

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2018 Summer Reliability Assessment



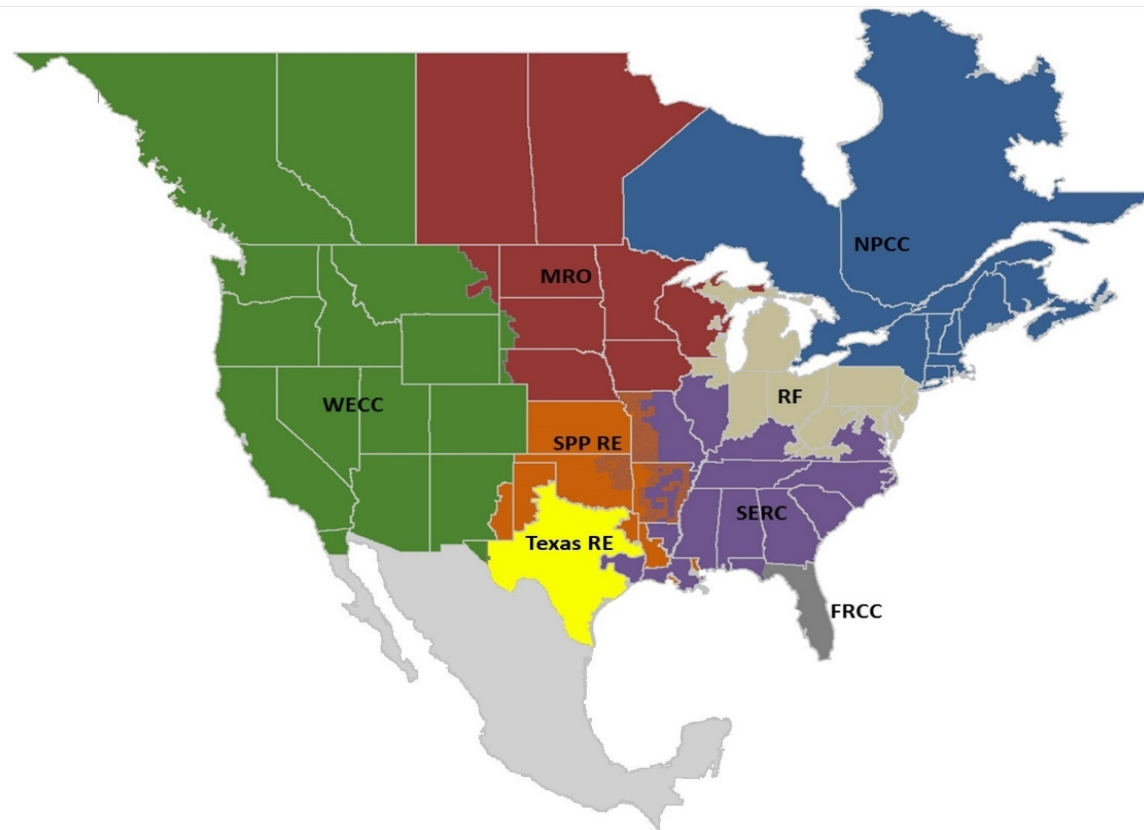
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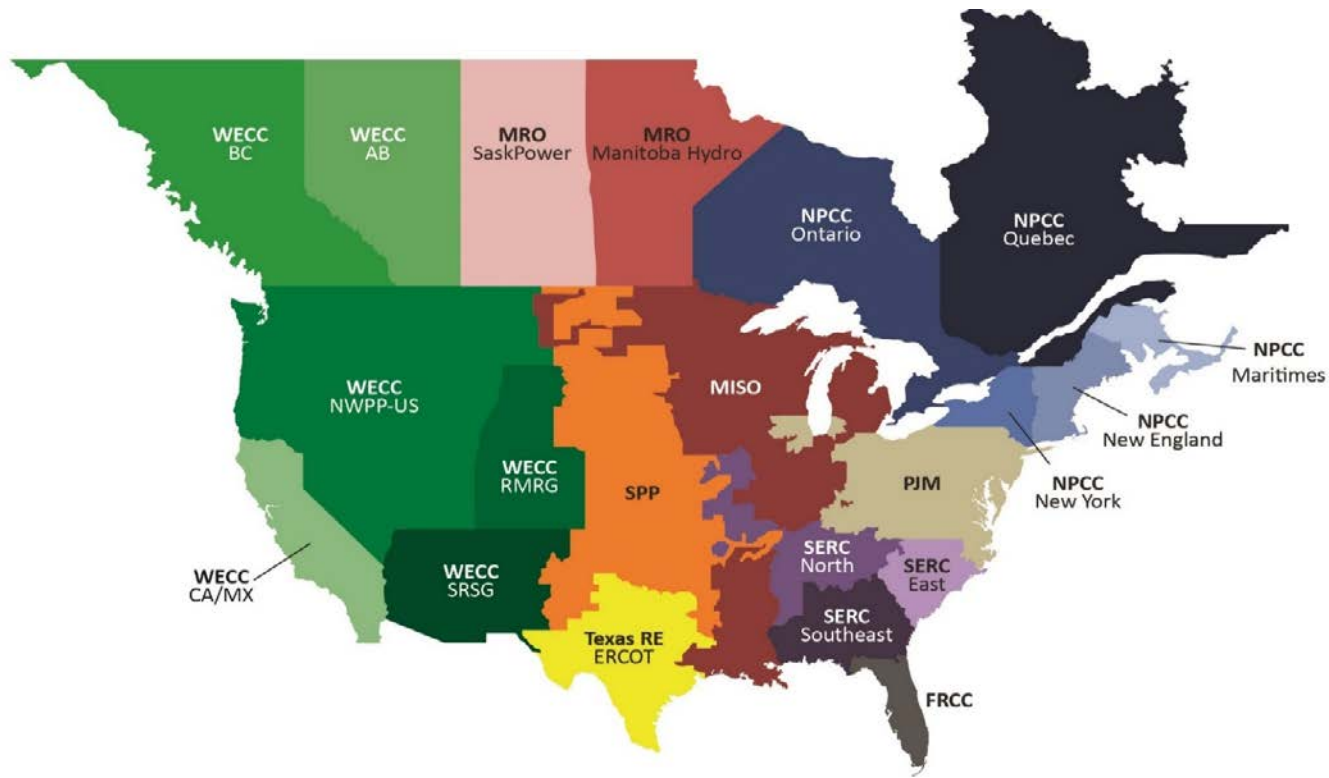
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of NERC and the eight 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 eight RE boundaries as shown in the map and corresponding table on page four. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another. The assessment areas are shown on page 4.



NERC Regions



NERC Assessment Areas

- | | | |
|--|--|--|
| <p>FRCC—Florida Reliability Coordinating Council</p> <ul style="list-style-type: none"> FRCC | <p>Texas-RE - Texas Reliability Entity</p> <ul style="list-style-type: none"> ERCOT | <p>WECC—Western Electricity Coordinating Council</p> <ul style="list-style-type: none"> WECC-CA/MX WECC-NWPP-AB WECC-NWPP-BC WECC-NWPP-US WECC-RMRG WECC-SRSG |
| <p>MRO—Midwest Reliability Organization</p> <ul style="list-style-type: none"> MRO-SaskPower MRO-Manitoba Hydro MISO | <p>NPCC—Northeast Power Coordinating Council</p> <ul style="list-style-type: none"> NPCC-Maritimes NPCC-New England NPCC-New York NPCC-Ontario NPCC-Québec | <p>SERC—SERC Reliability Corporation</p> <ul style="list-style-type: none"> SERC-East SERC-North SERC-Southeast |
| <p>SPP RE—Southwest Power Pool Regional Entity</p> <ul style="list-style-type: none"> SPP | <p>RF—ReliabilityFirst</p> <ul style="list-style-type: none"> PJM | |

About this Report

NERC's *2018 Summer Reliability Assessment* identifies, assesses, and reports on areas of concern regarding the reliability of the North American bulk power system (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 that they may be 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 (June–September) 2018 summer period. This assessment provides an evaluation of whether or not there is adequate generation and transmission necessary to meet projected summer peak demands. The assessment monitors and identifies potential reliability issues of interest 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:

