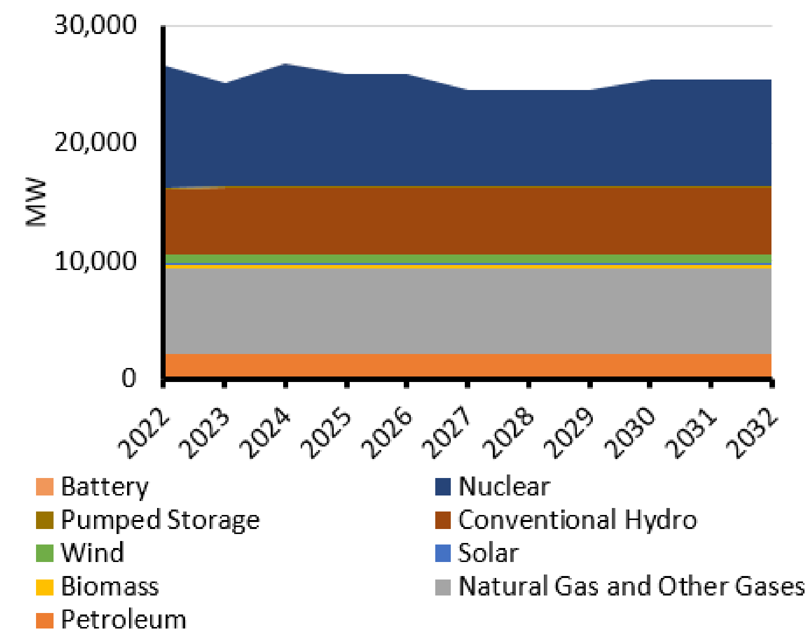
NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	22,930	23,490	23,856	24,104	24,288	24,477	25,166	25,081	25,678	25,694
Demand Response	850	712	367	367	367	367	367	367	367	367
Net Internal Demand	22,080	22,777	23,488	23,737	23,921	24,110	24,799	24,714	25,311	25,326
Additions: Tier 1	99	99	99	99	99	99	99	99	99	99
Additions: Tier 2	0	0	223	223	223	223	508	508	508	508
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	24,959	26,640	25,715	25,715	24,489	24,442	24,442	25,260	25,262	25,262
Anticipated Reserve Margin (%)	13.5%	17.4%	9.9%	8.7%	2.8%	1.8%	-1.0%	2.6%	0.2%	0.1%
Prospective Reserve Margin (%)	14.6%	18.5%	11.9%	2.0%	4.8%	3.7%	2.0%	5.7%	3.2%	3.1%
Reference Margin Level (%)	12.8%	16.3%	17.2%	16.0%	13.1%	13.3%	14.4%	14.8%	15.3%	13.4%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- Ontario's ARMs fall below the RML beginning in 2025—driven primarily by the nuclear refurbishment program, the retirement of Pickering Nuclear Generating Station, and demand growth. ARMs and fuel composition information in this 2022 LTRA assume Pickering units will retire in late 2026, however they could retire as early as 2025.
- IESO has initiated a suite of actions aimed at meeting its resource adequacy needs—including a series of procurement activities with varying forward periods designed to acquire capacity from both new and existing capacity—as outlined in the IESO's *2022 Annual Acquisitions Report*.
- IESO expects both energy and peak demand to grow steadily over the outlook period, driven primarily by economic and demographic growth. Ontario will remain summer peaking over the forecast horizon.
- A number of transmission projects are underway to address bulk system reliability concerns, reinforce connection in the northwest, and connect new loads in the southwest area of the province.

NPCC-Ontario Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Petroleum	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106
Natural Gas	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332
Biomass	300	300	300	300	300	300	300	300	300	300
Solar	123	123	123	123	123	123	123	123	123	123
Wind	771	771	771	771	771	771	771	771	771	771
Conventional Hydro	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564
Pumped Storage	110	110	110	110	110	110	110	110	110	110
Nuclear[30]	8,745	10,426	9,501	9,501	8,275	8,228	8,228	9,046	9,048	9,048
Battery	7	7	7	7	7	7	7	7	7	7
Total MW	25,058	26,739	25,8148	23,750	24,588	24,541	24,541	25,359	25,361	25,361

[30] Nuclear outages as a result of the nuclear refurbishment program are reflected in this table.

SCHEDULE MM-S2

NPCC-Ontario Assessment

Planning Reserve Margins

The ARMs fall below the RML beginning in 2025, driven primarily by the nuclear refurbishment program, the retirement of Pickering Nuclear Generating Station, and demand growth. Anticipated Shortfalls of about 1,700 MW are forecast for 2025 and 2026. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend the operation of the Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026. If approval is received from the Canadian Nuclear Safety Commission, this extension would reduce the potential capacity shortfall in 2026 described in the *2021 LTRA*. The ARM in the *2022 LTRA* is calculated with an assumed retirement of Pickering units in late 2026.

In order to address emerging resource adequacy needs, the IESO established a Resource Adequacy Framework[31] in 2021 to provide a flexible and cost-effective approach for competitively securing the resources necessary to meet Ontario's needs. The Resource Adequacy Framework sets out a multi-pronged approach to cumulatively address needs over varying time frames with the Annual Acquisition Report specifying the mechanisms and targets that are used to meet the needs, including expanded targets for IESO's annual capacity auction and a set of procurements aimed at acquiring capacity from both new and existing resources. In September 2022, Ontario's Ministry of Energy directed the IESO to obtain 4,000 MW of new capacity through three separate procurements. The targets of these procurements are not reflected in this report. The IESO completes a probabilistic assessment of its resource adequacy needs annually and publishes the results in the *2021 Annual Planning Outlook* (APO).[32] This LTRA is consistent with the *2021 Annual Planning Outlook*.

Energy Assessment

Energy adequacy assessments are conducted annually for the 20-year *2021 Annual Planning Outlook* study period. Currently, the energy modelling is deterministic and performed for median conditions. NPCC-Ontario examines the production of each resource, imports, exports, unserved energy, surplus baseload generation, and marginal cost to identify risks. Ontario is expected to experience increased energy adequacy risk when Pickering NGS retires in 2024–2025. In addition, unserved energy is expected to increase should some of Ontario's resources retire after contract expiry. The IESO is developing an RFP for new-build resources (the design of which was informed) in part, by energy assessments; and as a result, it includes incentives for resources that are able to meet energy needs as they emerge.

[31] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework

[32] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

SCHEDULE MM-S2

Probabilistic Assessment[33]

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.049	0.00	72.164
EUE (ppm)	0.00	0.00	0.492
LOLH (Hours per Year)	0.001	0.00	0.442
Operable On-peak Margin	4.4%	7.9%	-6.7%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is slightly lower in this ProbA than reported in the previous ProbA. As a result, the estimated LOLH and EUE for year 2024 decreased slightly to approximately zero. With the reported drop in capacity resources for the year 2026, there is an increase in the LOLH to 0,442 hours per year and EUE to approximately 72 MWh (0.492ppm). The Ontario area is summer peaking; the low LOLH risk occurs during the summer months.

Demand

Ontario will remain summer peaking over the forecast horizon. Peak demand is expected to grow over the outlook period, driven primarily by demographic and economic growth. Later in the forecast, decarbonization and electrification, including rapidly growing penetration of EVs, should continue to drive growth in peaks that will be partially offset by EE.

Energy demand is subject to the same factors as peak demands. In the near term, demand forecast uncertainty remains greater than usual although the source of uncertainty is shifting from the COVID-19 pandemic to the broader macroeconomic outlook. However, demand is expected to experience upward pressure from economic and demographic growth in the long term. Growth will also come from electrification of the transportation sector and significant growth in the resource sector (primarily mining and agriculture). Over this assessment period, IESO projects the total internal demand growth to increase at a CAGR of 1.27% for summer and 1.32% for winter. Overall, IESO expects to see an increase in energy demand over the forecast horizon.

Demand Side Management

As of the December 2020 capacity auction, DR (including dispatchable loads and hourly DR resources) has been enabled to compete with other resources to provide capacity. Resources with capacity obligations are required to be available for curtailment up to their secured capacity during times of system need. The December 2021 capacity auction procured 1,286 MW for the six-month summer obligation period beginning on May 1, 2022. This is an increase of nearly 300 MW over the prior year's capacity auction. Of this capacity, more than 900 MW is from DR.

Distributed Energy Resources

IESO estimates that total DERs in Ontario exceed 4,300 MW, including about 4,000 MW of contracted renewable resources. The IESO continues to collaborate with the DER community to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve DER visibility and identify opportunities for a more coordinated operation of Ontario's electric system. Although the output from DERs has plateaued, the need for more flexible generation to manage variability remains. Given that DERs are challenging to forecast, it can be difficult to efficiently commit non flexible resources or schedule transactions on the interties to manage supply and demand. To manage this variability, IESO initiates actions, such as committing dispatchable generation, curtailing intertie transactions, and scheduling additional 30-minute operating reserve to signal flexibility need.

Generation

Nuclear refurbishments at Bruce Nuclear Generating Station and the Darlington Nuclear Generating Station are expected to reduce the generation capacity availability in the coming years. During the refurbishment period, one to four units are expected to be on outage at any given time, including peak seasons. Once they return to service, they will continue to help meet Ontario's adequacy requirements in the mid- and long-term. In addition to the 1,286 MW secured at the annual IESO Capacity Auction for the summer of 2022 obligation period with contracted wind capacity of 160 MW from the Romney Wind Project (60 MW) and Nation Rise Wind Farm (100 MW). Additional wind farms are expected to be added in late 2022. Substantial resource turnover is anticipated in the coming years that is driven by nuclear retirements, nuclear refurbishments, and by the expiry of contracted resources. The availability of the nuclear fleet is a major resource turnover risk that requires additional attention. The transmission-connected supply mix has shifted from only synchronous generation facilities to more inverter-based generation facilities (e.g., wind, solar). There are very few natural-gas-fired generation facilities producing power under low demand conditions. As a result, the IESO-controlled grid relies primarily on baseload (run-of-the-river) hydroelectric generation facilities to provide most of the primary frequency response.

[33] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

SCHEDULE MM-S2

Energy Storage

The IESO views electricity storage as an important emerging resource and is actively working to enable its deployment. IESO has released a series of reports that outline the barriers to fair competition and detail a path for enduring participation of electricity storage resources in IESO's markets. Nonetheless, capacity from transmission connected storage remains relatively small in Ontario. There is a considerable amount of energy storage resources connected on the distribution system for peak shaving. Additional energy storage projects are expected and at different stages of development from feasibility studies to permitting. Energy storage uses in Ontario include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving.

Capacity Transfers

IESO has operating agreements with Hydro Québec and Manitoba Hydro to enable system backed imports from these jurisdictions that may be acquired as part of the IESO Capacity Auction. As part of the electricity trade agreement between Ontario and Québec, Ontario will supply 500 MW of capacity to Québec each winter from December to March until 2023. Ontario has the option to receive 500 MW of capacity from Québec for one summer before 2030 and expects to call on that option in the summer of 2026. The IESO and NYISO facilitates trading of capacity from Ontario to New York. To ensure that reliability in Ontario is maintained, only capacity that is determined by IESO to be above Ontario's required reserve margin levels over summer or winter season are exported.

Transmission

A new 400–450 km long 230 kV double-circuit transmission line is planned to come into service in Q3 2022 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid. There is a double-circuit 230 kV line that is operated as one electrical circuit in the Sudbury District that poses risks should a contingency event occur. The IESO has requested that Hydro One Limited initiate the work required to terminate the two physical circuits on their own terminal positions so they function as two separate circuits, addressing this risk. In the Windsor-Essex area, two projects have been initiated: development of a new switching station (expected in-service in Q3 2022) and a new double-circuit approximately 50-km 230 kV transmission line to bring additional supply to the area (by Q4 2025). The IESO has also recommended further transmission reinforcement to support the area's medium-term needs, identifying an additional double circuit 230 kV line (expected in-service by 2028) and a new 500 kV line (expected in service by 2030). In the Ottawa area, IESO has requested that work proceed to upgrade circuits between Merivale Transmission Station (TS) and Hawthorne TS with a planned in-service date of Q4 2023; this project will address supply capacity constraints to West Ottawa and support the deliverability of capacity imports from Québec. The IESO has recommended the upgrade of four limiting 230 kV circuits between Richview TS and Trafalgar TS in the Toronto area, resulting in an increase in the Flow East Towards Toronto (FETT) interface capability, by spring 2026. IESO currently has 71 miles of transmission lines under construction and 499 miles of planned transmission lines during the 10-year assessment period.

Reliability Issues

The ongoing nuclear refurbishment program that spans the next 12 years is a major resource risk that requires additional attention. IESO has regular meetings with nuclear operators to assess probable delays and to take appropriate mitigation actions.

Natural gas is delivered to Ontario from neighboring jurisdictions by mainlines and distribution utilities. Situated in Ontario is the Enbridge Gas Dawn Hub, Canada's largest integrated underground natural gas storage facility. The risk of fuel unavailability under extreme winter conditions in Ontario is reduced with a large portion of the natural gas fleet located in close proximity to the Dawn hub. Supply to Ontario's natural gas fleet is robust and supported by significant firm supply and transportation contracts.

Changes to demand and resource mix in response to potential decarbonization could have significant reliability implications. The IESO is currently studying decarbonization, both of the electricity system and the economy in general (including impacts on reliability) in its *Pathways to Decarbonization* study.[34]

[34] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Pathways-to-Decarbonization

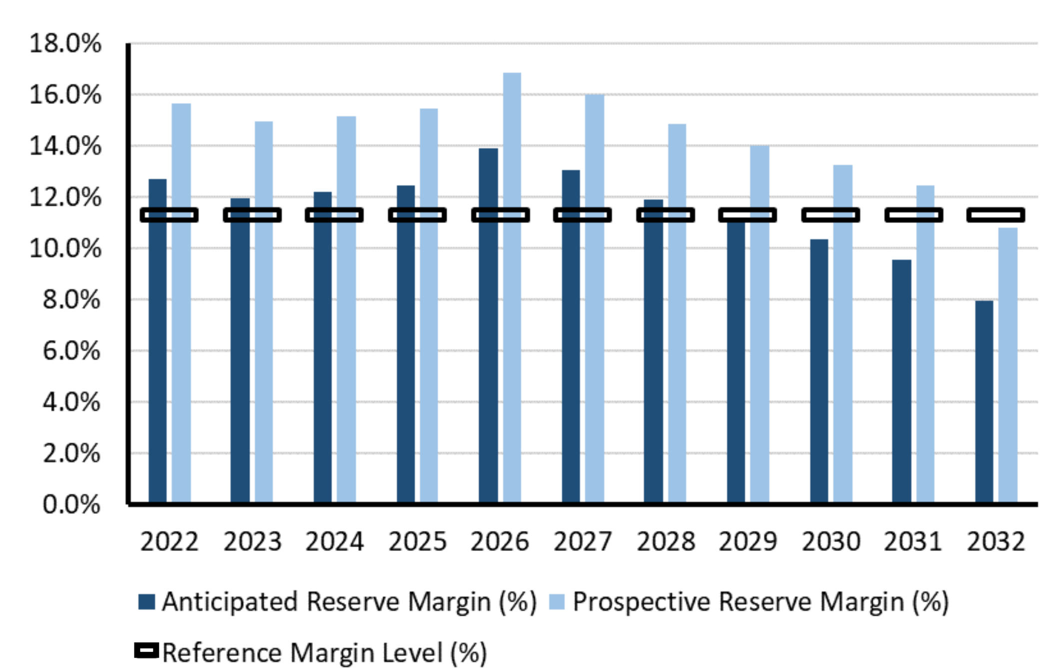
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

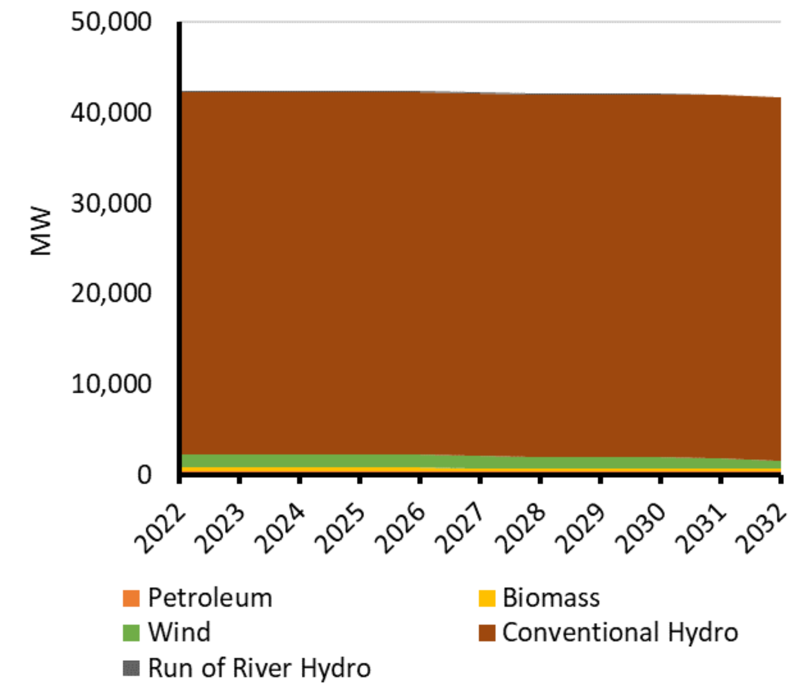
Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	40,390	40,554	40,769	41,102	41,445	41,822	42,090	42,333	42,547	42,864
Demand Response	3,348	3,650	3,883	3,989	4,181	4,209	4,241	4,241	4,241	4,241
Net Internal Demand	37,042	36,904	36,886	37,113	37,264	37,614	37,849	38,092	38,306	38,623
Additions: Tier 1	255	369	369	369	369	369	369	369	369	369
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-888	-1,079	-990	-145	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	41,226	41,040	41,116	41,909	41,765	41,727	41,682	41,674	41,606	41,331
Anticipated Reserve Margin (%)	12.0%	12.2%	12.5%	13.9%	13.1%	11.9%	11.1%	10.4%	9.6%	8.0%
Prospective Reserve Margin (%)	15.0%	15.2%	15.5%	16.9%	16.0%	14.8%	14.0%	13.3%	12.4%	10.8%
Reference Margin Level (%)	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

NPCC-Québec

Highlights

- The ARM remains above the RML except for last four winter periods of this assessment. However, the PRM is above the RML for all the years of this assessment except for the last winter peak period.
- Approximately 490 MW of capacity additions are expected over this assessment period. The Romaine-4 hydro unit (245 MW) is expected to be fully operational by the end of 2022. A 204 MW of wind generation is expected to be in service in 2024–2025. Finally, 41 MW of biomass are expected to be in service in 2024.
- A total of 500 MW of firm import capacity from Ontario is available to Québec each winter through 2022/2023 as part of an existing trade agreement between Québec and Ontario.
- The commissioning of the second Micoua-Saguenay 735 kV transmission line is expected by the end of 2022.

