2019–2020 Winter Reliability Assessment

November 2019

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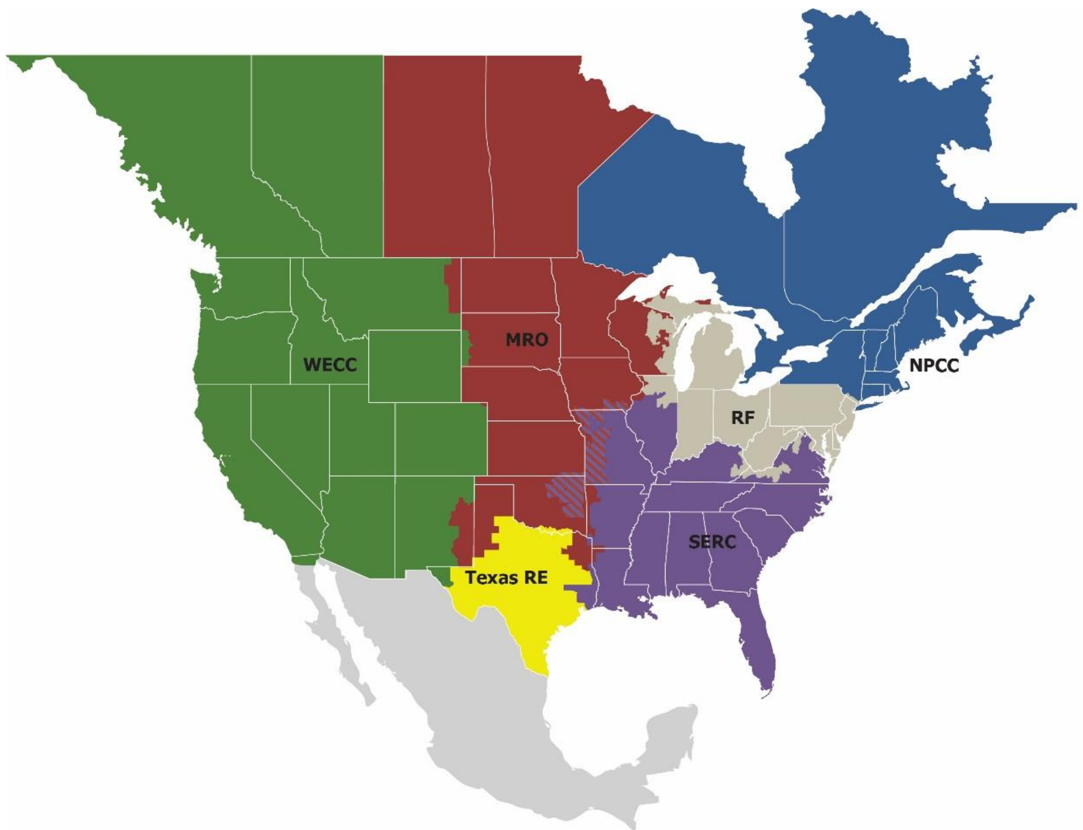
Preface

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 (REs), 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 divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



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

About this Report

NERC's *2019–2020 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA 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 Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. The report also provides an opportunity for the industry to discuss their plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

NERC's annual WRA covers the three-month (December–February) 2019–2020 winter period. This assessment provides an evaluation of generation resource and transmission system adequacy necessary to meet projected winter peak demands. This assessment also monitors and identifies potential reliability issues of interest and regional topics of concern. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

- **Adequate resources for winter:** Anticipated resources in all assessment areas meet or exceed their respective Reference Margin Levels for the upcoming winter period.[1] Accordingly, planned resources are adequate across the BPS, including United States and Canadian provinces, based on normal demand and average weather conditions (i.e., 50/50 forecasts).
- **Extreme weather continues to pose risk to BPS reliability during the winter season:** Extreme winter weather can challenge grid operators to maintain reliability. Harsh conditions characterized by extreme or prolonged cold temperatures over a large area of North America, such as those experienced during the 2014 polar vortex or the January 2019 cold snap, create special challenges to maintaining grid reliability in many parts of the North American grid.[2] Increased demand caused by frigid temperatures, higher generator forced outage rates, and derated output of some generation resources in susceptible areas could create conditions that lead system operators to take emergency operating actions and may result in energy emergencies:
  - NERC's operational risk assessments that are contained throughout this report identify BPS resource deficiencies in parts of North America that could occur during extreme winter weather. Potential extreme generation resource outages and peak loads that can accompany extreme winter weather may result in reliability risks in MISO, SPP, and ERCOT operating areas. Under studied conditions, grid operators would need to employ operating mitigations or energy emergency alerts (EEAs) to obtain resources necessary to meet extreme peak demands. In ISO-New England, as with the previous winter season, there is continuing concern that energy could be insufficient to satisfy electricity demand during an extended cold spell given the evolving resource mix and fuel delivery infrastructure.
  - Managing BPS reliability during wide-area cold spells requires effective regional operating protocols and generator preparedness. In January 2018, extreme winter weather in the South Central United States resulted in season-high loads and increased generator outages over a nine-state area. Portions of the transmission system throughout the south were constrained as large power transfers flowed through the area to make up for forced generator outages.[3] Reliability Coordinators (RCs) are preparing to meet future cold snaps with enhanced operating protocols for coordinating regional transmission flows during wide-area extreme events. SPP, MISO, and neighboring RCs have worked to clarify operating expectations, enhance communication processes, and develop training for operators on how to jointly mitigate reliability issues when extreme weather events simultaneously affect multiple RC areas. While ongoing winter preparation activities throughout the ERO incorporate the lessons from extreme winter events, NERC and the industry are taking additional steps to ensure BPS owners and operators prepare for extreme cold weather by initiating a Reliability Standards development project.[4]
- **Changing resource mix requires improved forecasting tools:** Accurate forecasting of demand and resources is important to the reliable operation of the BPS, yet generator forecasts become more challenging as the resource mix changes. Shortfalls in projected generation or higher-than-anticipated loads can lead to operating emergencies during tight conditions. During the January 2019 cold snap, day-ahead wind generation forecasts overestimated wind resource contributions in the MISO area by as much as 8 GW (i.e., over 56% of installed wind generation capacity).[5] Some models did not account for extreme low-temperature cut-outs of certain wind generators, contributing to forecast error. Operators in areas with increasing variable generation resources are taking steps to begin to address these risks, including working with Generator Owners to improve forecast models.

[1] The Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area. In some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. See **Data Concepts and Assumptions** section of this report.
[2] See the NERC event report: *January 2014 Polar Vortex Review*: https://www.nerc.com/pa/rrm/Pages/January-2014-Polar-Vortex-Review.aspx
[3] See the report: *South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, for a description of the significant operating condition the resulted from generator outages and transmission constraints during recent extreme cold weather: https://www.nerc.com/pa/rrm/ea/Pages/January_2018_South_Central_Cold_Weather_Event.aspx
[4] Details on this Reliability Standards project can be found on the *Project 2019-06 Cold Weather* project page: https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx
[5] See MISO Dispatchable Intermittent Resources Wind Forecasting Workshop: https://cdn.misoenergy.org/20190423%20MISO%20DIR%20Wind%20Forecasting%20Workshop340206.pdf

- **Fuel and energy assurance risk remains a reliability concern in some areas:** While Anticipated Reserve Margins indicate adequate resource availability for winter throughout the North American BPS, fuel assurance risk remains a reliability concern in some assessment areas. For natural gas, demand is growing as a generator fuel source and for winter space heating needs. For example, natural-gas-fired generation on-peak capacity has increased from 43% of the generation resource mix in 2014 to current level of 51% in the New England area with little increase in interstate pipeline capacity. Peak demand for natural gas can potentially exceed total capacity of the regional natural gas supply and delivery infrastructure. Generating units that lack alternate fuel sources or firm contracts for natural gas supply and transmission may not be able to deliver their energy capability. Fuel assurance risks and approaches to mitigation can vary by area. Some area highlights for the upcoming winter include the following:
  - ISO-New England has enhanced processes to support fuel assurance through market mechanisms. For the 2018–2019 winter, ISO-New England developed a *21-Day Energy Assessment Forecast and Report* to provide market participants with early indication of potential fuel scarcity conditions and help inform fuel procurement decisions; ISO-New England plans to continue publishing during the upcoming winter.[6] ISO-New England also continues to survey fossil-fueled generators on a weekly basis to monitor and confirm their current and near-term fuel availability throughout the winter period. New England also requests natural-gas-fired generators to confirm adequate natural gas nominations in order to meet their day-ahead obligations.
  - Regions include fuel assurance in their winter preparedness efforts. In the southeast (i.e., the SERC Region) for example, entities make use of firm pipeline transportation for natural gas generators and have assessed that they will maintain adequate fuel inventories at coal and oil-fired thermal generation plants.
  - In Canadian provinces, a variety of attributes and mechanisms support fuel assurance for the upcoming winter season. The provinces of Ontario, Maritimes, Alberta, and Saskatchewan have diverse generation resource mixes that include hydro and a variety of thermal resources. In the provinces of Quebec, Manitoba, and British Columbia, where hydroelectric generation is the primary resource, hydrological conditions are not expected to impact electric generation for the upcoming winter.
  - Operators have implemented steps to respond to fuel assurance risks, such as generator performance incentives via market mechanisms, identification of additional energy supplies, enhanced communications protocols between electric and natural gas system operators, and new energy forecasts that provide fuel supply information to wholesale electricity market participants. However, due to the complex interdependence of the electric and natural gas infrastructure, fuel assurance risk cannot be completely mitigated.
- **Higher natural gas storage inventories help reduce natural-gas-fired generator fuel supply risks for the upcoming winter season:** Natural gas injections into the largest storage areas in the continental United States have led to high preseason inventory levels. Adequate levels of natural gas storage are important for winter readiness in many areas because withdrawals may be necessary to meet peak-day demand. Prior to the start of winter, the largest facilities that are located in the East and South Central parts of the United States were at or near five-year high levels. Natural gas storage in Southern California, including the restricted Aliso Canyon storage facility, has also overcome storage deficits to be near the levels experienced at the start of the preceding winter.

[6] ISO-New England posts the *21-Day Energy Assessment Forecast and Report* on their Operations Reports web page: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results

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 forecasted peak demand.[7] Large year-to-year changes in anticipated resources or forecasted 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 2019–2020 winter as shown in the **Figure 1**.

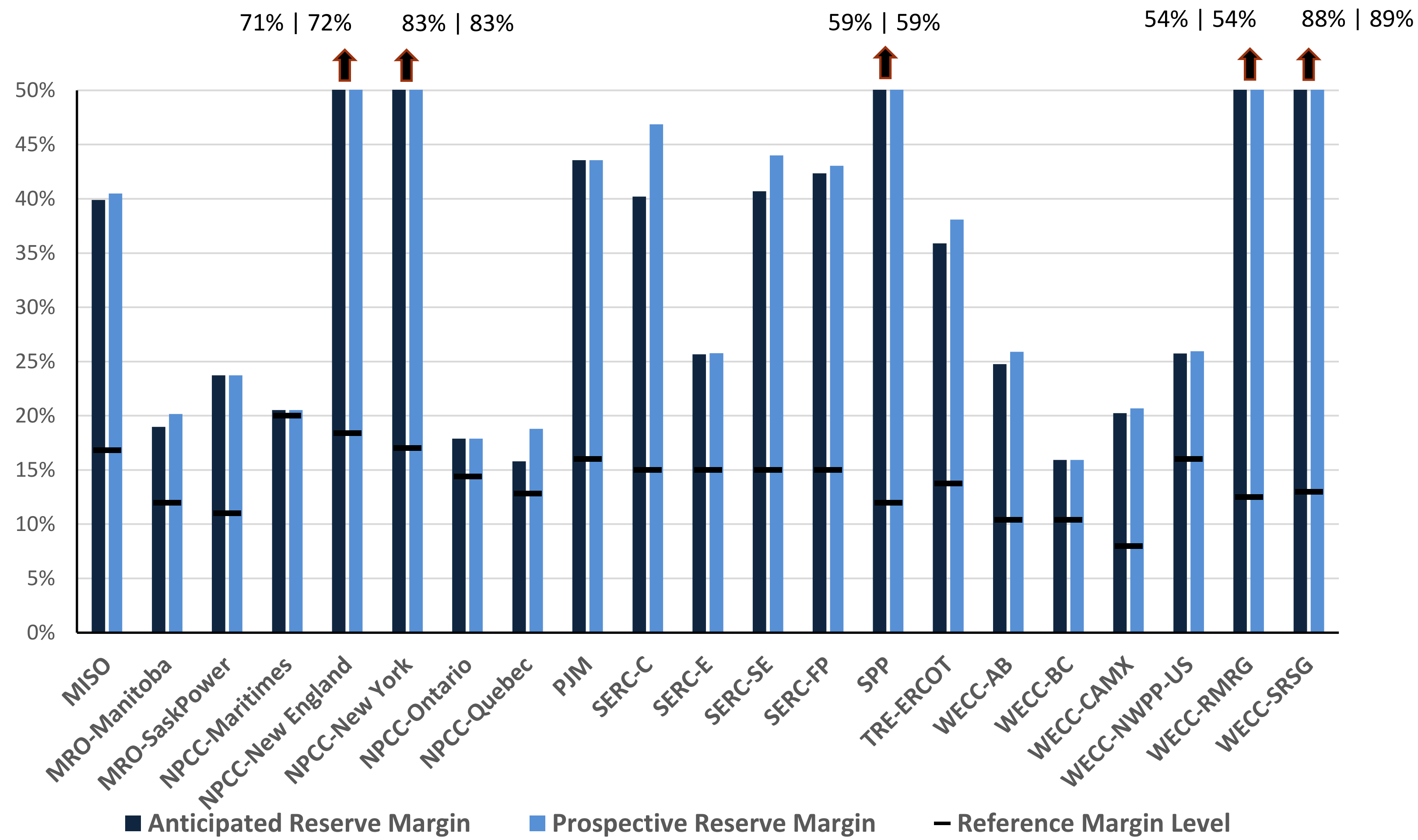


Figure 1: Winter 2019–2020 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[7] 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.