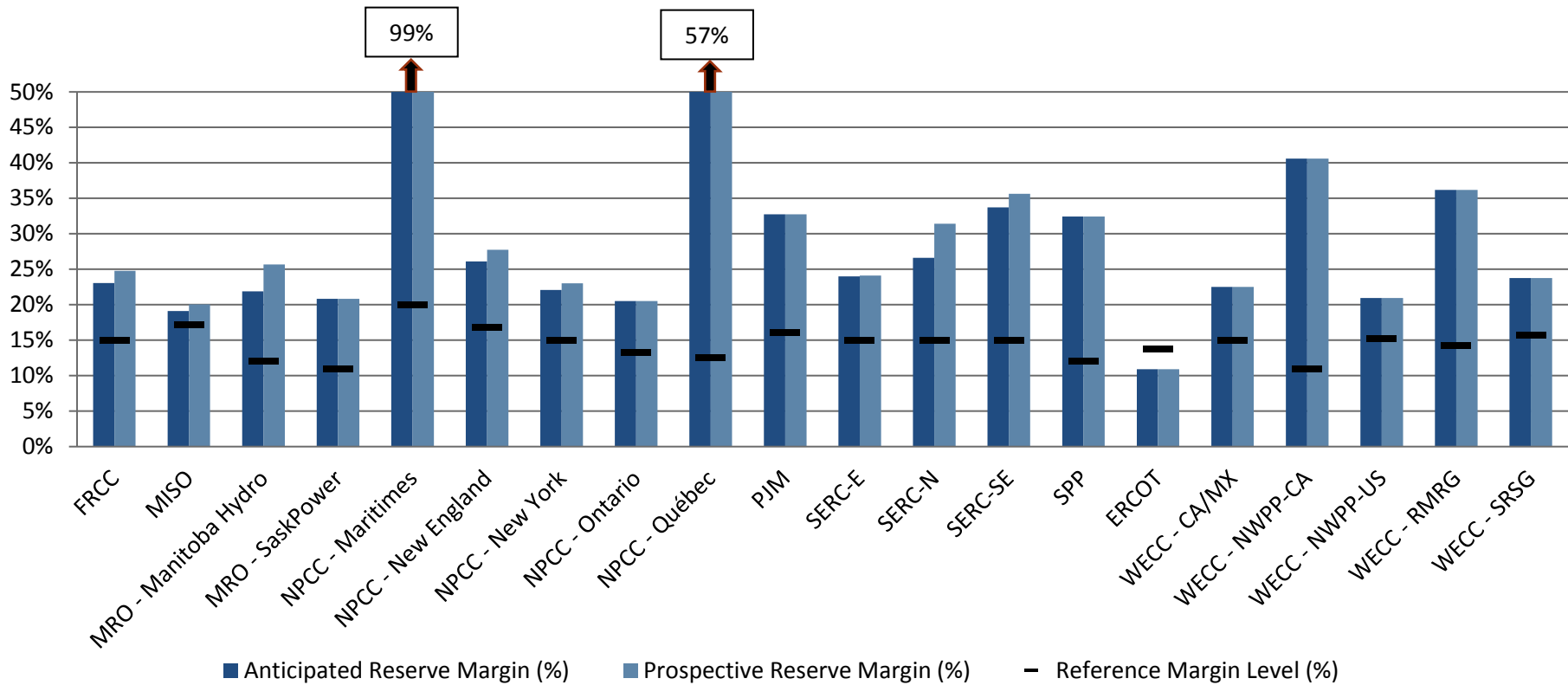
- The majority of assessment areas maintain sufficient resources to meet and exceed their Planning Reference Margin Levels for this summer. However, certain areas face additional operating challenges from either a resource shortfall or a diminishing resource surplus. Texas RE-ERCOT projects an Anticipated Reserve Margin of 10.9 percent. This Reserve Margin equates to a capacity shortfall of 2,000 MW based on the Reference Margin Level of 13.75 percent.
 - Texas RE-ERCOT's own assessment indicates that given this shortfall, the deployment of ancillary services and contracted load control programs may be required during peak demand periods.
 - Typical generator outages expected under normal conditions could limit Texas RE-ERCOT's ability to maintain operating reserves.
 - When extreme condition scenarios are reviewed, operational challenges occur during times of peak demand low wind output, and generator outages.
 - Reserve Margins can be very volatile, as evidenced by the 2017 LTRA Reference Case Reserve Margin of 18.22 percent for Texas RE-ERCOT declining to 11.76 percent in updated analysis just prior to publishing the 2017 LTRA late in 2018.
- Although MISO projects adequate reserves, more frequent reliance on behind-the-meter-generation (BTMG) and demand response will occur to meet reliability requirements. To access these resources, MISO operators will have to take actions to initiate emergency operating procedures more often than in the past. These actions are anticipated to provide sufficient energy or load relief to cover the normal forecasted system conditions.
- CAISO faces significant risk of encountering operating conditions that could result in operating reserve shortfalls. The increased risk is primarily a result of lower hydro conditions and the retirement of 789 MW of dispatchable natural gas generation that had been available in prior summers to meet high load conditions. The risk associated with the natural gas storage facility restrictions at the Aliso Canyon and other natural gas storage facilities to electric reliability is greater in the local reliability areas of Southern California than to the rest of the CAISO system. Operational constraints limit Aliso Canyon output, increasing ramping requirements in California. Any disruption in the Southern California gas system will be aggravated by the constraints at Aliso Canyon; in such a case, gas deliveries to power generation would be at risk.
- ISO-NE is adopting a new Pay-for-Performance market design. Scheduled for implementation on June 1, 2018, this new market design is intended to provide financial incentives for capacity resources to perform during scarcity conditions and thus enhance system reliability. Both internal and external market monitors continue to assess the development, operation, performance, and state of competition in the wholesale electricity markets operated by the ISO.
- The ERO continues to raise awareness on inverter-based resource performance through NERC alerts¹ and industry outreach. WECC staff reported significant efforts on the potential loss of solar generation associated with inverter controls.
- Despite substantial progress made in addressing and coordinating the interdependencies between natural gas and electric infrastructure, the growing reliance on natural gas continues to raise BPS reliability concerns. As underscored in NERC's recent special assessment report, *Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*,² planning approaches, operational procedures, and regulatory partnerships are needed to assure fuel deliverability, availability, security (physical and cyber), and resilience from potential disruptions.

¹ [NERC Inverter Alert Announcement](#), May 2, 2018

² [NERC Special Assessment](#), November, 2017

Resource Adequacy

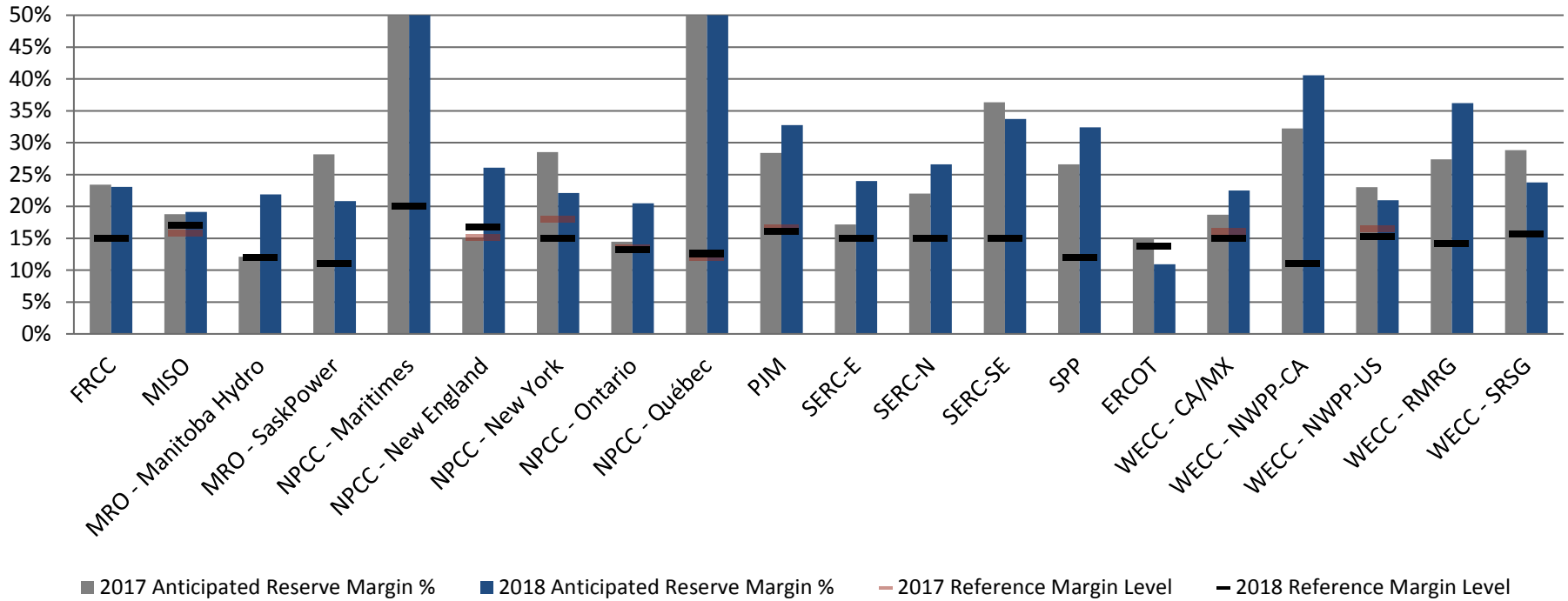
NERC uses the Anticipated Reserve Margin to evaluate resource adequacy by comparing the projected capability of Anticipated Resources to serve forecasted peak load.³ Large year-to-year changes in Anticipated Resources or forecasted peak load can greatly impact Planning Reserve Margin calculations. As shown in the figure below, most assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their planning Reference Margin Level for the 2018 summer period except for Texas RE-ERCOT.



