

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Summer Reliability Assessment

**June 2019**

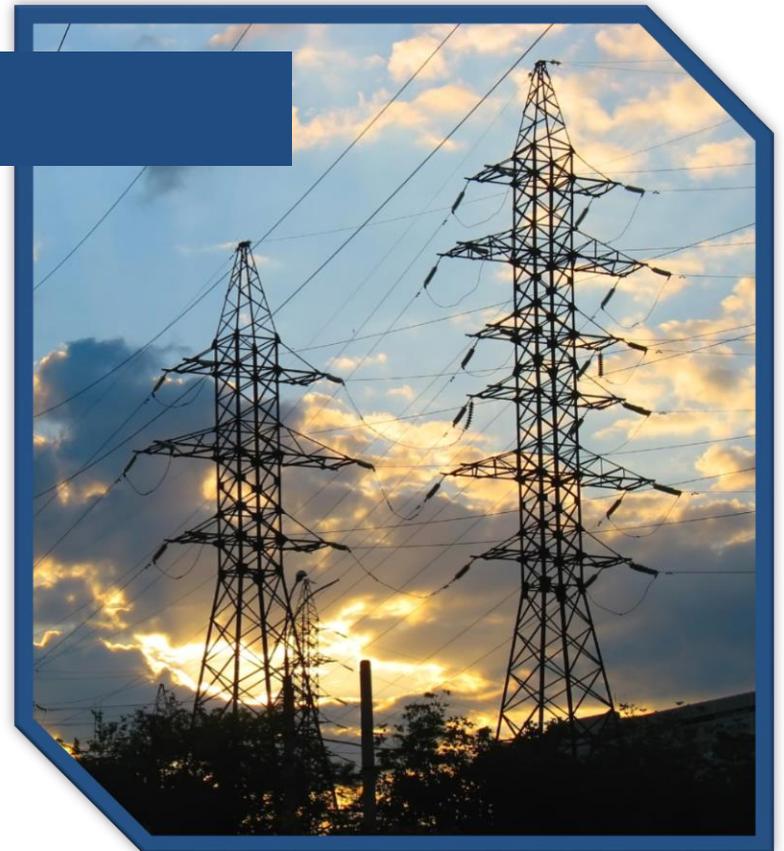


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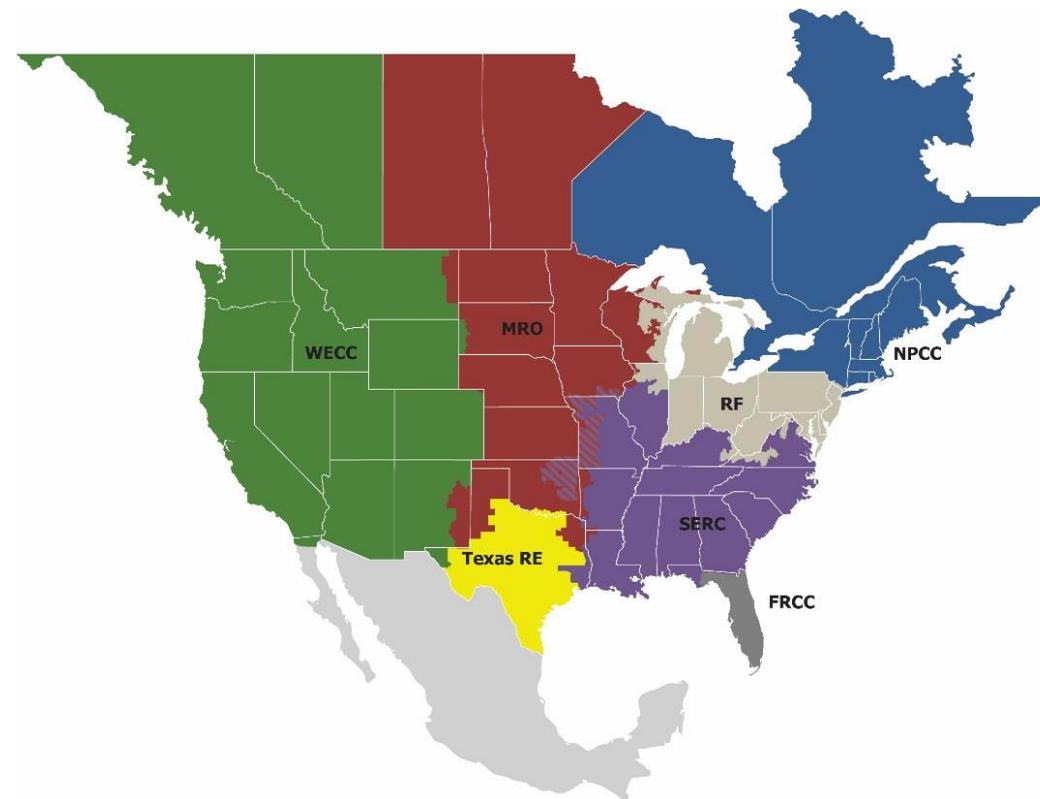
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## Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven 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. The North American BPS is divided into seven REs with boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region 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 Assessment Dashboards](#) section.

## About this Report

NERC’s *2019 Summer Reliability Assessment* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, this assessment presents peak electricity demand and supply changes and 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 summer period.



## Key Findings

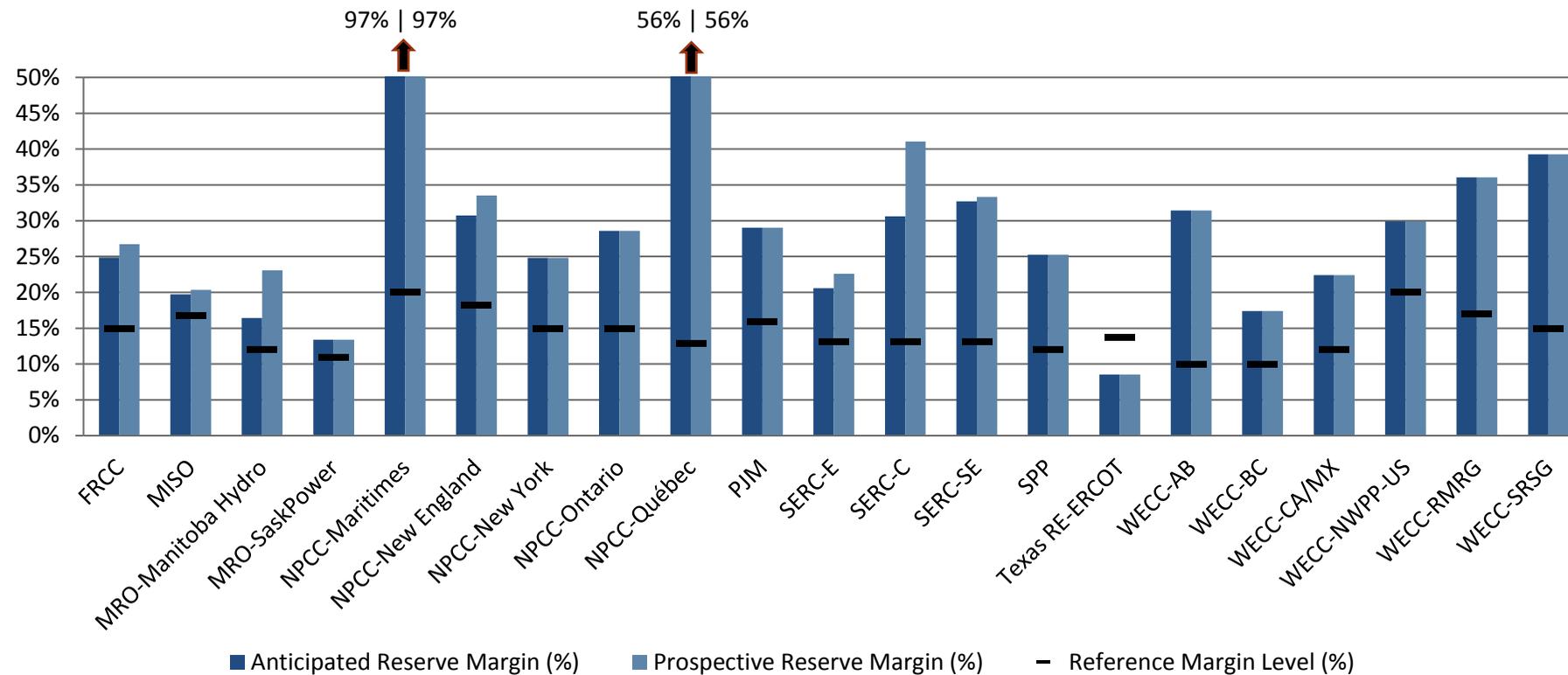
NERC's annual *Summer Reliability Assessment* covers the four-month Summer 2019 (June–September) period. This assessment provides an evaluation of whether there is adequate generation and transmission necessary to meet projected summer peak demands. The assessment monitors and identifies potential reliability issues and regional areas of concern that pertain to meeting projected customer demands. The following key findings represent NERC's independent evaluation of electric generation capacity and potential operational concerns that may need to be addressed:

- **ERCOT anticipates Energy Emergency Alerts may be needed to address resource shortfalls during periods of peak demand.** In ERCOT, the Anticipated Reserve Margin remains below the Reference Margin Level of 13.75%. ERCOT's Anticipated Reserve Margin decreased from 10.9% in Summer 2018 to 8.5% for the upcoming summer season. The reduction is caused by higher load growth, a planned generator retirement, and delays in new generation. If resource shortfalls occur, ERCOT anticipates implementing operating mitigations. These measures include importing additional power if available and energy emergency alerts that allow ERCOT to trigger emergency procedures such as voluntary load reduction.
- **Most assessment areas meet or exceed Reference Margin Levels and have sufficient electricity resources for anticipated conditions and more extreme scenarios.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage loss of load risk under normal conditions.<sup>1</sup> NERC also examined more extreme resource and demand conditions in each assessment area through seasonal risk scenarios. In some assessment areas, extreme summer peak loads and low-probability generator outage scenarios can result in insufficient resources to meet expected operating reserve requirements. In instances where operating reserve requirements are not met, system operators should employ operating procedures and mitigations, which may include demand response, Energy Emergency Alerts that support increased transfers, and other operational mitigations to manage resources and loads.
- **California faces ramping capability concerns.** In the California Independent System Operator (CAISO) area, there is the potential for operational risks at certain times of day as a result of shortages in resources with upward ramping capability. These shortage conditions are more prevalent during late afternoon as solar generation output decreases while system demand is still high. Transfers from neighboring areas may be needed during normal conditions when short on load-following resources capable of ramping up within the CAISO area.
- **Natural-gas-fired electric generation in Southern California will continue to need fuel from natural gas storage facilities for summer reliability.** The natural gas system operator in Southern California assesses that supplies from interstate pipelines alone may not be sufficient to meet the needs of all customers on summer peak load days, leaving electric generators at risk of curtailment. As a result, withdrawals from the Aliso Canyon natural gas storage facility would be necessary to ensure adequate fuel for generators in the Southern California area.
- **Elevated risk for wildfires in Western United States and parts of Canada poses risk to BPS reliability.** Government agencies predict above-normal wildfire risk for summer throughout parts of North America. Operation of the BPS 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. In some areas, pre-season planning includes expanded public safety power shut-off programs in addition to maintenance and operational preparations.

<sup>1</sup> For more information, see the description of the "Reference Margin Level" in the [Data Concepts and Assumptions](#) section of this report, or refer to NERC's Long-term Reliability Assessment: [https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC\\_LTRA\\_2018\\_12202018.pdf](https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf)

## Resource Adequacy

NERC uses the Anticipated Reserve Margin to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak load.<sup>2</sup> Large year-to-year changes in anticipated resources or forecasted peak load can greatly impact Planning Reserve Margin calculations. As shown in [Figure 1](#), other than Texas RE-ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their planning Reference Margin Level for the Summer 2019 period. Discussion of significant changes to Anticipated Reserve Margins in the Texas RE-ERCOT and WECC assessment areas are provided in the following sections.