NPCC-Québec Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Petroleum	436	436	436	436	436	436	436	436	436	436
Biomass	405	405	405	405	295	228	228	228	228	220
Wind	1,375	1,449	1,430	1,372	1,336	1,296	1,248	1,248	1,191	946
Conventional Hydro	40,048	40,054	40,060	40,065	40,068	40,071	40,073	40,076	40,078	40,081
Run-of-River Hydro	103	144	144	144	144	144	144	134	121	96
Total MW	42,368	42,488	42,475	42,422	42,279	42,174	42,129	42,122	42,054	41,779

SCHEDULE MM-S2

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is above the area's RML over this study period assessment except for the last three winter periods of 2030–2033. However, the PRM remains above the RML for almost all years of this assessment. Under the prospective scenario, a total of 1,100 MW of expected capacity supply is planned by the Québec area; this capacity could either be supplied by resources within the area or by imports. This capacity has not yet been backed by firm long-term contracts. However, based on its annual capacity needs, the Québec area proceeds with short-term capacity contracts in order to meet its capacity requirements.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

In its distribution service functions, Hydro-Québec performs an energy adequacy assessment in its supply plan and files results with the Régie de l'énergie (Québec Energy Board) in November of each year. Unserved energy and the generation surplus are metrics used to identify risks. Furthermore, an energy criterion accepted and approved by the Régie de l'énergie is also used to identify risks. The Québec area has adequate energy to meet its energy demand over the entire horizon of the analysis. The installed capacity in the Québec area is mainly composed of large reservoir hydro complexes (more than 90%) that can react quickly to adjust their generation output and meet the sharp changes in the net demand

Probabilistic Assessment[35]

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	7.1%	-1.6%	-2.3%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for the year of 2024 is higher in this ProbA than reported in the previous ProbA. Even with a smaller estimated Forecast Planning and Forecast Operable Reserve Margin, no LOLH and EUE is observed. Québec's probabilistic assessment results continue to indicate little risk of energy or capacity shortfall. The highest risk occurs in winter months and coincides with the hour of peak demand.

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Québec area demand forecast average annual growth is 0.7% during the 10-year period, comparable to the last year's forecast.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,563 MW on 2022/2023 winter peak demand. The area is also expanding its existing interruptible load program for commercial buildings that will grow from 424 MW in 2022/2023 winter to 505 MW in 2024/2025 winter. Another similar program for residential customers is in operation and should gradually rise from 47 MW for 2022/2023 winter to 621 MW for 2028/2029 winter. Enhancing interruptible programs for large industrial customers can add potential capacity that varies from 330 MW in the 2023/2024 winter period to 512 MW at the end of the assessment period.

Dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 203 MW for 2021/2022 winter, increasing to 371 MW for 2024/2025 winter.

Moreover, data centers specialized in blockchain application participants (new developments in the commercial sector) are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 261 MW for 2022/2023 winter and around 230 MW at the end of the study period.

EE and conservation programs are integrated in this assessment area's demand forecasts.

[35] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

SCHEDULE MM-S2

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to more than 622 MW in 2033. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter peaking area, solar PV on-peak contribution is minimal (less than 15 MW).

No potential operational DER impacts are expected in the Québec area due to the low DER penetration in the area.

Generation

The Romaine-4 unit (245 MW) is expected to be fully operational by the end of 2022. The integration of small hydro unit accounts for 41 MW new capacity during this assessment period. For other renewable resources, 204 MW of wind generation (73 MW on-peak value) is expected to be in service for the winter period 2024/2025. A total of 10 MW of biomass is expected to be in place by the end of 2022.

Capacity Transfers

In 2019, Hydro-Québec TransÉnergie conducted a transmission system planning assessment to fulfill NERC TPL-001-4 requirements. The loss of a 735 kV circuit on the Manic-Québec interface on a system where a 735 kV is out-of-service on the same interface (system adjustments are applied) caused the overload of the Saguenay series capacitor banks even after considering their overload capacity. The commissioning of the second Micoua-Saguenay 735 kV line is planned for 2023. Simulations performed on the 2023/2024 and 2028/2029 systems have confirmed the effectiveness of this solution. Until this second line is operational, this issue is monitored and addressed in real-time with a system operating limit (SOL), and power transfer is limited if an overload risk is detected. This new line is now under construction and is expected to be in service in 2023.

Transmission

The Romaine River Hydro Complex Integration Construction is in its final phase; its capacity will be 1,550 MW. Romaine-2 (640 MW), Romaine-1 (270 MW), and Romaine-3 (395 MW) have been commissioned. Romaine-4 (245 MW) is expected to be in service by the end of 2022. Hydro-Québec has identified the need to build a new 735 kV line that extends some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction and is expected to be in service in 2023.

The Hertel-New York Interconnection (Champlain Hudson Power Express) project to increase transfer capability between Québec and New York by 1,250 MW is currently in the permitting phase. It involves the construction of a ±400-kV dc underground transmission line about 60 km (37 miles) long from Hertel 735/315-kV substation just south of Montréal to the Canada–United States border. The project will connect to the CHPE in New York State. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, New York, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Hertel substation. The project is expected to be in service in December 2025.

Hydro Québec currently has no transmission under construction and 280 miles of planned transmission lines during this 10-year assessment period.

SCHEDULE MM-S2

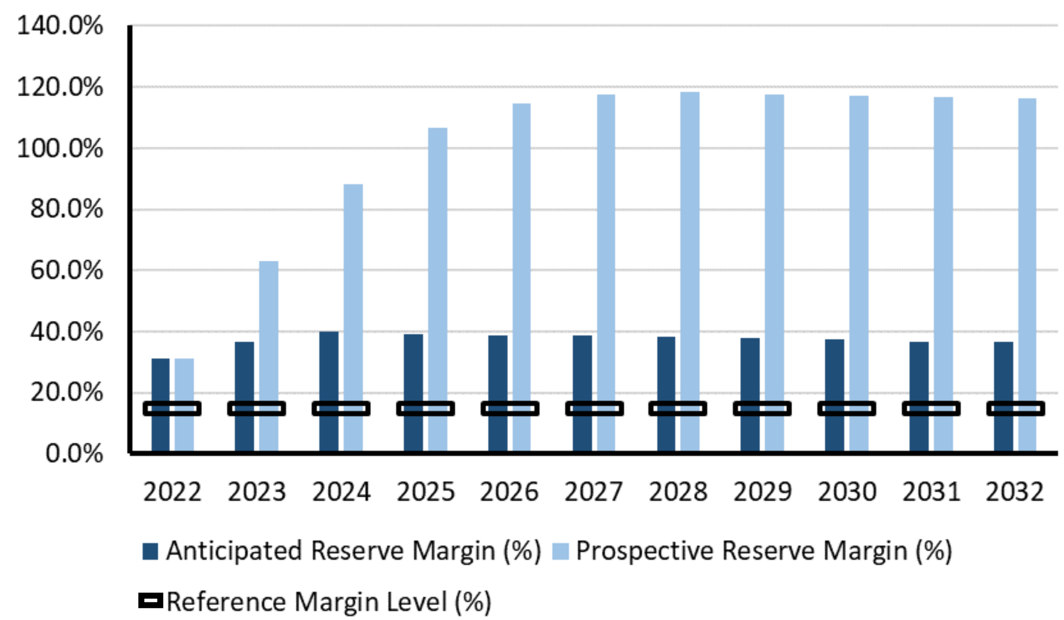
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

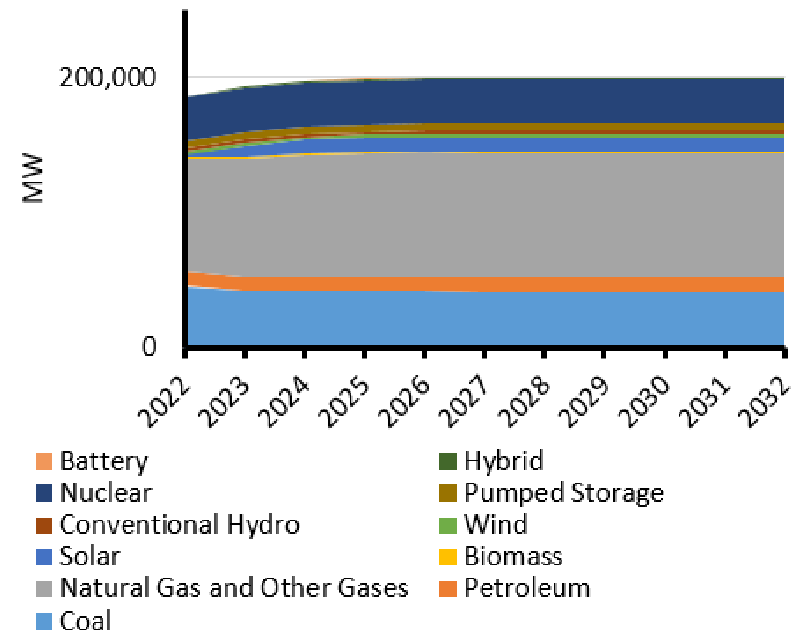
PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381
Demand Response	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240
Net Internal Demand	142,286	143,205	144,032	145,098	145,155	145,513	146,134	146,556	147,040	147,141
Additions: Tier 1	12,171	16,780	18,330	19,227	19,495	19,495	19,495	19,495	19,495	19,495
Additions: Tier 2	37,416	70,337	97,046	109,748	113,942	116,123	116,448	116,825	116,825	116,825
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	82	1,302	-321	-95	-299	-299	-299	-299	-299	-299
Existing-Certain and Net Firm Transfers	180,982	182,204	180,581	180,807	180,191	180,191	180,191	180,191	180,191	180,191
Anticipated Reserve Margin (%)	35.7%	39.0%	38.1%	37.9%	37.6%	37.2%	36.6%	36.3%	35.8%	35.7%
Prospective Reserve Margin (%)	60.2%	84.3%	102.9%	109.0%	110.8%	111.3%	110.6%	110.3%	109.6%	109.5%
Reference Margin Level (%)	14.8%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- The ARMs for each year in this assessment period do not fall below the PJM installed reserve requirement (the RML).

PJM Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	43,401	43,401	43,401	43,401	42,989	42,989	42,989	42,989	42,989	42,989
Petroleum	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986
Natural Gas	87,312	90,038	91,064	91,694	91,694	91,694	91,694	91,694	91,694	91,694
Biomass	964	964	964	964	964	964	964	964	964	964
Solar	8,470	10,183	10,299	10,299	10,299	10,299	10,299	10,299	10,299	10,299
Wind	1,949	1,979	2,375	2,642	2,910	2,910	2,910	2,910	2,910	2,910
Conventional Hydro	2,438	2,444	2,456	2,456	2,456	2,456	2,456	2,456	2,456	2,456
Pumped Storage	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131
Nuclear	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656
Hybrid	1,250	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Battery	4	57	57	57	57	57	57	57	57	57
Total MW	194,560	199,172	200,722	201,619	201,475	201,475	201,475	201,475	201,475	201,475

SCHEDULE MM-S2

PJM Assessment

Planning Reserve Margins
The ARMs for each year in this assessment period do not fall below the PJM installed reserve requirement (RML). Because PJM has extensive capacity resources, the risk for capacity shortages during non-peak periods is minimal.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods. PJM is forecasting around 30% installed reserves (including expected committed demand resources), well above the target installed reserve margin of 14.7% necessary to meet the 1-day-in-10 years LOLE criterion. PJM analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM has filed an effective load carrying capability methodology with FERC to properly calculate the reliability and capacity contribution of limited and variable resources.

Probabilistic Assessment
LOLH and EUE are zero for both 2024 and 2026 due to large forecast operable reserve margins. The reserve margins are significantly above the reference values of 14.7%.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	29.0%	29.0%	28.0%

* Provides the 2020 ProbA results for comparison

Demand
PJM produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables, including calendar effects, weather, economics, and end-use characteristics. Daily unrestricted peak load is defined as metered load plus estimated load drops and estimated distributed solar generation. Separately from the modeled forecast, a forecast of the peak impact of distributed solar generation is developed with internal installed solar capacity data and a forecast of solar capacity additions obtained from a vendor. The impact on peak is estimated by applying a historical capacity factor to installed capacity. Additionally, a separate forecast of load management is developed based on the amount of resources that have historically committed though PJM's FCM. The load management forecast is used to develop the net internal demand forecast.

PJM annually reviews its load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast. With respect to sector models, the commercial component of the load model was improved with the addition of service sector employment to more accurately reflect evolving economic conditions. Improvements to non-weather-sensitive models were also made to better align with underlying drivers and historical trends, reducing expected load impacts. Each year, PJM measures the accuracy of the long-term load forecast model by running it with up-to-date inputs, solving with actual weather, and comparing to actual load. This measure of accuracy is meant to show how well the model would have performed with the most recent forecast inputs. PJM reviews model accuracy results on the 10 highest coincident peak days for each season for a number of forecast horizons with the Load Analysis Subcommittee. Over this assessment period, PJM projects the total internal demand growth to increase at a CAGR of 0.37% for summer and 0.64% for winter.

Demand Side Management
DR resources can participate in all PJM markets: capacity, energy, and ancillary services:

Capacity: Capacity service providers have the ability to participate in PJM's reliability pricing model auctions up to three years in advance of the delivery year (PJM delivery year is June–May).

Energy: DR resources may register for and bid into PJM day-ahead and real-time energy (economic) markets.

Ancillary Services: DR resources may register for and must be certified for participation in PJM ancillary service markets as per the requirements for each ancillary service type as found in PJM manuals.

SCHEDULE MM-S2

Distributed Energy Resources

PJM expects[36] 3,176 MW of solar DERs at the time of the peak in 2024 and 5,828 MW in 2031. The effects of solar DERs are included in the load forecast for PJM. No solar DER effects are incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

PJM processed 1,028 requests to interconnect new generation, totaling 70,375 MW, nameplate capability and 44,179 MW of capacity interconnection rights. Wind, solar, and storage requests now total over 120,000 MW (nameplate) in PJM's interconnection queue. Solar has more than doubled over 2019, it now comprising 56% of PJM's queue.

PJM's existing installed capacity reflects a fuel mix comprising approximately 43% natural gas, 27% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling over 76,000 MW (nameplate), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56% of the generation in PJM's interconnection queue.

Prior to 2021, the variable resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations: it weights the output over all hours equally regardless of an individual hour's actual contribution to the annual loss of load risk, and it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC methodology. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect. As part of the process to implement the ELCC, a proposal was developed. PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as an input to its resource adequacy model. Pending FERC approval, the ELCC methodology will be applied to variable, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

Energy Storage

Energy storage continues to grow in PJM. Efficient grid operations in an era experiencing rapid growth of VERs will require increased electric system flexibility. Energy storage provides grid operators with the ability to meet load requirements when wind, solar, and other variable resources must alter power output because of weather conditions or because those units simply are unavailable. Energy storage resources can also improve transmission system efficiency by increasing network utilization factors. PJM has worked with several industry entities, including Department of Energy national laboratories, to advance the use of energy storage and ensure that PJM's wholesale market is capable of allowing all forms of energy storage technology to participate competitively.

Transmission

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many drivers. Initially, with its inception in 1997, PJM's Regional Transmission Expansion Plan (RTEP) consisted of system enhancements that were mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction of many drivers, including those that arise out of reliability, aging infrastructure, operational performance, market efficiency, public policy, and demand-side trends. Importantly though, RTEP development considers all drivers through a reliability criteria and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability, and short-circuit NERC Reliability Standard TPL-001-4.

Historically, baseline transmission projects have been driven by reliability criteria, market efficiency needs, and Transmission Owner criteria requirements. PJM's state agreement approach, authorized by FERC, expands the planning process to enable a state or group of states to propose a project to advance public policy requirements as long as the states involved agree to pay all costs of any related build-out included in the RTEP. The state agreement approach was developed seven years ago after extensive consultation with the Organization of PJM States as part of implementing FERC's Order 1000. In that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes." PJM currently has 35 miles of transmission lines under construction and 949 miles of planned transmission lines during this 10-year assessment period.