Summer 2018 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

³ Refer to the [Data Concepts and Assumptions](#) section for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.

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. The figure below provides the relative change from the 2017 summer period to the 2018 summer period.



Summer 2017 to Summer 2018 Anticipated Reserve Margins Year-to-Year Change

Note: Areas with reserve margins greater than 50 percent are shown as 50 percent.

Operational Challenges Impacting ERCOT

Based on ERCOT's preliminary summer *Seasonal Assessment of Resource Adequacy* report,⁴ released March 1, 2018, ERCOT expects to rely on a variety of operational tools to help manage tight reserves and maintain system reliability. The ERCOT report focuses on the availability of sufficient operating reserves to avoid emergency actions. It uses an operating reserve threshold of 2,300 MW to indicate the risk that an energy emergency alert Level 1 may be triggered during the time of the forecasted seasonal peak load. This threshold level is roughly analogous to the 2,300 MW physical responsive capability threshold for energy emergency alert Level 1. Physical responsive capability is a real-time capability measure used by ERCOT to indicate the amount of capacity that can quickly respond to system disturbances. One caveat associated with this report is that it does not account for additional capacity and voluntary load reductions that may be realized as the market responds to wholesale market price increases and anticipated capacity scarcity conditions.

ERCOT has a variety of operational tools to help manage tight reserves and maintain system reliability. For example, control room operators can release ancillary services (including load resources that can provide various types of operating reserves depending 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.

Assessing At-Risk Capacity

The Anticipated Reserve Margin for ERCOT falls to 10.9 percent for the 2018 summer period, below their Reference Margin Level of 13.75 percent. This projected shortfall in Planning Reserve Margins is primarily due to approximately 2,100 MW of delayed new resources and approximately 5,000 MW of plant retirements that were expected to be available to serve load for this summer. These resources were included in the Reference Case in the NERC *2017 Long-Term Reliability Assessment*,⁵ which projected an Anticipated Reserve Margin of 18.2 percent for the 2018 summer period. An updated analysis included in the LTRA assessment showed that after accounting for the retirements and delays projected an Anticipated Reserve Margin of 11.76 percent for the summer of 2018. The NERC *2017 Summer Reliability Assessment*⁶ projected an Anticipated Reserve Margin of 15.0 percent. This volatility in the projected availability of capacity resources in the ERCOT market is shown in the figure on the following page, which shows the cumulative changes in the Reserve Margin of 18.9 percent reported in ERCOT's May 2017 annual resource adequacy assessment (called the *Capacity, Demand, and Reserves*⁷ report) to the NERC *2018 Summer Reliability Assessment* projection of 10.9 percent.

An operational risk analysis (as introduced in NERC's *2015 Summer Reliability Assessment*)⁸ is shown in the figure after the reserve margin changes from May, 2017. The Operational Risk Assessment portion of the figure represents a deterministic analysis that shows what happens when applying typical maintenance outages and forced outages for thermal units, extreme weather forecast load level and forced outages, and low wind. While the cumulative impact of all of these extreme event scenarios occurring are shown, it does not have a high likelihood of occurring. However, it does show the relative impact of each scenario in terms of potential capacity loss with each one being large enough for a risk of at least emergency alert Level 1 events occurring. If forecasted summer conditions materialize, ERCOT may need to rely on emergency operating procedures and import capabilities from neighboring areas.

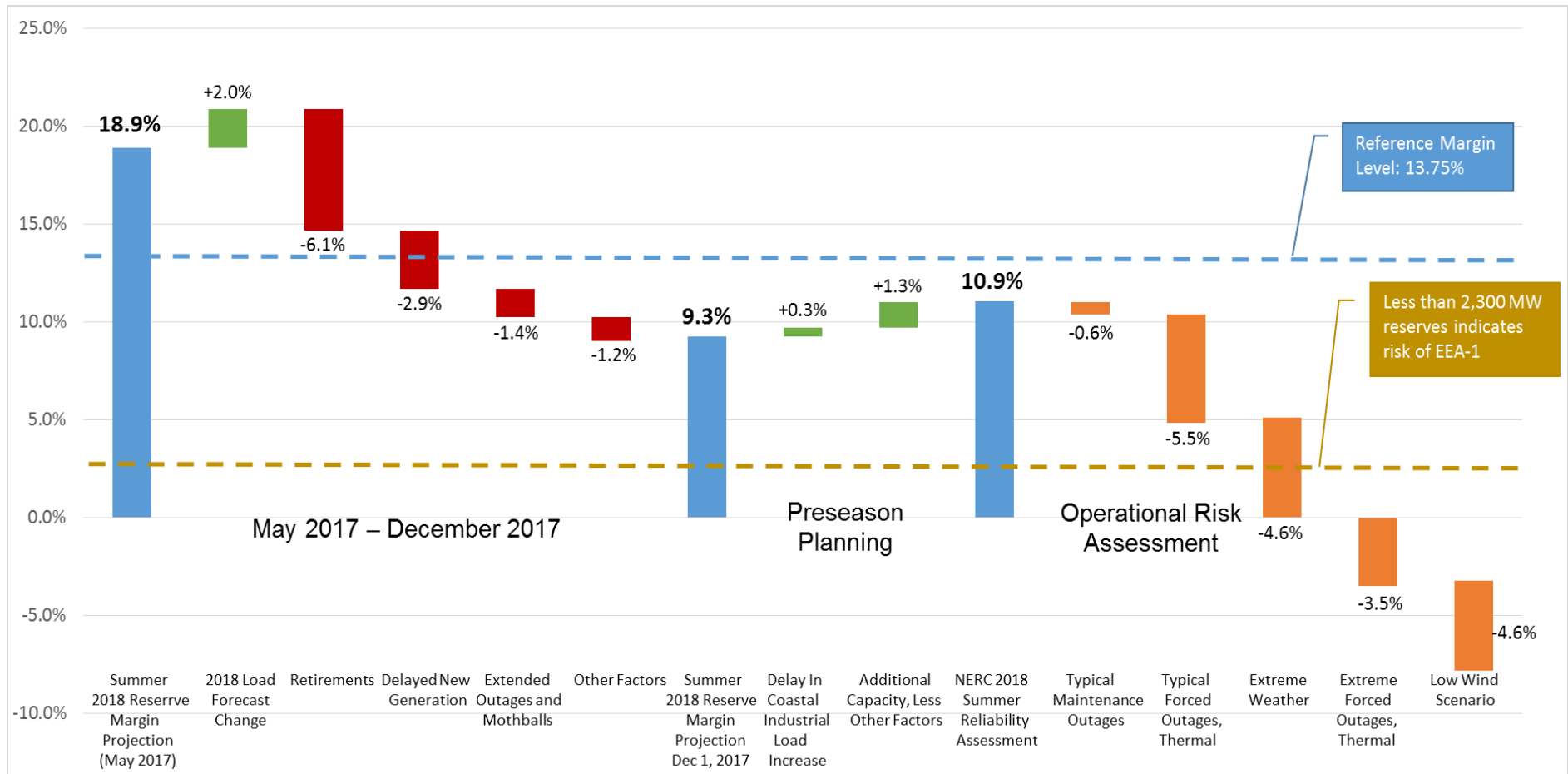
⁴For details, see the [ERCOT Seasonal Assessment of Resource \(SARA\) report](#), March 1, 2018