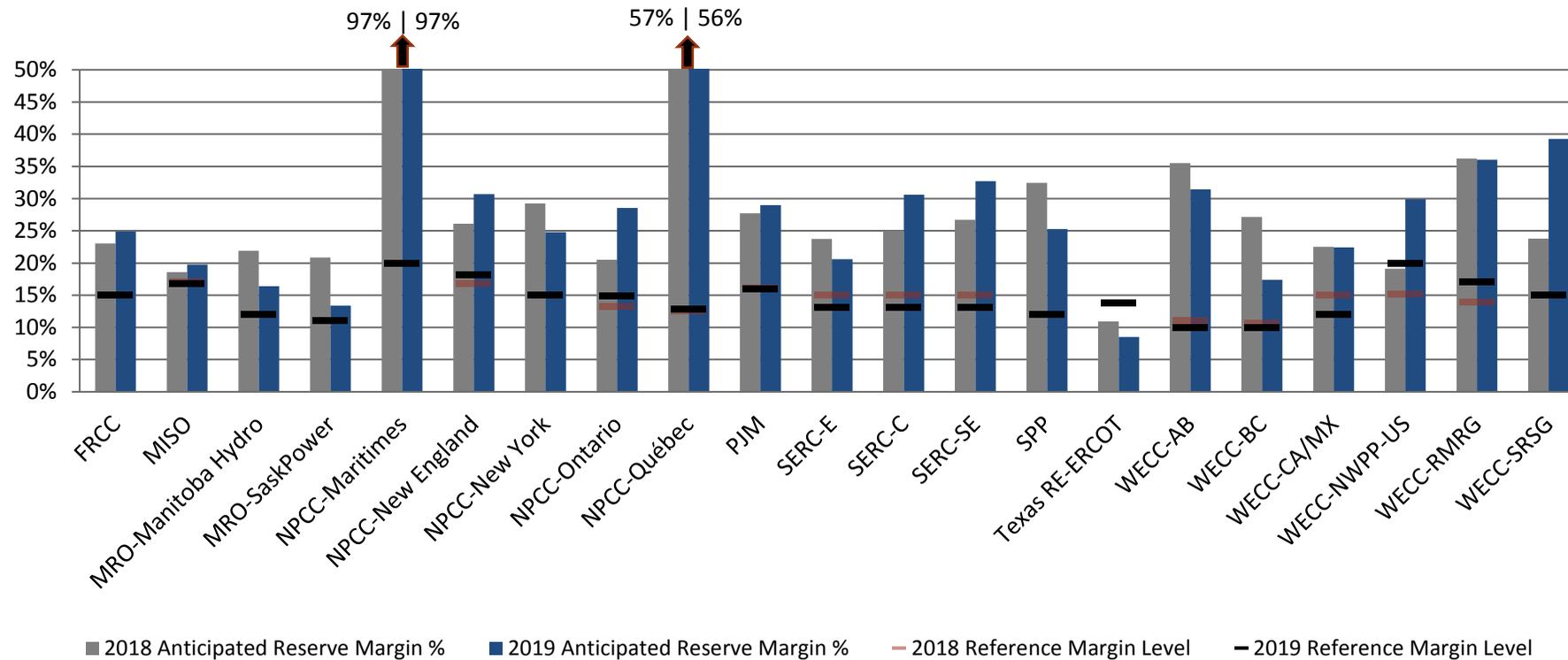


**Figure 1: Summer 2019 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level**

<sup>2</sup> Refer to the [Data Concepts and Assumptions](#) section for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.

### Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. This understanding can be used to further examine potential operational issues that emerge between reporting years. [Figure 2](#) provides the relative change from the Summer 2018 to the Summer 2019 period.



**Figure 1: Summer 2018 to Summer 2019 Anticipated Reserve Margins Year-to-Year Change**

## Risk Highlights for Summer 2019

### Tight Reserve Margins in Texas Lead to Operational Challenges

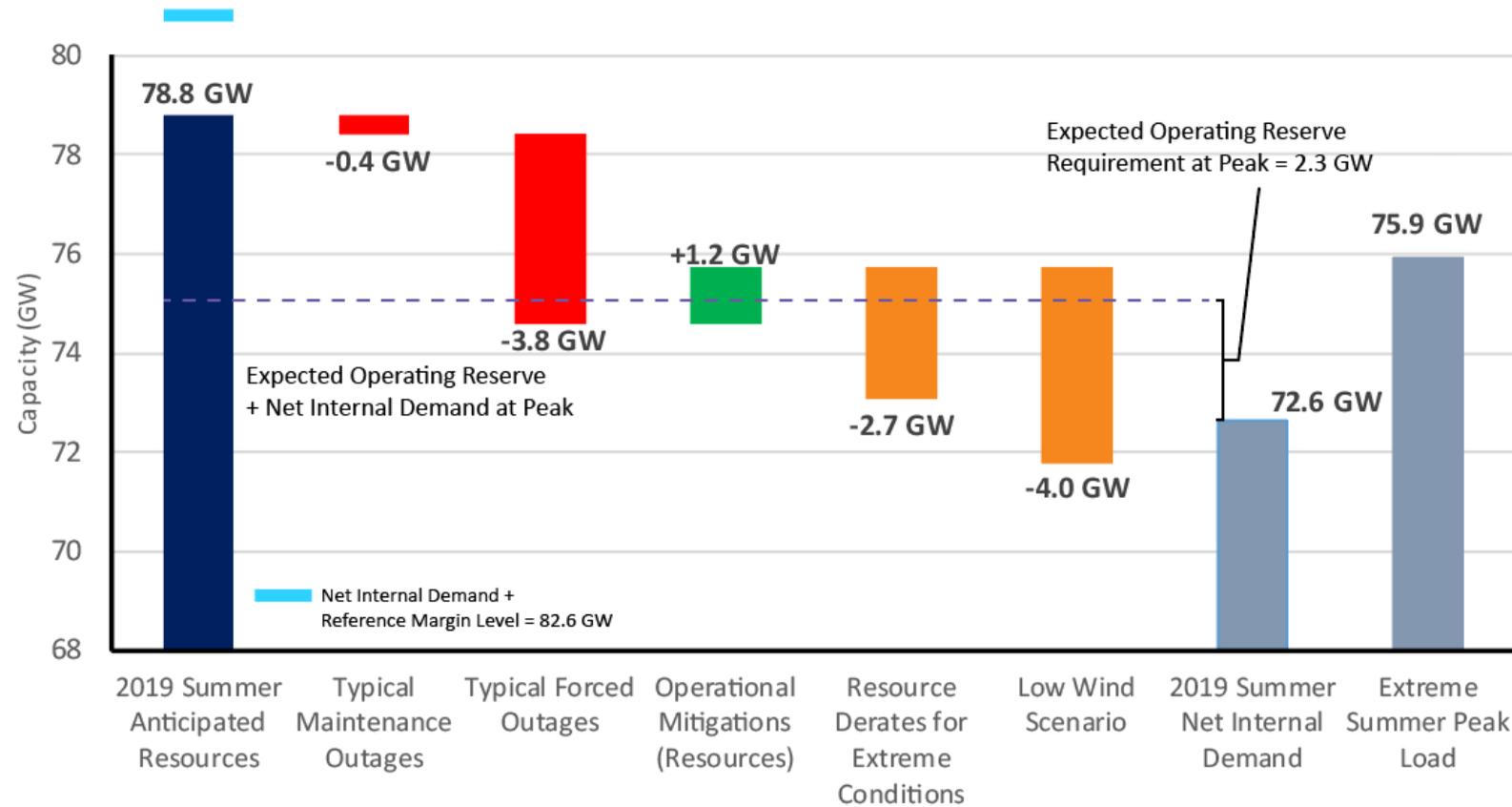
Texas RE-ERCOT enters the Summer 2019 season with a deficit in planning reserves, increasing the likelihood that system operators may need to employ procedures to maintain sufficient operating reserves. In 2018, ERCOT maintained sufficient generation resources through record levels of summer peak demand without resorting to Energy Emergency Alerts. This system performance, due in large part to high levels of generator availability, response to market signals, and unit performance, was notable given the Anticipated Reserve Margin of 10.9%, well-below the Reference Margin Level of 13.75%.<sup>3</sup> For the upcoming summer, growth in anticipated summer peak demand, delays in planned generation projects, and the announced mothballing of a 470 MW coal-fired unit (Gibbons Creek) are expected to push reserve margins still lower, to 8.5%.

Based on ERCOT's summer Seasonal Assessment of Resource Adequacy (SARA) report, released May 8, ERCOT expects that a number of operational tools may be needed this summer to help maintain sufficient operating reserves given the range of resource adequacy scenarios they evaluated.<sup>4</sup> For example, ERCOT system operators can release ancillary services (including load resources that can provide various types of operating reserves based on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids.

The SARA report informs ERCOT market participants and operators by deterministically considering the impact of potential variables that may affect the sufficiency of resources for the upcoming season. Historic ranges or expectations for generation maintenance outages, forced outages, and capacity derates during extreme weather conditions are applied deterministically as resource scenarios. The effect of these resource scenarios, along with normal and extreme peak demand scenarios, are examined to determine the potential for scarcity conditions and emergency operating procedure mitigation. **Figure 3** shows a risk assessment developed by NERC using *Summer Reliability Assessment* data and additional data from Texas RE-ERCOT, and the ERCOT 2019 Preliminary SARA report. A description of resource and demand variables is found in **Table 1**.

<sup>3</sup> See ERCOT's 2018 Summer Performance Update: [http://www.ercot.com/content/wcm/lists/144927/2018\\_Summer\\_Performance\\_One\\_Pager\\_FINAL.pdf](http://www.ercot.com/content/wcm/lists/144927/2018_Summer_Performance_One_Pager_FINAL.pdf)

<sup>4</sup> For details see ERCOT's SARA Report: <http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx>



**Figure 3: Texas RE-ERCOT Seasonal Risk Assessment**

**About the Seasonal Risk Assessment** The operational risk analysis shown in [Figure 3](#) 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 summer anticipated capacity, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in summer anticipated resources)
- 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 effects from low-probability, extreme events are also factored in, through additional resource derates or extreme resource scenarios, and extreme summer 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 Texas RE-ERCOT seasonal risk scenario in [Figure 3](#) can be found for each assessment area in the [Regional Assessment Dashboards](#) section of this report.

**Table 1: Resource and Demand Variables in the ERCOT Seasonal Risk Assessment**

Resource Scenarios	
<b>Typical Maintenance Outages</b>	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak load conditions. A value of 381 MW was determined based on the historical average of maintenance outages for June through September weekdays, for the last three summer seasons (2016–2018). Planned maintenance outages are generally accounted for in anticipated summer resources, however, this reduction covers additional generator outages granted by operators on a short-term basis as warranted by system conditions.
<b>Typical Forced Outages</b>	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. A value of 3,845 MW is based on historical average of forced outages for June through September weekdays, for the last three summer seasons (2016–2018).
<b>Operational Mitigations</b>	ERCOT assesses that certain operational mitigations, in addition to operating measures accounted for in SRA data and the preliminary SARA Report, can contribute 1,160 MW of additional resources to support maintaining operating reserve requirements. This value is based on three elements: <ul style="list-style-type: none"> <li>• Switchable generation resources currently serving the Southwest Power Pool (SPP) market that could become available to ERCOT in the event of an energy emergency (total of 489 MW)</li> <li>• Additional imports from the dc tie with the Mexican grid and from SPP beyond what was designated as long-term firm imports (total of 221 MW)</li> <li>• Distribution service providers implementation of distribution voltage reduction (contributing a total of 450 MW)</li> </ul>
<b>High Forced Outage Scenario (Low-likelihood Resource Derates)</b>	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. A capacity adjustment of 2,665 MW from the preliminary SARA report is based on historical forced outages assuming a 90% confidence interval.
<b>Low-Wind Scenario (Low-likelihood)</b>	The low-wind scenario is used to analyze the impact low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 3,960 MW is based on a low wind output scenario included in ERCOT’s preliminary summer SARA report. This capacity amount is calculated as the tenth percentile of wind output associated with the 100 highest net load hours (load minus wind output) for the 2015–2018 summer peak load seasons.
Demand Scenarios	
<b>2019 Net Internal Demand</b>	Net internal demand 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. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
<b>Extreme Summer Peak Load</b>	A seasonal load adjustment (3,303 MW) is added to 2019 net internal demand based on extreme weather conditions that occurred during Summer 2011. ERCOT compared this value to a statistical extreme load forecast (i.e., a “90/10 load forecast” and found the Summer 2011 peak load to be higher and therefore a more conservative scenario.

ERCOT's tight reserve margins create a potential need to declare an energy emergency alert under many of the peak and extreme conditions studied in the SARA.<sup>5</sup> Once normal operating actions to maintain operating reserves are exhausted, energy emergency alerts can provide system operators with access to additional resources as discussed above that are only available during scarcity conditions. ERCOT also anticipates that higher wholesale market prices during peak demand periods will incentivize power customers to voluntarily reduce load or increase energy output from load-serving generation facilities (such as industrial cogeneration and commercial-sector distributed generation) that can inject power into the ERCOT system. Based on recent ERCOT analysis, the potential amount of this demand and generation response for the upcoming summer is significant but uncertain because the ERCOT market has not experienced summer high prices subsequent to the market design changes implemented in 2012–2014.

## Seasonal Risk Assessments for Other Areas

Any area can face resource adequacy risk during peak conditions, even when Planning Reserve Margins exceed Reference Margin Levels. The reasons can be similar: generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, as well as 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 where appropriate, the potential effects that operating actions can have to mitigate shortfalls in operating reserves.