[36] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

SCHEDULE MM-S2

SERC-East

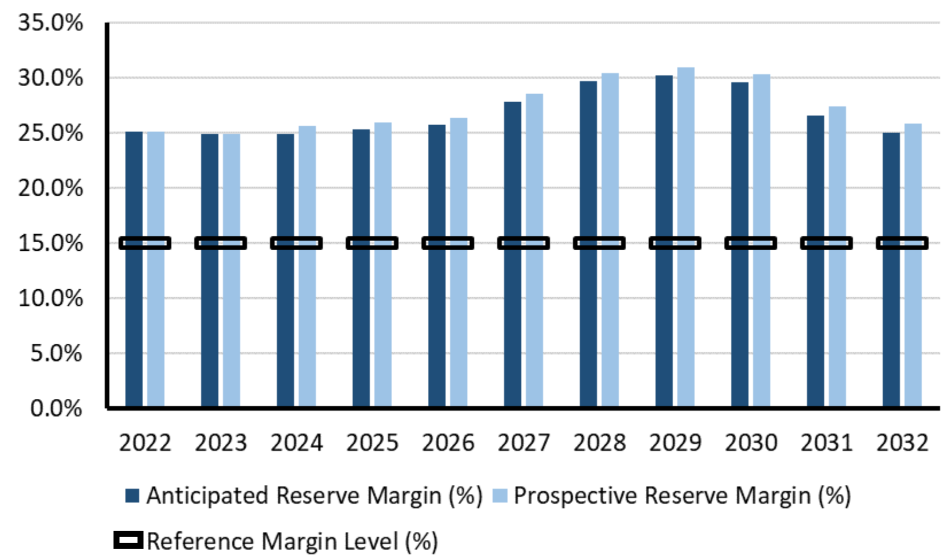
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

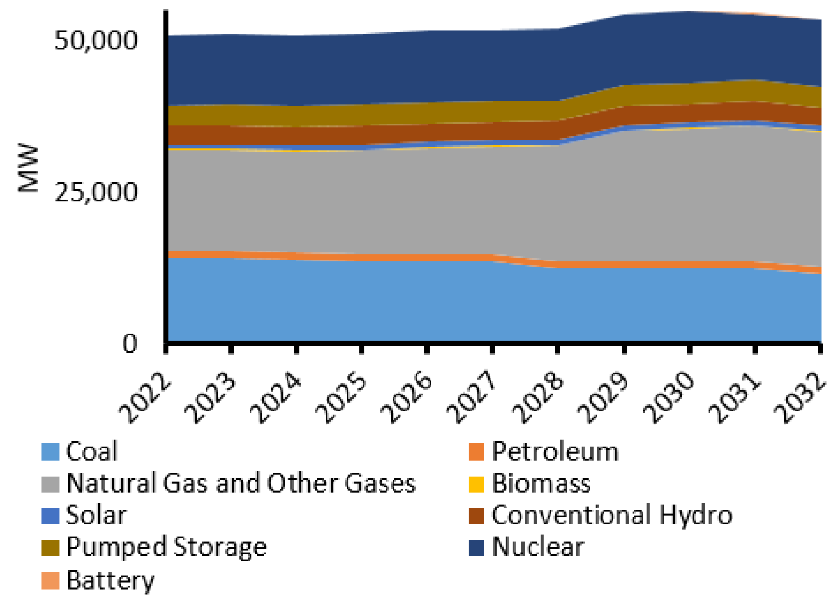
The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	44,878	44,996	45,091	45,320	45,490	45,953	46,135	46,706	47,164	47,636
Demand Response	1,130	1,131	1,136	1,141	1,142	1,143	1,144	1,145	1,146	1,147
Net Internal Demand	43,748	43,865	43,955	44,179	44,348	44,810	44,991	45,561	46,018	46,489
Additions: Tier 1	643	1,045	1,502	1,959	3,330	5,924	6,381	6,838	6,838	7,752
Additions: Tier 2	0	298	303	310	320	329	338	347	356	361
Additions: Tier 3	102	234	3,198	5,525	5,573	6,495	6,505	6,538	6,610	6,639
Net Firm Capacity Transfers	513	513	513	513	513	513	513	513	513	513
Existing-Certain and Net Firm Transfers	53,995	53,751	53,584	53,584	53,352	52,202	52,202	52,202	51,430	50,377
Anticipated Reserve Margin (%)	24.9%	24.9%	25.3%	25.7%	27.8%	29.7%	30.2%	29.6%	26.6%	25.0%
Prospective Reserve Margin (%)	24.9%	25.6%	26.0%	25.2%	27.3%	29.2%	29.8%	29.2%	26.2%	24.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Table contains summer data. Although SERC-East forecasts higher peak demand in some years during winter, the winter resource capacity and reserve margins are also higher.



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

SERC-East

SERC-East Fuel Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Coal	14,124	13,865	13,703	13,703	13,703	12,573	12,573	12,573	12,573	11,526
Petroleum	1,174	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141	1,141
Natural Gas	16,726	16,726	17,091	17,510	17,805	19,062	21,470	21,889	22,308	22,308
Biomass	158	158	158	158	158	158	158	158	158	158
Solar	793	848	848	848	848	848	848	848	848	848
Conventional Hydro	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104
Pumped Storage	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Nuclear	11,774	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,030	11,030
Battery	11	11	11	11	11	11	11	11	11	11
Total MW	51,227	51,038	51,241	51,660	51,903	52,030	54,438	54,857	54,536	53,489

SCHEDULE MM-S2

SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter.

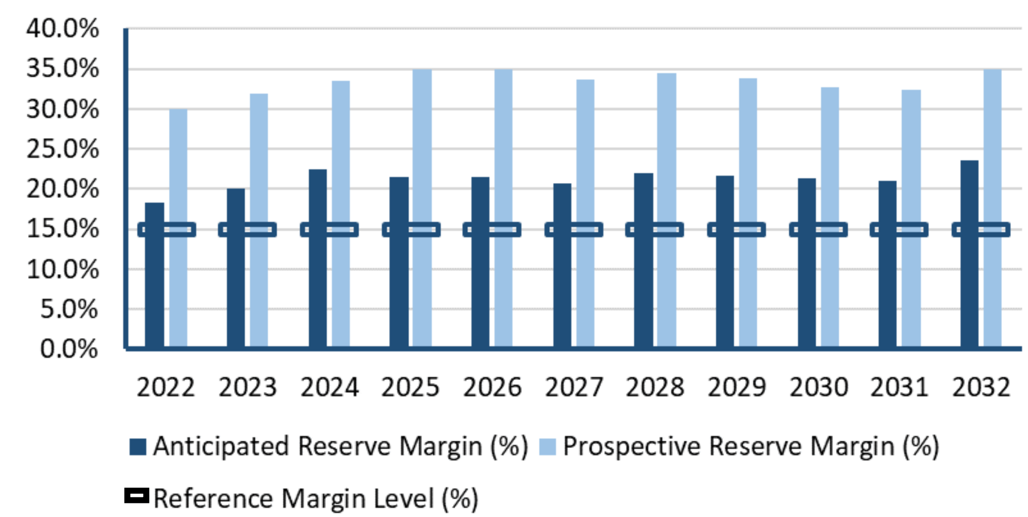
SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

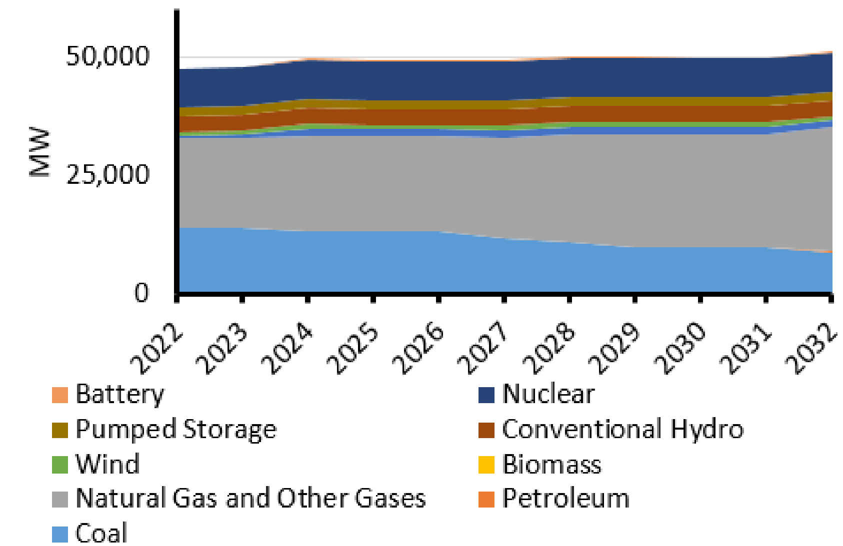
Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	41,343	41,791	41,787	41,794	41,825	41,978	42,052	42,145	42,235	42,452
Demand Response	1,786	1,751	1,754	1,758	1,762	1,761	1,759	1,758	1,757	1,756
Net Internal Demand	39,557	40,040	40,033	40,036	40,063	40,217	40,293	40,387	40,478	40,696
Additions: Tier 1	446	2,690	3,304	3,304	4,757	6,210	7,306	7,306	7,306	9,604
Additions: Tier 2	90	244	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310
Additions: Tier 3	50	100	930	1,640	2,505	3,215	3,925	4,111	4,297	4,755
Net Firm Capacity Transfers	-491	-491	-691	-691	-866	-866	-866	-866	-866	-866
Existing-Certain and Net Firm Transfers	47,063	46,323	45,323	45,323	43,568	42,840	41,710	41,680	41,680	40,712
Anticipated Reserve Margin (%)	20.1%	22.4%	21.5%	21.5%	20.6%	22.0%	21.7%	21.3%	21.0%	23.6%
Prospective Reserve Margin (%)	31.9%	33.5%	34.9%	34.9%	33.6%	34.5%	33.9%	32.7%	32.4%	34.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Table contains summer data. Although SERC-Central forecasts higher peak demand in some years during winter, the winter resource capacity and reserve margins are also higher.



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

SERC-Central

SERC-Central Fuel Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Coal	14,002	13,242	13,242	13,242	11,662	10,934	9,804	9,804	9,804	8,836
Petroleum	64	64	64	64	64	64	64	64	64	64
Natural Gas	18,750	20,064	19,812	19,812	21,265	22,718	23,814	23,784	23,784	26,082
Biomass	44	44	44	44	44	44	44	44	44	44
Solar	683	1,485	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530
Wind	958	958	958	958	958	958	958	958	958	958
Conventional Hydro	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413
Pumped Storage	1,755	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
Nuclear	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282
Battery	50	178	199	199	199	199	199	199	199	199
Total MW	48,000	49,504	49,318	49,318	49,191	49,916	49,882	49,852	49,852	51,182

SCHEDULE MM-S2

SERC-Southeast

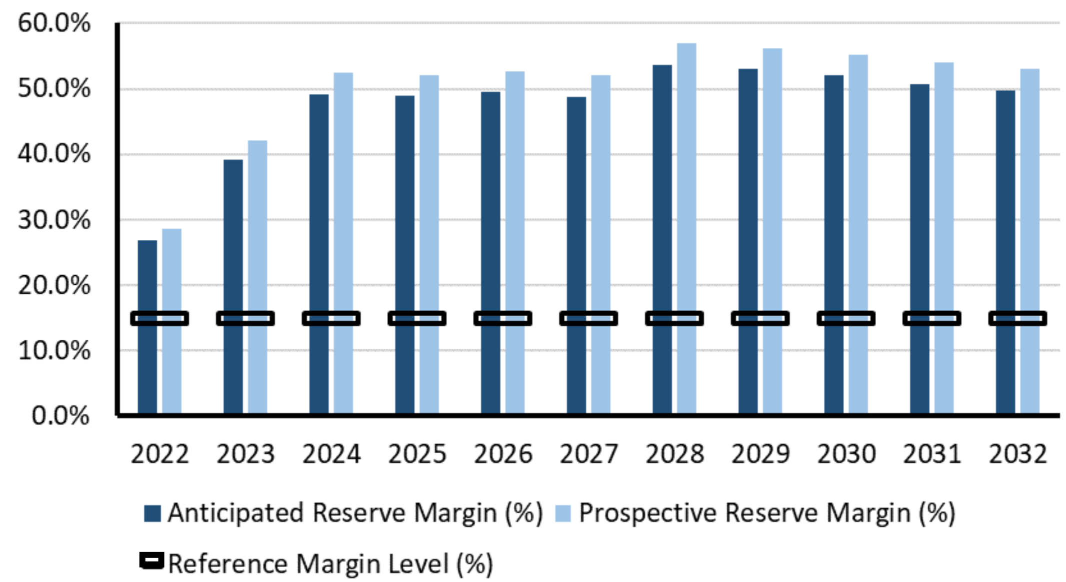
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

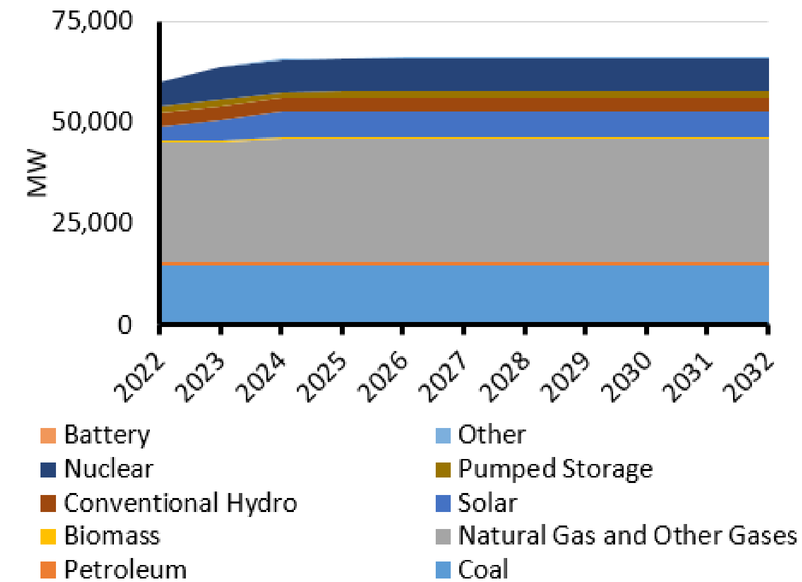
The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	46,082	45,630	45,826	45,814	46,022	44,638	44,826	44,938	45,290	45,586
Demand Response	1,197	2,118	2,129	2,223	2,222	2,222	2,213	2,090	2,091	2,091
Net Internal Demand	44,885	43,512	43,697	43,591	43,800	42,416	42,613	42,848	43,199	43,495
Additions: Tier 1	3,843	5,172	5,314	5,314	5,314	5,314	5,314	5,314	5,314	5,314
Additions: Tier 2	473	593	593	593	593	593	593	593	593	593
Additions: Tier 3	2,742	3,010	3,010	3,010	3,010	3,010	3,010	3,010	3,010	3,010
Net Firm Capacity Transfers	-1,308	-892	-871	-821	-821	-821	-820	-862	-866	-866
Existing-Certain and Net Firm Transfers	58,618	59,738	59,759	59,868	59,868	59,868	59,869	59,827	59,823	59,823
Anticipated Reserve Margin (%)	39.2%	49.2%	48.9%	49.5%	48.8%	53.7%	53.0%	52.0%	50.8%	49.8%
Prospective Reserve Margin (%)	42.0%	52.4%	52.1%	52.7%	52.0%	57.0%	56.2%	55.3%	54.0%	53.0%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

SERC-Southeast

SERC-Southeast Fuel Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Coal	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642
Petroleum	929	929	929	929	929	929	929	929	929	929
Natural Gas	29,572	30,276	30,276	30,335	30,335	30,335	30,335	30,335	30,335	30,335
Biomass	449	449	449	449	449	449	449	449	449	449
Solar	4,925	6,254	6,395	6,395	6,395	6,395	6,395	6,395	6,395	6,395
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	6,918	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	313	313	313	313	313	313	313	313	313	313
Battery	2	2	2	2	2	2	2	2	2	2
Total MW	63,769	65,802	65,943	66,002	66,002	66,002	66,002	66,002	66,002	66,002

SCHEDULE MM-S2

SERC-Florida Peninsula

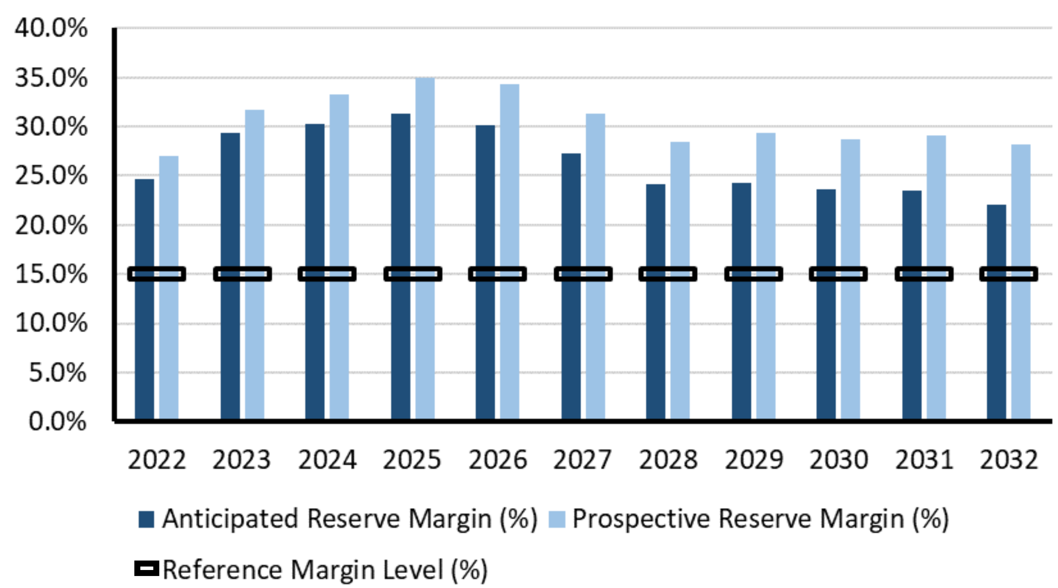
SERC-Florida Peninsula is a summer-peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

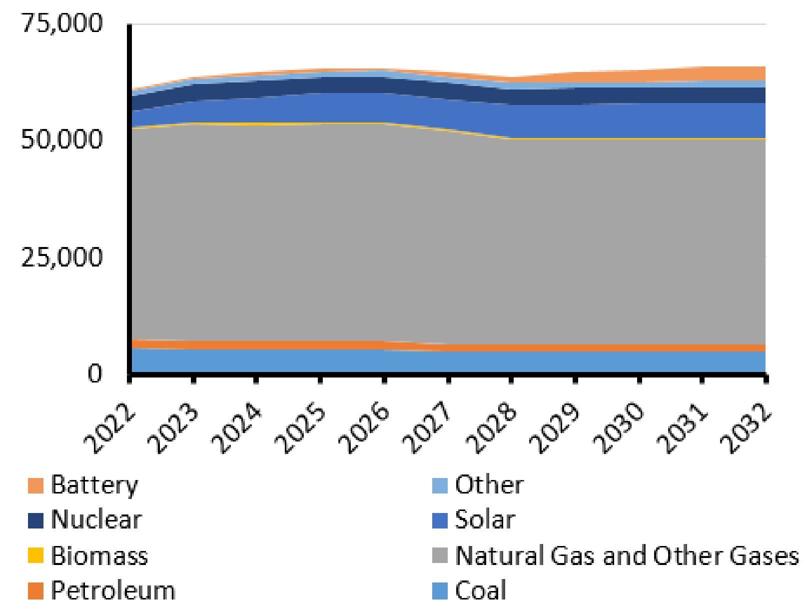
The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	52,427	52,857	53,140	53,654	54,128	54,605	55,322	56,010	56,600	57,313
Demand Response	2,949	2,965	2,990	3,024	3,064	3,107	3,154	3,197	3,205	3,214
Net Internal Demand	49,478	49,892	50,150	50,630	51,064	51,498	52,168	52,813	53,395	54,099
Additions: Tier 1	4,295	5,528	6,126	6,512	7,060	7,694	8,613	9,084	9,739	9,781
Additions: Tier 2	0	374	674	973	973	1,123	1,487	1,562	1,851	2,226
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	303	406	406	306	306	306	306	306	306	306
Existing-Certain and Net Firm Transfers	59,704	59,446	59,727	59,376	57,916	56,222	56,222	56,222	56,222	56,222
Anticipated Reserve Margin (%)	29.3%	30.2%	31.3%	30.1%	27.2%	24.1%	24.3%	23.7%	23.5%	22.0%
Prospective Reserve Margin (%)	31.7%	33.3%	34.9%	34.3%	31.4%	28.5%	29.3%	28.8%	29.1%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

SERC-Florida Peninsula Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	5,184	5,184	5,184	5,184	4,725	4,725	4,725	4,725	4,725	4,725
Petroleum	2,017	2,017	2,017	1,846	1,718	1,718	1,718	1,718	1,718	1,718
Natural Gas	46,322	46,085	46,440	46,342	45,503	43,846	43,846	43,846	43,846	43,846
Biomass	491	487	449	449	414	414	414	414	414	414
Solar	4,407	5,419	5,981	6,367	6,564	6,801	7,033	7,133	7,238	7,279
Nuclear	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502
Other	1,255	1,255	1,255	1,274	1,274	1,274	1,274	1,274	1,274	1,274
Battery	519	619	619	619	969	1,329	2,016	2,388	2,938	2,938
Total MW	63,696	64,568	65,447	65,582	64,670	63,610	64,529	65,000	65,655	65,697

SCHEDULE MM-S2

SERC Assessment

Highlights

- This narrative summary/highlight does not include parts of PJM and MISO areas that are within SERC boundaries.
- All SERC assessment areas are projected to maintain sufficient capacity to meet the reliability planning reserve margin during this assessment time frame.
- The load within three SERC assessment areas is projected to peak in winter.
- The SERC assessment areas continue to see growth in natural-gas-fired generation. Natural-gas-fired generation capacity is projected to make up over 50% of the generating capacity, approximately 118,621 MW by 2031.