⁵ [NERC 2017 Long-Term Reliability Assessment](#), December 2017

⁶ [NERC 2017 Summer Reliability Assessment](#), May, 2017

⁷ [Report on the Capacity, Demand and Reserves \(CDR\) in the ERCOT Region](#), May 2, 2017

⁸ [NERC 2015 Summer Reliability Assessment](#), May, 2015



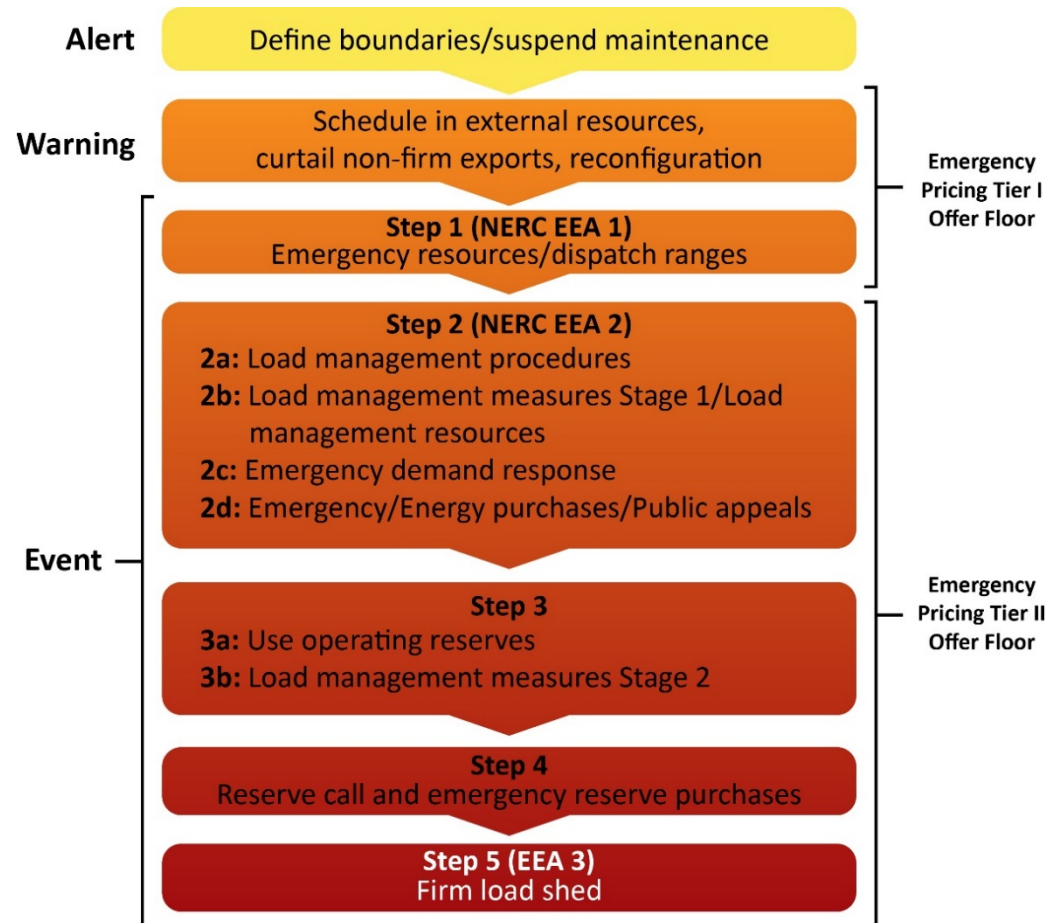
Contributing Factors to ERCOT's Reserve Margin Changes Since May 2017 and Operational Risk for Summer 2018

The above figure shows the most significant changes since the 2017 ERCOT CDR, including the following:

- A load forecast decrease of 1,175 MW in the summer 2018 peak load that increases the reserve margin approximately two percent
- Retirement of 4,273 MW of coal capacity in January and February 2018 (Big Brown, Monticello, and Sandow plants, owned by Vistra Energy)
- Retirement of 806 MW of natural-gas-fired capacity in late 2017 (Greens Bayou Unit 5 and S.R. Bertron Units 2-4)
- Delayed Tier 1 resources totaling about 2,100 MW and extended outages and mothballs of approximately 1,000 MW

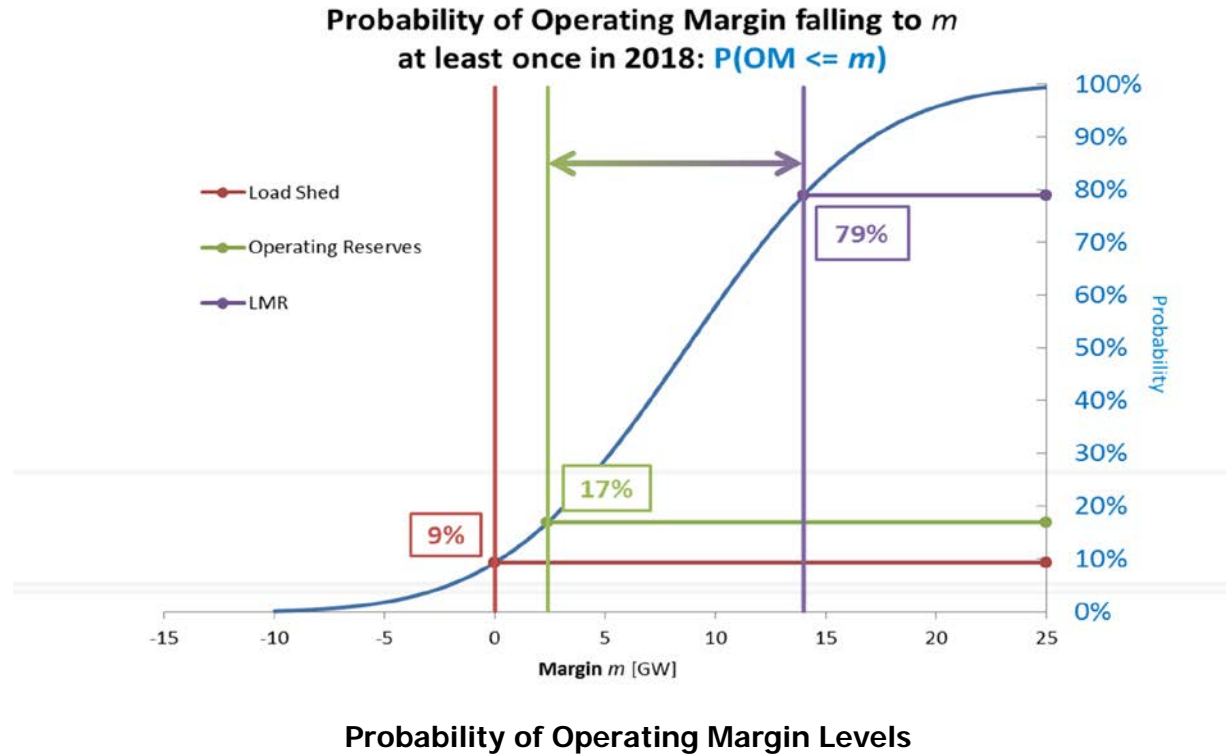
Operational Challenges Impacting MISO

Although adequate reserves are projected by MISO, in order to meet reliability requirements, it is projected that more frequent reliance on BTMG and demand response will occur, as their surplus capacity (approximately two percent) diminishes. To access these resources, MISO operators will have to take actions to initiate emergency operating procedures more often than in the past, as these resources are a substantial amount of their reserves. These actions are anticipated to provide sufficient energy or load relief to cover the normal forecasted system conditions. For a high demand, high outage scenario, MISO is expecting to rely heavily on demand response. The access to demand response resources is outlined in the sequence of actions in MISO’s Maximum Generation Emergency Procedures shown in the figure below:⁹



⁹ As presented in the [MISO 2018 Summer Readiness Workshop, April 24, 2018](#)

While progression through these steps indicates increasing risk, the first two steps are taken to access relied upon resources. This sequence corresponds to NERC energy emergency alerts Level 1, 2, and 3. The figure below¹⁰ represents the probability of a decrease in Operating Margin levels for the summer 2018 period in MISO. As shown, there is a 79 percent chance of the operating margin falling to a level that would result in a NERC energy emergence alert Level 2 being issued. Also shown is that there is a nine percent chance of load shed occurring.