## CAISO Faces Concerns with Ramping Capability, Natural Gas Supply

For Summer 2019, the risk of resource shortfalls in CAISO is lower than last summer. However, there is increased risk of insufficient ramping capability during peak conditions. Conditions for hydroelectric generation are well above normal due to replenishment of reservoirs and mountain snow during the preceding winter, greatly reducing the potential for operating reserve shortfalls. However, the *2019 Summer Loads and Resources Assessment* highlights concerns with shortages in load-following resources capable of ramping up, particularly during late afternoon when solar generation output decreases while system demand is still high.<sup>6</sup> Increasing penetrations of solar resources and the retirements of dispatchable generation units has contributed to a shortage of ramping resources. When faced with such shortages, operators will need to call upon neighbors for imports to maintain system frequency. Should extreme temperatures extend over a large area to the point where neighbors lack surplus energy, load could be at risk from a shortage in ramping capability.

The impacts to electric generation resulting from operating restrictions at the Aliso Canyon natural gas storage facility remain an item of focus for electric reliability within the Western Interconnection. Withdrawals from natural gas storage facilities were at a high level during Winter 2018–2019 due to colder than average winter temperatures, resulting in below average storage levels approaching the Summer 2019 season. The Southern California Gas Company (SoCalGas) forecasts that it will be able to meet the forecasted peak day demand under a “best case” supply assumption even without supply from Aliso Canyon.<sup>7</sup> However, under a worst case supply assumption, supply from Aliso Canyon will be necessary to meet that forecasted peak day demand. Should operating restrictions result in natural gas supply curtailments that affect electric generation in the Southern California area, mitigation procedures that have been in place since 2016 can be used to maintain BPS reliability.

In addition to managing natural gas storage to meet summer demand, SoCalGas also uses summer months to begin increasing storage levels in preparation for peak winter months. Winter storage levels can be impacted in some scenarios that involve reduced natural gas storage receipts due to supply infrastructure servicing.

<sup>5</sup> A description of Energy Emergency Alerts and processes for communicating and coordination during operating emergencies is contained in NERC Reliability Standard *EOP-011-1 – Emergency Operations* available at the following link: <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf>

<sup>6</sup> See CAISO 2019 Summer Loads and Resources Assessment here: <http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf>

<sup>7</sup> See Southern California Gas Company (SoCalGas) *2019 Summer Technical Assessment*, April 4, 2019, available at the link below. At the time of drafting the NERC 2019 SRA, the California Public Utilities Commission (CPUC) summer technical assessment for Aliso Canyon had not been released. The CPUC assessment is expected to provide the most current and comprehensive information, including potential impacts to the BPS in Southern California. [http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News\\_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf](http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf)

## Mitigation Operating Plans

Should CAISO system operating conditions go into the emergency stages, such as operating reserve shortfalls where non-spinning reserve requirement cannot be maintained or spinning reserve is depleted and operating reserve falls below minimum requirement, the following mitigation operating plan will be implemented to minimize loss of load in the CAISO Balancing Authority area:

- Use the Flex Alert program, signaling that the CAISO expects high peak load condition. This program has been proven to reduce peak load in the CAISO Balancing Authority area.
- Use the CAISO Restricted Maintenance program. This program is intended to reduce potential forced outages, therefore, minimizing forced outage rate during the high peak load condition.
- Perform manual post day-ahead unit commitment and exceptional dispatch of resources under contract to ensure the ability to serve load and meet flexible ramping capability requirements.
- Perform manual exceptional dispatch of inertia resources that have resource adequacy obligation to serve CAISO load.
- Use the CAISO Alert/Warning/Emergency (AWE) program.
- Use the demand response program including the Reliability Demand Response Resources (RDRR) under the “Warning” stage.
- Perform manual exceptional dispatch of physically available resources that are not under capacity contract.

## Wildfire Risk and Potential for Impacts to the BPS

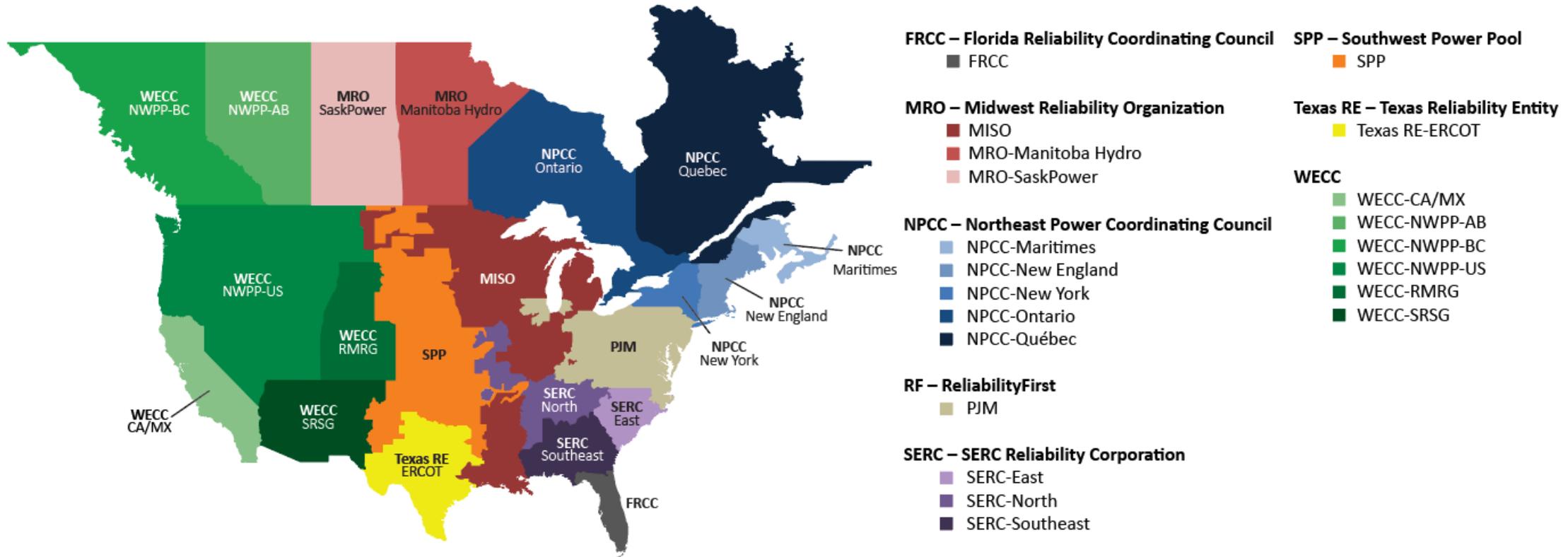
Government agencies predict above-normal wildfire risk for the summer throughout parts of North America. The National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico published a three-month seasonal potential wildfire outlook (April-June), which predicts above normal wildfire potential for California and the Pacific Northwest (Western Oregon and Washington), Western Alberta, British Columbia, and Northern Mexico.<sup>8</sup>

Operation of the BPS 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. With the widely dispersed nature of the transmission system in western parts of North America, outages due to wildfires are generally not widespread. Furthermore, utilities are enhancing wildfire prevention planning in California and other areas to address increased risk. In some cases, plans could include expanding power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively deenergized in high fire-risk areas to prevent wildfire ignitions. Other activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

<sup>8</sup> See the *North American Seasonal Fire Outlook*, issued May 10, 2019: [https://www.predictiveservices.nifc.gov/outlooks/NA\\_Outlook.pdf](https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf)

## Regional Assessment Dashboards

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



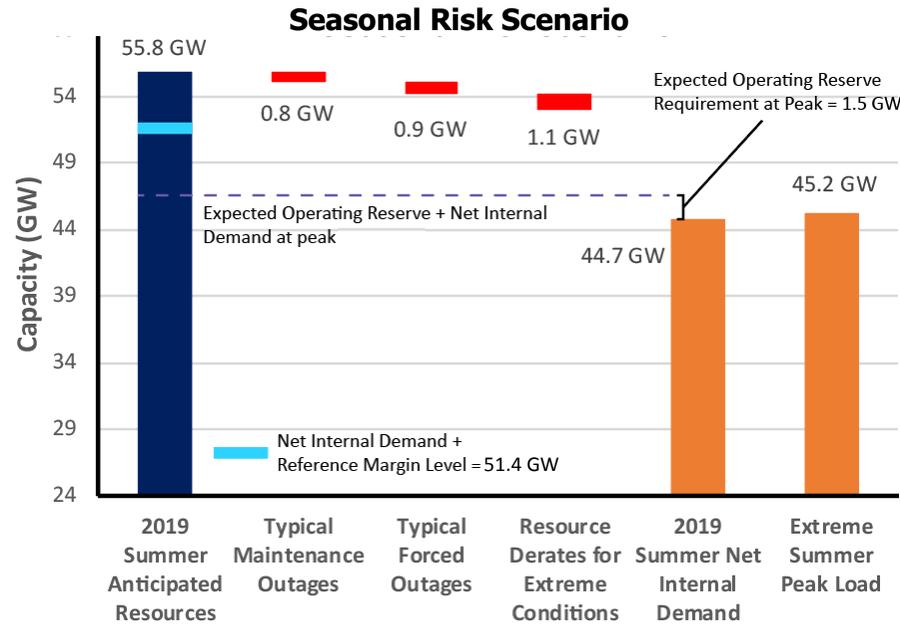
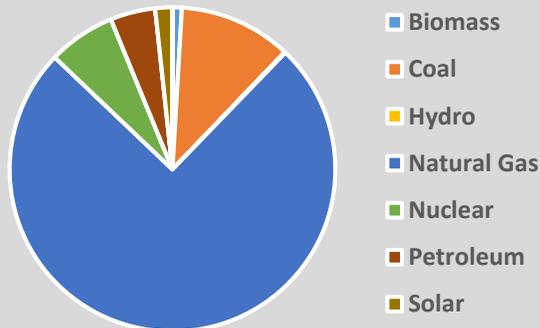


**FRCC**

The Florida Reliability Coordinating Council's (FRCC) membership includes 32 Regional Entity Division members and 22 Member Services Division members composed of investor-owned utilities, cooperatives, municipal utilities, power marketers, and independent power producers.

FRCC is divided into 10 Balancing Authorities with 36 registered entities (including both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles across Florida.

**On-Peak Capacity: Generation Mix**



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. FRCC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

**Risk Scenario Summary**

**Observation:**

Resources meet operating reserve requirements under studied scenarios.

**Scenario Assumptions**

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Historical average MW during summer season
- **Extreme Derates:** 3% capacity derate applied on all natural gas unit capacity

FRCC Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	47,495	47,670	0.4%
Demand Response: Available	2,957	2,951	-0.2%
Net Internal Demand	44,538	44,719	0.4%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	53,010	52,163	-1.6%
Tier 1 Planned Capacity	321.6	2,221	> 100%
Net Firm Capacity Transfers	1,477	1,456	-1.4%
Anticipated Resources	54,809	55,840	1.9%
Existing-Other Capacity	763.9	834	9.2%
Prospective Resources	55,573	56,674	2.0%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	23.1%	24.9%	1.8
Prospective Reserve Margin	24.8%	26.7%	1.9
Reference Margin Level	15.0%	15.0%	0.0

**Highlights**

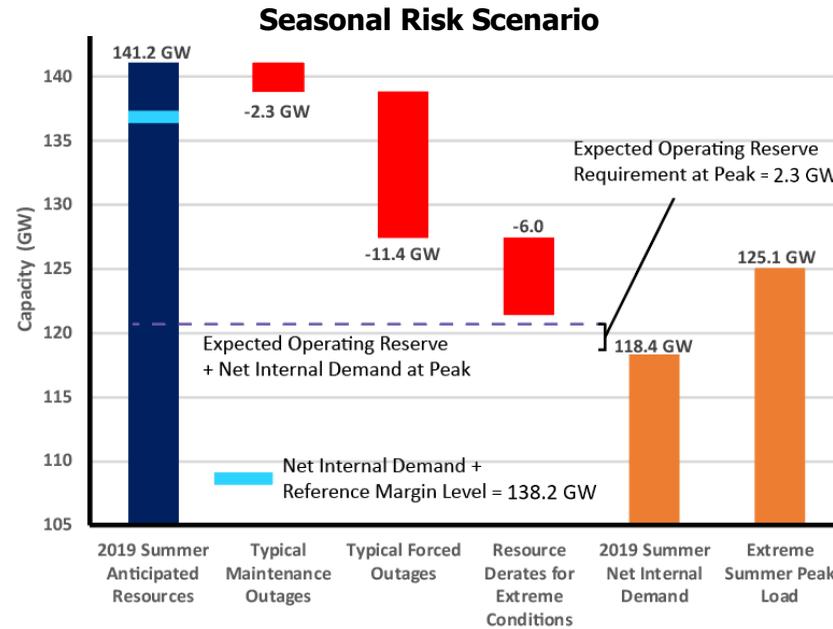
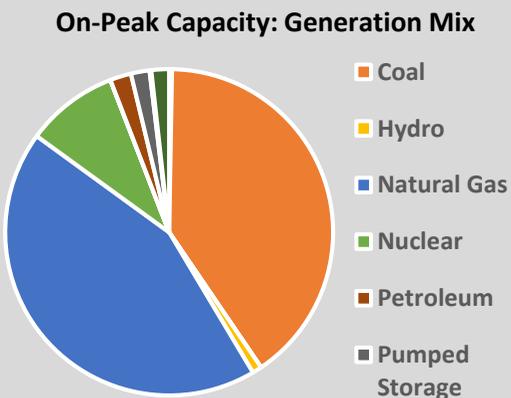
- FRCC has not identified any emerging reliability issues that are expected to impact reliability in the FRCC Region for the upcoming 2019 summer season.
- The BPS within the FRCC Region is expected to perform reliably for the anticipated 2019 summer season condition.
- On July 1, 2019, Regional Entity responsibilities will shift from FRCC to SERC for entities in Florida. FRCC will continue to provide member services and will remain a NERC assessment area.