Planning Reserve Margins
ARMs are at or above 20% in all assessment areas and do not fall below the NERC 15% target reference margin at any point during this assessment period.

The SERC Resource Adequacy Working Group is beginning to explore developing a SERC subregional reliability reference margin to determine resource adequacy with the changes to the resource mix and the growth of IBRs. In this *2022 LTRA*, SERC continues to use the default target reference margin of 15% .

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
SERC is made up of many members that perform their own internal studies and participate in studies under the direction of the SERC Engineering Committee. Some entities have performed studies to evaluate the fuel resiliency of all generating assets in their portfolio, including fuel supply, fuel delivery, inventory, and backup contingencies to determine the potential impact fuel diversity has on the Planning Reserve Margin. These studies suggest that SERC's overall fuel supply position is among the most resilient in the United States due to a well diverse generation portfolio, advantageous location with respect to major natural gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel.

Reserve margin studies performed by SERC members consider a wide range of peaking conditions, including extreme weather conditions and historical water conditions. Low water conditions impact plant cooling and can have an associated reduction in plant output. This impact is modeled in reserve margin studies by increasing equivalent forced outage rates of affected plants and can lead to the identification of additional supply shortfall risk. VERs are assigned monthly net dependable capacities based on reviews of historical performance and/or historical irradiance in the geographic area.

Probabilistic Assessment
The 2022 ProbA indicates slightly tighter reserve margin results for year 2024 as compared to the 2020 ProbA. Probabilistic annual indices indicate a small loss of load risk during the morning hours of winter peak as solar resources continue to increase.

SERC-East is transitioning from a summer-peaking area to a winter peaking one. This change in peaking is mainly driven by two factors: continued electrification as well as growing solar resources that shave off the summer peak. Probabilistic Base Case results indicate a trend of growing risk during winter morning hours when solar resource capacity is low. The results for year 2026 indicate that the reliability metrics during January morning hours degrade as solar resources grow. As SERC-East transitions to peaking in winter, the growth in solar capacity projected for 2026 helps reduce loss of load risk during summer hours.

SERC East Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	5.26	64.33	92.49
EUE (ppm)	0.024	0.272	0.389
LOLH (Hours per Year)	0.01	0.06	0.081
Operable On-peak Margin	15.9%	15.0%	16.1%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 25–30% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 24.9% and 25.7% respectively, resulting in negligible LOLH and EUE.

SERC Central Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	18.4%	18.6%	17.1%

SCHEDULE MM-S2

Anticipated Reserve Margins are in the 20–24% range over the 10-year period and are above the 15% reference margin if 2024 and 2026, 22.4% and 21.5% respectively, resulting in negligible LOLH and EUE.

SERC Florida Peninsula Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2.26	1.09	1.13
EUE (ppm)	0.009	0.004	0.004
LOLH (Hours per Year)	0.004	0.002	0.002
Operable On-peak Margin	11.4%	18.3%	18.6%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 22–31% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 30.2% and 30.1% respectively, resulting in negligible LOLH and EUE.

SERC Southeast Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.03	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	30.2%	26.8%	30.8%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 39–54% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 49.2% and 49.5% respectively, resulting in negligible LOLH and EUE.

SERC will focus on extreme weather as a risk and is looking to assess the impact of severe cold weather on their system. SERC plans to pick a specific case of cold weather, assume outage rates on their resource mix, and then look at differing load levels for the given cold weather case. Recent reports have identified the need to quantify cold weather across SERC as some of the SERC subregions were impacted in the recent cold weather events.

Demand

Methods to develop total internal demand projections vary amongst the entities in each assessment area. Utilities constantly monitor load projections, weather patterns, economic patterns, emerging technology (like EVs), and customer growth to determine forecast models and other factors. The assessment areas also use statistical models to calculate naturally occurring trends. The following text provides an overview of forecasting methodologies within each assessment area.

Projected demand growth within the assessment areas is relatively flat, about 0.7% over the years. SERC-Florida Peninsula has the highest growth rate of about 1% while SERC-Southeast is forecasting a growth rate of -0.2%. Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to BTM distributed generation and appliance standards. These factors will continue suppressing load in the future.

Demand Side Management

Entities within the SERC Region use a variety of controllable and dispatchable DR programs to reduce peak demand. Larger commercial and industrial customers may participate in incentive programs to reduce exposure to high power prices. The electrical load of these customers is often referred to as interruptible load. Generally, DR programs require a minimum lead-time to implement and may or may not have a limited number of implementations in order to mitigate reliability impacts on the BES.

Entities may also directly control residential switches and devices (referred to as direct control load management) to reduce peak demand dispatched for up to a certain amount of hours annually. Dispatchable Voltage Regulation programs that reduce peak demand by optimizing distribution-level voltage are another tool at entities' disposal.

These programs historically mitigate local reliability issues; however, recent pilot programs in SERC aggregate multiple states' DR programs to provide subregional DR similar to the Interruptible Load programs dispatched up to a certain amount of times annually to mitigate high power prices and with unlimited implementation for reliability events.

The capacity available on peak of these types of programs depends on contractual obligations and historical performance derates, which are largely weather dependent. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

SCHEDULE MM-S2

Distributed Energy Resources

Entities continue to monitor DER penetration levels, assess the impacts from DER, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the energy management system and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar.

To date, there are no notable reliability impacts reported to the Regional Entity. Development of a SERC-wide estimated penetration forecast is not available at this time for BTM. The SERC VER Working Group continues to evaluate the appropriate methods for determining growth of solar in the SERC Region.

Generation

SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (51%), coal (18%), and nuclear (13%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (18%) are minimal. Entities within SERC will add approximately 10,633 MW of natural gas generation over the period. Overall, the assessment areas will encounter 15,310 MW of net additions and retirements over within the next 10 years. Approximately 16 GW of utility-scale transmission BES-connected Tier 1 solar projects are expected in the interconnection queue over the next five years and are largely developing in SERC-East and SERC-Florida Peninsula. No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more BTM solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Energy Storage

Entities in SERC are starting to see an increase in the number of request of energy storage systems in their queues. Energy storage solutions, particularly batteries, continue to be viewed as an increasing necessity for support of grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e., solar and wind). Many energy storage sites are reported as being paired with solar generation and are discharged into the system to meet customer demand. In the next 10 years, over 3700 MW of nameplate capacity Tier 1 energy storage facilities are being projected in the SERC footprint, over 93% in SERC-Florida Peninsula and 7% in SERC-Central assessment areas.

Capacity Transfers (Reliance on Assistance)

SERC members participate in the committee and study group structure to perform First Contingency Incremental Transfer Capability studies for the Region. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.
Annually, the SERC Long-Term Working Group performs a study to evaluate transfer capability for a summer peak condition in the planning period that covers year one through year five. In addition, the SERC Near-Term Working Group performs two studies annually, prior to each upcoming seasonal peak (summer and winter). For a SERC study, SERC members apply a selection of transfers in pairs of varying magnitudes and directions non-simultaneously to a model with expected base transfers. The study's objective is to identify transmission system weaknesses, and not necessarily to evaluate whether the transfer itself could actually happen. The model is coordinated through the SERC and Multi-regional Modeling Working Group model building processes, and the model includes projections for generation dispatch, transmission system topology, system demand, and approved transmission uses. For each transfer, N-1 events for the entity and its neighbors are evaluated and monitored.

Transmission

SERC entities in the SERC assessment area are expecting more than 2,500 miles of overhead ac transmission lines throughout the assessment period (400–599 kV: over 20 miles, 300–399 kV: over 300 miles, 200–299 kV: over 600 miles, 151–199 kV: over 500 miles, 121–150 kV: over 400 miles, 100–120 kV: around 300 miles, and <100 kV: over 40 miles). These projects are in the planning/construction phase, and they are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (345/138kV, 161/500kV), upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability. However, there are some localized constraints exist under certain contingency situations in SERC-East and SERC-Central, where existing operating guides are coordinated to mitigate the potential overload and remain reliable.

Transmission and operational limitations exist near multiple generation sites in SERC-Central due to line loading and transfers on the 161 kV transmission system. To maintain reliability and mitigate around these constraints, must run units will operate during specific load levels or re-dispatching generation to reduce line loading and transfer issues.

SCHEDULE MM-S2

Reliability Issues

SERC and its members have not identified any other emerging reliability issues that do not have existing solutions. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the supply chain issues, changing resource mix, transmission projects and temporary mitigations, summer and dual peaking scenarios, extreme weather events, and critical infrastructure sector interdependency.

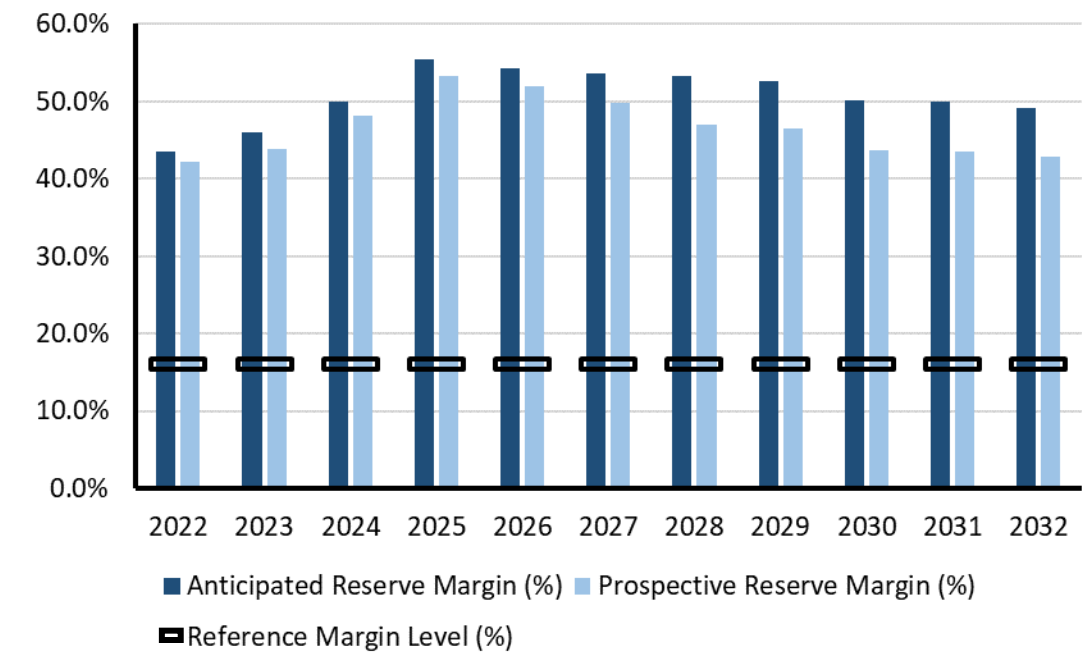
SCHEDULE MM-S2

SPP

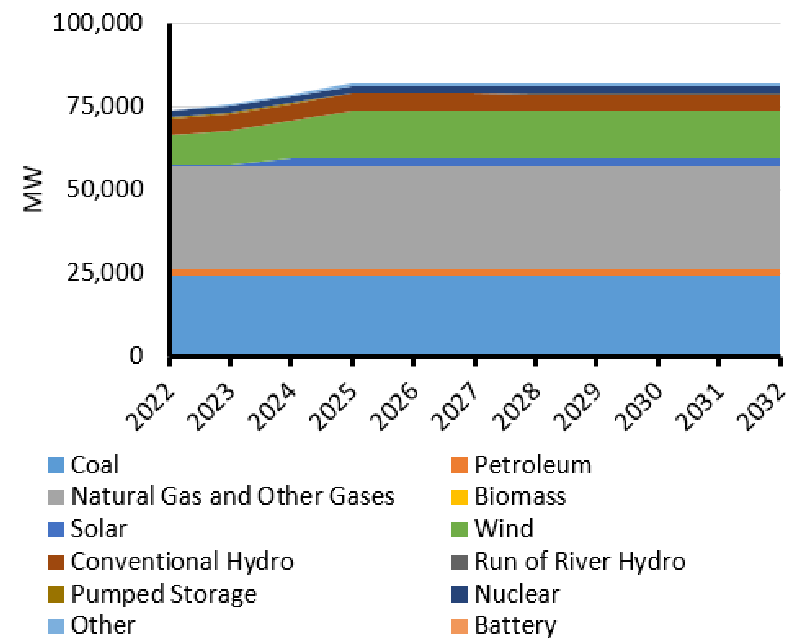
Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	52,398	52,999	53,383	53,998	54,220	54,452	54,697	55,641	55,873	56,161
Demand Response	730	776	823	901	943	990	1,029	1,040	1,254	1,263
Net Internal Demand	51,668	52,224	52,561	53,097	53,277	53,462	53,668	54,601	54,619	54,898
Additions: Tier 1	4,902	7,630	10,880	10,880	10,880	10,880	10,880	10,880	10,880	10,880
Additions: Tier 2	575	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
Additions: Tier 3	17,985	25,658	44,484	48,088	50,588	50,588	50,588	50,588	50,588	50,588
Net Firm Capacity Transfers	-238	-213	-193	-173	-231	-156	-157	-157	-157	-157
Existing-Certain and Net Firm Transfers	70,527	70,665	70,822	71,057	70,998	71,068	71,066	71,055	71,044	71,035
Anticipated Reserve Margin (%)	46.0%	49.9%	55.4%	54.3%	53.7%	53.3%	52.7%	50.1%	50.0%	49.2%
Prospective Reserve Margin (%)	44.6%	47.8%	53.1%	51.3%	49.5%	48.8%	48.2%	45.7%	45.6%	44.9%
Reference Margin Level (%)	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- ARMs do not fall below the RML for this assessment period.
- In 2022, the SPP Board approved an increase in PRMs for load responsible units from 12% to 15%. The Board also approved performance-based capacity accreditation rules for conventional resources. The two actions are aimed at ensuring sufficient resources are procured and available to meet peak demand as the resource mix evolves. Changes will go into effect in 2023.

SPP Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226
Petroleum	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849
Natural Gas	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938
Biomass	43	43	43	43	43	43	43	43	43	43
Solar	631	2,506	2,506	2,486	2,482	2,478	2,477	2,473	2,468	2,468
Wind	10,188	11,038	14,288	14,291	14,289	14,288	14,286	14,284	14,284	14,282
Conventional Hydro	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941
Run-of-River Hydro	18	18	18	18	18	18	18	18	18	18
Pumped Storage	444	444	444	444	444	444	444	444	444	444
Nuclear	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949
Other	601	661	661	661	661	661	661	661	661	661
Total MW	75,827	78,613	81,862	81,845	81,840	81,835	81,831	81,826	81,821	81,818

SCHEDULE MM-S2

SPP Assessment

Planning Reserve Margins

ARMs do not fall below the RML of 16% (SPP coincident) for the entire 10-year assessment period. The RML is determined by a probabilistic LOLE study. While the SPP PRM shows a robust amount of excess capacity, these margins do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. There is potential to still experience times of capacity shortfall based on performance impacts during high load periods despite the current projected LTRA PRM capacity. The *2022 Summer Reliability Assessment* provides an illustration of an extreme demand and low resource risk period in the SPP Seasonal Risk Scenario.[37]

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

SPP performs a biennial LOLE study to establish PRMs. SPP (with input from the stakeholders) develops the inputs and assumptions used for the LOLE study to analyze the ability to reliably serve the SPP BA area 50/50 forecasted peak demand while utilizing a security-constrained economic dispatch. SPP will study the PRM such that the LOLE for the applicable planning year (2- and 5-year studies) does not exceed 1-day-in-10 years. At a minimum, the PRM will be determined with probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure that the LOLE does not exceed 1-day-in-10 years. In the 2021 LOLE study, other than the application of projected resource retirements, a future resource mix was not applied when analyzing Year 5 (2026) to establish the minimum PRM to maintain an LOLE 1-day-in-10 years. SPP performed a future generation sensitivity based on a future resource mix from the 2022 Integrated Transmission Planning (ITP) process.