¹⁰ As presented in the [MISO 2018 Summer Readiness Workshop, April 24, 2018](#)

Operational Challenges Impacting CAISO

As reported in the CAISO *2018 Summer Loads and Resources Assessment*,¹¹ “the CAISO faces significant risk of encountering operating conditions that could result in operating reserve shortfalls. The increased risk in 2018 over 2017 is primarily a result of lower hydro conditions and the retirement of 789 MW of dispatchable natural gas generation that had been available in prior summers to meet high load conditions that persist after the solar generation ramps down in the late afternoon. The risk increases during late summer when hydro availability decreases as the snow runoff progressively declines through the runoff season and solar production declines in the late afternoon hours due to shorter days. CAISO is at greatest operational risk if seasonal peak hot weather conditions occur in late August and early September.” The CAISO report does not consider the limitations at the Aliso Canyon Natural Gas Storage Facility. Natural gas limitations and pipeline outages could exacerbate these conditions. An update on Aliso Canyon is provided in the next section below.

In the CAISO report, 2,000 scenarios were constructed using historic temperatures, demand, and current power plant availability. This assessment found a 50 percent chance that CAISO will need to declare a Stage 2 Emergency for at least one hour this summer. 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, CAISO will implement a mitigation operating plan to minimize loss of load in the CAISO BA. This plan is made up of the following:

- Use the Flex Alert program, signaling that CAISO expects a high peak load condition. This program has been proven to reduce peak load in the CAISO BA area.
- Use CAISO’s Restricted Maintenance program. This program is intended to reduce potential forced outages, thus minimizing forced outage rate during a 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 intertie resources that have resource adequacy obligation to serve CAISO load.
- Use the 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 have not received an RA contract for the month.

¹¹CAISO [2018 Summer Loads and Resources Assessment](#)

Impacts of the Aliso Canyon Natural Gas Storage Operating Restrictions

The outlook for energy reliability in Southern California and in the Desert Southwest remains challenging due to uncertainty about the status of its natural gas system. The challenges to the natural gas system are greater than for the previous two summers and create the potential for natural gas providers to either curtail natural gas to the electric generators in Southern California or use natural gas from the Aliso Canyon underground natural gas storage facility. The challenges stem primarily from continuing outages on as many as four key natural gas pipelines and the operational constraints limiting the use of the Aliso Canyon natural gas storage facility. While the ability for the CAISO electric system in Southern California to maintain electric reliability poses a potential challenge with the loss of key storage capacity and natural gas pipeline facilities, when combined with the increasingly high use of the interstate pipelines, inherent flexibility may be reduced in the natural gas infrastructure serving the Desert Southwest and Southern California. Additionally, the availability of alternative resources may be less this summer due to below average hydroelectric conditions.

Inverter-Based Resource Performance

Recent grid disturbances in the Western Interconnection that involve the reduction in output of solar photovoltaic (PV) resources has put a spotlight on the performance of inverter-based resources connected to the BPS. On August 16, 2016, the Blue Cut Fire resulted in a solar PV reduction of around 1,200 MW. NERC and the Western Electricity Coordinating Council (WECC) launched a task force to identify the primary causes of the disturbance, which led to the publication of the *Blue Cut Fire Disturbance Report*.¹² The report identified potential risks to the reliability of the BPS, including erroneous frequency-based tripping in some inverters and the use of momentary cessation by inverters nearly across the fleet.

Once these issues were identified through event analysis, NERC began outreach with industry and vendors to educate them on potential risks and mitigation strategies. NERC posted a Level 2 Alert,¹³ which required a response from recipients and recommended specific actions to be taken by registered entities to address and mitigate these adverse characteristics observed in BPS-connected solar PV resources.

On October 9, 2017, the Canyon 2 Fire resulted in another grid disturbance in the West, and NERC and the NERC Inverter-Based Resource Performance Task Force began identifying the causes of this disturbance. NERC published the *Canyon 2 Fire Disturbance Report*.¹⁴ The report identified additional risks of solar PV tripping and continued use of momentary cessation, which pose a potential reliability risk to the BPS.

NERC recently posted another Level 2 Alert¹⁵ requiring a response for further data collection and recommending mitigating actions to address voltage-related tripping, improvements in dynamic modeling, and mitigation of momentary cessation. These recommendations are intended to apply to all solar PV resources connected to the BPS.

¹² [Blue Cut Fire Disturbance Report](#)

¹³ [Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings](#)

¹⁴ [Canyon 2 Fire Disturbance Report](#)

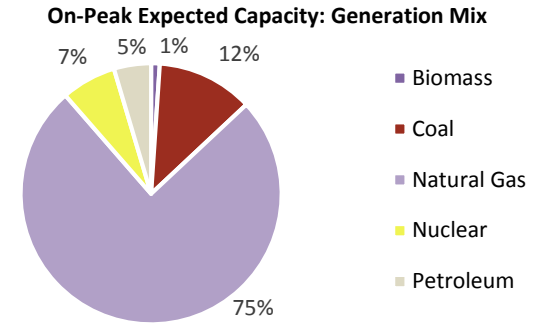
¹⁵ [Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings - II](#)



FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 32 Regional Entity Division members and 23 Member Services Division members composed of investor-owned utilities (IOUs), cooperatives, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 BAs with 45 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.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	1%
Coal	12%
Hydro	<1%
Natural Gas	75%
Nuclear	7%
Petroleum	5%
Solar	<1%



FRCC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change (
Total Internal Demand (50/50)	47,580	47,495	-0.2%
Demand Response: Available	2,922	2,957	1.2%
Net Internal Demand	44,658	44,538	-0.3%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	53,403	53,010	-0.7%
Tier 1 Planned Capacity	467	322	-31.1%
Net Firm Capacity Transfers	1,252	1,477	18.0%
Anticipated Resources	55,122	54,809	-0.6%
Existing-Other Capacity	744	764	2.7%
Prospective Resources	55,866	55,573	-0.5%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	23.4%	23.1%	-0.3%
Prospective Reserve Margin	25.1%	24.8%	-0.3%
Reference Margin Level	15.0%	15.0%	0.0%

Highlights

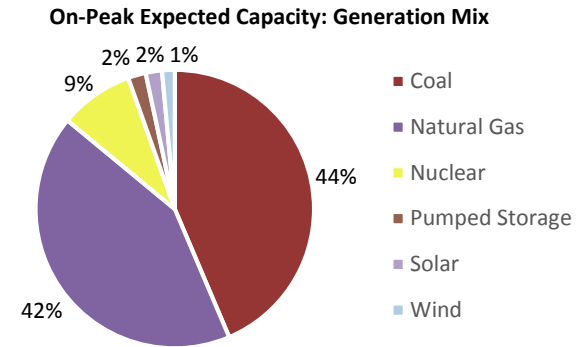
- FRCC has not identified any emerging reliability issues that are expected to impact the reliability of the FRCC Region for the upcoming 2018 summer season.
- The BES within the FRCC Region is expected to perform reliably for anticipated 2018 summer season conditions.
- The legal challenge against the newly constructed Sabal Trail pipeline has been resolved, and the pipeline is in service. Should any future actions regarding operability of the pipeline materialize, the Region will continue to work with potentially affected parties to understand timing and any impacts on the FRCC BES.