Changes from Year-to-Year

Figure 2 provides the relative change in the Anticipated Reserve Margin from the 2018–2019 winter to the 2019–2020 winter. A significant decline can indicate potential operational issues that emerge between reporting years. The areas of MRO-Manitoba, NPCC-Maritimes, SERC-SE, WECC-AB, and WECC-BC all had noticeable reductions in Anticipated Reserve Margins between 2018–2019 winter to the 2019–2020 winter. The area of WECC-CAMX had the largest reduction in Anticipated Reserve Margins from year-to-year. Additional details are provided in the Data Concepts and Assumptions section of this report.

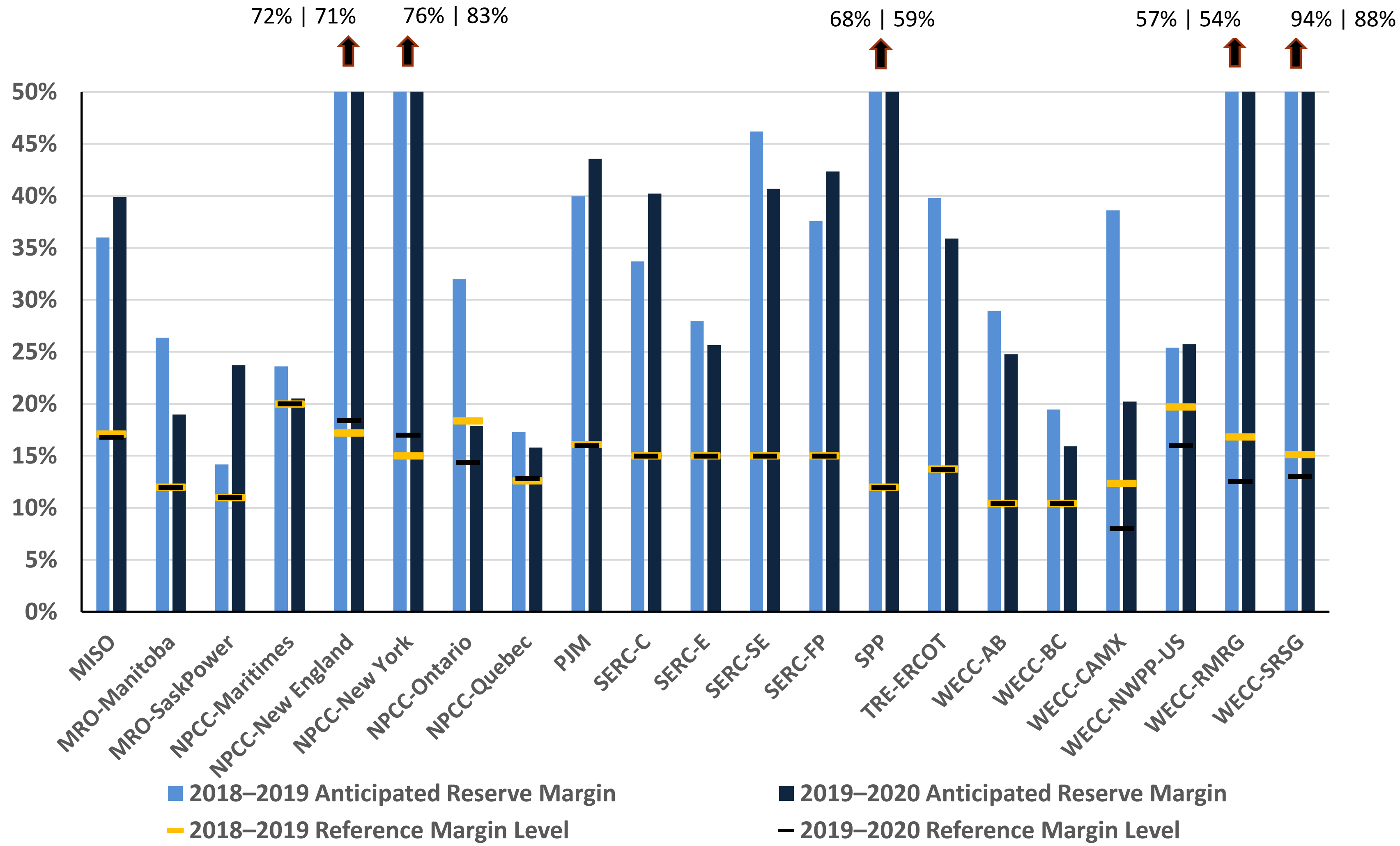


Figure 2: Winter 2018–2019 to Winter 2019–2020 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

Peak demand forecast for most assessment areas has decreased or remained below 1% compared to prior seasonal assessments. Some assessment areas are forecasting growth in net internal demand of over 3%. The increases in forecasted net internal demand for each assessment area are shown in **Figure 3**.[8]

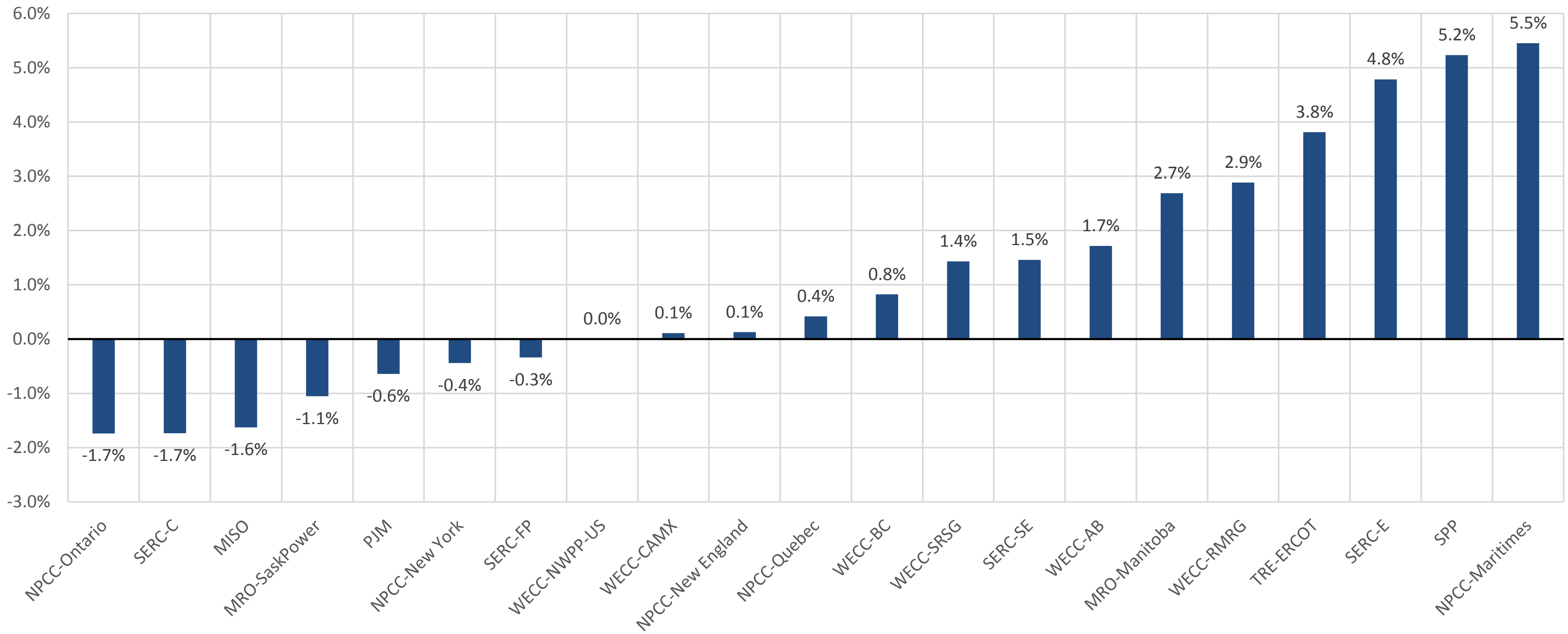


Figure 3: Change in Net Internal Demand: 2019–2020 Winter Forecast Compared To 2018–2019 Winter Forecast

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

Risk Highlights for Winter 2019–2020

About the Seasonal Risk Assessment

The operational risk analysis shown in Figure 4 provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity, such as 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 WRA reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in through additional resource derates or extreme resource scenarios and extreme winter peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the ISO-NE seasonal risk scenario in Figure 4 can be found for each assessment area in the Regional Assessment Dashboards section of this report.

Seasonal Risk Assessments of Area Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. The Regional Assessment Dashboards section in this report includes a seasonal risk scenario for each area that illustrates variables in resources and load, and the potential effects that operating actions can have to mitigate shortfalls in operating reserves where appropriate. Figure 4 shows an example seasonal risk assessment for the ISO-New England area that was developed using WRA data and additional data from NPCC and ISO-New England. A description of resource and demand variables is found in Table 1.

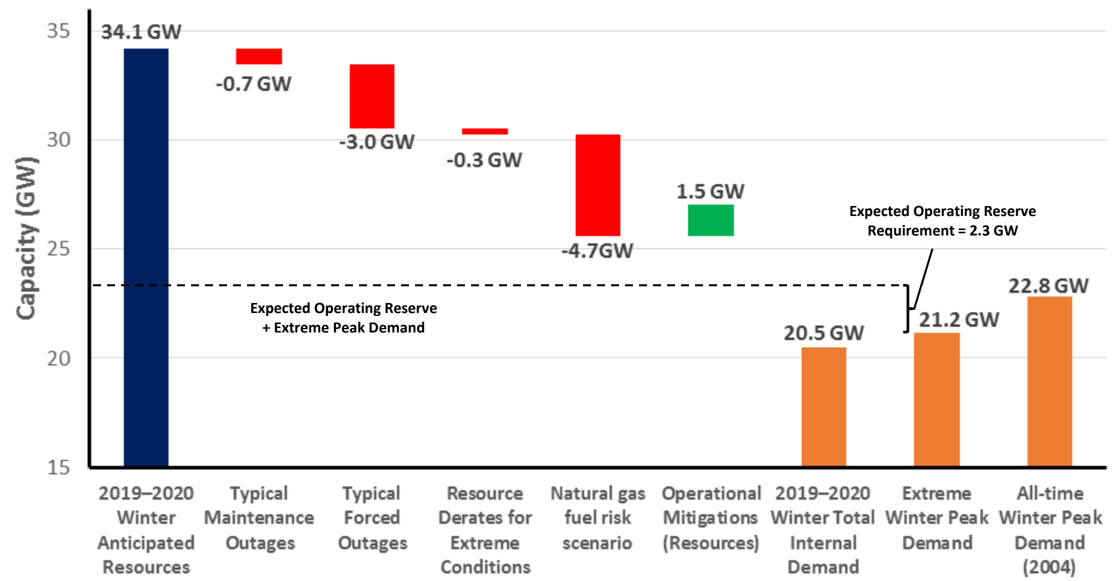


Figure 4: ISO-NE Area Seasonal Risk Assessment

The seasonal risk assessment for ISO-New England shows that resources are available to meet extreme conditions; however, energy security challenges remain a concern in the ISO-New England area. Based on the assumptions in Table 1, resources are available to meet expected operating reserve requirements for the normal and extreme demand and outage scenarios analyzed. By examining various maintenance and forced outage scenarios and derated resource conditions, the analysis provides insights into operational challenges that can occur as a result of prolonged and extreme cold temperatures. However, the seasonal risk assessment may not account for all of the unique energy assurance risks associated with the area. As the generation resource mix changes in New England, there is a reduction in on-site fuel storage and an increased dependency on constrained natural gas infrastructure. Long-duration cold spells and disruptions to primary and back-up fuel supply lines are not explicitly considered in the New England seasonal risk scenario and can create challenging operating conditions.