## 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.



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. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

#### Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers
- **Extreme Derates:** Additional outages based on analysis of past five years summer peak outages

### MISO Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	124,704	124,744	0.0%
Demand Response: Available	5,990	6,385	6.6%
Net Internal Demand	118,714	118,359	-0.3%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	141,425	139,220	-1.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-8	1,955	-
Anticipated Resources	141,417	141,175	-0.2%
Existing-Other Capacity	1,104	591	-46.5%
Prospective Resources	142,521	141,766	-0.5%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	19.1%	19.3%	0.2
Prospective Reserve Margin	20.1%	19.8%	-0.3
Reference Margin Level	17.1%	16.8%	-0.3

### Highlights

- MISO does not anticipate reliability issues during the upcoming season for typical resource outages and load. MISO studied the summer system reliability under various resource outage and load scenarios. MISO held a summer readiness workshop with its members on April 23, 2019, to prepare for summer operations.
- MISO worked with entities in the SERC Region to develop an operating procedure to address potential issues that may result from high MISO north and south transfers. These transfers between MISO operating areas can cause entities in other Regions to experience loop flows that can impact system operations.
- MISO's Load Modifying Resource (LMR) FERC filing is expected to provide MISO's operators with greater access to the existing capabilities of LMRs. Enhancements include requiring LMR units to operate to their existing capability and added processes to schedule LMRs in anticipation of emergency conditions.

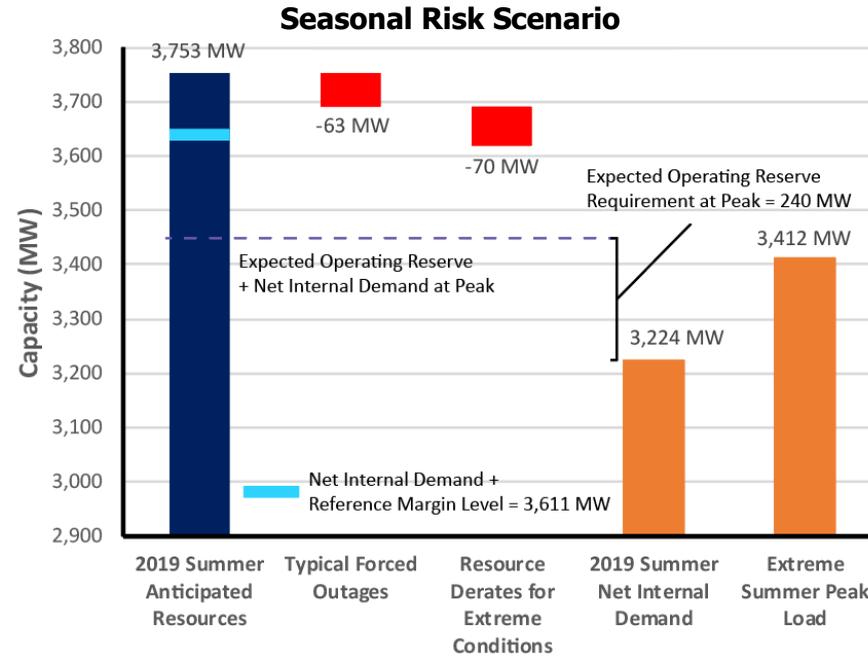
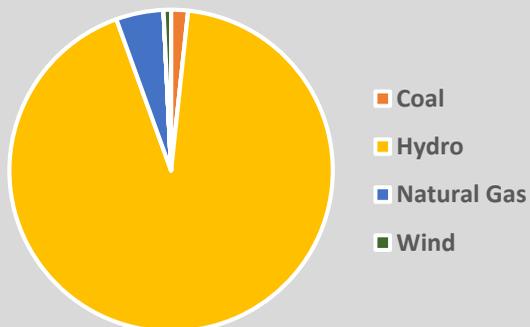


## MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 573,000 customers throughout Manitoba and natural gas service to about 279,000 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.

### On-peak Capacity: Generation Mix



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-Manitoba determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under studied scenarios.

#### Scenario Assumptions

- **Extreme Peak Load:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate

MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	3,237	3,224	-0.4%
Demand Response: Available	0	0	0.0%
Net Internal Demand	3,237	3,224	-0.4%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	5,288	5,161	-2.4%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-1,342	-1,408	4.9%
Anticipated Resources	3,946	3,753	-4.9%
Existing-Other Capacity	122.3	215	75.4%
Prospective Resources	4,068	3,968	-2.5%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	21.9%	16.4%	-5.5
Prospective Reserve Margin	25.7%	23.1%	-2.6
Reference Margin Level	12.0%	12.0%	0.0

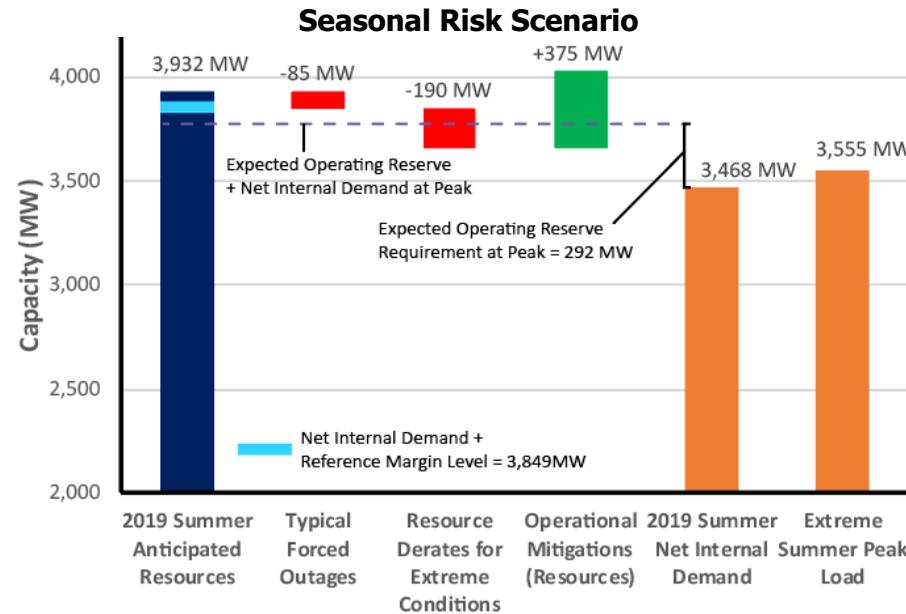
### Highlights

- There are no emerging reliability issues for the upcoming season in the Manitoba Hydro assessment area.
- Manitoba Hydro completed and commissioned the third HVdc line and placed it into service in July 2018. This addition significantly increased the system reliability by introducing an additional corridor for transmission of power generated by the bulk of Manitoba Hydro's generation in northern Manitoba to Southern Manitoba where the majority of the load is located.
- Reservoirs are at adequate storage levels and capable of supplying through design drought conditions.



## 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 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 summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under typical scenarios. Operating mitigations would be needed to meet reserve requirements in extreme outages and peak loads.

#### Scenario Assumptions

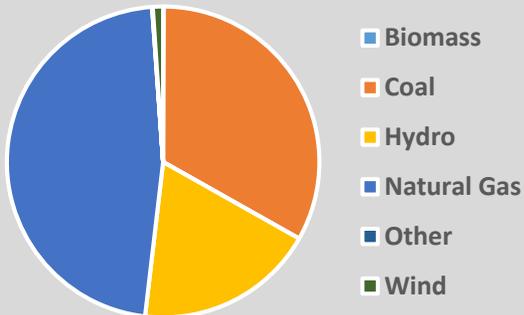
- **Extreme Peak Load:** Peak load with peak lighting and industrial demand
- **Maintenance Outages:** Estimated based on average maintenance outages in Summer 2018
- **Forced Outages:** Estimated using SaskPower model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	3,426	3,553	3.7%
Demand Response: Available	85	85	0.0%
Net Internal Demand	3,341	3,468	3.8%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	4,013	3,907	-2.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	4,038	3,932	-2.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,038	3,932	-2.6%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	20.8%	13.4%	-7.4
Prospective Reserve Margin	20.8%	13.4%	-7.4
Reference Margin Level	11.0%	11.0%	0.0

### Highlights

- No reliability issues are expected for the upcoming summer season. Saskatchewan experiences peak load in winter. Reserve margin is expected to be higher than the reference reserve margin for the upcoming summer
- SaskPower conducts an annual summer season joint operating study with Manitoba Hydro, with inputs from Basin Electric Power Cooperative (North Dakota), and prepares operating guidelines for identified issues.
- In case of extreme load 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.

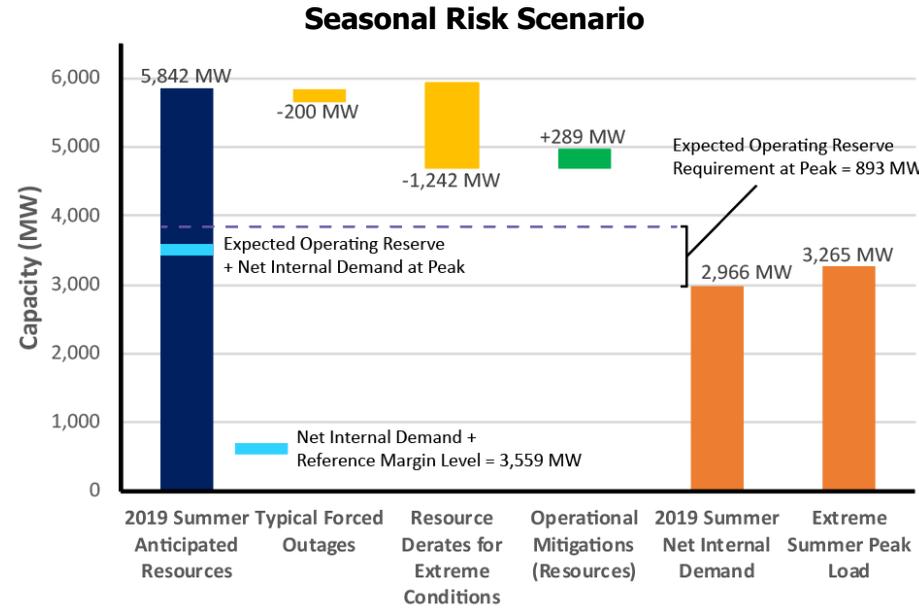
### On-Peak Capacity: Generation Mix





### 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 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	3,235	3,255	0.6%
Demand Response: Available	300	289	-3.7%
Net Internal Demand	2,935	2,966	1.1%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	5,828	5,842	0.2%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	5,828	5,842	0.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,828	5,842	0.2%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	98.6%	97.0%	-1.6
Prospective Reserve Margin	98.6%	97.0%	-1.6
Reference Margin Level	20.0%	20.0%	0.0

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-Maritimes determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

#### Risk Scenario Summary

##### Observation:

Resources meet operating reserve requirements under studied scenarios.

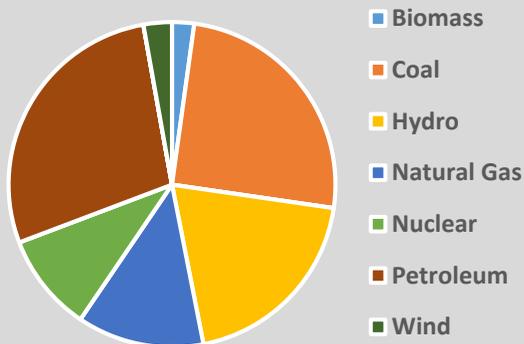
##### Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

#### Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were 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.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.