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.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	44%
Hydro	<1%
Natural Gas	42%
Nuclear	9%
Petroleum	<1%
Pumped Storage	2%
Solar	2%
Wind	1%



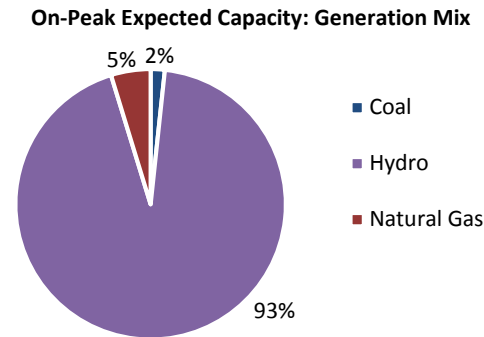
MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	125,002	124,704	-0.2%
Demand Response: Available	5,144	5,990	16.5%
Net Internal Demand	119,858	118,714	-1.0%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	142,398	141,425	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-45	-8	-81.8%
Anticipated Resources	142,353	141,417	-0.7%
Existing-Other Capacity	1,151	1,104	-4.1%
Prospective Resources	143,504	142,521	-0.7%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	18.8%	19.1%	0.3%
Prospective Reserve Margin	19.7%	20.1%	0.4%
Reference Margin Level	15.8%	17.1%	1.3%

Highlights

- MISO does not anticipate reliability issues for the upcoming season. The reserve margin for summer 2018 is projected to be 19.1 percent, which is two percentage points higher than the target reserve margin of 17.1 percent. This diminishing surplus will result in MISO using emergency operating procedures to access additional resources more frequently.
- MISO also studies the summer system reliability during a high outage, high load scenario. For these conditions, MISO expects to rely heavily on demand response.
- MISO also holds a summer readiness workshop with its members to prepare for summer operations.
- MISO relies on LMRs, such as BTMG and demand response, to meet reliability standard of one-day-in-10 loss of load expectation. Accessing LMRs will require MISO operators to initiate emergency operating procedures more frequently.



Existing On-Peak Generation	
Generation Type	Percent
Coal	2%
Hydro	93%
Natural Gas	5%
Wind	<1%



MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to 556,000 customers throughout Manitoba and natural gas service to 272,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 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.

MRO - Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	3,313	3,237	-2.3%
Demand Response: Available	0	0	-
Net Internal Demand	3,313	3,237	-2.3%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	5,149	5,288	2.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,435	-1,342	-6.5%
Anticipated Resources	3,714	3,946	6.2%
Existing-Other Capacity	130	122	-5.9%
Prospective Resources	3,844	4,068	5.8%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	12.1%	21.9%	9.8%
Prospective Reserve Margin	16.0%	25.7%	9.7%
Reference Margin Level	12.0%	12.0%	0.0%

Highlights

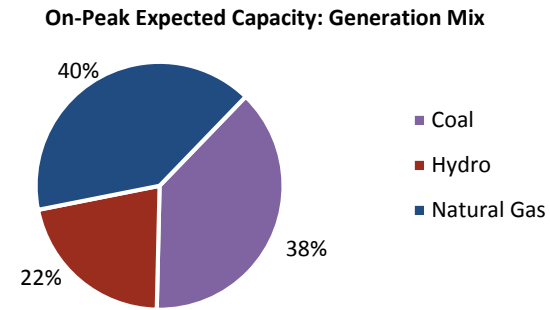
- There are no emerging reliability issues for the upcoming season in the Manitoba Hydro assessment area that are unique to the assessment area. There are also no reliability impacts to the resource adequacy.
- Although future precipitation is uncertain, current river flows and storage conditions are close to average; therefore, Manitoba Hydro is not anticipating severe drought conditions to impact summer operations.



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.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	38%
Hydro	22%
Natural Gas	40%
Wind	<1%



MRO - SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	3,353	3,426	2.2%
Demand Response: Available	241	85	-64.7%
Net Internal Demand	3,112	3,341	7.4%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	3,964	4,013	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	3,989	4,038	1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	3,989	4,038	1.2%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	28.2%	20.9%	-7.3%
Prospective Reserve Margin	28.2%	20.9%	-7.3%
Reference Margin Level	11.0%	11.0%	0.0%

Highlights

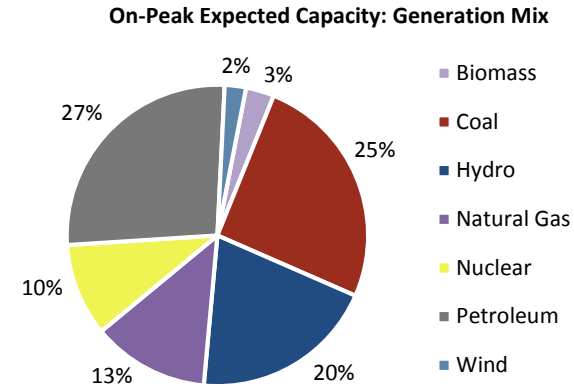
- No emerging generation or transmission based reliability issues are expected for the upcoming summer season.
- There are no known operational challenges anticipated for the upcoming season.
- SaskPower conducts an annual summer season joint operating study with Manitoba Hydro, with inputs from Basin Electric Power Cooperative (North Dakota) for the summer assessment period. As part of the study, any identified issues are communicated by issuing applicable guidelines to respective control rooms before the summer season begins.



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.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	3%
Coal	25%
Hydro	20%
Natural Gas	13%
Nuclear	10%
Petroleum	27%
Wind	2%



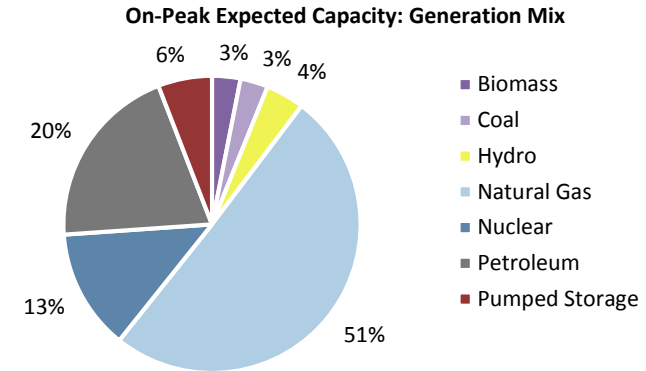
NPCC - Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	3,320	3,235	-2.6%
Demand Response: Available	369	300	-18.7%
Net Internal Demand	2,951	2,935	-0.5%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	5,636	5,828	3.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	5,636	5,828	3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	5,636	5,828	3.4%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	91.0%	98.6%	7.6%
Prospective Reserve Margin	91.0%	98.6%	7.6%
Reference Margin Level	20.0%	20.0%	0.0%

Highlights

- During the NERC 2018 summer assessment period, the Maritimes area has not identified any issues that are expected to impact system reliability.
- If conditions were to change due to unplanned transmission or generator outages, operating adjustments would be addressed by Operations Engineering through established procedures.



Existing On-Peak Generation	
Generation Type	Percent
Biomass	3%
Coal	3%
Hydro	4%
Natural Gas	51%
Nuclear	13%
Petroleum	20%
Pumped Storage	6%
Solar	<1%
Wind	<1%



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 Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	26,482	25,729	-2.8%
Demand Response: Available	382	408	6.8%
Net Internal Demand	26,100	25,321	-3.0%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	28,738	30,460	6.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,246	1,468	17.8%
Anticipated Resources	29,984	31,928	6.5%
Existing-Other Capacity	315	421	33.7%
Prospective Resources	30,299	32,349	6.8%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	14.9%	26.1%	11.2%
Prospective Reserve Margin	16.1%	27.8%	11.7%
Reference Margin Level	15.1%	16.8%	1.7%

Highlights

- ISO New England (ISO-NE) does not anticipate any reliability issues for the upcoming 2018 summer assessment period. The forecasts indicate adequate transmission capability and sufficient capacity margins to meet the expected peak demand and operating reserves.
- Over the last several years, sustained growth in distributed PV has been observed and is anticipated to continue for the long-term. By the end of 2017, a total of 2,390 MW (1,500 MW behind-the-meter and 890 MW in front of the meter) of nameplate PV has been installed within the Region. An additional 299 MW of PV is forecast for the 2018 summer assessment period. Efforts to further improve the BTMG PV forecasts in the long-term, short-term, and real-time process are ongoing.
- ISO-NE will be replacing the existing forward capacity market shortage-event penalty structure with a new Pay-for-Performance market design. Scheduled for implementation on June 1, 2018, this new market design is intended to provide financial incentives for capacity resources to perform during scarcity conditions and thus enhance system reliability conditions and thus enhance system reliability.