Table 1: Resource and Demand Variables in the ISO-NE Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to all planned outages for the period, including any known long-term outages, generation outages, reductions due to transmission work, and external outages that would affect ISO-NE imports. The value is a snapshot of these considerations that is produced monthly and forecasted out two years.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. ISO-NE calculated this capacity value from historical forced outages in previous winters.
Resource Derates for Extreme Conditions (Low-likelihood)	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. The assumed forced outage for this scenario is based on the sum of the unplanned outages plus the natural-gas-fired generation at risk of not having fuel during 90/10 peak load conditions.
Extreme Natural Gas Fuel Risk Scenario (Low-likelihood)	ISO-NE depends on a large fleet of natural-gas-fired generation that may be at risk due to unavailability of natural gas during colder temperatures. ISO-NE calculates the amount of generator natural gas at risk due to lack of natural gas during cold weather based on dry-bulb peak hour temperature. This assumes no generator natural gas at risk for temperatures at or above 30°F and a reduction curve for temperatures below 30°F. The electric generating capacity depicted as at-risk in Figure 4 is the maximum.
Operational Mitigations	An estimated combination of load relief achieved through operating procedure actions (e.g., requesting voluntary load curtailment of market participants, the purchase of available emergency capacity and energy from market participants or neighboring RC or Balancing Authority areas, request for generators and demand response resources not subject to market obligations to voluntarily provide energy for reliability, requesting voluntary load curtailment by large industrial and commercial customers, and radio and television appeals for voluntary load curtailment).
Demand Scenarios	
2019–2020 Winter Net Internal Demand	This is the forecasted 50/50 net winter peak load that integrates state historical demand, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs. Energy efficiency is included in this demand forecast and assumes that behind-the-meter (BTM) solar generation will be off-line or unable to generate for the peak winter hours.
Extreme Winter Peak Load	A seasonal load adjustment is added to the 2019–2020 net internal demand based on a 90/10 statistical extreme load forecast.

Seasonal Risk Assessments for Other Areas

Seasonal risk scenarios for each assessment area are presented in the Regional Assessment Dashboards section of this report. Potential extreme generation resource outages and peak loads that can accompany extreme winter weather may result in reliability risks in MISO, SPP, ERCOT, and CAISO areas as well as the Canadian provinces of Quebec and Maritimes. Some parts of the system within the WECC area could also experience resource shortfalls in low-likelihood resource derate scenarios. Under studied conditions for these areas, grid operators would need to employ operating mitigations or EEAs to obtain resources necessary to meet extreme peak demands.

Changing Resource Mix Requires Improved Forecasting Tools

Accurate forecasting of demand and resources is important to the reliable operation of the BPS, yet generator forecasts can become less accurate as variable generation resources contribute more to on-peak capacity. During the January 2019 cold snap, day-ahead wind generation forecasts for the MISO area overestimated wind resource contributions by as much as 8 GW (over 56% of installed wind generation capacity). See Figure 5 for a plot of forecast and realized wind generation during the cold weather event. Low-temperature cutoff thresholds for some wind turbine generators were unidentified in wind forecast models, resulting in a significant deviation in actual wind generator outputs at low temperatures. During the January 2019 cold snap, MISO operators implemented emergency procedures, including voluntary load reduction, demand response, and the issuance of an EEA, to manage challenging operating conditions.

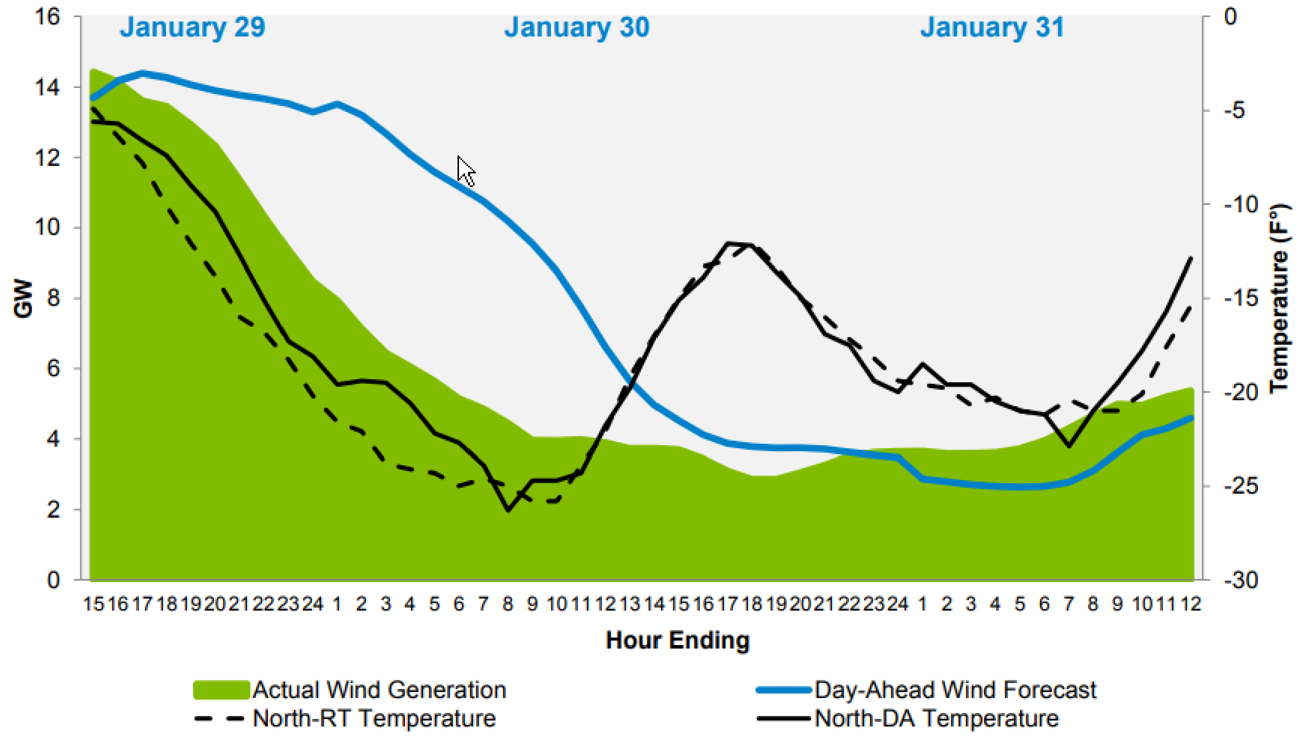


Figure 5: MISO Wind Generation during January 2019 Cold Snap [Source: MISO]

Although wind generation makes up a relatively small portion of the on-peak capacity for MISO and several other areas (see Figure 6 for a comparison of wind generation contributions for the upcoming winter and the 2014–2015 winter), the unanticipated reduction in wind generation capacity during extreme peak conditions can result in operating emergencies. System operators are taking steps in areas to begin to address these risks, such as the following:

- MISO worked with stakeholders and wind forecast vendors to ensure that operating parameters under extreme weather conditions are recognized in wind forecasts. MISO is also working with load-serving entities and operators in the MISO South area to improve load forecast accuracy and mid-term peak load forecasts for impending extreme conditions.
- In response to increasing wind penetration levels, SPP is continuing to evolve processes and procedures that address wind forecasting errors. A team of forecasting and modeling staff are established to support system operators with real-time decision making tools to ensure energy/capacity adequacy.

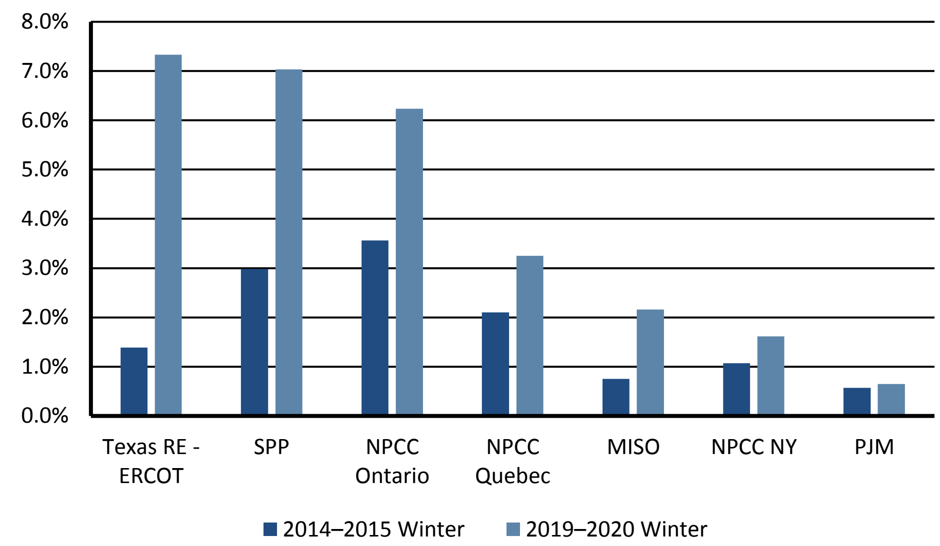


Figure 6: Wind Generation Contribution to On-Peak Winter Capacity

Higher Natural Gas Storage Inventories Help Reduce Natural-Gas-Fired Generator Fuel Supply Risks for the Winter Season

Natural gas injections into the largest storage areas in the continental United States have led to high preseason inventory levels as seen in **Figure 7**. Withdrawals from natural gas storage can be important to meeting peak-day demand. Prior to the start of winter, the largest natural gas storage facilities that are located in the East and South Central parts of the United States were at or near five-year high levels.

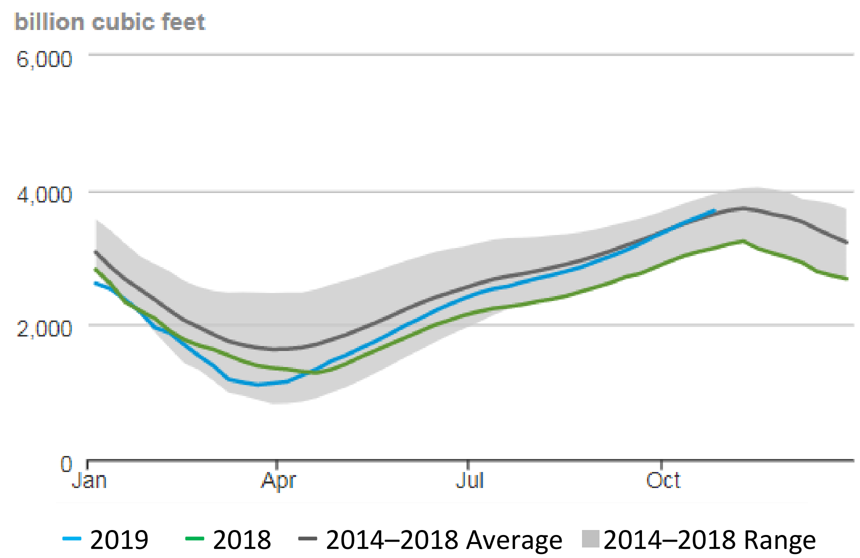


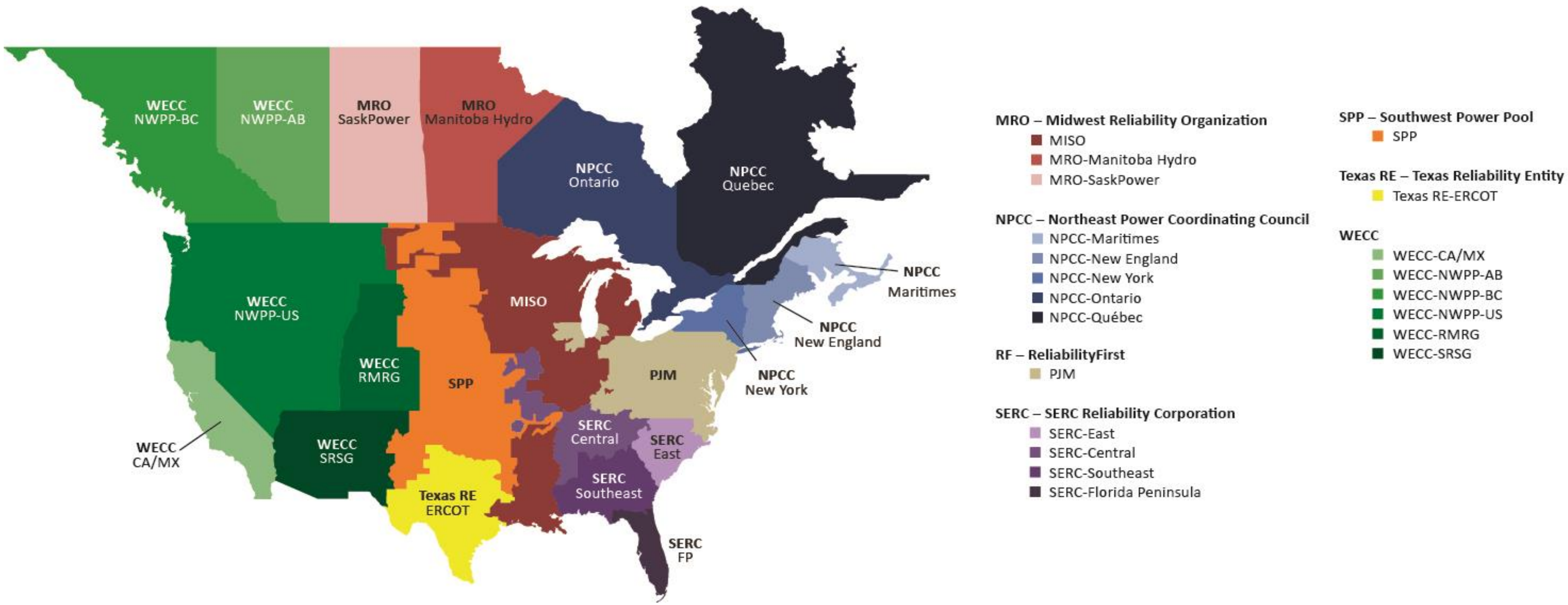
Figure 7: Total Natural Gas Storage in Continental United States as of October 25, 2019 [Source: EIA]

Natural gas storage in Southern California, including the restricted Aliso Canyon storage facility, has overcome storage deficits to be near storage levels last seen at the start of the 2018–2019 winter. With preseason natural gas storage levels similar to last year and improved outlook for natural gas supply pipelines (two supply pipelines into Southern California that were unavailable in the 2018–2019 winter are expected to be available for the upcoming winter), the California Public Utilities Commission (CPUC) staff assesses the risk of natural gas demand exceeding capacity to be the same or lower than last year.[9] However, natural gas supplies (including withdrawals from Aliso Canyon) could exceed peak day demand resulting in curtailment of noncore customers (including natural-gas-fired generators) in some scenarios assessed by CPUC staff. As in the three preceding winters, CAISO has operating procedures in place that are designed to mitigate potential risk to BPS reliability from natural gas curtailment to electricity generators. System operator actions may include employing demand response, redispatching generation, and increasing electricity imports to affected areas.