The assumptions applied for planning year 2026 are shown as follows:

- 38,000 MW nameplate wind (additional 7,444 MW from the Base Case)
- 9,000 MW nameplate solar (additional 8,762 MW from the Base Case)
  - 125% overbuild (10,952 MW nameplate with overbuild)
- 3,700 MW four-hour duration battery

To effectively model the generation portfolio for analysis, existing wind facility capabilities were increased by 24% to simulate 38,000 MW of nameplate wind generation and replicate the historical wind profiles for each weather year. Since the SPP system currently has less than 300 MW of nameplate solar resources, a different methodology was used to reflect the future growth of solar installations. Locations that were developed in the 2022 ITP Future 2, Year 5 scenario were used for the analysis, resulting in 55 new solar locations. Additional information and conclusions are outlined in the *2021 LOLE Study Report*.[38]

Probabilistic Assessment

The 2020 Probabilistic Assessment results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2022 and 2024. The 2022 Probabilistic Assessment Base Case results indicate minimal LOLH and EUE for both years 2024 and 2026. The slight increase of the EUE is due to thermal retirements, increased VER penetration, and higher forecasted demand.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.27	0.84
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	13.3%	19.7%	19.6%

* Provides the 2020 ProbA results for comparison

Demand

SPP load peaks during the summer season; the 2022 load forecast is projected to peak at 51,058 MW, which is lower than the previous year's LTRA forecast for the 2022 summer season. A diversity factor is used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. Over this assessment period, SPP projects the total internal demand growth to increase at a CAGR of 0.77% for summer and 0.91% for winter.

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area.

[37] See NERC's 2022 Summer Reliability Assessment, page 28: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf

[38] https://www.spp.org/Documents/67465/2021%20SPP%20LOLE%20Study%20Report.pdf

SCHEDULE MM-S2

Demand Side Management

As an additional sensitivity to the 2021 LOLE study, SPP modeled high level constraints applied to the current DR programs to understand the possible reliability impacts when constraining the programs to a limited number of calls per year and limited number of hours per day. The parameters were applied to each DR program, resulting in a PRM increase of approximately 0.5%. With the footprint's projected DR growth over the next few years, it will be important to model these programs accurately to better depict the reliability implications for the SPP system. The potential growth expansion in the DR and electrification will introduce a new level of uncertainty and reliability risk.

Distributed Energy Resources

The SPP assessment area has less than 50 MW of installed BTM solar currently, but it is forecasting between 700–750 MW of DERs in the 5–10-year planning horizon. The SPP Model Development, Economic Studies, and the Supply Adequacy working groups develop policies and procedures around DERs.

Generation

Since the *2021 LTRA*, SPP members have reported approximately 300 MW of conventional resources being retired. Reliability impacts of generator retirements are assessed throughout the planning process, and no impacts from these confirmed retirements are anticipated. Additionally, the impact of confirmed retirements on resource adequacy was analyzed in the 2021 LOLE study, and the impacts that retired generation have on the transmission system are analyzed in the annual ITP.

Energy Storage

There are approximately 17,000 MW of energy storage and hybrid resources in generator interconnection queue with 500 MW of that generation under contract by members across the SPP assessment area. These resources are being modeled as generation in the planning assumptions both near- and long-term.

Starting with the 2023 summer season, the ELCC methodology will be implemented for standalone energy storage resources. This will be the first set of policies for accreditation implemented by SPP for energy storage resources. By applying ELCC methodology, energy storage resources will be more properly accredited, which becomes critical as more conventional generators near retirement and cause SPP historical planning reserve margin levels to decline.

Capacity Transfers (Reliance on Assistance)

Planning entities in the SPP assessment area coordinate with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis, during the model build season, SPP staff coordinates the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

In April 2019, SPP and ERCOT executed a coordination plan that superseded the prior coordination agreement. The coordination plan addressed operational issues for the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff.

Transmission

The SPP 2021 ITP Assessment and the 2022 SPP Transmission Expansion Plan Report are both posted on the SPP website. Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. SPP currently has no transmission under construction and 58 miles of planned transmission lines during this 10-year assessment period.

Reliability Issues

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. A lack of water can impact the generator's capacity output and reduce its ability to serve load or ease congestion on the system. An additional concern could be the impact on coal availability that might cause units to run at a derated level to conserve supplies. These extreme conditions are studied in SPP's seasonal assessment process to identify mitigations prior to peak conditions. Additional analysis is performed with updated information as part of operations planning.

SCHEDULE MM-S2

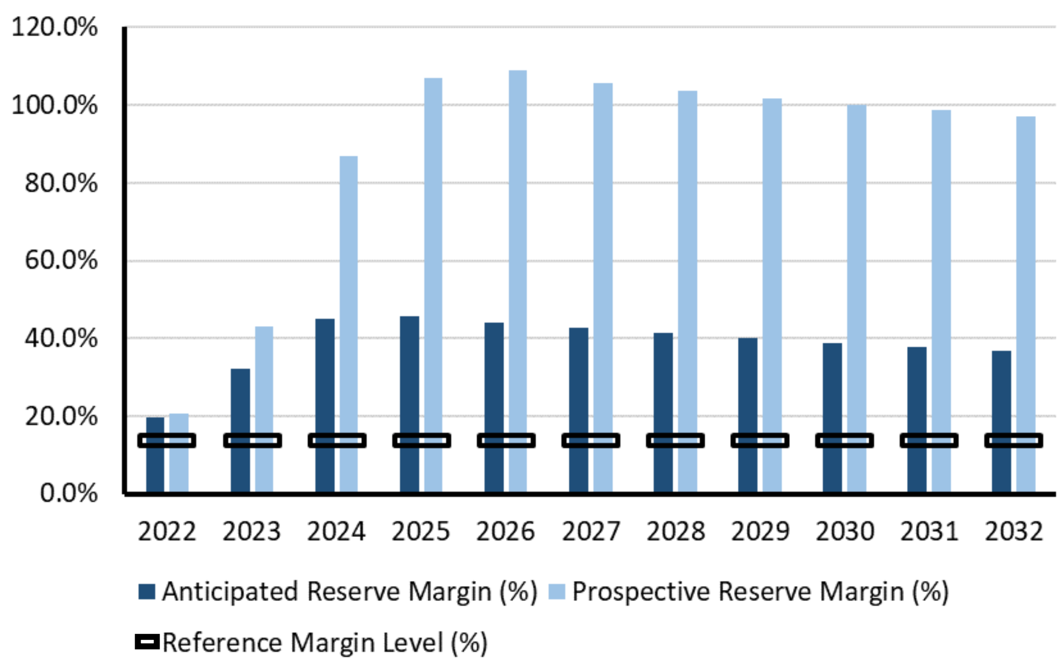
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

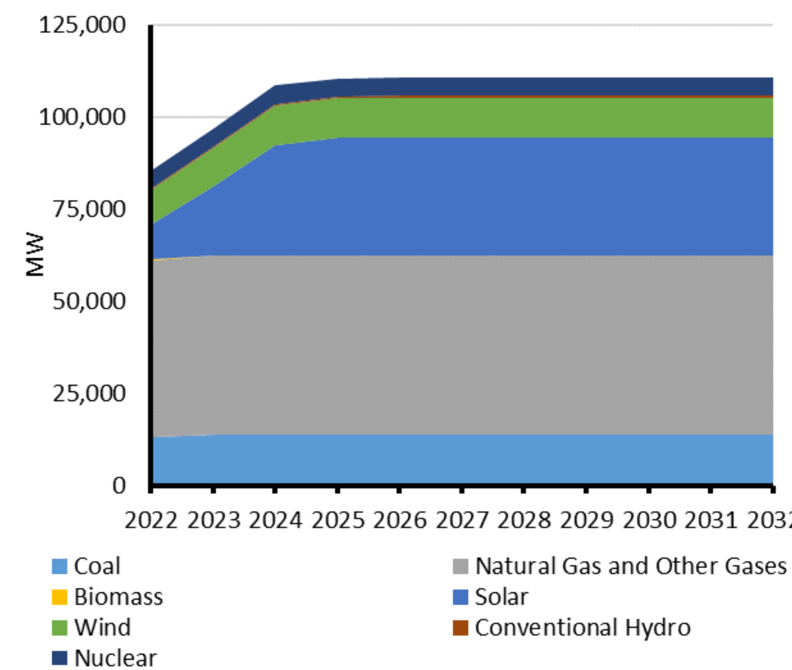
ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,030 generation units, and serves more than 26 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	79,329	80,554	81,581	82,606	83,398	84,146	84,878	85,569	86,233	86,863
Demand Response	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750
Net Internal Demand	76,579	77,804	78,832	79,856	80,648	81,396	82,128	82,820	83,483	84,114
Additions: Tier 1	10,730	22,307	24,323	24,485	24,485	24,485	24,485	24,485	24,485	24,485
Additions: Tier 2	7,703	31,833	48,480	52,081	52,081	52,081	52,081	52,081	52,081	52,081
Additions: Tier 3	1,348	11,760	17,779	21,499	22,520	23,191	23,191	23,191	23,191	23,191
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	90,559	90,559	90,559	90,559	90,554	90,554	90,554	90,554	90,554	90,554
Anticipated Reserve Margin (%)	32.3%	45.1%	45.7%	44.1%	42.6%	41.3%	40.1%	38.9%	37.8%	36.8%
Prospective Reserve Margin (%)	43.1%	86.7%	106.9%	108.9%	104.2%	102.3%	100.5%	98.8%	97.2%	95.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- Texas RE-ERCOT's ARM is above the RML (13.75%) throughout this assessment period. The ARM continues on its increasing trend of recent prior years with the expected addition of nearly 25,000 MW of new capacity, most of which is solar generation.
- The continuing penetration of wind and solar is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season, but the spring can also be impacted since it is the peak unit maintenance season when planned outages are at their highest for the year.
- In addition to transmission and generator weatherization requirements in Texas, energy adequacy concerns that result from the impacts of severe winter storms have been addressed by the Public Utility Commission of Texas (PUCT), ERCOT, and market participants with market design changes for improving price signals, expanding ancillary service products (e.g., firm fuel supply service) as well as other operational reliability initiatives, such as improved reliability unit commitment and load resource deployment. Proposals for additional improvements are currently being considered.
- The Railroad Commission of Texas has adopted a weatherization rule for natural gas facilities (e.g., natural gas processing plants, natural gas pipelines directly serving electricity generators) to contribute to the reduction of power outages that occur during weather emergencies.

Texas RE-ERCOT Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	48,843	48,854	48,854	48,854	48,854	48,854	48,854	48,854	48,854	48,854
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	18,786	29,766	31,703	31,865	31,865	31,865	31,865	31,865	31,865	31,865
Wind	10,199	10,784	10,864	10,864	10,864	10,864	10,864	10,864	10,864	10,864
Conventional Hydro	475	475	475	475	475	475	475	475	475	475
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	97,007	108,584	110,600	110,762	110,762	110,762	110,762	110,762	110,762	110,762

SCHEDULE MM-S2

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2023–2032). The ARM increases significantly for the summers of 2023 and 2024 due to the expected addition of 22,306 MW of summer Tier 1 capacity, most of which is solar. Nevertheless, there are energy adequacy concerns due to the net load impacts of high solar capacity growth as well as extreme winter and summer weather events that have impacts on generator availability that can extend into the subsequent spring and fall seasons.

To address these energy adequacy concerns, the PUCT opened a rulemaking docket to reform the ERCOT wholesale market (Docket No. 52373); an initial outcome is the Commission's Wholesale Market Design Blueprint.[39] For Phase I of the Blueprint, the PUCT worked with ERCOT and market participants to institute short-term market design changes for improving price signals, improving and expanding ancillary service products (e.g., firm fuel supply service), and enhancing operational reliability through improved reliability unit commitment and load resource deployment among other initiatives. The Commission is now considering proposals for implementing long-term market structure changes (Phase 2). The proposals include a load-side reliability mechanism, a dispatchable energy credit program, a backstop reliability service, and/or a hybrid model that consists of various combinations of these proposals. A consulting company was hired to evaluate the market design proposals.

As part of the docket, the PUCT is also determining what aspects of resource adequacy assessment should be enshrined in the PUCT rules instead of being placed under the purview of ERCOT and market participants. At the Commission's June sixteenth open meeting, the commissioners agreed that establishing multiple metrics and associated standards appropriate for gauging success to meet system reliability needs is important as is increasing the frequency of resource adequacy reporting. These elements will be addressed as part of the Phase 2 rule-making proceedings. The PUCT further instructed ERCOT to continue collaborating with the Commission and market participants on other resource adequacy assessment reform efforts.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

The continuing penetration of solar in the Texas RE-ERCOT area is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season when solar generation ramps down during the early evening hours while load is still relatively high. ERCOT developed a probabilistic Operating Reserve Risk Model designed for analysis of the hours with the highest risk of reserve shortages. The model simulates 10,000 reserve outcomes for a day during the summer and winter peak demand months. The models report the probability that ERCOT will need to declare energy emergency alerts (EEA) for those highest-risk hours based on reserve capacity reaching various EEA risk thresholds, including the point where firm load shed is required. For example, the summer of 2022 model indicates a progression of increasing hourly EEA risk probabilities from the early afternoon through the early evening hours with the peak EEA probability occurring for hour-ending 7:00 p.m. (see **Figure 23**).

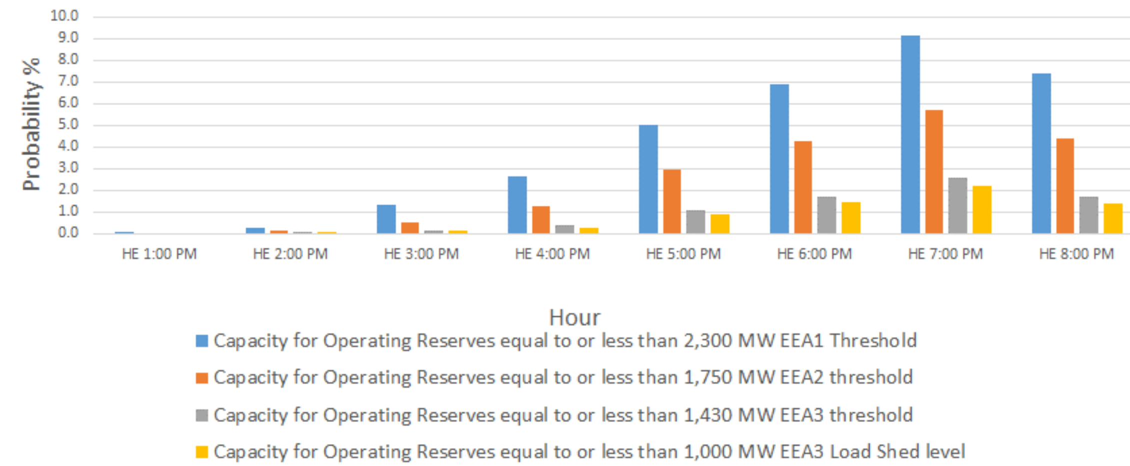


Figure 23: Likelihood of Energy Emergency Alerts in Summer [Source: ERCOT]

Probabilistic Assessment

The Base Case study shows much more risk than what was indicated in the 2020 ProbA Study. Essentially all of the risk is in the winter, largely driven by the incorporation of additional forced outage risk. While the projected reserve margin for 2024 is much higher than what was projected in the 2020 ProbA Study, the additional reserves are from solar, which does not provide significant winter reliability value. The high level of reliability modeled in the summer is contingent on the projected construction of over 20 GW above current levels.

[39] http://interchange.puc.texas.gov/Documents/52373_372_1210865.PDF

SCHEDULE MM-S2

Base Case Summary of Study Year Results			
	2024*	2024	2026
EUE (MWh)	12.86	492.03	1,235.40
EUE (ppm)	0.03	1.09	2.63
LOLH (Hours per Year)	0.01	0.15	0.30
Operable On-peak Margin	10.2%	36.7%	35.9%

* Provides the 2020 ProbA results for comparison

For the ProbA risk scenario study to be concluded in 2023, ERCOT is assessing the impact of transmission limits on reliability indices for the 2026 study year. The scenario focuses on the ability for IBRs concentrated in the western part of the state to serve load in the central and eastern side of the state using the transmission network. It is desirable to include transmission limits in the reliability assessment in order to reflect the dependence of IBRs on transmission to deliver to load.

Demand

ERCOT's summer peak demand is forecasted to increase by 1.2% per year from 2022–2032. This rate is the same as for the forecast used in the *2021 LTRA*. Annual energy is forecasted to increase by 1.9% per year for the same period. Summer peak demand in the far west area (which encompasses the metropolitan area of Odessa and Midland) is forecasted to grow by 4.0% per year for 2022–2032. The growth rate was 3.1% as forecasted for the *2021 LTRA*. The primary driver of this incremental growth is the future addition of cryptocurrency-based business in this part of the state. Demand growth from oil and natural gas production activities is not a material driver for the increased growth rate in the far west area.

An emerging load forecasting issue is large loads associated with interruptible computer operations—principally crypto miners. Developing a forecast of these large flexible loads is a challenge due to different metering/telemetry configurations; specifically, whether they are standalone or co-located (i.e., behind the meter) at generation sites.

Currently there are no adjustments for EVs or battery storage devices in the ERCOT long-term forecast used for the LTRA. ERCOT is in the early stages of working with a vendor to create an EV forecast.

An outcome of Winter Storm Uri in February 2021 was an increased emphasis on energy conservation/energy reduction initiatives. The impact that these initiatives may have on the load forecast is unknown at this time.

Demand Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of non-controllable load resources providing responsive reserve service and deployable emergency resources, referred in this section as ERCOT Emergency Response Service (ERS) or ERCOT ERS. Responsive reserves make up an ancillary service for controlling system frequency. These reserves are provided by industrial loads and are procured on an hourly basis in the day-ahead market. Reserves are dispatched by automatic tripping based on under frequency relay settings (59.7 Hz) or manual dispatch instruction within 10 minutes. ERCOT ERS consists of 10-minute and 30-minute ramp DRs and DERs that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spinning reserves.