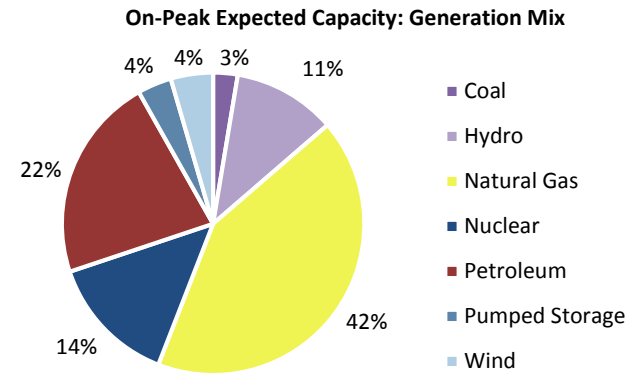


NPCC-New York

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 encompassing approximately 11,000 miles of transmission lines, over 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

*Changed per NERC assessment default level of 15% used in the NERC 2017 Long-Term Reliability Assessment.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	3%
Hydro	11%
Natural Gas	42%
Nuclear	14%
Petroleum	22%
Pumped Storage	4%
Solar	<1%
Wind	4%



NPCC - New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	33,178	32,904	-0.8%
Demand Response: Available	1,192	1,219	2.3%
Net Internal Demand	31,986	31,685	-0.9%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	38,581	39,066	1.3%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	2,533	1,625	-35.8%
Anticipated Resources	41,114	40,950	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	41,114	40,950	-0.4%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	28.5%	29.2%	0.7%
Prospective Reserve Margin	28.5%	29.2%	0.7%
Reference Margin Level	18.1%	15.0%	N/A*

Highlights

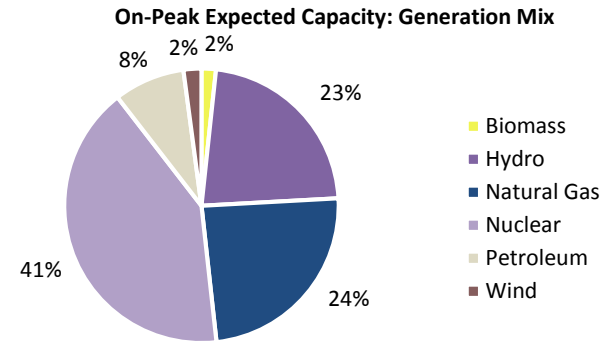
- New York is not anticipating any issues for the upcoming season.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run-time on peaking units, 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 for the province of Ontario. Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	2%
Hydro	23%
Natural Gas	24%
Nuclear	41%
Petroleum	8%
Solar	<1%
Wind	2%



NPCC - Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	22,614	22,002	-2.7%
Demand Response: Available	737	630	-14.5%
Net Internal Demand	21,877	21,372	-2.3%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	24,692	25,731	4.2%
Tier 1 Planned Capacity	354	23	-93.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	25,045	25,754	2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,045	25,754	2.8%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	14.5%	20.5%	6.0%
Prospective Reserve Margin	14.5%	20.5%	6.0%
Reference Margin Level	13.5%	13.3%	-0.2%

Highlights

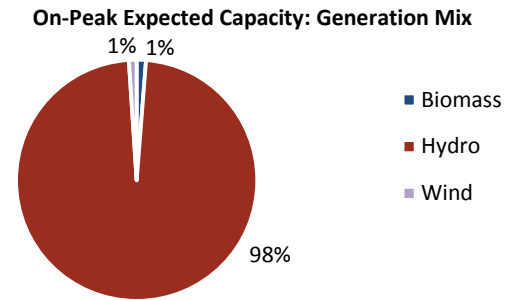
- IESO anticipates that it will maintain system reliability during the upcoming season.
- The IESO’s seasonal planning includes an extreme weather scenario that accounts for high demands, lower ratings for thermal generation, and lower hydro availability in the summer months. The IESO’s most recent 18 Month Outlook, published March 21, 2018, identified several weeks in the summer period where there are potential resource shortfalls (without the use of the interties) under extreme conditions. If extreme weather materializes, the IESO may reject some generator maintenance and make use of imports to ensure that Ontario demand is met.



NPCC-Québec

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8 million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	1%
Hydro	98%
Wind	1%



NPCC - Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	20,506	20,534	0.1%
Demand Response: Available	0	0	-
Net Internal Demand	20,506	20,534	0.1%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	34,478	34,014	-1.3%
Tier 1 Planned Capacity	5	0	-100.0%
Net Firm Capacity Transfers	-1,855	-1,829	-1.4%
Anticipated Resources	32,628	32,185	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	32,628	32,185	-1.4%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	59.1%	56.7%	-2.4%
Prospective Reserve Margin	59.1%	56.7%	-2.4%
Reference Margin Level	12.0%	12.6%	0.6%

Highlights

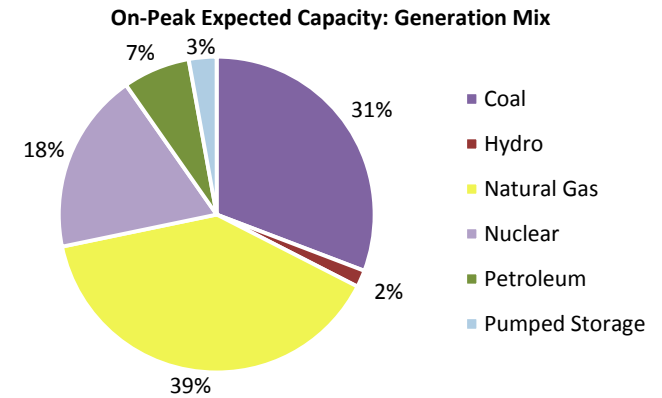
- No particular resource adequacy problems are forecasted since the system is winter peaking.
- Québec area expects to be able to provide assistance to other areas if needed, up to the transfer capability available.
- The Reference Margin Level is set to 12.6 percent for the 2018 summer operating period for the Québec area.
- Maintenance and construction schedules will be coordinated to not impact inter-area transfer capabilities with neighboring systems.



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 61 million people and covers 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	31%
Hydro	2%
Natural Gas	39%
Nuclear	18%
Petroleum	7%
Pumped Storage	3%
Solar	<1%
Wind	<1%



PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	152,999	152,108	-0.6%
Demand Response: Available	9,120	9,095	-0.3%
Net Internal Demand	143,879	143,013	-0.6%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	179,695	185,440	3.2%
Tier 1 Planned Capacity	734	0	-100.0%
Net Firm Capacity Transfers	4,304	4,419	2.7%
Anticipated Resources	184,734	189,859	2.8%
Existing-Other Capacity	319	0	-100.0%
Prospective Resources	185,053	189,859	2.6%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	28.4%	32.8%	4.4%
Prospective Reserve Margin	28.6%	32.8%	4.2%
Reference Margin Level	16.6%	16.1%	-0.5%

Highlights

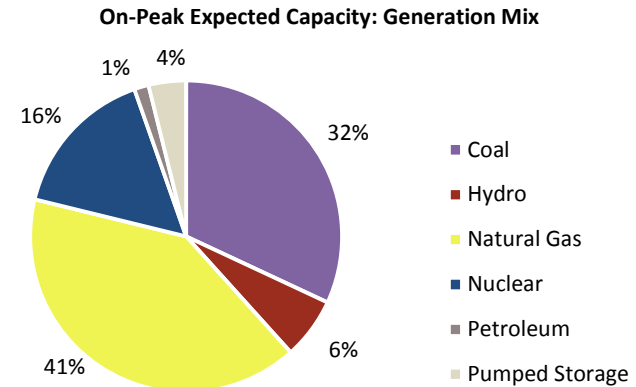
- The PJM reserve margin for this summer is 32.8 percent with a requirement of 16.1 percent. With this level of surplus, PJM has not identified any emerging reliability issues regarding resource adequacy.
- In addition, PJM has performed a pre-seasonal operations analysis, and no concerns have been identified for the upcoming summer season.