[9] See the report: *Winter 2019-2020 Southern California Reliability Assessment,* October 24, 2019, prepared by the CPUC staff: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Winter2019-20ReliabilityAssessment_Final.pdf

Regional Assessment Dashboards

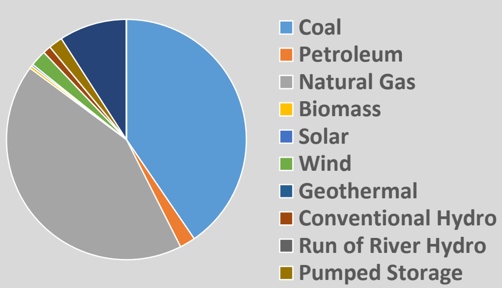
The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis.



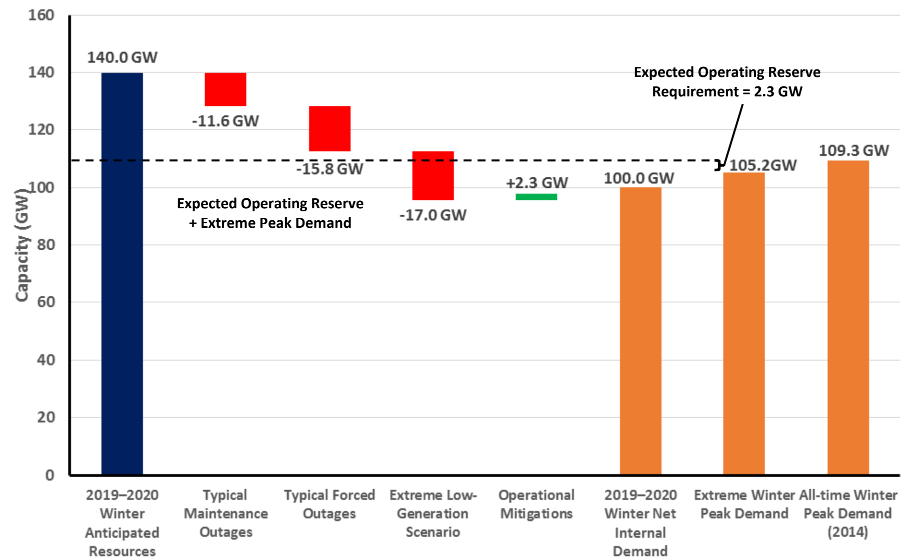
MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering 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 Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



Seasonal Risk Scenario



The table and chart above provide potential winter peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MISO determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this chart.

Risk Scenario Summary

Operating mitigations or EEAs may be needed under extreme peak demand and outage scenarios studied.

Scenario Assumptions

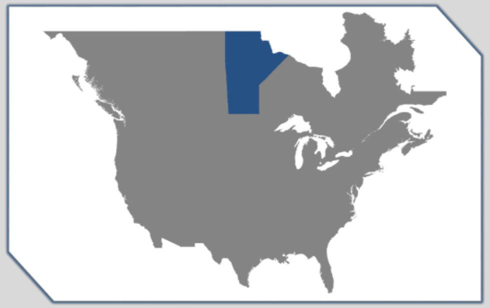
- Extreme Peak Load: 90/10 forecast
- Outages: Average from highest peak hour over the past five winters
- Extreme Generation Scenario: Additional outages corresponding to maximum generation outages observed at highest peak hour in past five years
- Operational Mitigations: Derived from required deployable contingency reserves.

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018–2019 WRA	2019–2020 WRA	2018–2019 vs. 2019–2020 WRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	102,587	103,841	1.2%
Demand Response: Available	2,715	3,822	40.8%
Net Internal Demand	99,873	100,019	0.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	135,995	139,555	2.6%
Tier 1 Planned Capacity	176	778	>100%
Net Firm Capacity Transfers	-8	-383	>100%
Anticipated Resources	136,163	139,951	2.8%
Existing-Other Capacity	1,067	535	-49.9%
Prospective Resources	137,230	140,486	2.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	35.7%	39.9%	4.2
Prospective Reserve Margin	37.0%	40.5%	3.5
Reference Margin Level	17.1%	16.8%	-0.3

Highlights

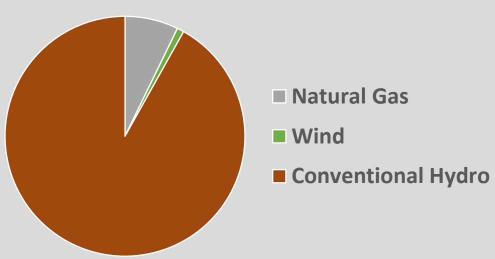
- MISO anticipates that reliability will be maintained during the upcoming season. Increases in anticipated resources as a result of a reduction in planned outages as well as growth in demand response contribute to higher Anticipated Reserve Margins compared to last winter.
- To address regional transfer limit issues identified during prior winter events, MISO and neighboring operators are implementing enhanced communications and operating procedures for joint actions during emergencies. MISO has also implemented new market rules for reserve procurement that account for regional transfer limits.
- MISO monitors wind forecast accuracy and has taken steps to address forecast issues, such as those observed during the January 30–31, 2019, Maximum Generation Event. In addition to MISO forecasting enhancements, the Dispatchable Intermittent Resource Workshop in April 2019 focused on MISO market rule changes and wind forecasting process.
- Winter preparedness is discussed annually at the MISO Winter Readiness Workshops, which were held this year on October 22.

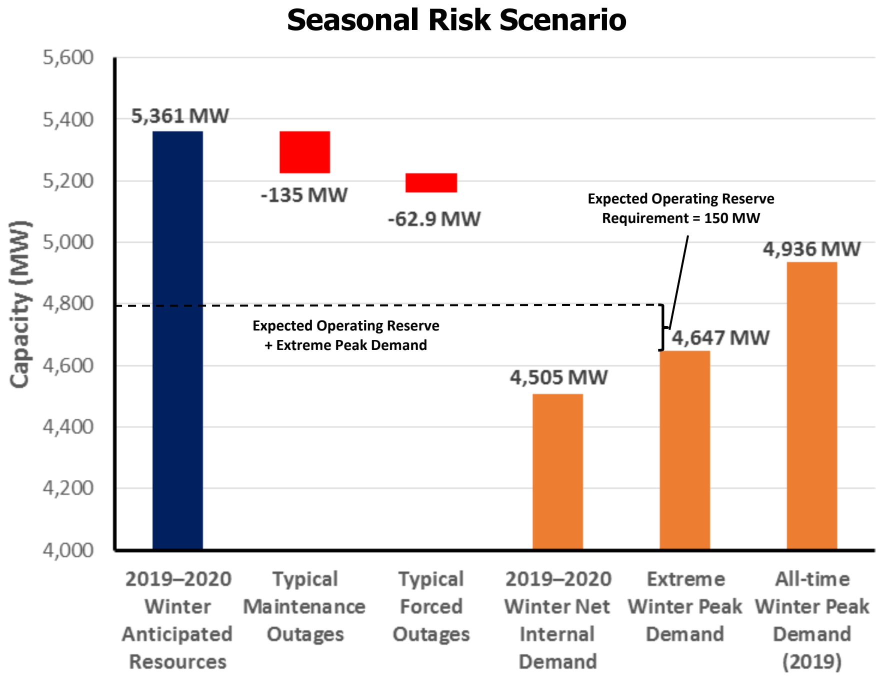


MRO-Manitoba Hydro

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 people 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.





The table and chart above provide potential winter peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** Exceeded only 1 hour in 10 years, considering historical hourly weather and load analysis and internal demand resources
- **Outages:** Based on historical operating experience

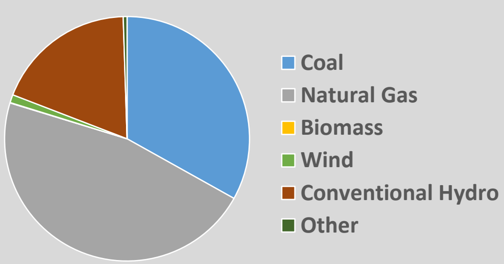
MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	4,388	4,505	2.7%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,388	4,505	2.7%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,583	5,469	-2.0%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-38	-108	>100%
Anticipated Resources	5,545	5,361	-3.3%
Existing-Other Capacity	5	53	>100%
Prospective Resources	5,458	5,414	-0.8%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	26.4%	19.0%	-7.4
Prospective Reserve Margin	24.4%	20.2%	-4.2
Reference Margin Level	12.0%	12.0%	0.0

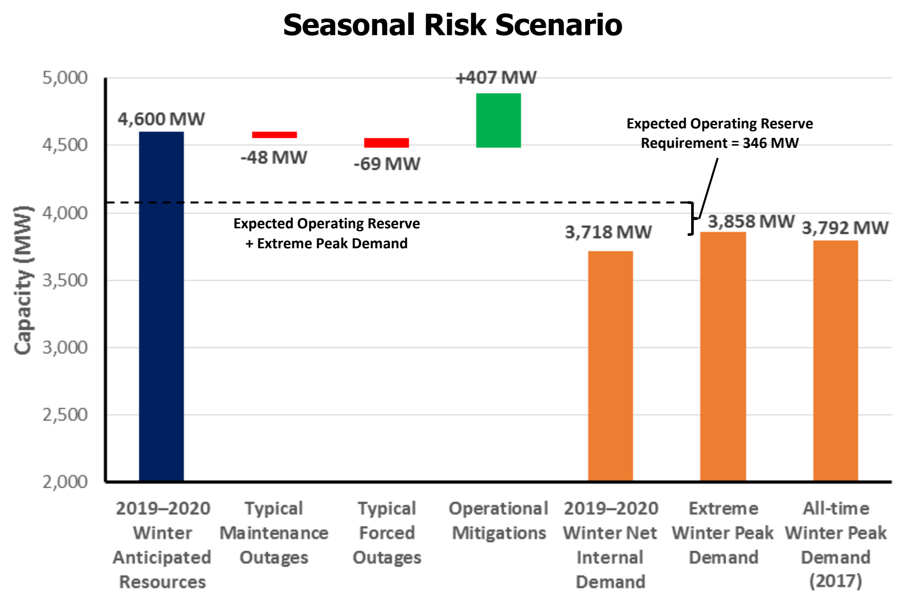
Highlights

- The Anticipated Reserve Margin during the winter of 2019–2020 exceeds the Reference Margin Level of 12%.
- Since the 2018–2019 WRA, Manitoba Hydro experienced 115 MW (nameplate) of confirmed retirements, consisting of 100 MW of coal generation and 15 MW of hydro generation

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 people. 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.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Peak demand, with lighting and all large consumer loads
- **Maintenance Outages:** Estimated based on average maintenance outages for December 2019
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** None applied. All derates are included in winter anticipated capacity.

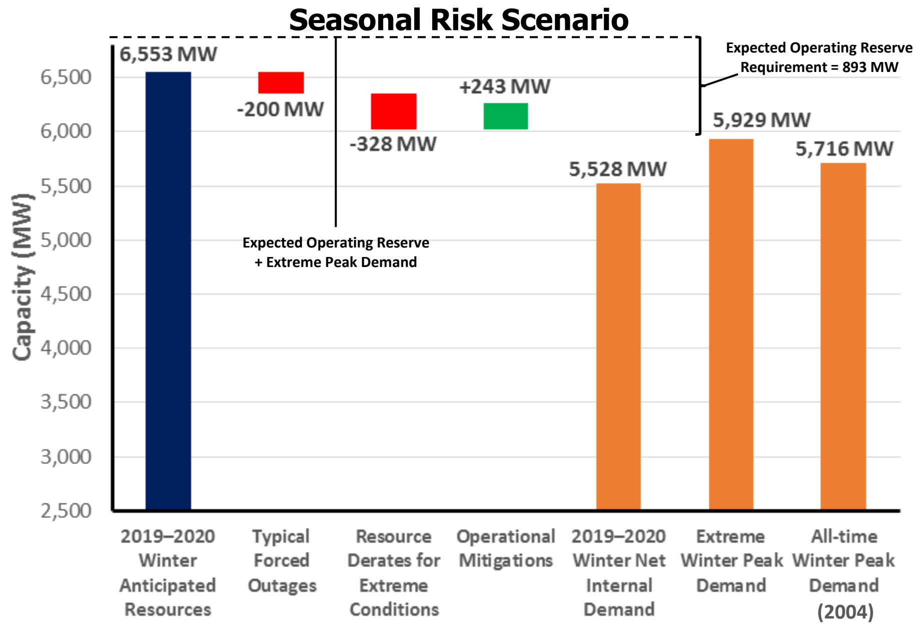
MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,843	3,803	-1.0%
Demand Response: Available	85	85	0.0%
Net Internal Demand	3,758	3,718	-1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	4,266	4,222	-1.0%
Tier 1 Planned Capacity	0	353	-
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	4,291	4,600	7.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,291	4,600	7.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	14.2%	23.7%	9.5
Prospective Reserve Margin	14.2%	23.7%	9.5
Reference Margin Level	11.0%	11.0%	0.0

Highlights

- SaskPower is projecting increased generation resources for the upcoming winter season with the expected addition of a 350 MW combined cycle natural gas generator in December. Anticipated resources exceed the 11.0% Reference Margin Level.
- The risk of operating reserve shortage during peak load times or EEA could increase if the new 350 MW planned generation is delayed (not expected), or in the event of large generation forced outage. Risk is greater during November 2019 when a 291 MW coal unit is off-line for overhaul maintenance.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro and receives inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion 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 people.



NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	5,387	5,528	2.6%
Demand Response: Available	253	243	-4.0%
Net Internal Demand	5,134	5,285	2.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	6,560	6,663	1.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	-110	>100%
Anticipated Resources	6,560	6,553	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,560	6,553	-0.1%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	27.8%	20.5%	-7.3
Prospective Reserve Margin	27.8%	20.5%	-7.3
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential winter peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

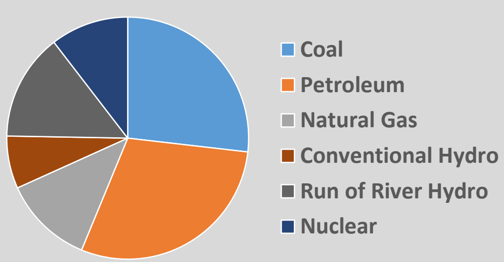
Operating mitigations or EEAs may be needed under extreme peak demand and outage scenarios studied.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Based on ambient temperature thermal derates and extreme case involving total loss of wind capacity

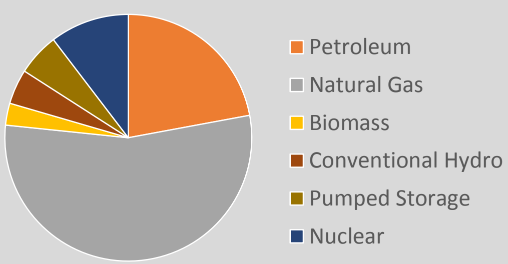
Highlights

- The Maritimes area anticipates system reliability will be maintained during the upcoming season.
- The Maritimes is a winter-peaking system with few planned transmission or generator outages. Operators are equipped with procedures and mitigations to address unplanned outages and maintain system reliability.

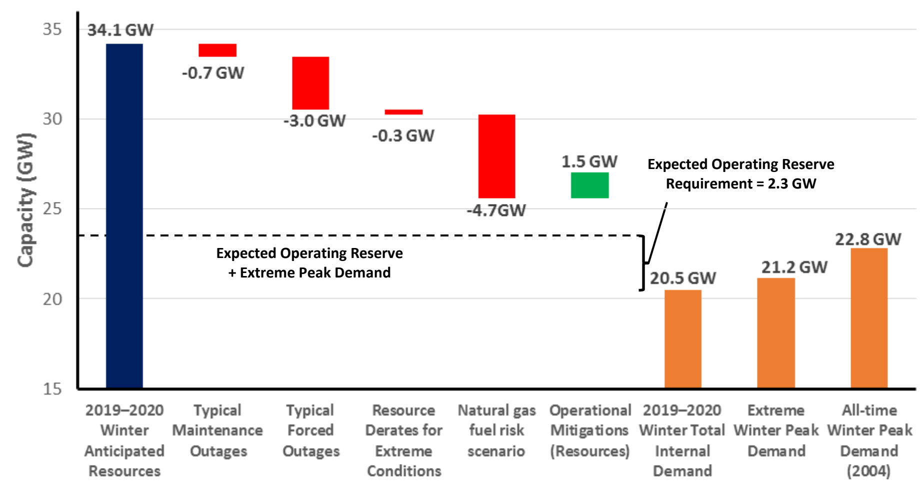


NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves 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, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.



Seasonal Risk Scenario



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	20,357	20,476	0.6%
Demand Response: Available	403	497	23.1%
Net Internal Demand	19,954	19,979	0.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	32,939	33,120	0.6%
Tier 1 Planned Capacity	302	12	-96.0%
Net Firm Capacity Transfers	986	1,017	3.1%
Anticipated Resources	34,226	34,149	-0.2%
Existing-Other Capacity	204	189	-7.5%
Prospective Resources	34,437	34,338	-0.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	71.5%	70.9%	-0.6
Prospective Reserve Margin	72.6%	71.9%	-0.7
Reference Margin Level	17.2%	18.4%	1.2

The table and chart above provide potential winter peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Based on weekly averages
- **Extreme Natural Gas Fuel Risk Scenario:** ISO-NE calculates the amount of generator at risk due to lack of natural gas during cold weather. No natural gas generation at risk above 30°F and a reduction curve for temperatures below 30°F.
- **Operating Mitigations:** Based on ISO-NE operating procedures

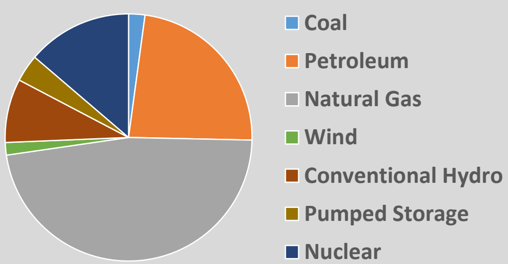
Highlights

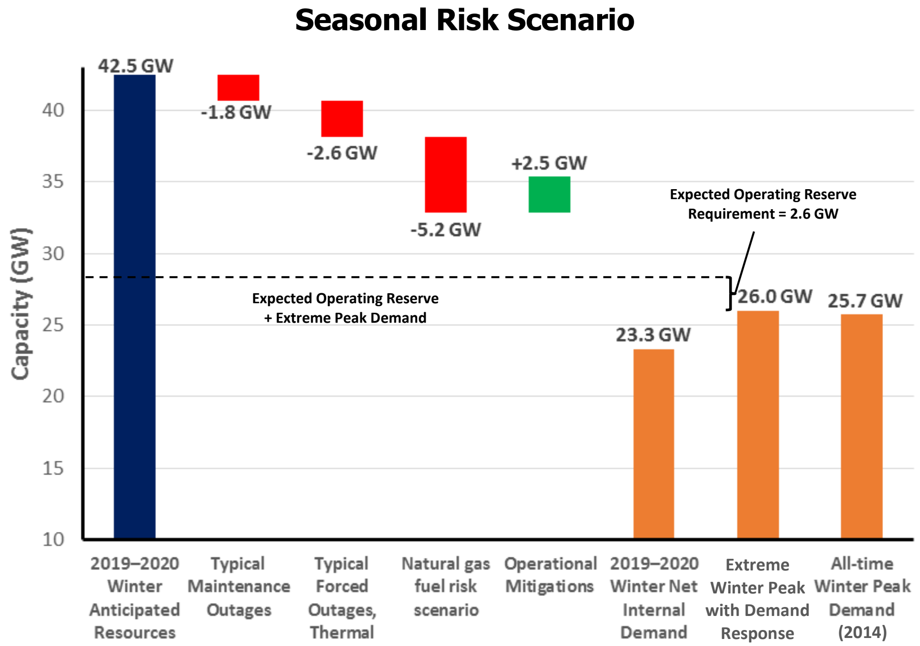
- The New England area expects to have sufficient resources to meet the 2019–2020 extreme winter peak demand forecast of 21,173 MW. However, as with the previous winter season, there is continuing concern that energy could be insufficient to satisfy electricity demand during an extended cold spell given the evolving resource mix and fuel delivery infrastructure.
- During the winter of 2018–2019, ISO-NE implemented a *21-Day Energy Assessment Forecast and Report* to provide market participants with early indication of potential fuel scarcity conditions and help inform fuel procurement decisions; ISO-NE plans to continue producing this report during the winter of 2019–2020. Additionally, ISO-NE's Energy Market Opportunity Cost project, which was instituted in 2018 and continuing for the upcoming winter, can help preserve the generating capacity of oil-fired and dual-fueled units until operating conditions warrant dispatching them.
- In June 2019, the 680 MW Pilgrim nuclear unit was retired. However, new combined-cycle and combustion natural gas turbine generating units totaling over 860 MW have been added in the area that offset significant change in capacity.

NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

The NERC 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 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 2019–2020 IRM at 17%.





The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** 90/10 load forecast with demand response adjustments
- **Typical Outages:** based on scheduled maintenance and GADS forced outage data
- **Natural Gas Fuel Risk Scenario:** Extreme scenario assumes all nonfirm supply is unavailable in a period of extended cold weather.
- **Operational Mitigation:** 2.5 GW of effects from emergency operating procedure.

NPCC-New York Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018–2019 WRA	2019–2020 WRA	2018–2019 vs. 2019–2020 WRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	24,269	24,123	-0.6%
Demand Response: Available	637	853	33.9%
Net Internal Demand	23,632	23,270	-1.5%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	39,214	41,815	6.6%
Tier 1 Planned Capacity	974	0	-100.0%
Net Firm Capacity Transfers	1,482	678	-54.3%
Anticipated Resources	41,671	42,493	2.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,596	42,493	2.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	76.3%	82.6%	6.3
Prospective Reserve Margin	76.0%	82.6%	6.6
Reference Margin Level	15.0%	17.0%	2.0

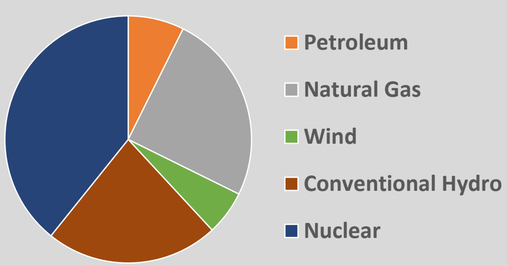
Highlights

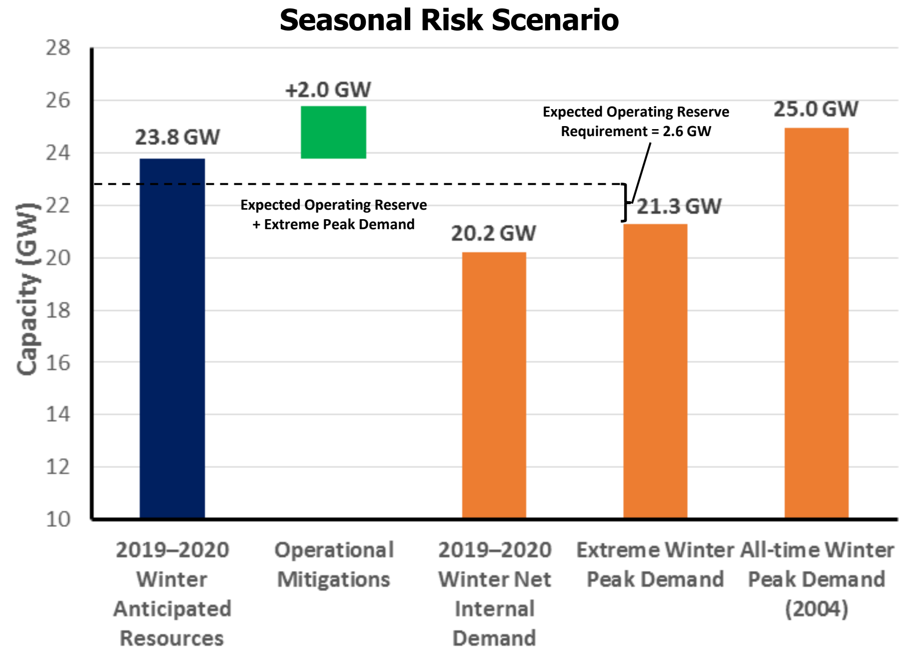
- New York is a summer peaking area and no emerging reliability issues are anticipated during the 2019–2020 winter assessment period. Capacity margins above the NYISO's operating reserve requirements are projected.
- NYISO is monitoring the potential for natural gas supplies to electric generators to be affected by natural gas infrastructure maintenance scheduled through the end of December. Potential risk to the BPS is mitigated by extensive dual-fuel generator capability. Generator preparations are informed by prior winter experience and include increased on-site fuel reserves, firm contracts with suppliers of back-up fuel, aggressive replenishment plans, and proactive pre-winter maintenance.
- Capacity transfers between New York and the adjacent areas of Ontario and PJM will be effected by tie-line maintenance for the duration of the winter season. The impacts have been coordinated between areas and accounted for in planned operations.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 415,000 square miles and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Ontario IESO treats demand response as a resource for its own assessments while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined from the most severe historical weather
- **Outages:** Accounted for in anticipated resources. No additional outages due to extreme conditions anticipated.
- **Extreme Derates:** None applied based on operating experience
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

NPCC-Ontario Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018–2019 WRA	2019–2020 WRA	2018–2019 vs. 2019–2020 WRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	21,334	21,115	-1.0%
Demand Response: Available	795	924	16.3%
Net Internal Demand	20,539	20,191	-1.7%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	27,666	24,298	-12.2%
Tier 1 Planned Capacity	40	0	-100.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	27,206	23,798	-12.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	27,206	23,798	-12.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.5%	17.9%	-14.6
Prospective Reserve Margin	32.5%	17.9%	-14.6
Reference Margin Level*	18.4%	14.4%	-4.0

* Difference in Reference Margin Level between the 2019–2020 WRA and the prior year is due to change in calculation method by IESO.