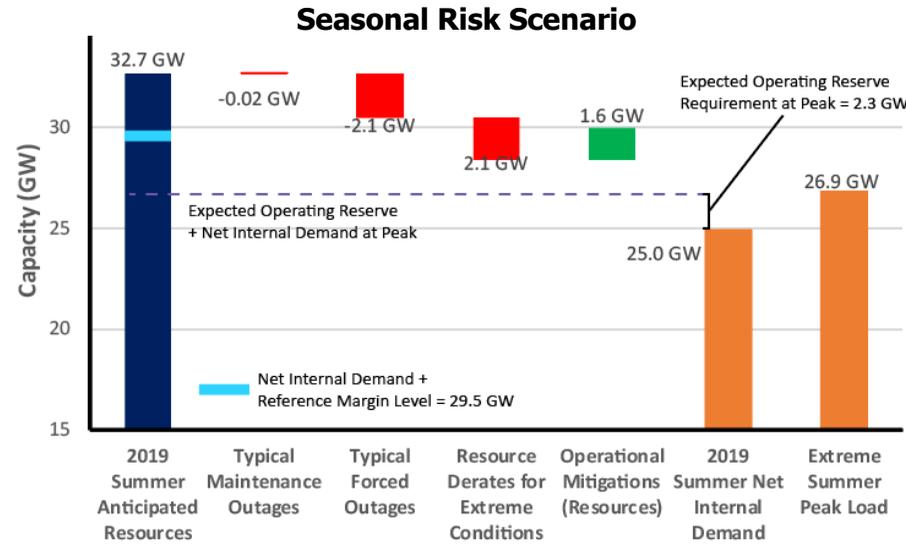
#### On-Peak Capacity: Generation Mix





## 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.



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	25,729	25,323	-1.6%
Demand Response: Available	408	340	-16.7%
Net Internal Demand	25,321	24,983	-1.3%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	30,460	30,144	-1.0%
Tier 1 Planned Capacity	0	1,185	-
Net Firm Capacity Transfers	1,468	1,328	-9.5%
Anticipated Resources	31,928	32,657	2.3%
Existing-Other Capacity	421	704	67.2%
Prospective Resources	32,349	33,361	3.1%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	26.1%	30.7%	4.6
Prospective Reserve Margin	27.8%	33.5%	5.7
Reference Margin Level	16.8%	18.3%	1.5

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-New England determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under studied scenarios.

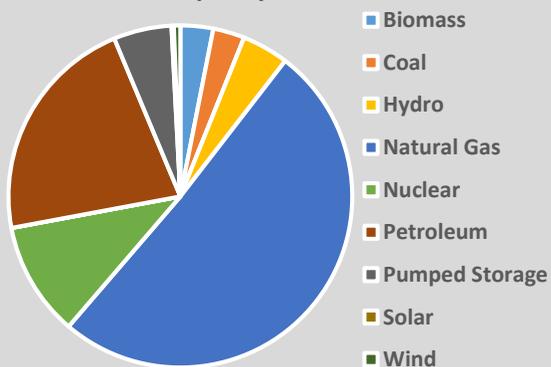
#### Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Near-zero MW due to summer peaking area
- **Extreme Derates:** Based on historical forced outages and any additional reductions for fuel-supply risk
- **Operating Mitigations:** Based on ISO-NE operating procedures

### Highlights

- The New England area expects to have sufficient resources to meet the 2019 summer peak demand forecast of 25,323 MW, with a corresponding projected net margin of 7,674 MW after accounting for demand response resources. This net margin is a 1,067 MW increase from the 2018 Anticipated Reserve Margin forecast. The increase can be largely attributed to new generation becoming available prior to the 2019 summer and a decrease in forecasted net demand.
- The upcoming retirement of the 674 MW Pilgrim nuclear unit is offset by additions in excess of 1,000 MW of combined cycle and combustion gas turbine generating units.
- The 2019 summer demand forecast is 406 MW (1.6%) lower than the 2018 summer forecast and takes into account the demand reductions associated with energy efficiency and behind-the-meter photovoltaic (BTM-PV) systems.
- The 18.3% Reference Margin Level is based on New England’s net installed capacity requirement for the 2019–2020 commitment period, which was approved by FERC.

### On-Peak Capacity: Generation Mix



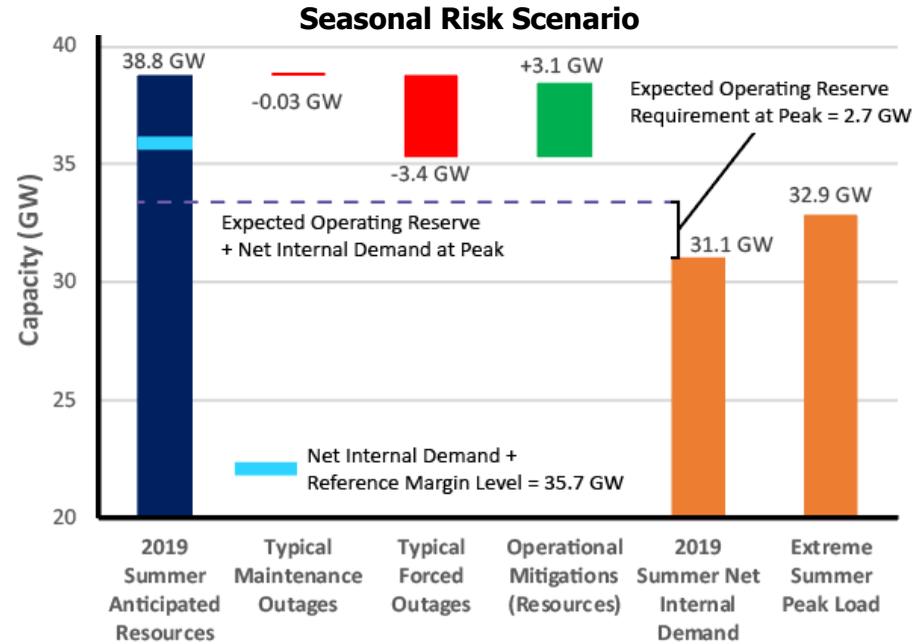
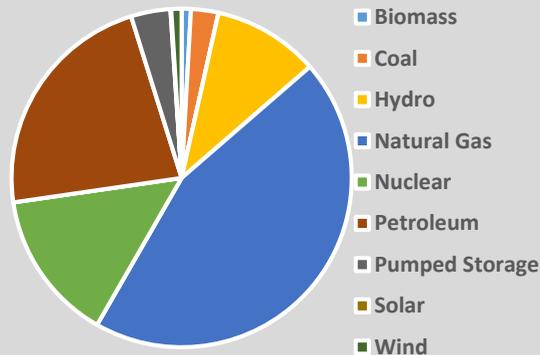


## NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority (NYBA) 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 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%.

### On-Peak Capacity: Generation Mix



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-New York determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under studied scenarios.

#### Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Forced Outages:** Based on five-year average performance
- **Operational Mitigation:** Based on operational/emergency procedures in NYISO Emergency Operations Manual

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	32,904	32,382	-1.6%
Demand Response: Available	1,219	1,309	7.4%
Net Internal Demand	31,685	31,073	-1.9%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	39,066	37,304	-4.5%
Tier 1 Planned Capacity	260	27	-89.6%
Net Firm Capacity Transfers	1,625	1,452	-10.7%
Anticipated Resources	40,950	38,783	-5.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	40,950	38,783	-5.3%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	29.2%	24.8%	-4.4
Prospective Reserve Margin	29.2%	24.8%	-4.4
Reference Margin Level	18.2%	15.0%	-3.2

### Highlights

- 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.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run-time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in New York City.

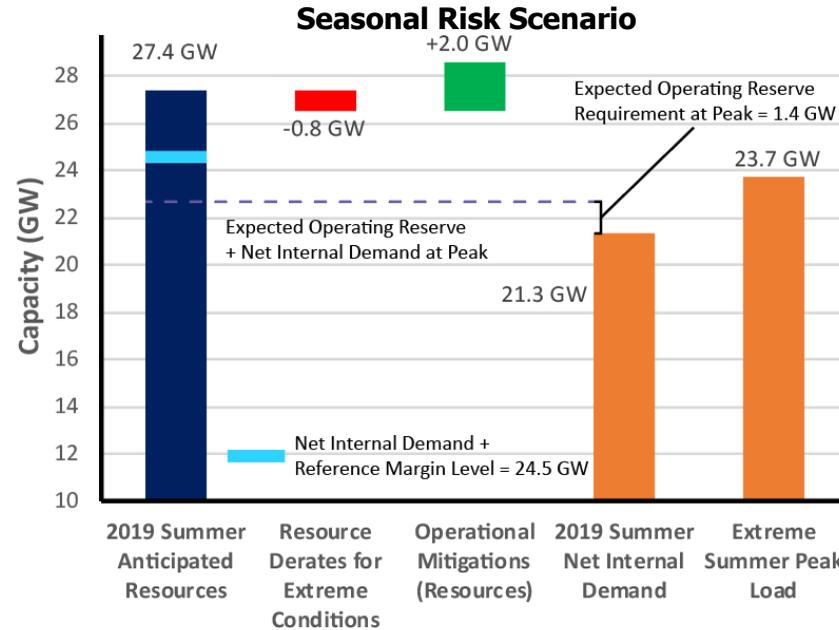
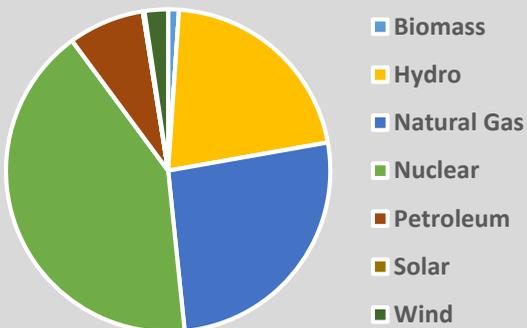


## NPCC-Ontario

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.

### On-Peak Capacity: Generation Mix



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 summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Risk Scenario Summary

#### Observation:

Resources meet operating reserve requirements under studied scenarios.

#### Scenario Assumptions

- **Extreme Peak Load:** Based on severe historic weather conditions
- **Extreme Derates:** Based on thermal unit derating curves, and historical hydro performance in low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	22,002	22,105	0.5%
Demand Response: Available	630	790	25.4%
Net Internal Demand	21,372	21,315	-0.3%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	25,731	26,581	3.3%
Tier 1 Planned Capacity	23	924	>100%
Net Firm Capacity Transfers	0	-102	-
Anticipated Resources	25,754	27,403	6.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	25,754	27,403	6.4%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	20.5%	28.6%	8.1
Prospective Reserve Margin	20.5%	28.6%	8.1
Reference Margin Level	13.3%	14.9%	1.6

### Highlights

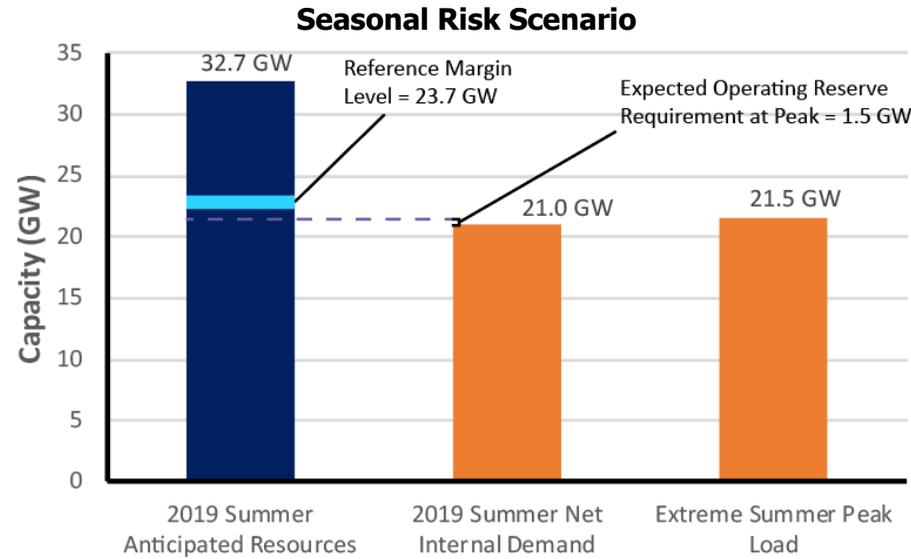
- There are sufficient resources to maintain the reliability of Ontario’s electricity system under normal weather conditions for Summer 2019.
- The IESO recently revised its outage approval methods and will evaluate outages using its extreme weather scenario with only firm resources and up to 2,000 MW of imports.
- Driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has renewed its approach to planning with a particular emphasis on its commitment to regular sharing of information with stakeholders. As a first step in delivering on this commitment, and helping generators and transmitters plan for and schedule outages, the IESO now extends its 18-month outage planning horizon to five years twice yearly.



### 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 eight 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 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	20,534	21,005	2.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	20,534	21,005	2.3%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	34,014	34,303	0.8%
Tier 1 Planned Capacity	0	28	-
Net Firm Capacity Transfers	-1,829	-1,663	-9.1%
Anticipated Resources	32,185	32,667	1.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,185	32,667	1.5%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	56.7%	55.5%	-1.2
Prospective Reserve Margin	56.7%	55.5%	-1.2
Reference Margin Level	12.6%	12.8%	0.2

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-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

### Highlights

- No issues are anticipated for the summer operating period since the system is winter peaking.
- A new 735 kV line is expected to be commissioned in May 2019 to meet NERC Reliability Standards and will provide more flexibility to operators.
- The Québec area expects to be able to provide assistance to neighboring areas if needed, up to the transfer capability available.