ERCOT ERS is procured for 4-month periods during the year. ERCOT initiates the notification to reduce load; this is sent to the designated qualified scheduling entity (QSE) managing the load resources in the program, and then it is forwarded by the QSE to the load resource obligated to reduce its load. ERCOT ERS loads must meet qualification criteria and undergo a load curtailment test once every 365 days. Winter Storm Uri triggered multiple rounds of programmatic reforms. For example, the Commission recently proposed increasing the ERCOT ERS program budget from $50 to $75 million as well as allowing ERCOT the flexibility to contract ERCOT ERS for up to 24 hours in a contract term rather than four hours as currently specified in the PUCT rules.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service provider's (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial and industrial as well as (and most recently) residential loads during EEA events. These programs are available for the months of June through September from 1:00–7:00 p.m. weekdays (except holidays), and they are deployed concurrently with ERCOT ERS via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. The TDSP load management programs were also provided as pilots for most of the 2021/2022 winter season (Mid-December 2021 through February 2022).

On the horizon is potential treatment of crypto miners and other similar loads as controllable load resources that can be deployed to maintain grid reliability when needed. The PUCT, ERCOT, and market participants are working on resolving various policy, market, operational and planning issues associated with interconnecting these loads and potentially using them as reliability resources.

SCHEDULE MM-S2

Distributed Energy Resources

ERCOT's formal definition of distributed generation is as follows: An electrical generating facility located at a customer's point of delivery (point of common coupling) 10 MW or less and connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system. Distributed generators (DG) include energy storage resources as well. Over the last few years, ERCOT has instituted a new generation resource taxonomy. DGs are now distinguished by whether they are transmission or distribution-connected, whether they fully participate in the ERCOT market or just get paid for exported energy (settlement-only generators), and whether they are registered or not registered with ERCOT.

DGs that register with ERCOT are modelled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

Generation

Solar capacity continues to be rapidly added to Texas RE-ERCOT, and ERCOT is seeing a greater magnitude of five-minute solar ramps as a result. In addition to instituting an intra-hour solar forecast in 2021, ERCOT is in the process of implementing a new ancillary service called ERCOT Contingency Reserve Service (ECRS). As the wind and solar generation fleet continues to grow, ECRS will give the ERCOT control room the capability of deploying resources that can respond within 10 minutes in anticipation of net demand ramps. ERCOT is currently targeting to implement this service by mid-2023.

Also, in early 2022, ERCOT made methodology changes it its non-spinning reserve service, which is used to address large net load ramps among other uses. For example, the definition of the net load uncertainty is now the difference between the highest five-minute net load within the hour and the forecasted net load. Previously, the uncertainty was defined as the difference between the hourly net load and the forecasted net load. Another change was to switch from using the four-hours-ahead net load forecast to the six-hours-ahead net load forecast.

ERCOT completed its *South Texas Stability Assessment*, which evaluated the stability-related needs for the Lower Rio Grande Valley (LRGV) area, which is subject to both import constraints under peak load conditions and export constraints under high IBR output conditions. The outcome of the study was the LRGV System Enhancement Project, consisting of system improvements to improve stability constraints, sub-synchronous resonance vulnerability, operational flexibility, future load and generation integration, and grid resiliency considering hurricane risk. The project was endorsed by the ERCOT Board of Directors in December 2021.

ERCOT also completed its *Long-Term West Texas Export Special Study* in January 2022. The purpose of the study was to evaluate potential transmission improvements to increase transfer capability from renewable-rich areas in West Texas to urban demand centers further east. Transfers from West Texas are currently limited by both voltage and dynamic stability constraints as well as thermal constraints closer to demand centers. ERCOT presented two alternative short-listed options lists based on a 2030 study case. One of the lists included a HVDC line to move power to the Houston area. ERCOT will continue to evaluate system improvement options that consider emerging trends in generation capacity development and demand growth.

ERCOT considers natural gas limitations for natural-gas-fired generators in its Regional Transmission Plan through the inclusion of extreme events that represent the loss of multiple natural-gas generators following the loss of any single gas pipeline. These events are identified by evaluating the natural-gas-pipeline network topology and survey responses from natural gas generators.

The Texas regulators and ERCOT have enacted several mitigation strategies to address natural gas curtailment risks. For example, pursuant to PUCT guidance, ERCOT developed a Nodal Protocol Revision Request (NPRR) to create a firm fuel supply service. This service is intended to help maintain system reliability in the event of a natural gas curtailment or other fuel supply disruption. As another example, ERCOT's Black Start Working Group reviewed black start resource availability during Winter Storm Uri, and they subsequently developed an NPRR to require black start units to have on-site fuel specifically reserved for black start operations. The NPRR is waiting for approval by the ERCOT Board and PUCT. In 2021, the Texas Legislature passed Senate Bill 3, which, among other things, created the Texas Electricity Supply Chain Security and Mapping Committee. This committee recently completed a map of Texas' state electricity supply chain with critical infrastructure identified, including natural gas facilities. This map can be used in future assessments to ensure reliability of the grid, especially under extreme weather conditions. Finally, the PUCT opened a docket on electric-gas coordination to address natural gas supply and infrastructure issues.

Energy Storage

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 7,400 MW of battery energy storage capacity to be operational in the Texas RE-ERCOT area within the next five years. This capacity represents projects with signed interconnection agreements and proof of financial commitments to build the interconnecting transmission facilities.

SCHEDULE MM-S2

The majority of the installed energy storage projects have limited duration energy capability. ERCOT uses a generator with a negative minimum power to represent withdrawal and a generator with a positive maximum power to represent injection when modeling energy storage resources in transmission planning studies. That said, ERCOT is moving to a single “combination” generator within a few years once system changes have been put into production. The discharging behavior of energy storage resources with duration of at least four hours is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources need to have the reactive power capability to be available at all MW levels when charging or discharging if they are required to provide voltage support and to meet the voltage ride-through requirements to remain connected to the system. ERCOT is currently reviewing its policies, procedures, and systems to support larger penetration levels of energy storage resources, and ERCOT expects to make changes between now and the end of 2024.

Capacity Transfers (Reliance on Assistance)

ERCOT coordinates with neighboring grids through coordination plans (last updated in May 2022) that cover dc tie emergency operations, procedures for generators that can switch between grids, and block load transfers (groups of loads that are transferred to a neighboring grid for service on a temporary basis).

Transmission

ERCOT completed its 2021 Regional Transmission Plan in December 2021.[40] The plan constitutes 67 projects with 33 projects designated as needed by 2023. There are currently 73 miles of transmission lines under construction and 238 miles of planned transmission lines during the 10-year assessment period. Many of the Regional Transmission Plan projects were identified as preferred projects in the ERCOT Permian Basin Load Interconnection Study and Delaware Basin Load Integration Study. Most of the planned improvements identified in the 2021 Regional Transmission Plan are 138 kV and 345 kV upgrades. The projects identified as 345 kV upgrades consist of new substations, line additions, line upgrades, new 345/138 kV transformers, 345/138 kV transformer upgrades, and reactor additions.

The recently updated ERCOT Transmission Project and Information Tracking list (February 2022) includes the addition or upgrade of 3,634 circuit miles of 138 kV and 345 kV transmission circuits and 12,174 MVA of 345/138 kV transformer capacity that are planned in Texas RE-ERCOT for 2022–2028.

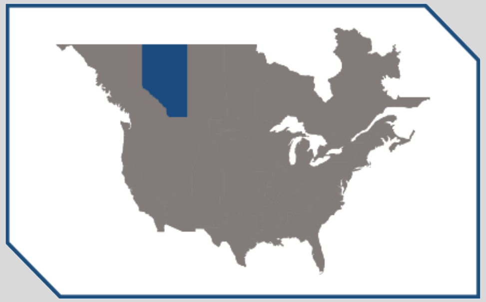
Finally, the ERCOT Board-approved LRGV System Enhancement Project, which includes an estimated 351 right-of-way miles of new 345 kV transmission lines; it is expected to be in service by 2027.

Reliability Issues

An emerging issue is that large loads associated with interruptible computer operations—principally cryptocurrency miners—are requesting accelerated interconnection of their loads to the grid. Such loads could reach up to 25,000 MW by 2026 based on current interconnection plans. ERCOT implemented an interim interconnection process in March 2022 to ensure that large loads with accelerated interconnection time lines are interconnected reliably and that NERC Reliability Standards are met. ERCOT also created a Large Flexible Load Task Force to consider a host of interconnection, operational, market, and grid planning topics. One of the key issues is the extent to which these loads can become controllable load resources that can be dispatched as needed for maintaining grid reliability.

[40] https://www.ercot.com/gridinfo/planning

SCHEDULE MM-S2



WECC-AB

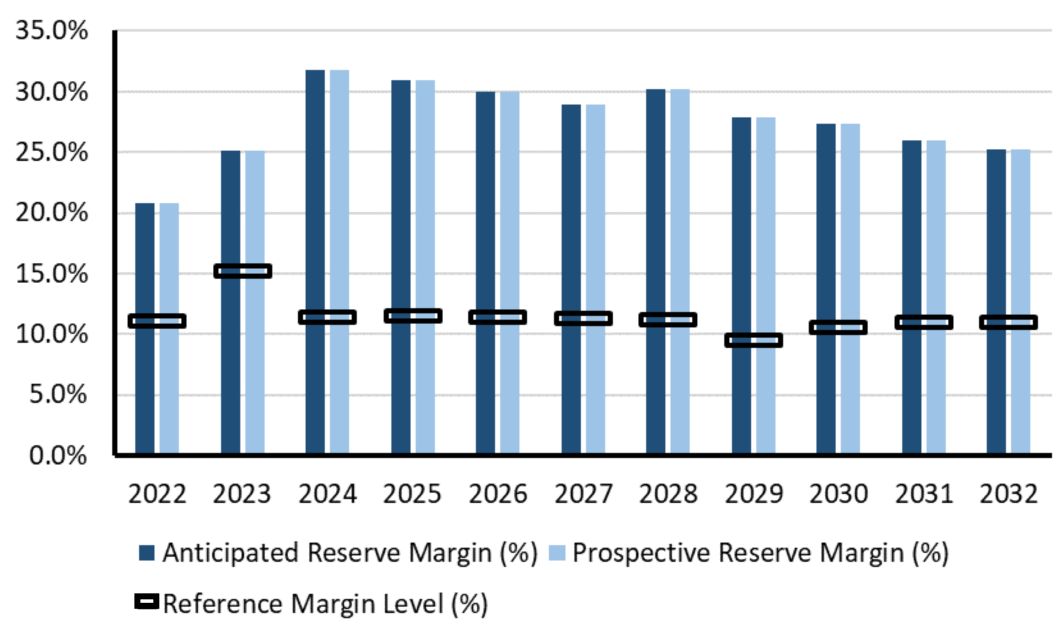
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

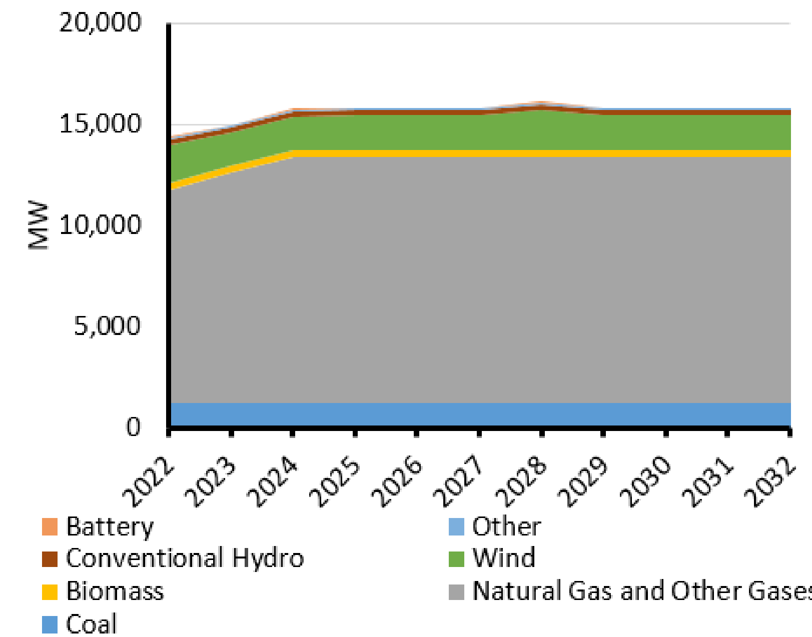
WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

WECC-AB Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	11,961	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,961	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622
Additions: Tier 1	2,044	2,830	2,852	2,852	2,852	2,962	2,852	2,852	2,852	2,852
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	968	1,846	2,216	2,532	2,648	2,701	3,241	4,033	4,103	4,103
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	12,925	12,925	12,948	12,948	12,948	13,148	12,949	12,949	12,949	12,949
Anticipated Reserve Margin (%)	25.1%	31.7%	31.0%	30.0%	28.9%	30.2%	27.8%	27.3%	25.9%	25.2%
Prospective Reserve Margin (%)	25.1%	31.7%	31.0%	30.0%	28.9%	30.2%	27.8%	27.3%	25.9%	25.2%
Reference Margin Level (%)	15.2%	11.4%	11.5%	11.4%	11.3%	11.2%	9.5%	10.6%	11.0%	10.9%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- Alberta is expecting continued seasonal demand growth at a rate below the average of the other areas.
- ARMs do not fall below the RML for this assessment period.
- With the majority of Alberta's portfolio being baseload resources, natural gas resources in particular, WECC is not concerned with reliability risk from variability in demand or resources.

WECC-AB Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,235	1,235	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
Natural Gas	11,354	12,141	12,147	12,147	12,147	12,147	12,148	12,148	12,148	12,148
Biomass	336	336	336	336	336	336	336	336	336	336
Wind	1,642	1,642	1,697	1,697	1,697	1,990	1,697	1,697	1,697	1,697
Conventional Hydro	291	291	274	274	274	291	274	274	274	274
Other	61	61	62	62	62	62	62	62	62	62
Battery	49	49	49	49	49	49	49	49	49	49
Total MW	14,969	15,755	15,799	15,799	15,799	16,110	15,801	15,801	15,801	15,801

SCHEDULE MM-S2

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML throughout the 10-year assessment period. Starting in Winter 2022/2023, Alberta shows a shortfall of reserve margins when only existing-certain and net-firm transfers are considered, meaning imports may be necessary if new wind, solar, or natural gas resources were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a loss of load probability (LOLP) less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Alberta's probabilistic assessment results continue to indicate little risk of energy or capacity shortfall. The highest risk occurs in winter months and coincides with the hour of peak demand.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0	0	0
EUE (ppm)	0	0	0
LOLH (Hours per Year)	0	0	0
Operable On-peak Margin	20.2%	22.4%	33.5%

* Provides the 2020 ProbA results for comparison

Demand

Alberta's peak demand (winter) compound annual growth rate for the 10-year period is 0.6. It is below the average of the other areas with a seasonal peak growth typically at around 0.67%.

Demand Side Management

DR is not a significant resource in the AB assessment area.

Distributed Energy Resources

Alberta Electric System Operator (AESO) is expecting a nearly 15% average annual growth rate over the time horizon.

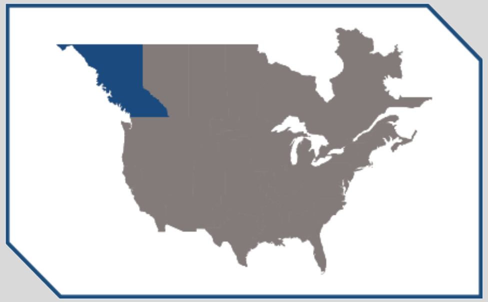
Generation

Nearly 800 MW of new natural-gas-fired generation (Tier 1) is being added during this assessment period in Alberta. Some BPS-level solar PV (730 MW nameplate) and wind (1,370 MW nameplate) is also in development over the 10-year period. For purposes of this assessment, solar does not contribute to winter on-peak resource capacity while new wind contributes about half of its nameplate capacity. There are no confirmed retirements on the horizon in the assessment area. Consequently, little change to the resource mix is expected.

Transmission

There are 335 miles of transmission lines in planning for construction during this assessment period.