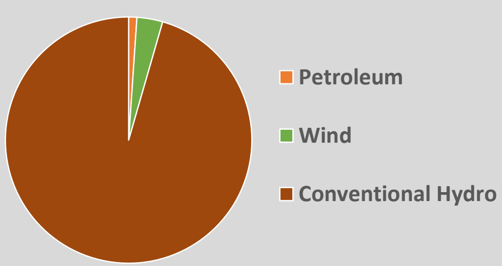
Highlights

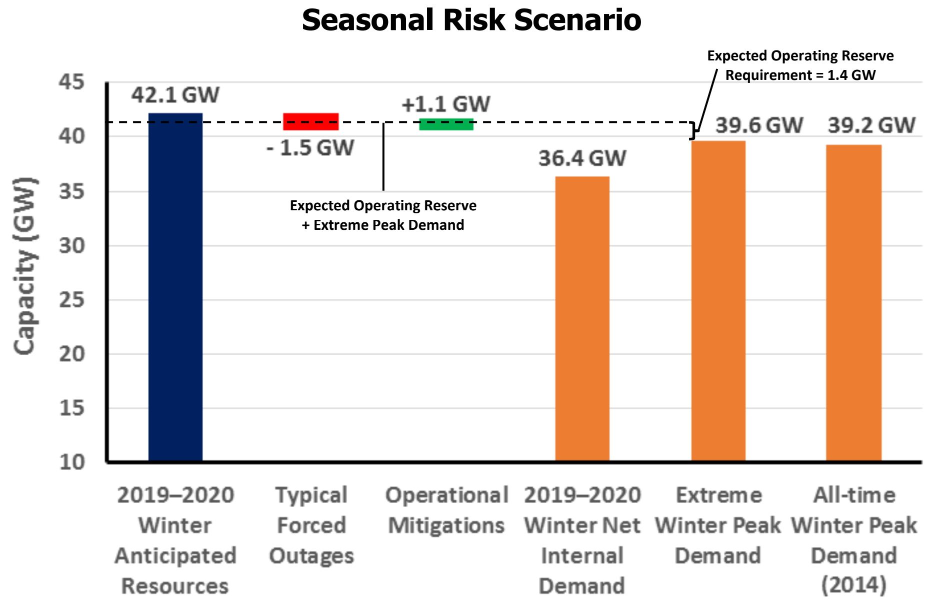
- IESO anticipates that it will maintain reliability on its system through the winter of 2019–2020.
- Nuclear refurbishment schedules and other nuclear and hydroelectric planned outages will reduce generation capacity for the coming winter season; however, IESO expects to have sufficient generation supply to meet demand.
- Imports and exports between New York and Ontario continue to be impacted due to an ongoing interconnection equipment outage at the St. Lawrence Transmission Station. The IESO and affected parties continue to work toward a resolution.

NPCC-Québec

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

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





NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	38,461	38,665	0.5%
Demand Response: Available	2,354	2,284	-3.0%
Net Internal Demand	36,107	36,382	0.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	42,046	41,917	-0.3%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	299	202	-32.4%
Anticipated Resources	42,345	42,119	-0.5%
Existing-Other Capacity	0	1,100	0.0%
Prospective Resources	43,445	43,219	-0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	17.3%	15.8%	-1.5
Prospective Reserve Margin	20.3%	18.8%	-1.5
Reference Margin Level	12.6%	12.8%	0.2

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** It is based on 50/50 load forecast with two standard deviations.
- **Forced Outages:** Hydro resources operate in extreme conditions without increased outage rates.
- **Operational Mitigations:** 1,100 MW of non-firm imports are anticipated to be available in short-term capacity purchases.

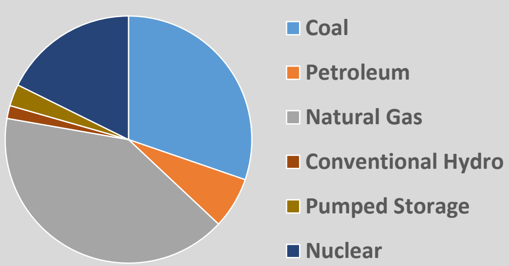
Highlights

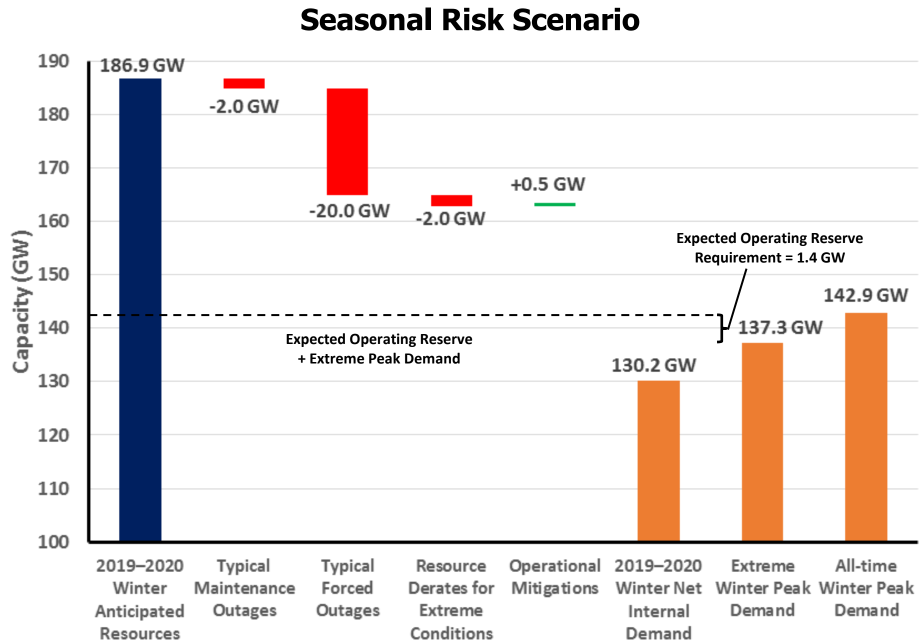
- Québec predicts that it will maintain system resource adequacy this winter.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2019–2020 winter assessment period.
- A new 735 kV line was commissioned in May 2019 providing more flexibility to system operators and limiting the severity of potential system contingencies at the southern interface.

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 people 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.





PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018–2019 WRA	2019–2020 WRA	2018–2019 vs. 2019–2020 WRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	132,357	131,148	-0.9%
Demand Response: Available	1,331	965	-27.5%
Net Internal Demand	131,026	130,183	-0.6%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	181,864	186,070	2.3%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,535	830	-46.0%
Anticipated Resources	183,399	186,899	1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	183,399	186,899	1.9%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	40.0%	43.6%	3.6
Prospective Reserve Margin	40.0%	43.6%	3.6
Reference Margin Level	16.1%	16.0%	-0.1

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. PJM determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages and Derates:** Estimated from analysis of previous winter peak periods

Highlights

- The PJM reserve margin for this winter is 43.6%, which exceeds the Reference Margin Level of 16%. With this level of capacity, PJM has not identified any emerging resource adequacy issues.
- While not specific to the winter, PJM's capacity performance initiative continues to apply to more resources over time and is getting near full participation.

SERC

On April 30, 2019, the Federal Energy Regulatory Commission issued an order formally approving the transfer of all registered entities in the Florida Reliability Coordinating Council (FRCC) Region to SERC by July 1, 2019. The integration of FRCC entities resulted in an additional SERC subregion and SERC assessment area for inclusion in NERC's reliability assessments.

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into four assessment areas: SERC-E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC Region includes 36 Balancing Authorities, 21 Planning Authorities, and four Reliability Coordinators.

SERC Resource Adequacy Data

Demand, Resource, and Reserve Margins	SERC-E	SERC-C	SERC-SE	SERC-FP	2018–2019 WRA SERC Total	2019–2020 WRA SERC Total	2018–2019 vs. 2019–2020 WRA
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	45,334	40,907	45,863	43,962	173,790	176,066	1.3%
Demand Response: Available	966	1,983	2,305	2,887	7,691	8,141	5.9%
Net Internal Demand	44,368	38,924	43,558	41,075	166,099	167,925	1.1%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	54,650	54,223	63,069	55,383	225,549	227,325	0.8%
Tier 1 Planned Capacity	574	0	117	1,826	1,952	2,516	28.9%
Net Firm Capacity Transfers	530	355	-1,905	1,257	-907	237	-
Anticipated Resources	55,754	54,578	61,280	58,465	226,594	230,078	1.5%
Existing-Other Capacity	42	2,585	1,445	289	2,665	4,361	63.6%
Prospective Resources	55,796	57,164	62,726	58,754	229,359	234,439	2.2%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	25.7%	40.2%	40.7%	42.3%	36.4%	37.0%	0.6
Prospective Reserve Margin	25.8%	46.9%	44.0%	43.0%	38.1%	39.6%	1.5
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0

Highlights

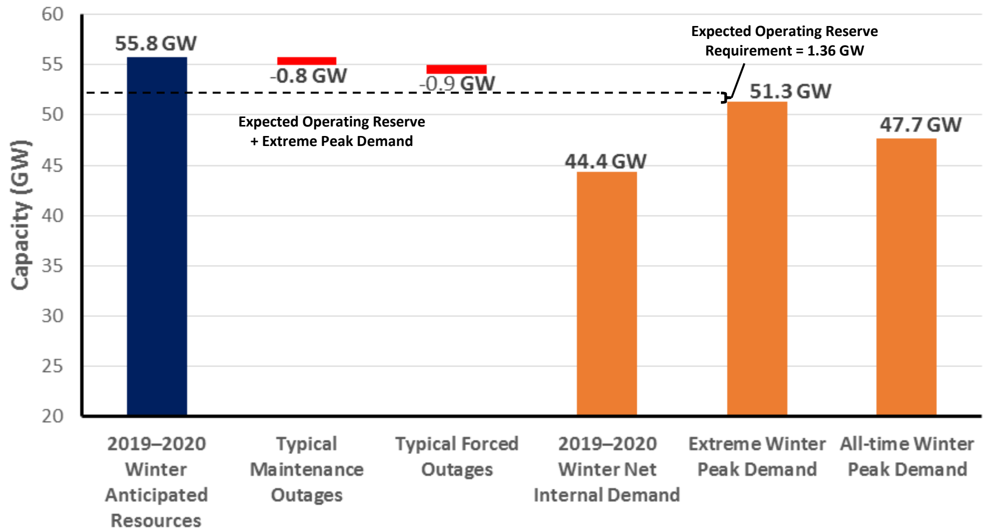
- SERC entities have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC entities are not anticipating any significant reliability issues resulting from fuel supply, inventory, or transportation.
- To address regional transfer limit issues identified during prior winter events, MISO and neighboring operators, including SERC-SE entities, are implementing enhanced communications and operating procedures for joint actions during emergencies.

Charts

The charts on the following pages provide potential seasonal peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the following pages present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below each chart. See the **Data Concepts and Assumptions** for more information about the charts.