### Risk Scenario Summary

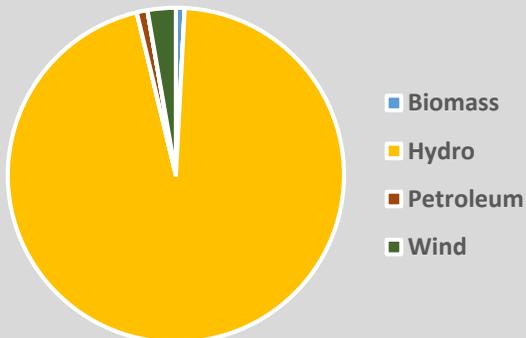
#### Observation:

Resources meet operating reserve requirements under studied scenarios.

### Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Anticipated Resources:** Includes planned generator outages, deratings, bottling, historic hydroelectric reduction and 100% reduction in installed wind generation capacity

### On-Peak Capacity: Generation Mix

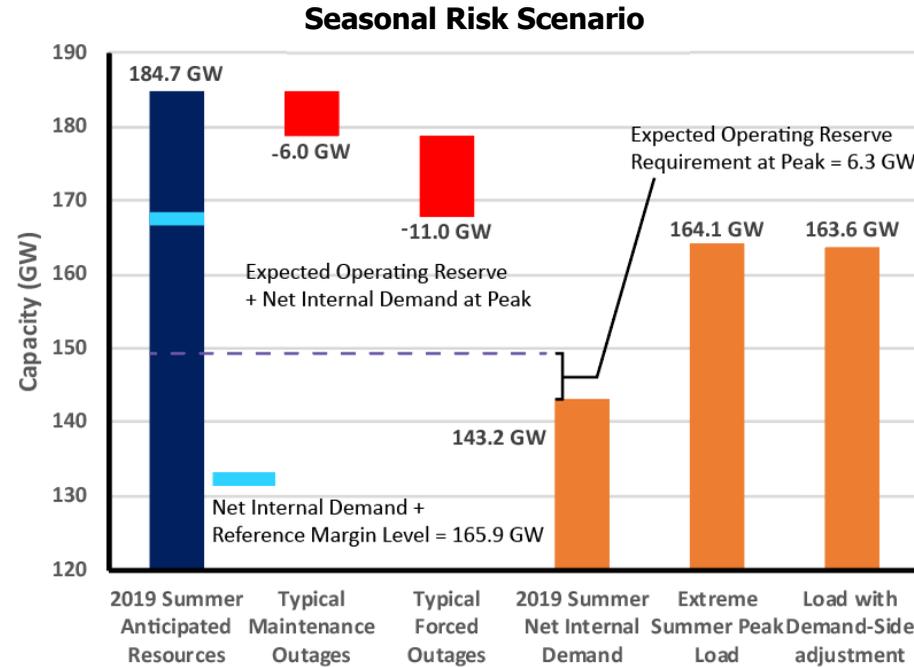




**PJM**

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.



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. PJM determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

**Risk Scenario Summary**

**Observation:**

Resources meet operating reserve requirements under studied scenarios.

**Scenario Assumptions**

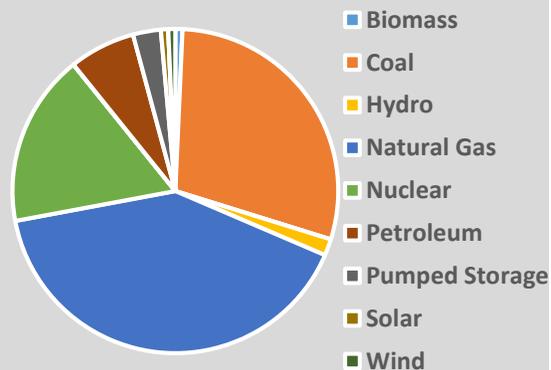
- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Approximate values based on review of previous summer peak periods

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	152,108	151,358	-0.5%
Demand Response: Available	9,095	8,154	-10.3%
Net Internal Demand	143,013	143,204	0.1%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	185,440	181,013	-2.4%
Tier 1 Planned Capacity	0	2,200	-
Net Firm Capacity Transfers	4,419	1,535	-65.3%
Anticipated Resources	189,859	184,748	-2.7%
Existing-Other Capacity	0	0	0
Prospective Resources	189,859	184,748	-2.7%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	32.8%	29.0%	-3.8
Prospective Reserve Margin	32.8%	29.0%	-3.8
Reference Margin Level	16.1%	15.9%	-0.2

**Highlights**

- The PJM reserve margin for this summer is 29.0% with a requirement of 15.9%. With this level of capacity, PJM has not identified any emerging reliability issues regarding resource adequacy.
- Ohio Valley Electric Cooperative (OVEC) moved from MISO into PJM in December 2018. OVEC has two large generating plants that have moved from having significant transfers into PJM to now being part of the PJM market dispatch.

**On-Peak Capacity: Generation Mix**





## SERC

SERC’s assessment areas are traditionally summer-peaking and cover approximately 72,000 circuit miles and serve a population estimated at 23 million.

For NERC’s assessment, the Region is divided into three assessment areas: SERC- E, SERC-C, and SERC-SE. The assessment areas include 12 Balancing Authorities: Cube Hydro Carolinas LLC, Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric and Kentucky Utilities (LG&E/ KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA), Southern Company Services, Inc. (SOCO), Southeastern Power Administration (SPA), and Tennessee Valley Authority (TVA).

SERC Resource Adequacy Data						
Demand, Resource, and Reserve Margins	SERC-E	SERC-C	SERC-SE	2018 SRA SERC Total	2019 SRA SERC Total	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Net Change (%)</b>
Total Internal Demand (50/50)	43,704	40,781	47,311	131,994	131,796	-0.2%
Demand Response: Available	1,054	1,964	2,293	4,640	5,311	14.5%
Net Internal Demand	42,650	38,817	45,018	127,354	126,485	-0.7%
<b>Resource Projections</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Megawatts</b>	<b>Net Change (%)</b>
Existing-Certain Capacity	50,976	50,391	61,182	161,532	162,549	0.6%
Tier 1 Planned Capacity	0	0	458	1,875	458	-75.6%
Net Firm Capacity Transfers	455	301	-1,905	-3,133	-1,150	-63.3%
Anticipated Resources	51,431	50,692	59,734	160,274	161,857	1.0%
Existing-Other Capacity	852	4,060	289	2,361	5,200	120.2%
Prospective Resources	52,282	54,752	60,023	162,635	167,057	2.7%
<b>Planning Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Percent</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	20.6%	30.6%	32.7%	25.9%	28.0%	2.1
Prospective Reserve Margin	22.6%	41.1%	33.3%	27.7%	32.1%	4.4
Reference Margin Level	13.15%	13.15%	13.15%	15.00%	13.15%	-1.85

### Highlights

- To date, there are no significant reliability risks expected for the 2019 summer season in the SERC Region.
- SERC continues to prepare for the integration of entities within FRCC. Both FRCC and the SERC Region are coordinating activities to ensure a successful transition of the new registered entities into the SERC Region’s reliability programs and processes. For more information, visit the FRCC RE Integration webpage.<sup>9</sup>
- To align with SERC’s subregional naming convention in its regional studies and assessments, the SERC North Assessment Area was changed to SERC Central Assessment Area in NERC Reliability Assessments.
- SERC Southeast entities have experienced loop flows from a high regional transfers between MISO North and MISO South. As a result, the impacted utilities along with MISO developed an operating procedure to address potential reliability issues that could result from high MISO regional transfers.

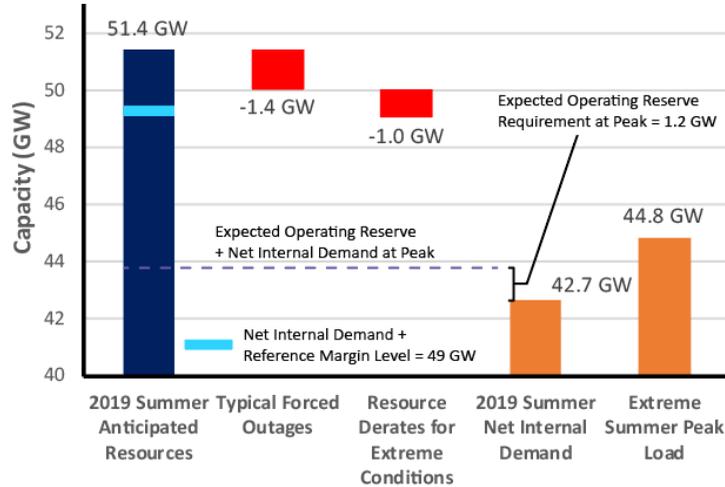
### Charts

The charts on the next page provide potential summer 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. SERC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the [Seasonal Risk Scenario Chart Description](#) for more information about the charts.

<sup>9</sup> See <http://www.serc1.org/outreach/frcc-re-integration>

SERC-E

Seasonal Risk Scenario



Risk Scenario Summary

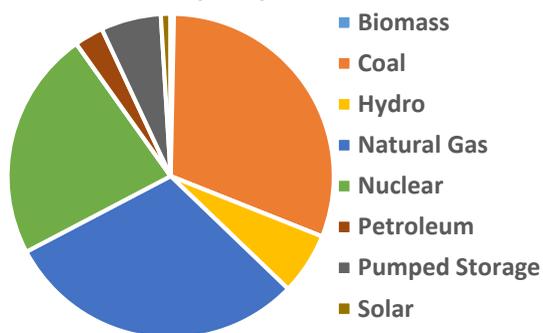
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

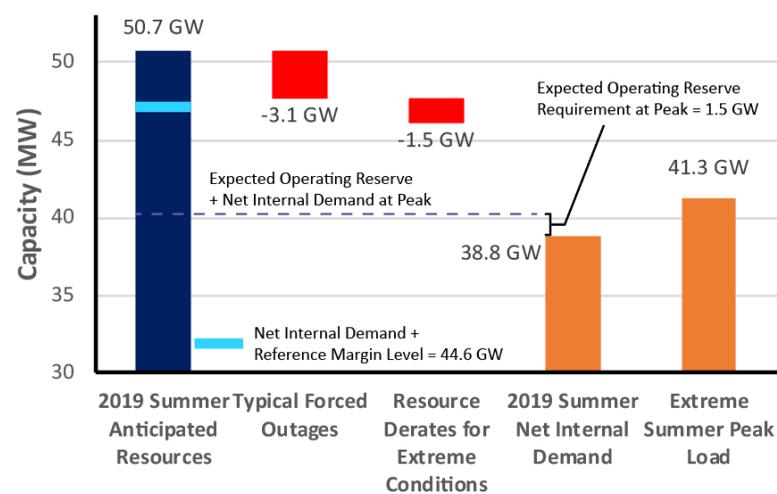
- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



SERC-C

Seasonal Risk Scenario



Risk Scenario Summary

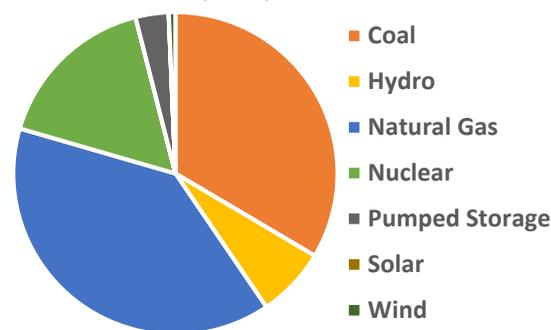
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

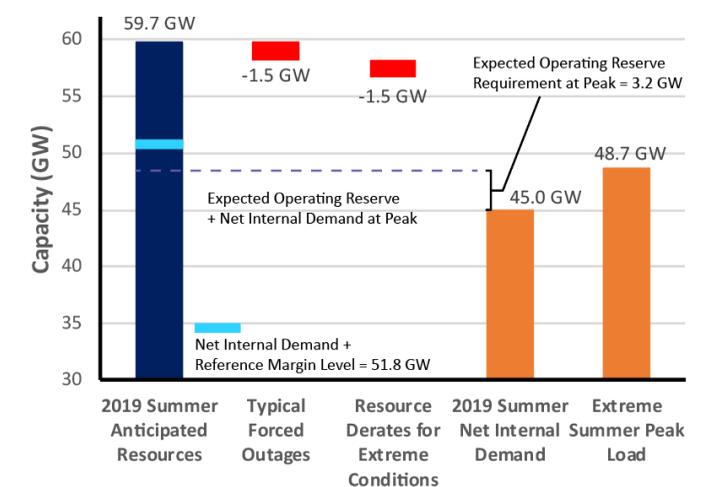
- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