SCHEDULE MM-S2



WECC-BC

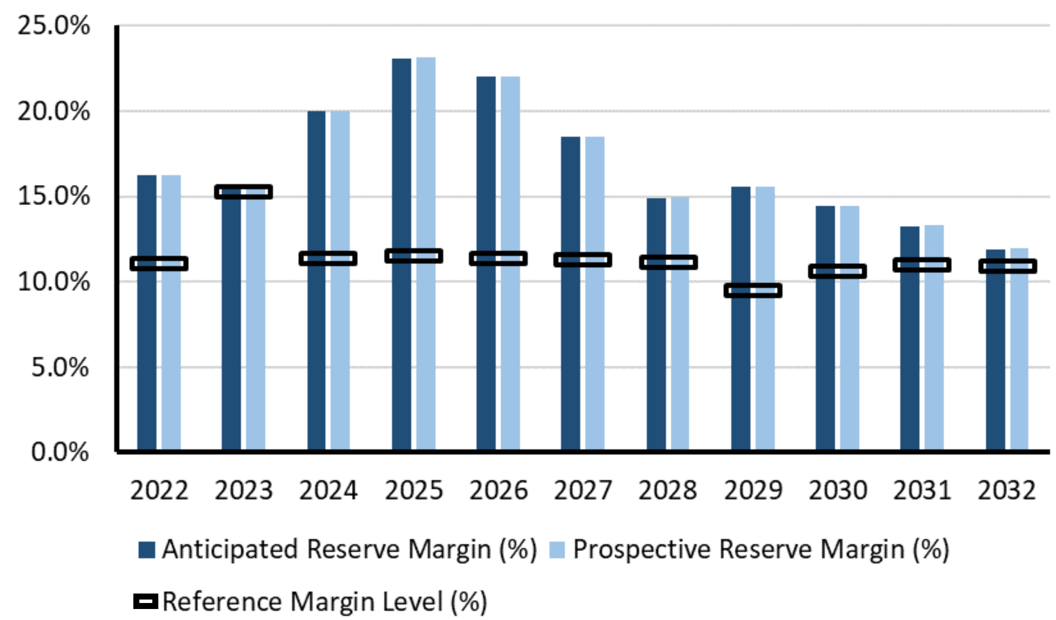
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

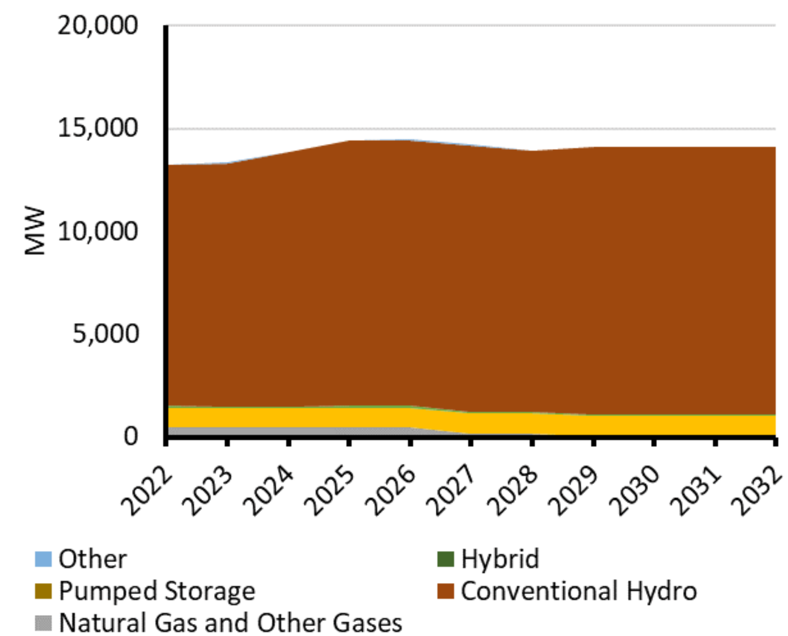
WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

WECC-BC Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	11,552	11,572	11,711	11,850	11,992	12,122	12,236	12,357	12,483	12,635
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,552	11,572	11,711	11,850	11,992	12,122	12,236	12,357	12,483	12,635
Additions: Tier 1	289	827	899	939	980	994	1,020	1,020	1,020	1,020
Additions: Tier 2	0	0	4	4	4	4	4	4	4	4
Additions: Tier 3	0	0	0	39	39	38	39	92	92	92
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,056	13,056	13,518	13,518	13,231	12,934	13,119	13,119	13,119	13,119
Anticipated Reserve Margin (%)	15.5%	20.0%	23.1%	22.0%	18.5%	14.9%	15.6%	14.4%	13.3%	11.9%
Prospective Reserve Margin (%)	15.5%	20.0%	23.1%	22.0%	18.5%	14.9%	15.6%	14.5%	13.3%	11.9%
Reference Margin Level (%)	15.2%	11.4%	11.5%	11.4%	11.3%	11.2%	9.5%	10.6%	11.0%	10.9%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- ARMs do not fall below the RML for this assessment period.
- With the majority of their portfolio being baseload resources, conventional hydro in particular, WECC is not concerned with reliability risk from variability in demand or resources.

WECC-BC Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Natural Gas	451	451	450	450	163	163	54	54	54	54
Biomass	974	974	971	971	971	971	968	968	968	968
Wind	62	62	84	84	84	86	84	84	84	84
Conventional Hydro	11,836	12,375	12,890	12,930	12,971	12,686	13,011	13,011	13,011	13,011
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,345	13,883	14,417	14,457	14,211	13,929	14,139	14,139	14,139	14,139

SCHEDULE MM-S2

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML throughout the 10-year assessment period. Starting in Winter 2023/2024 and then 2027/2028 onwards, British Columbia shows a shortfall of existing-certain and net-firm transfers, meaning imports may be necessary if new solar or conventional hydrogeneration resources were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

British Columbia's probabilistic assessment results continue to indicate little risk of energy or capacity shortfall though load-loss hours and unserved energy metrics are slightly higher than found in the previous ProbA. The highest risk generally occurs in winter months and coincides with the hour of peak demand though the study year 2026 results indicate some risk in the shoulder months of October and November.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	8.452	24.229	281.047
EUE (ppm)	0.137	0.37	4.13
LOLH (Hours per Year)	0.001	0.002	0.034
Operable On-peak Margin	20.2%	22.4%	33.5%

* Provides the 2020 ProbA results for comparison

Demand

British Columbia's peak demand (winter) compound annual growth rate for the 10-year period is 1.0.

Demand Side Management

DR is not a significant resource in the British Columbia assessment area.

Generation

The planned retirement of 101 MW of natural-gas-fired generation in 2025, followed by another 210 MW of natural-gas-fired capacity in 2026, contributes to the reduction in existing resources. However, plans are in place to increase hydro capacity over the next five years, helping to meet expected demand growth. Because of hydro's storage capabilities, WECC is not concerned with this area's ability to meet variability in demand and/or resources. The only potential issue would be an expansion of the U.S. West's drought conditions causing less fuel availability for the hydro resources; however, this has not had a significant impact to date. WECC will continue monitoring the drought conditions for fuel availability.

Transmission

There are 775 miles of transmission lines in planning for construction during this assessment period.

SCHEDULE MM-S2

WECC-CA/MX

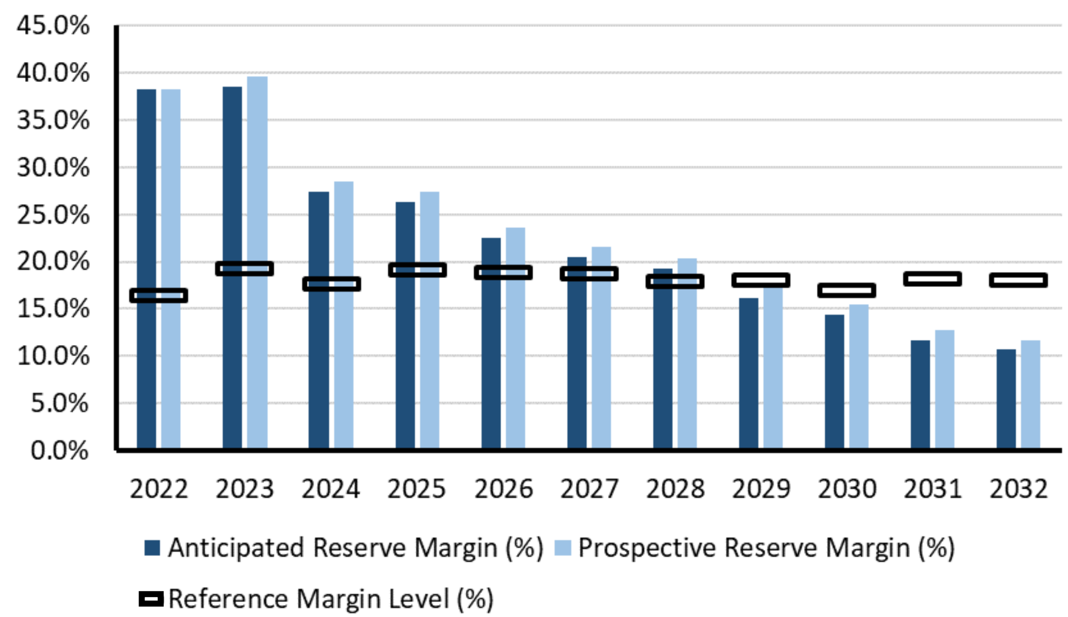
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

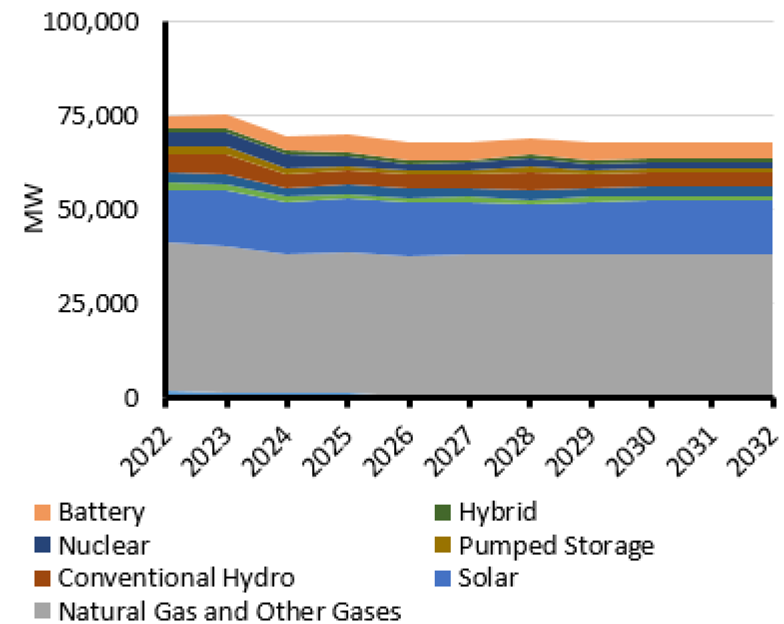
WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

WECC-CA/MX Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	57,091	57,759	58,609	59,184	60,028	60,652	61,423	62,164	62,967	63,526
Demand Response	862	881	897	913	928	943	959	974	989	989
Net Internal Demand	56,229	56,879	57,712	58,271	59,100	59,709	60,465	61,190	61,978	62,537
Additions: Tier 1	5,673	6,203	7,839	7,850	8,051	7,890	8,056	8,333	8,333	8,333
Additions: Tier 2	639	595	647	647	647	649	647	647	647	647
Additions: Tier 3	868	1,575	1,575	1,575	1,575	1,577	1,561	1,863	20,540	20,540
Net Transfers	1,559	2,019	1,925	2,585	2,191	1,130	1,252	753	0	0
Existing-Certain and Net Transfers	72,192	66,271	65,072	63,515	63,121	63,327	62,151	61,652	60,899	60,899
Anticipated Reserve Margin (%)	38.5%	27.4%	26.3%	22.5%	20.4%	19.3%	16.1%	14.4%	11.7%	10.7%
Prospective Reserve Margin (%)	39.6%	28.5%	26.9%	23.1%	20.2%	19.1%	15.9%	14.2%	11.5%	10.5%
Reference Margin Level (%)	19.2%	17.7%	19.1%	18.9%	18.7%	17.9%	18.0%	16.9%	18.2%	18.1%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- CA/MX's probabilistic assessment results continue to indicate a high risk of energy or capacity shortfall. The highest risk for loss of load is in the months of July through September during the hours of 4:00–7:00 p.m. This time period corresponds to the three hours after forecasted demand peaks each day in in California.
- Load-loss hours and unserved energy metrics are improved from the previous ProbA. Actions taken by regulators and industry to accelerate resource acquisition and delay retirements has helped provide the needed capacity.

WECC-CA/MX Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Coal	1,592	1,598	1,598	487	487	487	487	487	487	487
Petroleum	184	185	185	185	185	185	184	184	184	184
Natural Gas	38,737	36,468	37,231	37,231	37,425	37,425	37,389	37,659	37,659	37,659
Biomass	779	778	778	778	778	778	779	779	779	779
Solar	14,561	14,101	14,166	14,177	14,183	13,412	14,197	14,204	14,204	14,204
Wind	1,972	1,229	1,229	1,229	1,229	1,318	1,229	1,229	1,229	1,229
Geothermal	2,487	2,490	2,490	2,490	2,490	2,490	2,485	2,485	2,485	2,485
Conventional Hydro	5,214	3,657	3,657	3,657	3,657	4,716	3,657	3,657	3,657	3,657
Pumped Storage	1,983	1,159	1,159	1,159	1,159	1,889	1,159	1,159	1,159	1,159
Nuclear	3,880	3,877	2,772	1,667	1,667	1,667	1,667	1,667	1,667	1,667
Hybrid	1,030	1,029	1,029	1,029	1,029	1,029	1,030	1,030	1,030	1,030
Other	152	152	152	152	152	152	152	152	152	152
Battery	3,734	3,731	4,540	4,540	4,540	4,540	4,541	4,541	4,541	4,541
Total MW	76,306	70,455	70,986	68,780	68,981	70,087	68,956	69,232	69,232	69,232

SCHEDULE MM-S2

WECC-CA/MX Assessment

Planning Reserve Margins
The ARM falls below the RML in the summer of 2029. Starting in the summer of 2024 onwards, CA/MX shows a shortfall of existing-certain and net-firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin is needed to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resources and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

California LSEs are the only ones with a state-regulated target for PRMs. This was recently increased to 17.5%.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, specifically those in the sunniest southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

CA/MX's probabilistic assessment results continue to indicate a high risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of July through September during the hours of 4:00–7:00 p.m. This time period corresponds to the three hours after forecasted demand peaks each day in in California. The magnitude of unserved energy in any one hour of load loss ranges from less than a MW to 16,000 MW.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2,402,976	37,305	498,885
EUE (ppm)	8,818	136	1,785
LOLH (Hours per Year)	56	0.721	9.792
Operable On-peak Margin	15.3%	30.3%	25.7%

* Provides the 2020 ProbA results for comparison

Demand
CA/MX's peak demand (summer) compound annual growth rate for the 10-year period is 1.19.

Demand Side Management
Demand side management has played an important role in preventing energy shortfalls during extreme heat events in the area. Additionally, CA/MX anticipates quintupling summer efficiency reductions to peak demand along with six–fold increase in winter EE.

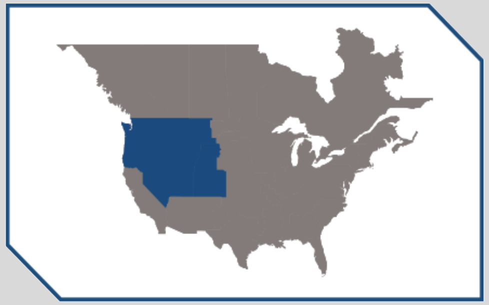
Distributed Energy Resources
Although BTM solar PV resources continue to be added to the CA/MX system, their contribution at the hour of system peak demand in summer has fallen 7.4% as that hour has shifted to later in the day. In winter, the contribution of BTM solar PV at the peak hour has increased by 7.4%.

Energy Storage
Significant amounts of energy storage additions are planned. Energy storage in the West may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV and storage. Of the 24.5 GW of new energy storage in the Western Interconnection, over 15.2 GW is being developed in California

Energy Transfers (Reliance on Assistance)
The energy and capacity risk analysis performed by WECC for this LTRA uses WECC's energy transfer modeling; complete firm transfer information is not available. Imports are expected to increase in CA/MX for much of the assessment horizon.

Transmission
There are 1,050 miles of transmission lines under construction or in planning for construction during this assessment period.

SCHEDULE MM-S2



WECC-WPP

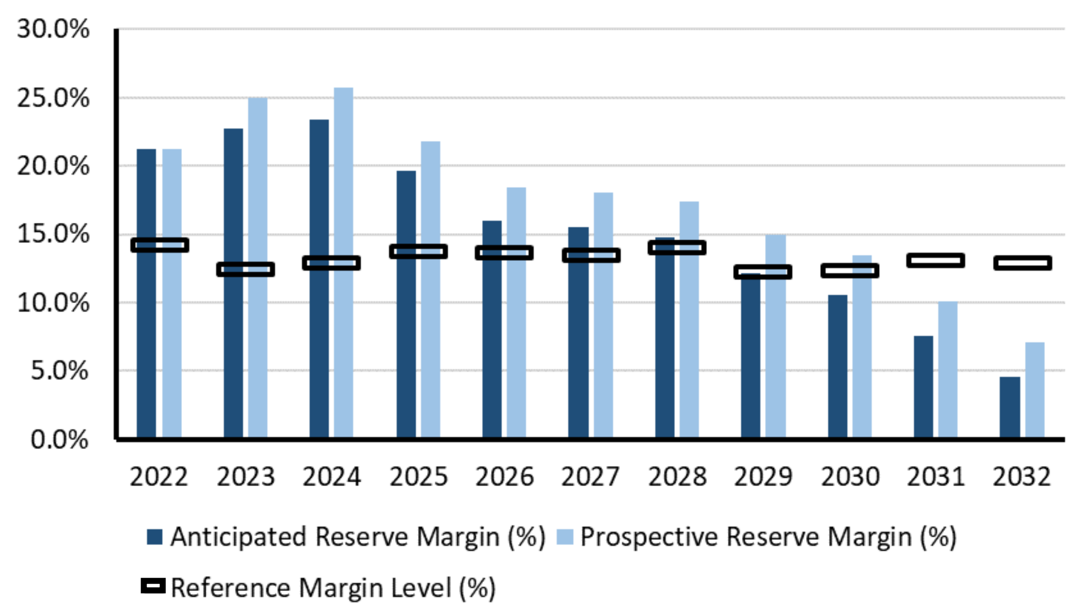
WECC-WPP (Western Power Pool) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

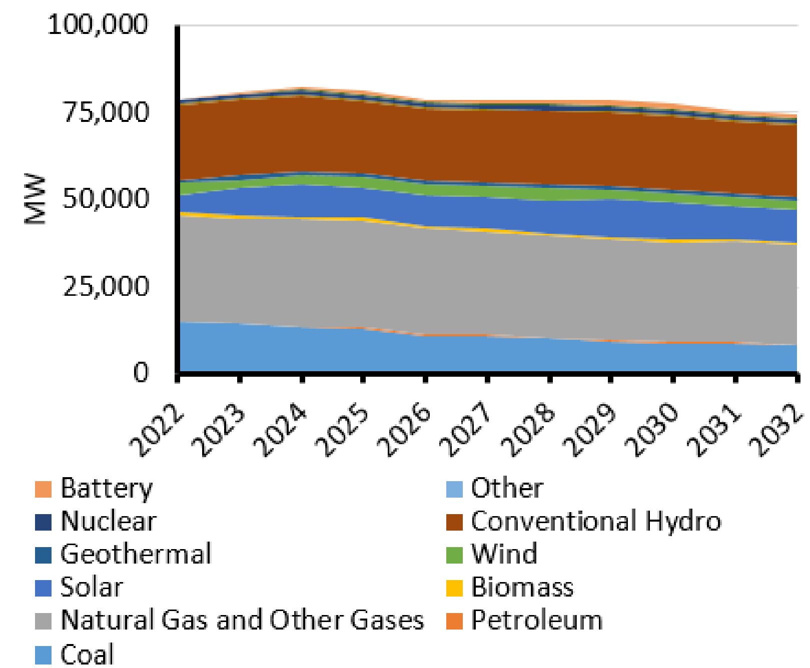
WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

WECC-WPP Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	67,258	68,559	69,475	69,636	70,389	71,095	71,715	72,229	72,827	73,613
Demand Response	1,603	1,618	1,658	1,670	1,685	1,689	1,705	1,712	1,724	1,475
Net Internal Demand	65,655	66,941	67,817	67,965	68,703	69,406	70,009	70,516	71,103	72,138
Additions: Tier 1	3,906	7,228	7,422	7,565	8,085	8,695	9,207	9,207	8,694	8,694
Additions: Tier 2	1,469	1,469	1,354	1,550	1,557	1,591	1,712	1,731	1,572	1,588
Additions: Tier 3	42	1,113	2,284	2,943	2,943	3,512	4,182	5,925	6,926	6,951
Net Transfers	0	0	0	0	800	957	0	450	800	800
Existing-Certain and Net Transfers	76,655	75,343	73,734	71,282	71,262	70,968	69,284	68,777	67,816	66,716
Anticipated Reserve Margin (%)	22.7%	23.4%	19.7%	16.0%	15.5%	14.8%	12.1%	10.6%	7.6%	4.5%
Prospective Reserve Margin (%)	24.9%	25.7%	21.8%	17.9%	17.6%	16.9%	14.5%	13.4%	10.1%	7.1%
Reference Margin Level (%)	12.5%	12.9%	13.8%	13.7%	13.5%	14.0%	12.3%	12.4%	13.1%	12.9%



Planning Reserve Margins



Existing and Tier 1 Resources

SCHEDULE MM-S2

Highlights

- The Western Resource Adequacy Program (WRAP), which is being implemented by WPP, is a regional reliability planning and compliance program with the intent to deliver an assessment-area-wide approach for assessing and addressing resource adequacy.
- WECC's probabilistic assessment results for the WPP assessment area continue to indicate a risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of June through September during the five hours after demand peaks for the day.