SERC-E

Seasonal Risk Scenario

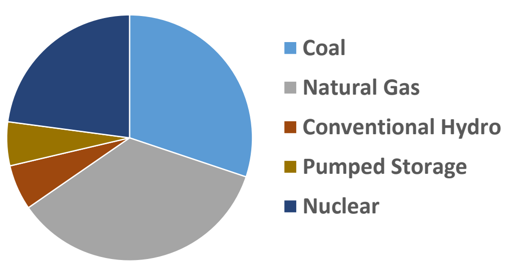


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

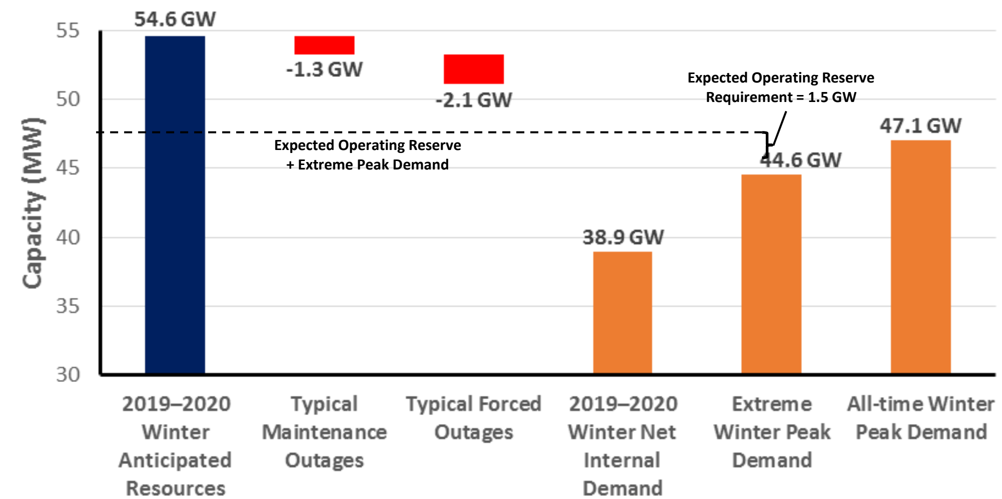
Scenario Assumptions

- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



SERC-C

Seasonal Risk Scenario

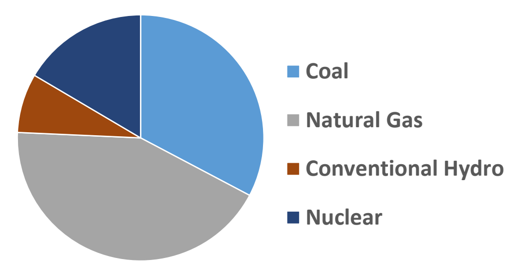


Risk Scenario Summary

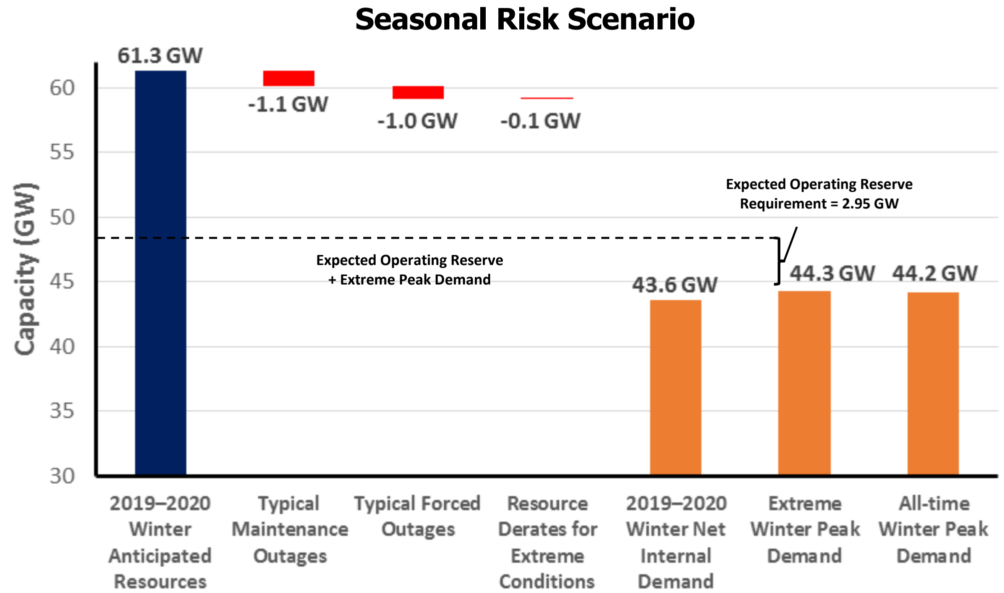
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



SERC-SE

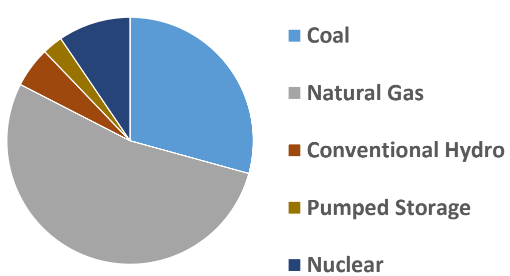


Risk Scenario Summary

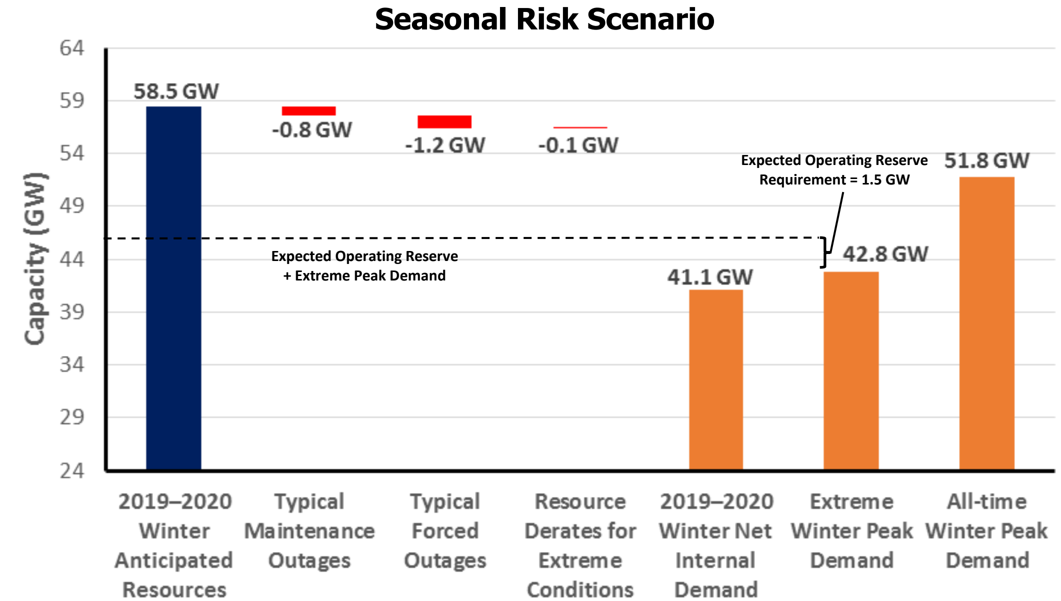
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



SERC-FP

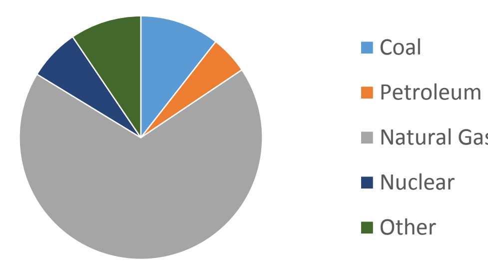


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

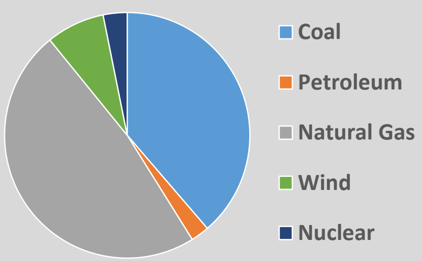
- **Extreme Peak Load:** Based on 90/10 Forecast
- **Outages:** Historical average MW during winter peaks
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



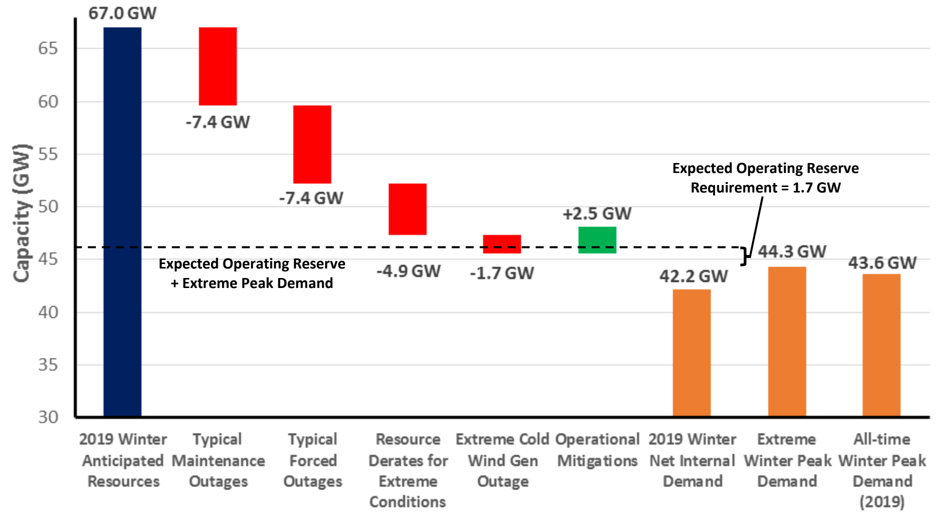
SPP

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 people.



Seasonal Risk Scenario



The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SPP determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data
- **Extreme Cold Wind Gen Outage:** 1.7 GW of wind potentially off line when temperatures fall below their cold weather performance packages
- **Operational Mitigations:** Additional capacity from committed generation to mitigate energy emergencies

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	40,510	42,399	4.7%
Demand Response: Available	432	223	-48.3%
Net Internal Demand	40,078	42,176	5.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,767	67,395	-0.5%
Tier 1 Planned Capacity	5	0	-100.0%
Net Firm Capacity Transfers	-330	-378	14.5%
Anticipated Resources	67,442	67,018	-0.6%
Existing-Other Capacity	100	0	-100.0%
Prospective Resources	67,542	66,972	-0.8%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	68.3%	58.9%	-9.4
Prospective Reserve Margin	68.5%	58.8%	-9.7
Reference Margin Level	12.0%	12.0%	0.0

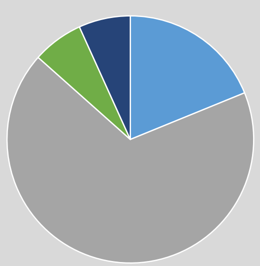
Highlights

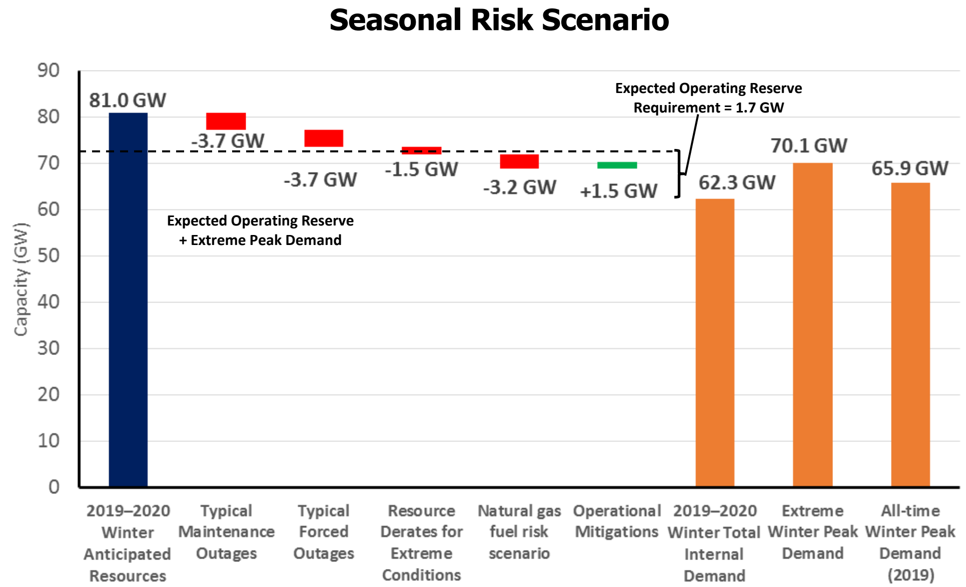
- SPP anticipates having adequate planning reserves for the winter season.
- SPP has worked with neighboring areas to address potential electric deliverability issues associated with extreme weather events, such as those observed during the January 2018 cold snap. Efforts are aimed at enhancing communications and operator preparedness.
- Increasing levels of wind generation can create operational challenges in the area at times. The Uncertainty Response Team supports operators with real-time decision making to ensure adequate energy capacity. Additionally, SPP has taken steps to address load and wind forecasting errors.
- The winter workshop was held on October 1, 2019, for SPP members.

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 Balancing Authority. 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 Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has 650 generation units, and serves more than 25 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT Region.





The table and chart above provide potential winter peak demand and resource condition information. The table presents a standard seasonal assessment and comparison to the previous year's assessment. The chart presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions.

Risk Scenario Summary

Operating Mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** Based on 2011 historic winter peak load
- **Typical Outages:** A capacity derate for thermal resources based on historical averages (Wind, solar, and hydro outages are accounted for in capacity contribution percentages.)
- **Derates for Extreme Conditions:** The expected amount of natural-gas-fired generator derates/outages due to natural gas curtailment at the time of an extreme peak load
- **Natural Gas Risk Scenario:** Extreme, low-likelihood event reflecting the amount of additional natural-gas-fired generation derates and outages for extreme-low (sub 20°F) temperatures
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, voltage reduction, and mothballed capacity) to support maintaining operating reserves, not already counted in WRA reserve margins

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018–2019 WRA**	**2019–2020 WRA**	**2018–2019 vs. 2019–2020 WRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	58,229	62,257	6.9%
Demand Response: Available	1,912	2,685	40.5%
Net Internal Demand	56,317	59,572	5.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	77,628	79,741	2.7%
Tier 1 Planned Capacity	762	1,191	56.3%
Net Firm Capacity Transfers	346	50	-85.5%
Anticipated Resources	78,735	80,982	2.9%
Existing-Other Capacity	840	509	-39.4%
Prospective Resources	79,921	82,284	3.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	39.8%	35.9%	-3.9
Prospective Reserve Margin	41.9%	38.1%	-3.8
Reference Margin Level	13.75%	13.75%	0.0

Highlights

- ERCOT anticipates no reliability issues for the upcoming winter season and should have sufficient generation resources available to meet system-wide peak demand.
- ERCOT expects to have sufficient resources under a scenario that assumes extreme peak load conditions with an associated increase in unit outages and derates due to weather-related natural gas supply disruptions.
- An additional 1,179 MW of planned winter-rated resource capacity is projected to be added by the start of the winter season based on developer information provided to ERCOT.
- Texas Reliability Entity and ERCOT conducted their seventh winter Generator Weatherization Workshop on September 5, 2019, where plant engineers presented their experiences with recent extreme weather events and shared lessons learned and planning advice. There have been no changes to winter preparedness programs.