SERC-SE

Seasonal Risk Scenario



Risk Scenario Summary

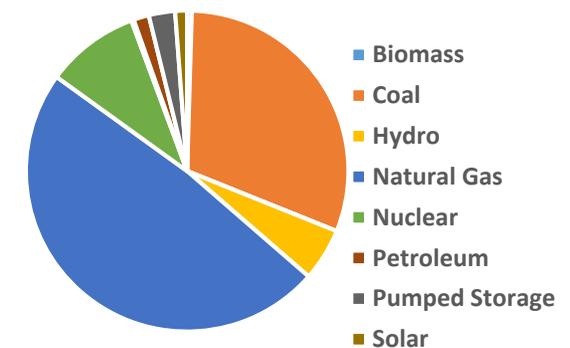
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



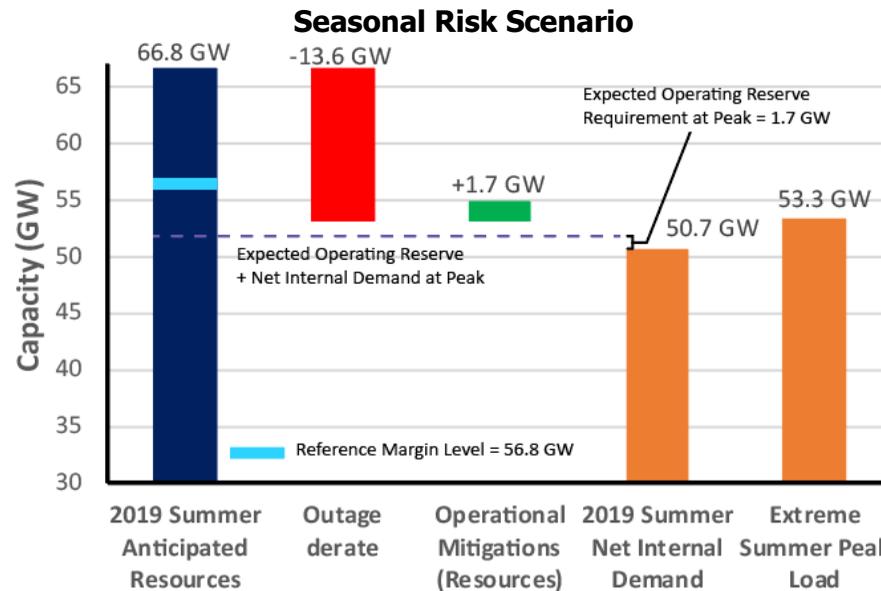
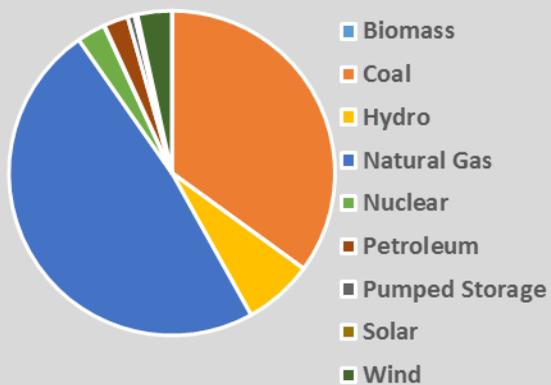


**SPP**

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 WECC. 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.

**On-Peak Capacity: Generation Mix**



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. SPP determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the [Seasonal Risk Scenario Chart Description](#) for more information about this chart.

**Risk Scenario Summary**

**Observation:** Resources meet operating reserve requirements under studied scenarios.

**Scenario Assumptions**

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A derate for forced outages and performance in extreme weather based on historical data

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	52,554	51,520	-2.0%*
Demand Response: Available	867	835	-3.8%
Net Internal Demand	51,687	50,685	-1.9%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	67,649	67,960	0.5%
Tier 1 Planned Capacity	779.85	64	-91.8%
Net Firm Capacity Transfers	19	-1,244	-
Anticipated Resources	68,447	66,780	-2.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	68,447	66,780	-2.4%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	32.4%	31.8%	-0.6
Prospective Reserve Margin	32.4%	31.8%	-0.6
Reference Margin Level	12.0%	12.0%	0.0

\* In 2018, Total Internal Demand was calculated on a non-coincident peak basis, resulting in higher demand calculations compared to coincident peak basis used for the 2019 SRA.

**Highlights**

- SPP does not anticipate any emerging reliability issues impacting the area for the 2019 summer season.
- SPP has experienced mid-range forecast error uncertainty in wind forecasts as the penetration of wind generation increases. This is not an issue if the error is short lived, but if the error continues throughout the day it can lead to short-term supply scarcity. Within SPP, a team is developing mitigation to ensure appropriate ramp product is available on a daily basis.

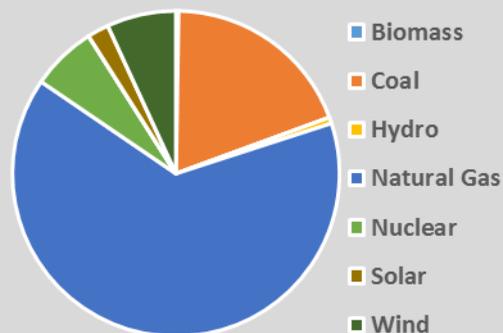


## Texas RE-ERCOT

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.

### On-Peak Capacity: Generation Mix



Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
<b>Demand Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Total Internal Demand (50/50)	72,756	74,853	2.9%
Demand Response: Available	2,301	2,227	-3.2%
Net Internal Demand	70,455	72,626	3.1%
<b>Resource Projections</b>	<b>MW</b>	<b>MW</b>	<b>Net Change</b>
Existing-Certain Capacity	76,654	77,482	1.1%
Tier 1 Planned Capacity	738.95	607	-17.9%
Net Firm Capacity Transfers	753	721	-4.2%
Anticipated Resources	78,146	78,810	0.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,146	78,810	0.9%
<b>Reserve Margins</b>	<b>Percent</b>	<b>Percent</b>	<b>Annual Difference</b>
Anticipated Reserve Margin	10.9%	8.5%	-2.4
Prospective Reserve Margin	10.9%	8.5%	-2.4
Reference Margin Level	13.75%	13.75%	0.0

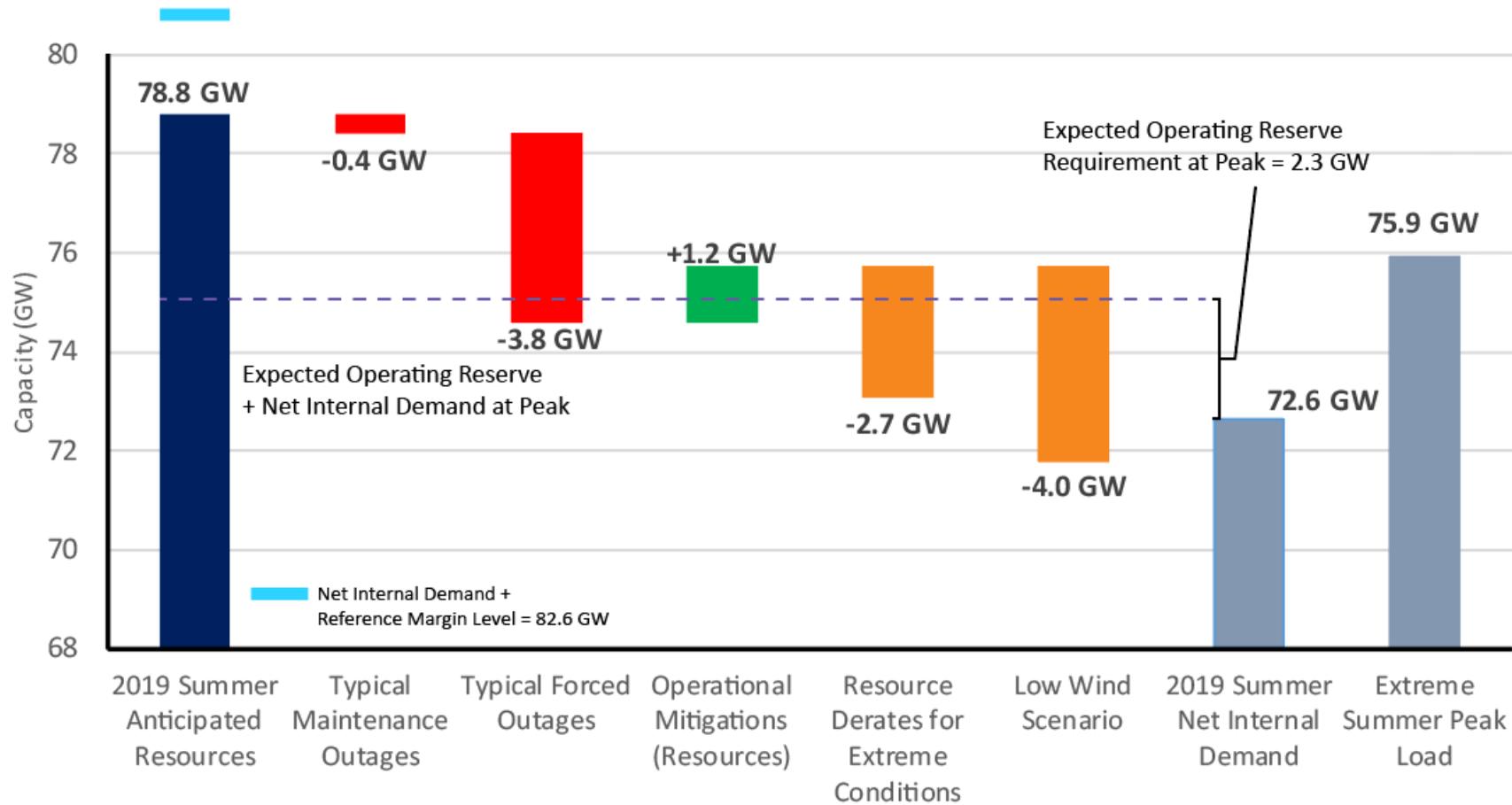
### Highlights

- Despite growth in anticipated resources relative to last summer, even higher expected summer peak demand, combined with delays in planned generation projects and the announced mothballing of a 470 MW coal-fired unit, are expected to result in a tighter reserve margin for the upcoming summer.
- Notable transmission improvements include a new 250 MVar STATCOM expected to be in-service prior to summer in the Far West Texas region to support the rapid growth of oil and gas production load in the Permian Basin. Additionally, a new 345 kV line in Central Texas will be energized in the spring to support the San Antonio area.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for the upcoming season. However, delays or cancellations of planned transmission expansion projects, if they occur, may contribute to potential localized reliability concerns.

### Charts

The chart on the next page provide potential summer 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. ERCOT determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the [Seasonal Risk Scenario Chart Description](#) for more information about the chart.

Seasonal Risk Scenario



The table on page 26 and the chart above provide potential summer 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**

**Observation:**

Operating Mitigations and Energy Emergency Alerts may be needed under peak and extreme conditions studied.

**Scenario Assumptions (see Table 1 on Page 9 for detailed discussion)**

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three year summer periods
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins.



**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 (SRSR), 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	SRSR	2018	2019	2018 vs. 2019 SRA
Demand Projections	MW	MW	MW	MW	MW	MW	Total MW	Total MW	Net Change (%)
Total Internal Demand (50/50)	11,111	8,432	52,929	47,619	12,636	23,415	154,256	156,142	1.2%
Demand Response: Available	0	0	957	614	225	368	3,569	2,164	-39.4%
Net Internal Demand	11,111	8,432	51,972	47,006	12,411	23,047	150,687	153,979	2.2%
Resource Projections	MW	MW	Net Change (%)						
Existing-Certain Capacity	14,560	9,746	61,806	60,056	16,627	31,413	184,981	194,208	5.0%
Tier 1 Planned Capacity	43	152	1,818	1,007	257	684	1,098	3,961	>100%
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0.0%
Anticipated Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Planning Reserve Margins	Percent	Percent	Annual Difference						
Anticipated Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Prospective Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Reference Margin Level	10.0%	10.0%	12.0%	20.0%	17.0%	15.0%	15.4%	15.4%	0.0

**Highlights**

- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- WECC and NERC are monitoring the transition of Reliability Coordinator (RC) responsibilities in the Western Interconnection as Peak RC winds down toward disestablishment at the end of 2019. NERC-certified RCs are scheduled to assume responsibilities in California (July 1) and British Columbia (September 2). All other areas will complete transition prior to December 31. Certification site visits, shadow-operating periods with Peak RC, and WECC-sponsored RC transition activities are being 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.
- Above-average snowpack levels and the anticipated abundance of hydroelectric generation in California may be used to displace generation from natural-gas-fired units, freeing up more natural gas for Southern California if fuel availability becomes an issue.
- Localized short-term operational issues may occur due to wildfires, if seasonal wildfire predictions are accurate. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.

**Charts**

The charts on the next page provide potential summer 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 summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the [Seasonal Risk Scenario Chart Description](#) for more information about the charts.