WECC-WPP Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	14,304	13,311	13,046	10,876	10,876	10,028	9,318	8,729	8,736	7,968
Petroleum	307	307	309	309	309	309	307	307	307	307
Natural Gas	30,057	30,798	30,755	30,588	29,837	29,286	29,144	28,802	28,846	28,642
Biomass	778	775	773	767	737	737	670	670	669	667
Solar	7,795	9,371	8,624	8,762	9,245	9,547	10,718	10,718	9,369	9,301
Wind	2,497	2,575	3,093	3,067	3,067	3,264	2,452	2,427	2,880	2,822
Geothermal	1,151	1,151	1,154	1,138	1,138	1,138	1,114	1,114	1,123	1,123
Conventional Hydro	22,016	21,876	20,896	20,829	20,822	21,406	21,780	21,780	20,798	20,798
Nuclear	1,094	1,094	1,093	1,093	1,093	1,093	1,088	1,088	1,082	1,082
Hybrid	91	505	504	504	504	504	505	505	506	506
Other	77	77	78	78	78	78	77	77	78	78
Battery	486	1,237	1,335	1,340	1,345	1,820	1,823	1,823	1,822	1,822
Total MW	80,562	82,572	81,157	78,848	78,548	78,707	78,493	77,536	75,711	74,611

SCHEDULE MM-S2

WECC-WPP Assessment

Planning Reserve Margins

The ARM falls below the RML in the summer of 2029 and the winter of 2031/2032. Starting in the summer of 2024 onwards, WPP shows a shortfall of existing-certain and net transfers, meaning imports may be necessary if new resources were to be significantly delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

With the formation of the new WRAP, the WPP is working towards defining what an adequate reserve margin for their footprint will be. WECC is monitoring the WRAP's endeavors.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, those in the sunniest, southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

WPP's probabilistic assessment results continue to indicate risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of June through September, during the five hours after demand peaks for the day. The magnitude of unserved energy in any one hour of load-loss range from less than a MW to 13k MW.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	248,573	1,722	11,280
EUE (ppm)	621.8	4.22	27.18
LOLH (Hours per Year)	4.389	0.036	0.233
Operable On-peak Margin	24.9%	25.8%	21.0%

* Provides the 2020 ProbA results for comparison

Demand

WPP's peak demand (summer) compound annual growth rate for the 10-year period is 1.0.

Distributed Energy Resources

WPP is seeing a 13% average annual growth rate in BTM solar PV on-peak capacity.

Energy Storage

Significant amounts of energy storage additions are planned. Energy storage in the west may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV and storage. Of the 24.5 GW of new energy storage in the Western Interconnection, 6 GW are being developed in WPP.

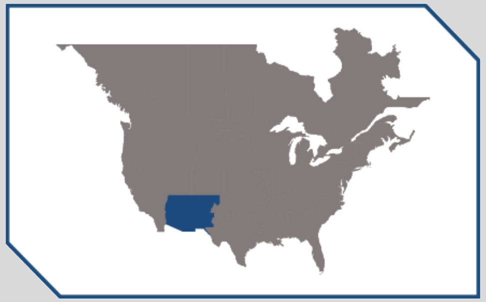
Energy Transfers (Reliance on Assistance)

Energy and capacity risk analysis performed by WECC for this *LTRA* use WECC's modeling of energy transfers. Complete firm transfer information is not available. Imports are expected to increase into WPP area in the summer of 2027.

Transmission

There are over 3,400 miles of transmission lines under construction or in planning for construction during this assessment period.

SCHEDULE MM-S2



WECC-SRSG

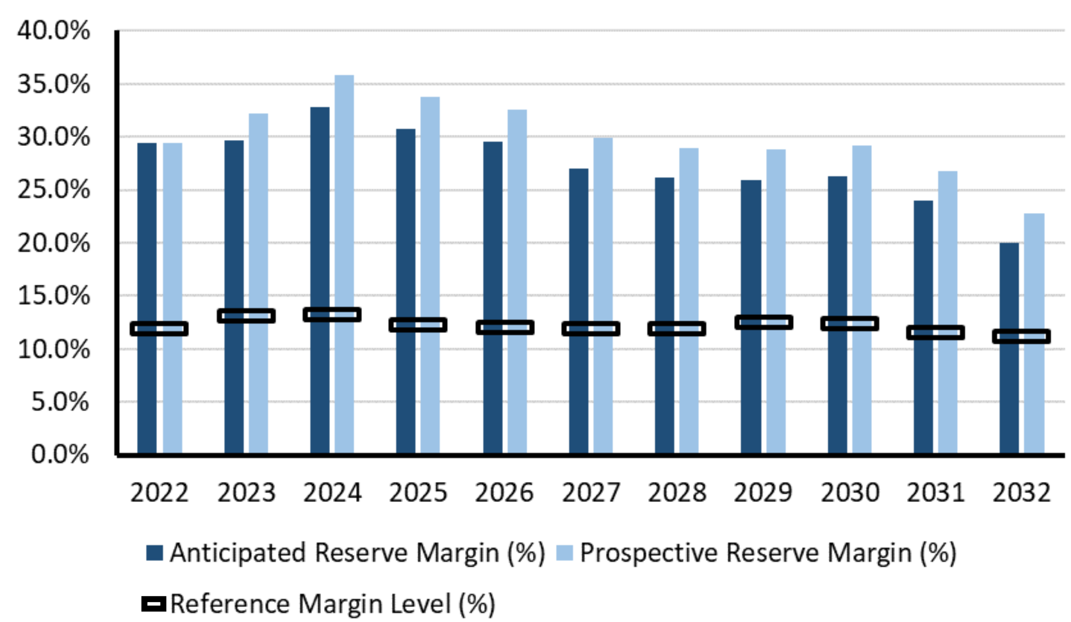
WECC-SRSG (Southwest Reserve Sharing Group) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

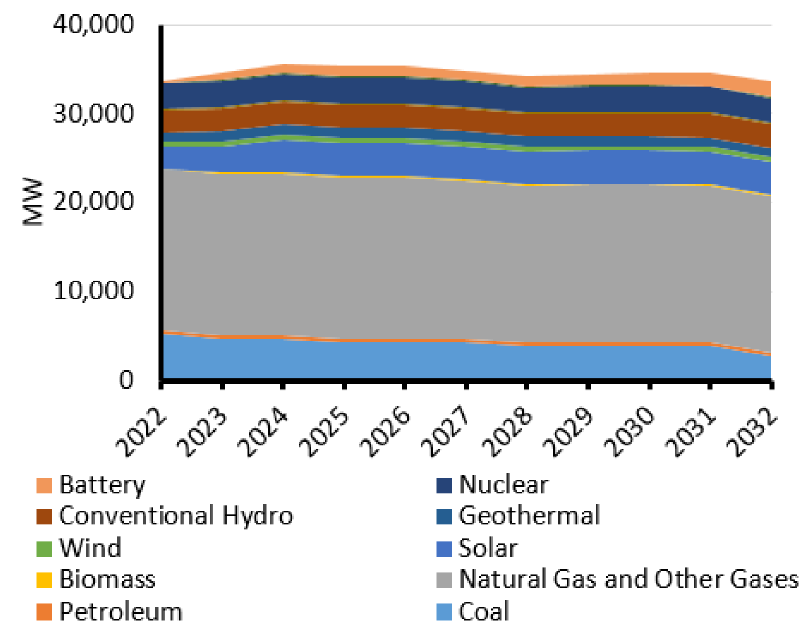
WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

WECC-SRSG Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	27,039	27,154	27,864	28,516	29,186	29,634	30,049	30,513	30,935	31,441
Demand Response	421	399	437	402	409	416	394	399	402	409
Net Internal Demand	26,618	26,755	27,426	28,114	28,777	29,218	29,655	30,114	30,533	31,032
Additions: Tier 1	2,834	3,833	3,954	3,954	3,954	3,939	3,955	4,224	4,224	4,586
Additions: Tier 2	670	812	847	847	847	841	849	849	849	849
Additions: Tier 3	538	683	1,277	1,902	1,902	2,031	2,328	2,859	3,352	4,378
Net Transfers	0	0	573	1,142	1,658	2,652	3,016	3,437	3,348	3,561
Existing-Certain and Net Transfers	31,694	31,694	31,896	32,465	32,591	32,912	33,393	33,813	33,639	32,663
Anticipated Reserve Margin (%)	29.7%	32.8%	30.7%	29.5%	27.0%	26.1%	25.9%	26.3%	24.0%	20.0%
Prospective Reserve Margin (%)	32.2%	35.8%	33.8%	32.6%	29.9%	29.0%	28.8%	29.1%	26.8%	22.8%
Reference Margin Level (%)	13.1%	13.3%	12.2%	12.1%	11.9%	11.9%	12.6%	12.3%	11.5%	11.2%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- The SRSG assessment area continues to be summer peaking. Summer demand peaks beginning at 4:00 p.m. Winter demand peaks in the mornings before 8:00 a.m.
- Seasonal demand rates of growth continue to be roughly twice the other areas' averages.
- SRSG's probabilistic assessment results indicate that the risk of energy shortfall is increasing from the 2024 to 2026 study years. The highest risk for loss of load is in the months of July through September during the 6:00 p.m. hour (after demand peaks for the day).

WECC-SRSG Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	4,713	4,713	4,342	4,342	4,342	3,848	3,848	3,848	3,848	2,712
Petroleum	318	318	318	318	318	318	319	319	319	319
Natural Gas	18,234	18,234	18,234	18,234	17,843	17,773	17,779	17,779	17,697	17,697
Biomass	94	94	94	94	94	94	94	94	94	94
Solar	3,004	3,782	3,782	3,782	3,782	3,735	3,782	3,782	3,781	3,738
Wind	559	562	562	562	562	588	562	561	560	549
Geothermal	1,031	1,031	1,031	1,031	1,031	1,031	1,033	1,033	1,033	1,033
Conventional Hydro	2,825	2,825	2,825	2,825	2,825	2,722	2,825	2,825	2,825	2,825
Nuclear	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821
Hybrid	145	145	145	145	145	145	145	145	145	145
Battery	785	1,003	1,124	1,124	1,124	1,124	1,125	1,394	1,394	1,756
Total MW	34,528	35,527	35,277	35,277	34,886	34,198	34,332	34,600	34,515	33,688

SCHEDULE MM-S2

WECC-SRSG Assessment

Planning Reserve Margins

The ARM is above the RML throughout this assessment period. Starting in the summer of 2030, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP of less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, specifically those in the sunniest Southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

SRSG's probabilistic assessment results indicate that the risk of energy shortfall is increasing from the 2024 to 2026 study years. The highest risk for loss of load is in the months of July through September during the 6:00 p.m. hour (one hour after demand peaks for the day). The magnitude of unserved energy in any one hour of load-loss ranges from less than 1 MW to 9,000 MW.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	81.33	83.58	9352.15
EUE (ppm)	0.750	0.68	71.17
LOLH (Hours per Year)	0.004	0.003	0.368
Operable On-peak Margin	5.50%	28.08%	24.85%

***** Provides the 2020 ProbA results for comparison

Demand

The SRSG's 10-year peak demand compound annual growth rates are among the highest of all assessments areas. The winter 1-year CAGR is over 2% while the summer peak demand 10-year CAGR is 1.7%.

Demand Side Management

Demand forecasters in the Southwest anticipate that EE and conservation programs will help to reduce demand growth. In summer, EE programs are estimated to offset peak demand by 315 MW currently and are projected to account for 1,315 MW of reduction in peak demand by 2032.

Distributed Energy Resources

SRSG is seeing a 13% average annual growth rate in BTM solar PV on-peak capacity.

Energy Storage

Significant amounts of energy storage additions are planned. Energy storage in the west may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV + storage. Of the 24.5 GW of new energy storage in the Western Interconnection, 2.4 GW are being developed in SRSG.

Energy Transfers (Reliance on Assistance)

Energy and capacity risk analysis performed by WECC for this LTRA use WECC's modeling of energy transfers. Complete firm transfer information is not available. Imports are expected to increase across the Southwest for summers starting in 2025.

Transmission

There are over 581 miles of transmission lines under construction or in planning for construction during this assessment period.

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Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[41] for the summer and winter of each year.[42] Projected total internal demand is based on normal weather (50/50 distribution)[43] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area

Assessment Area	Peak Season	Coincident / Noncoincident[44]	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-US	Summer	Noncoincident	
WECC-RMRG	Summer	Noncoincident	

[41] Glossary of Terms Used in NERC Reliability Standards.
[42] The summer season represents June–September and the winter season represents December–February.
[43] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[44] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

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Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident**[44]	**Load Forecasting Entity**
WECC-SRSG	Summer	Noncoincident	

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.
Anticipated Resources • Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. • Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements • Firm capacity transfers (Imports minus Exports): transfers with firm contracts • Less confirmed retirements[45]
Prospective Resources: Includes all "anticipated resources" plus the following: • Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons. • Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation. • Less unconfirmed retirements.[46]

[45] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[46] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

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Resource Categories

Generating Unit Status: Status at time of reporting:

- **Existing:** It is in commercial operation.
- **Retired:** It is permanently removed from commercial operation.
- **Mothballed**: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- **Cancelled**: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- **Tier 1**: A unit that meets <u>at least one</u> of the following guidelines (with consideration for an area's planning processes):[47]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- **Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):**[48]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- **Tier 3**: A units in an interconnection queue that do not meet the Tier 2 requirement.

[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[48] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin: The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin: The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

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Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

Adequacy: The ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components

Operating Reliability: The ability of the electricity system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators can and should take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[49]
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as “cascading blackouts,” the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[50] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[51] which is defined by the following characteristics.

Adequate Level of Reliability: It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:

- The BES does not experience instability, uncontrolled separation, cascading,[52] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[53]
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[49] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: https://www.nerc.com/files/glossary_of_terms.pdf
[50] https://www.nerc.com/pa/RAPA/Pages/BES.aspx
[51] https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf
[52] NERC’s Glossary of Terms defines Cascading: “Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.”
[53] NERC’s Glossary of Terms defines Disturbance: “1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.”

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- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this *LTRA* are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRM relative to its RML—a "target" or requirement based on traditional capacity planning criteria. For a description of each assessment area's RMLs refer to the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area** table. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss of load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Refer to supplementary tables posted on NERC's Reliability Assessments web page to see the on-peak capacity contribution of existing wind and solar resources for each assessment area).[54]

On the basis of the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss of Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH should be evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study horizons. LOLH does not inform of the magnitude or the frequency of loss of load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact

[54] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

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- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss of load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss of load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[55] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Low Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hrs and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hrs and EUE > 0.002% of total annual net energy.

NERC Capacity Supply Categories

Future capacity additions are reported in three categories:

Tier 1: Planned capacity that meets at least one of the following requirements is included as anticipated resources:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: Planned capacity that meets at least one of the following requirements is included as prospective resources:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study

[55] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

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- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to RTO/ ISOs)

Tier 3: Tier 3 is other planned capacity that does not meet any of the above requirements.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electricity industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

Under Construction: Construction of the line has begun.

Planned (any of the following):

- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement

Conceptual (any of the following):

- A line projected in the transmission plan
- A line that is required to meet a NERC TPL standard or powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Other projected lines that do not meet requirements of "Under Construction" or "Planned"

SCHEDULE MM-S2

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2023–2027)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	18.3%	PRM	Yes: Established Annually[56]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20.0%[57]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.4–13.6%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[58]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	18.9–23.1%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro Québec, NPCC Criteria
PJM	14.4–14.8%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, Reliability*First* BAL-502-RFC-02 Standard
SERC-Central	15.0%[59]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-East	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[56] In MISO, the states can override the MISO PRM.
[57] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.
[58] The NERC LTRA RML for NY is 15%; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2021/2022 IRM at 20.7%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.
[59] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

SCHEDULE MM-S2

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2023–2027)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-Florida Peninsula	15.0%[61]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[62]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SPP	16.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[63]
WECC-BC	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[64]	17.4–19.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-WPP	13.5–15.2%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SRSG	10.7–12.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[61] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[62] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[63] WECC's Reference Margin Level in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[64] California is the only state in the WI that has a wide-area PRM, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

SCHEDULE MM-S2

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric	)	
Company d/b/a Ameren Missouri for Approval	)	
of a Subscription-Based Renewable Energy Program	)	File No.: EA-2022-0245

AFFIDAVIT OF MATT MICHELS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matt Michels, being first duly sworn on his oath, states:

My name is Matt Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

\s\ Matt Michels
Matt Michels

Sworn to me this 18th day of January, 2023.