WECC

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 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 people, it is geographically the largest and most diverse of the NERC Regional Entities. 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, and all or portions of the 14 western states in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB) and British Columbia (WECC BC). These subregional divisions are used for this study as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data

Demand, Resource, and Reserve Margins	WECC AB	WECC BC	CA/MX	NWPP-US	RMRG	SRSG	2018–2019	2019–2020	2018–2019 vs. 2019–2020 WRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,939	11,468	39,615	47,643	10,423	15,852	136,151	136,939	0.6%
Demand Response: Available	0	0	845	307	225	126	1,561	1,503	-3.7%
Net Internal Demand	11,939	11,468	38,770	47,336	10,198	15,726	134,590	135,436	0.6%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**		**Net Change (%)**
Existing-Certain Capacity	14,896	13,284	46,613	58,781	15,740	29,162	183,411	178,476	-2.7%
Tier 1 Planned Capacity	0	9	0	40	0	433	3,302	482	-85.4%
Net Firm Capacity Transfers	0	0	0	700	0	0	700	700	0.0%
Anticipated Resources	14,896	13,294	46,613	59,521	15,740	29,594	187,414	179,658	-4.1%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	15,031	13,294	46,785	59,619	15,740	29,685	191,803	180,154	-6.1%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**		**Annual Difference**
Anticipated Reserve Margin	24.8%	15.9%	20.2%	25.7%	54.4%	88.2%	39.2%	32.7%	-6.5
Prospective Reserve Margin	25.9%	15.9%	20.7%	25.9%	54.4%	88.8%	42.5%	33.0%	-9.5
Reference Margin Level	10.4%	10.4%	8.0%	16.0%	12.5%	13.0%	14.1%	11.7%	-2.4

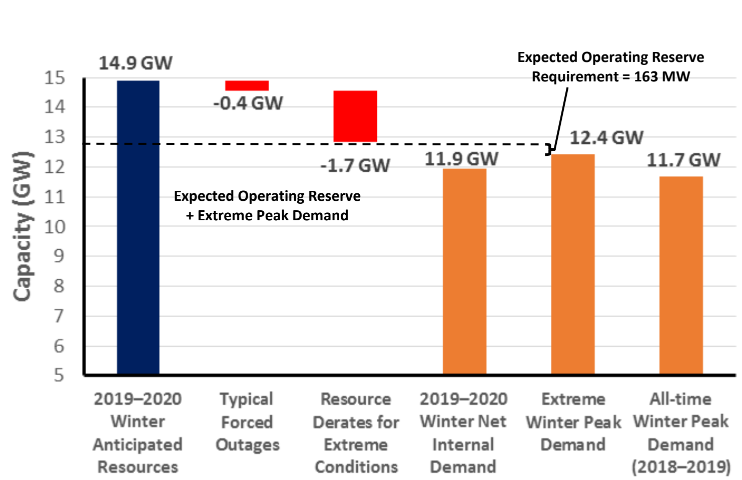
Highlights

- WECC anticipates that its six assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level and maintain resource adequacy through the 2019–2020 winter season.
- WECC and NERC are monitoring the transition of RC responsibilities in the Western Interconnection as Peak RC prepares for disestablishment at the end of 2019. Changes in NERC-certified RCs have occurred in California (July 1), British Columbia (September 2), and will occur in other parts of the Western Interconnection by December 3. Certification site visits, shadow-operating periods with Peak RC, and WECC-sponsored RC transition activities have been implemented to manage reliability risks.
- Inventories of the Aliso Canyon natural gas storage facility remain an item of focus for reliability within the Western Interconnection. This condition is being closely monitored by the CAISO, SoCal Gas, and WECC's Situational Awareness Group. Current natural gas storage inventory of the Southern California natural gas system is 71.2 Bcf, comparing that to 79.2 Bcf of storage for this time last year. Current storage capacity is 135 Bcf.
- Winterization techniques are implemented throughout the freezing zones to mitigate against severe weather or unexpected equipment failure. National Weather Service models predict mild winter conditions in the Western Interconnection.

The charts on the next page provide potential peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Data Concepts and Assumptions for more information about the charts.

WECC-Alberta

Seasonal Risk Scenario

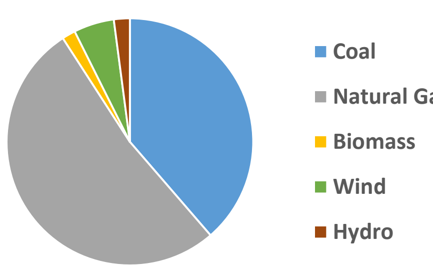


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

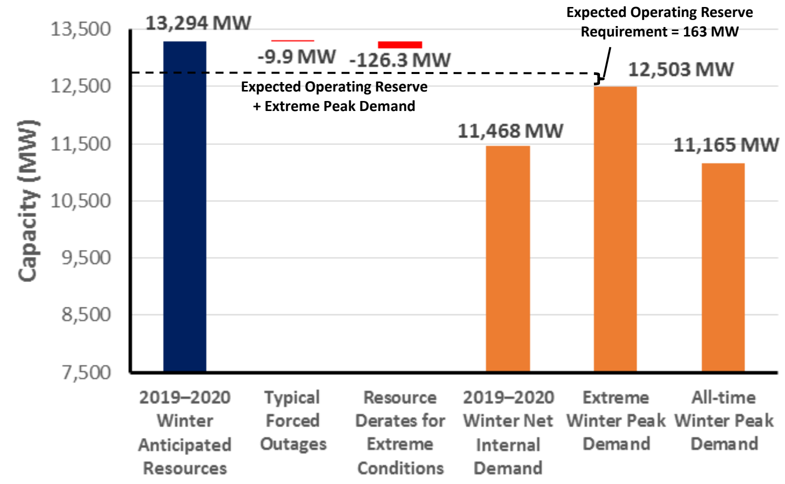
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-British Columbia

Seasonal Risk Scenario

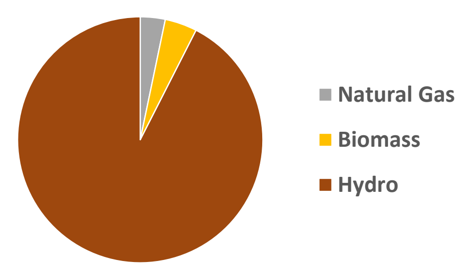


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

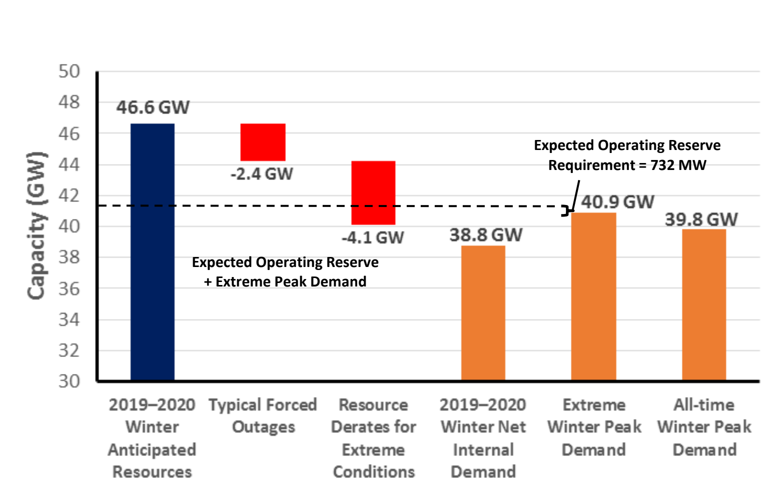
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-California/Mexico

Seasonal Risk Scenario

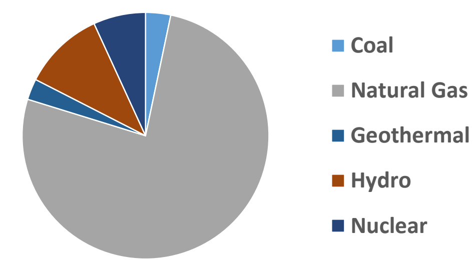


Risk Scenario Summary

Operating Mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions.

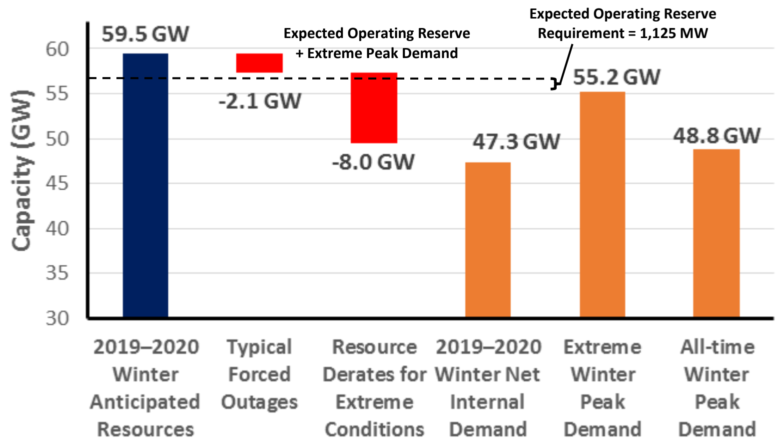
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Northwest Power Pool

Seasonal Risk Scenario

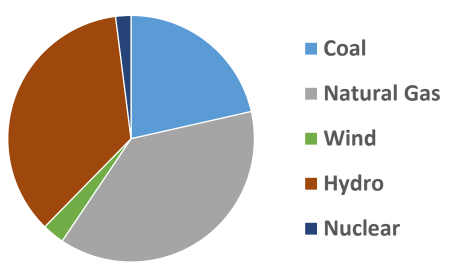


Risk Scenario Summary

Operating Mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions.

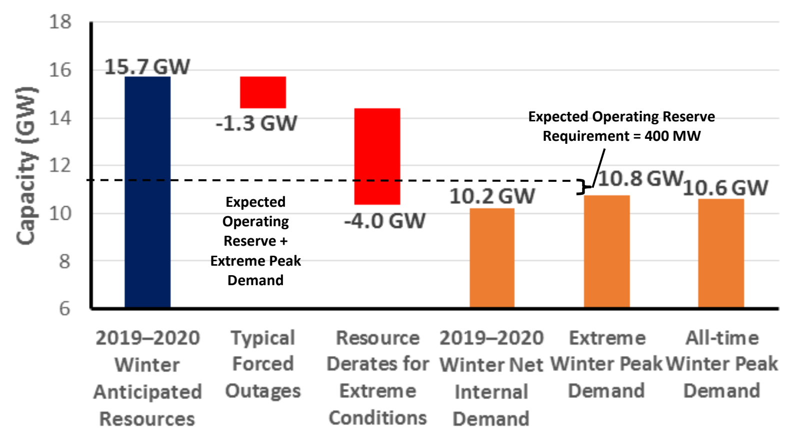
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario

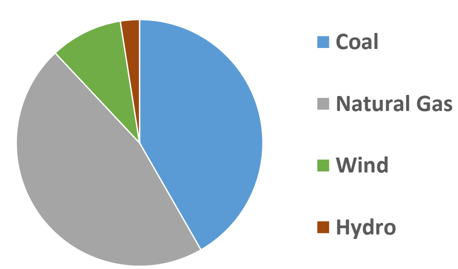


Risk Scenario Summary

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

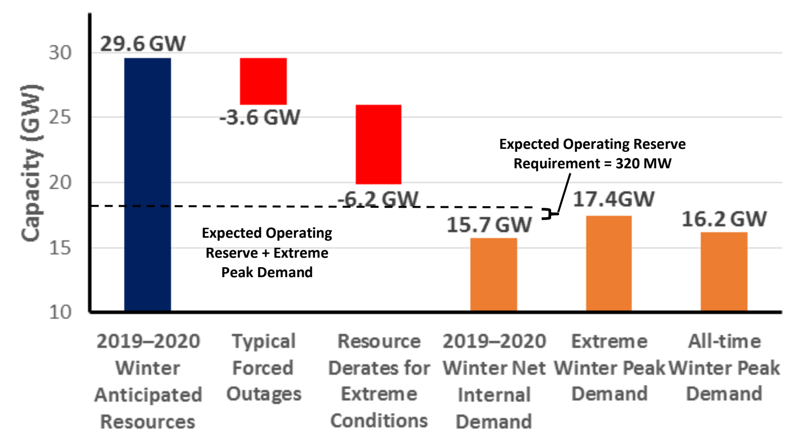
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario

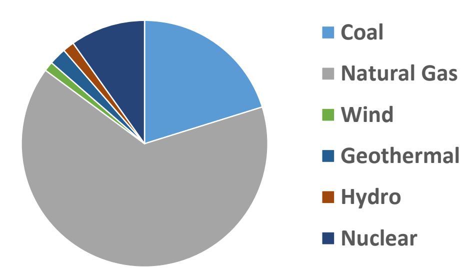


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



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 electric 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 electric 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.
• *2019 Long-Term Reliability Assessment* data has been used for most of this 2019 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[10] or total internal demand for the summer and winter of each year.[11]
• Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] 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 following categories to provide a consistent approach for collecting and presenting resource adequacy:
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 winter season: unit must have a firm capability and have a power purchase agreement (PPA) 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.

[10] *Glossary of Terms* used in NERC Reliability Standards

[11] The summer season represents June–September and the winter season represents December–February.

[12] 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.

[13] 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.

Reserve Margin Definitions

Reserve margin 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.

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 Assessment Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter 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 (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. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme winter peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.