WECC-Alberta

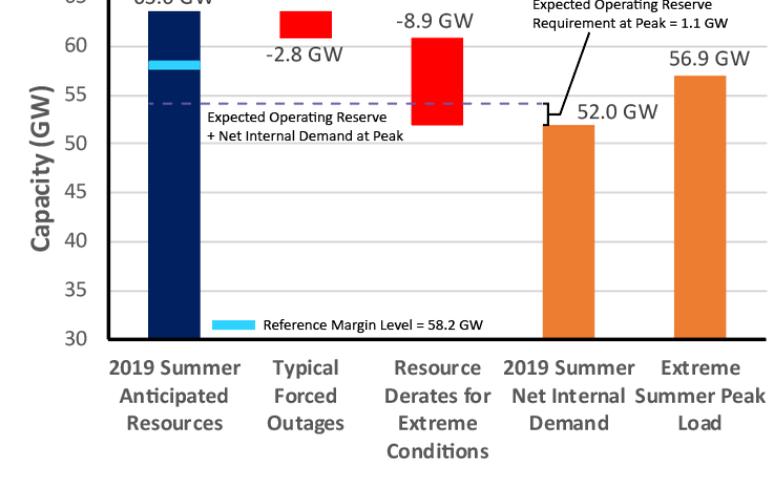
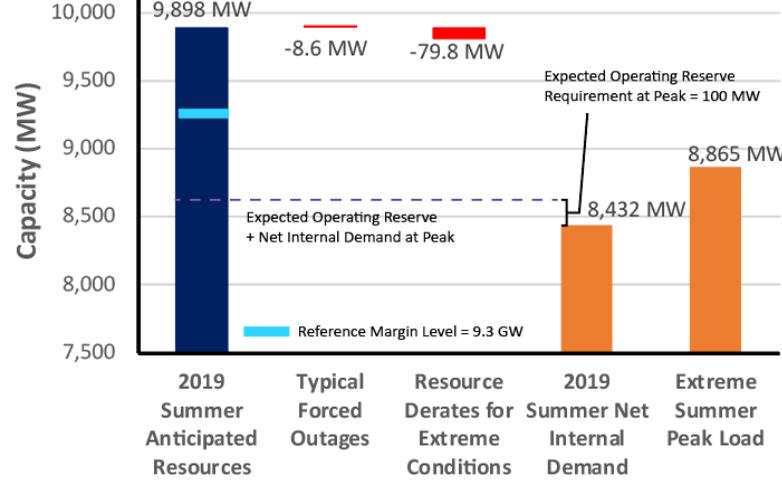
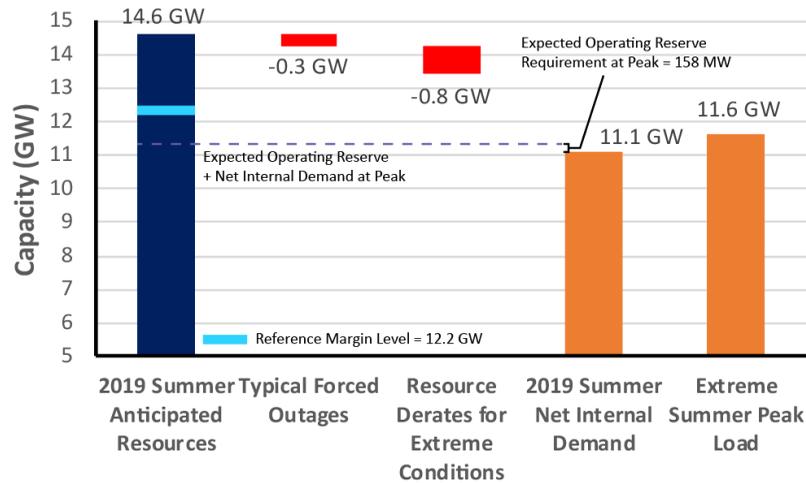
WECC-British Columbia

WECC-California/Mexico

Seasonal Risk Scenario

Seasonal Risk Scenario

Seasonal Risk Scenario



Risk Scenario Summary

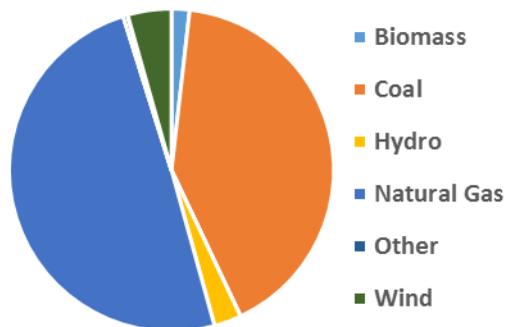
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Risk Scenario Summary

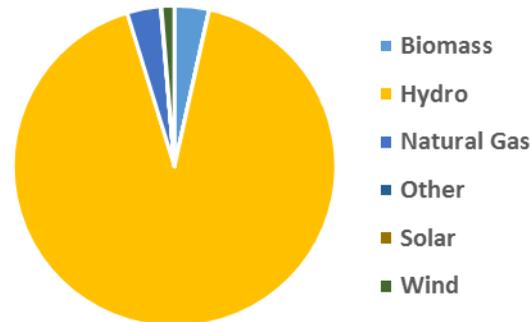
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Risk Scenario Summary

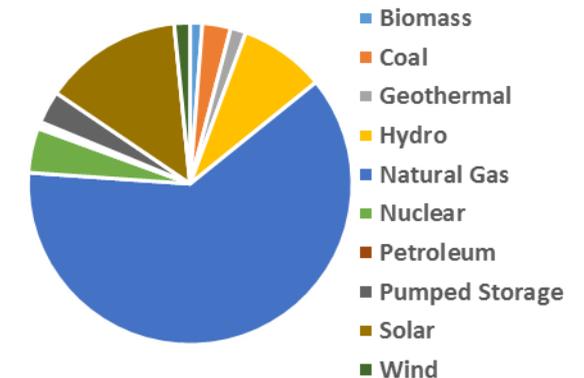
Observation:

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.

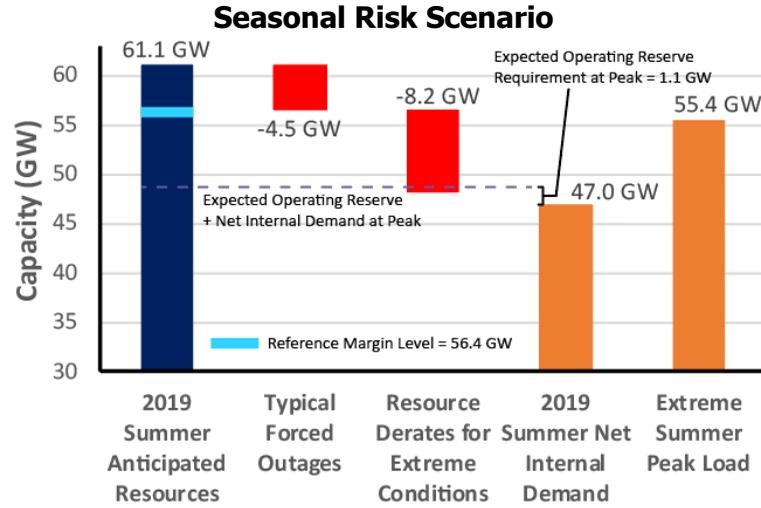
Scenario Assumptions

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

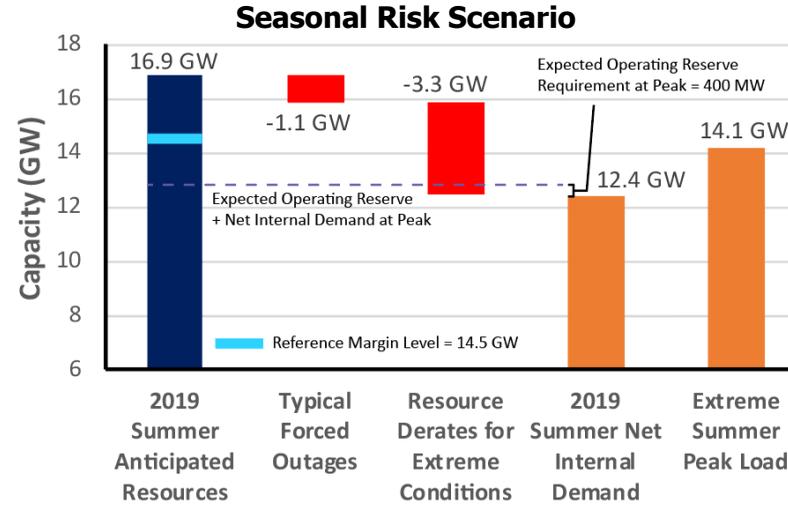
On-Peak Capacity: Generation Mix



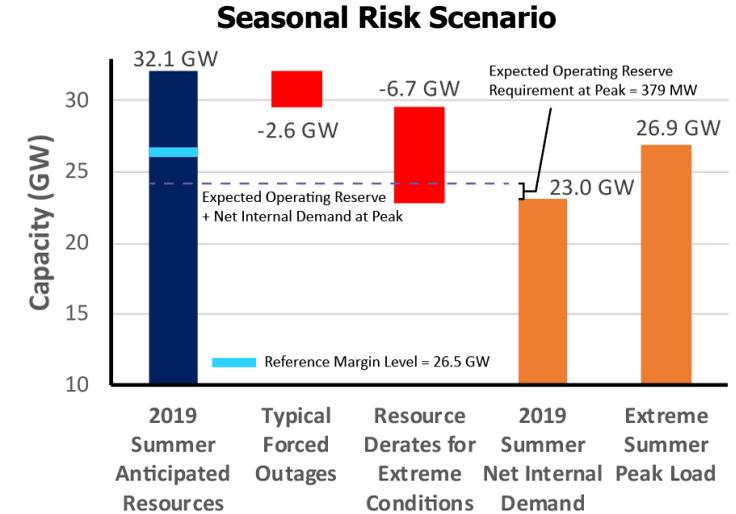
WECC-Northwest Power Pool



WECC-Rocky Mountain Reserve Sharing Group



WECC-Southwest Reserve Sharing Group



Risk Scenario Summary

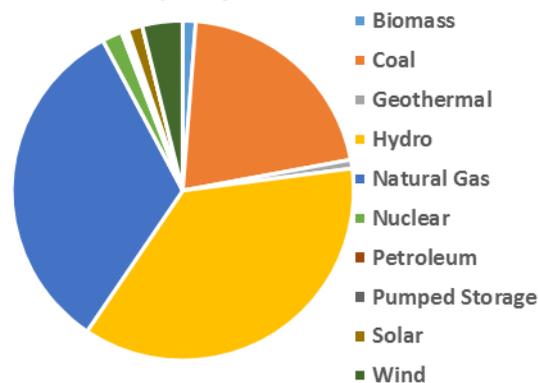
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Risk Scenario Summary

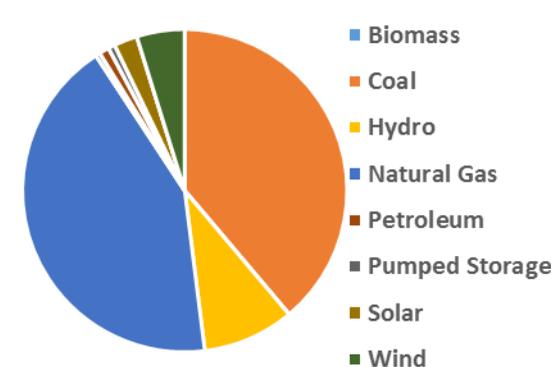
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Risk Scenario Summary

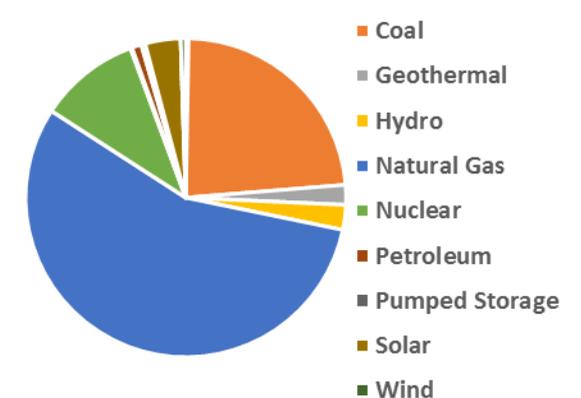
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



## 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.
- *2018 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<sup>10</sup>, or total internal demand, for the summer and winter of each year.<sup>11</sup>
- Total internal demand projections are based on normal weather (50/50 distribution<sup>12</sup>) and are provided on a coincident<sup>13</sup> 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 units, 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 (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:** includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports):** 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 summer or summer season but do not meet the requirements of existing-certain.

### Reserve Margin Definitions

**Reserve Margins:** 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, shown as a percentage:

<sup>10</sup> [Glossary of Terms](#) Used in NERC Reliability Standards

<sup>11</sup> The summer season represents June–September and the winter season represents December–February.

<sup>12</sup> 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.

<sup>13</sup> Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. 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

### 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 Summer Anticipated Resources (from the Resource Adequacy Data table). The two orange columns at the right show two demand scenarios: normal peak net internal demand from the Resource Adequacy Data table and an extreme summer peak demand, both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the Summer Anticipated Resources, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in Summer 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 resulting 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 summer 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 summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

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