SERC

The SERC assessment area covers approximately 308,900 square miles, serves a population estimated at 39.4 million and is divided into three reporting areas: SERC-E, SERC-N, and SERC-SE. The SERC assessment area consists of 11 Balancing Authorities including: Cube Hydor Carolinas, Associated Electric Cooperative, Inc., Duke Energy Carolinas and Duke Energy Progress, Electric Energy, Inc., LG&E and KU Services Company, PowerSouth Energy Cooperative, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Southern Company Services, Inc., and Tennessee Valley Authority.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	32%
Hydro	6%
Natural Gas	41%
Nuclear	16%
Other	<1%
Petroleum	1%
Pumped Storage	4%
Solar	<1%
Wind	<1%



SERC Resource Adequacy Data						
Demand, Resource, and Reserve Margins	SERC-E	SERC-N	SERC-SE	2017 SRA SERC Total	2018 SRA SERC Total	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	42,620	41,454	47,370	131,994	131,444	-0.4%
Demand Response: Available	1,083	1,789	2,100	4,640	4,972	7.2%
Net Internal Demand	41,537	39,665	45,270	127,354	126,472	-0.7%
Resource Projections	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	51,318	51,206	61,792	161,532	164,317	1.7%
Tier 1 Planned Capacity	0	0	0	1,875	0	-100.0%
Net Firm Capacity Transfers	184	-983	-1,255	-3,133	-2,054	-34.4%
Anticipated Resources	51,502	50,223	60,537	160,274	162,263	1.2%
Existing-Other Capacity	42	1,902	862	2,361	2,806	18.8%
Prospective Resources	51,544	52,126	61,399	162,635	165,069	1.5%
Planning Reserve Margins	Percent	Percent	Percent	Percent	Percent	Annual Difference
Anticipated Reserve Margin	24.0%	26.6%	33.7%	25.8%	28.3%	2.5%
Prospective Reserve Margin	24.1%	31.4%	35.6%	27.7%	30.5%	2.8%
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	0.0%

Highlights

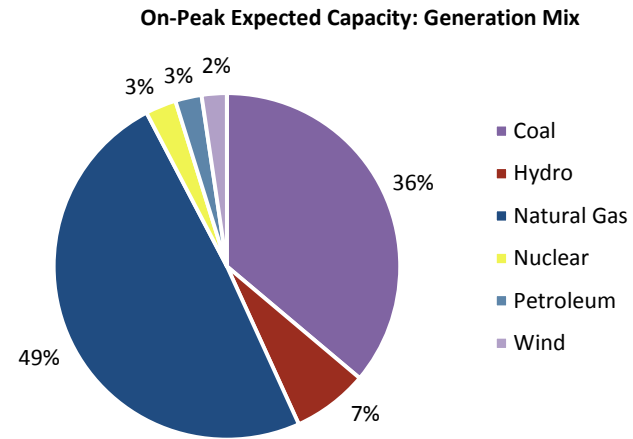
- There are no emerging reliability issues identified within the SERC Region for the 2018 summer period.
- Entities are monitoring emerging issues, such as pseudo-ties requests and loop flows, to ensure reliability and prevent operational challenges.
- Entities will continue to perform studies internal to their companies and coordinate studies with their neighbors through communication with the SERC committee structure.
- Entities also perform sensitivity studies using a 50/50 and 90/10 extreme weather load forecast to assess system impacts under various weather conditions, including drought.



SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 575,000 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 Southwest Power Pool Regional Entity, MRO, 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 18 million people.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	36%
Hydro	7%
Natural Gas	49%
Nuclear	3%
Other	<1%
Petroleum	3%
Pumped Storage	<1%
Solar	<1%
Wind	2%



SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	52,587	52,554	-0.1%
Demand Response: Available	828	867	4.7%
Net Internal Demand	51,759	51,687	-0.1%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	65,092	67,649	3.9%
Tier 1 Planned Capacity	67	780	1064.0%
Net Firm Capacity Transfers	369	19	-94.9%
Anticipated Resources	65,528	68,447	4.5%
Existing-Other Capacity	0	0	-
Prospective Resources	65,528	68,447	4.5%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	26.6%	32.4%	5.8%
Prospective Reserve Margin	26.6%	32.4%	5.8%
Reference Margin Level	12.0%	12.0%	0.0%

Highlights

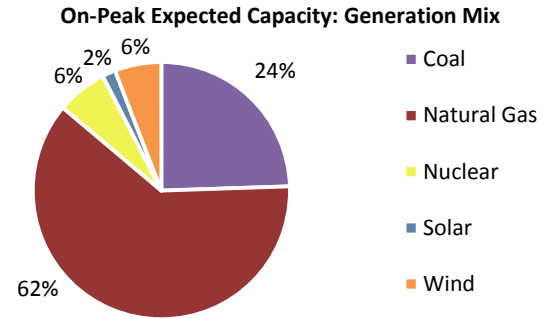
- The SPP assessment area does not have any emerging reliability issues that are considered unique.
- The SPP assessment area will be performing a special operating study for the upcoming summer season, which will be an impact analysis on the addition of two new generation facilities in SPP’s footprint. These switchable generators currently provide energy to the ERCOT but may also connect to SPP and provide energy; the SPP assessment area is currently working to develop reliable processes and procedures that will govern this specific situation.



Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas and operates as a single Balancing Authority. ERCOT is a summer peaking area that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines, and 566 generation units, and it serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT area.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	<1%
Coal	24%
Hydro	<1%
Natural Gas	62%
Nuclear	6%
Solar	2%
Wind	6%



ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2017 SRA	2018 SRA	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Net Change
Total Internal Demand (50/50)	72,934	72,756	-0.2%
Demand Response: Available	2,572	2,301	-10.5%
Net Internal Demand	70,362	70,455	0.1%
Resource Projections	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	77,845	76,654	-1.5%
Tier 1 Planned Capacity	2937	739	-74.8%
Net Firm Capacity Transfers	140	753	438.5%
Anticipated Resources	80,922	78,146	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	80,922	78,146	-3.4%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	15.0%	10.9%	-4.1%
Prospective Reserve Margin	15.0%	10.9%	-4.1%
Reference Margin Level	13.8%	13.8%	0.0%

Highlights

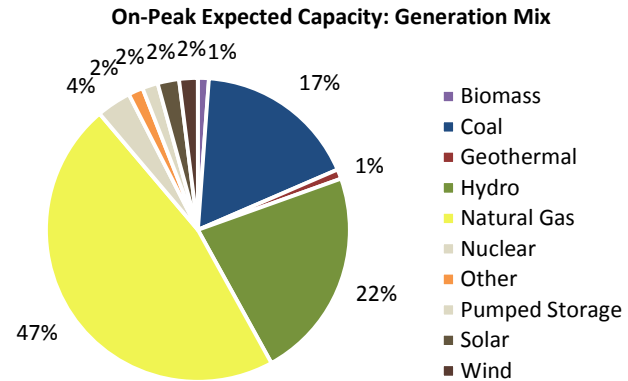
- ERCOT does not have any known operational challenges for the upcoming season other than the capacity reserves issue described below.
- Generation unit retirements that occurred in early 2018, along with reported delays in Tier 1 resource capacity by generation project developers, are expected to result in tight reserve margins for the upcoming summer. ERCOT has a variety of operational tools to help manage tight reserves, maintain system reliability, and to help maintain sufficient operating reserves.
- Higher wholesale market prices, during peak demand periods, are anticipated to 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).
- There are no significant issues associated with neighboring assessment areas expected for the summer. In the event that issues were to occur, ERCOT has coordination agreements in place with SPP and MISO that address operation of the dc ties, switchable generation resources, and block load transfers.



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 five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas. 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.

Existing On-Peak Generation	
Generation Type	Percent
Biomass	1%
Coal	17%
Geothermal	1%
Hydro	22%
Natural Gas	47%
Nuclear	4%
Other	2%
Petroleum	<1%
Pumped Storage	2%
Solar	2%
Wind	2%



WECC Resource Adequacy Data								
Demand, Resource, and Reserve Margins	CA/MX	NWPP CA	NWPP US	RMRG	SRSG	2017	2018	2017 vs. 2018 SRA
Demand Projections	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Total MW	Total MW	Net Change
Total Internal Demand (50/50)	54,700	19,184	49,579	12,618	23,827	154,627	154,256	-0.2%
Demand Response: Available	1,480	0	1,286	423	380	3,889	3,569	-8.2%
Net Internal Demand	53,220	19,184	48,293	12,195	23,447	150,738	150,687	0.0%
Resource Projections	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Megawatts	Net Change
Existing-Certain Capacity	53,358	26,627	59,218	17,443	32,101	183,062	184,981	1.0%
Tier 1 Planned Capacity	3,447	344	50	12	12	994	1,098	10.5%
Net Firm Capacity Transfers	8,385	0	-858	-846	-3,097	0	0	0.0%
Anticipated Resources	65,190	26,971	58,410	16,609	29,016	184,056	186,079	1.1%
Existing-Other Capacity	0	0	0	0	0	0	0	0.0%
Prospective Resources	65,190	26,971	58,410	16,609	29,016	184,056	186,079	1.1%
Planning Reserve Margins	Percent	Percent	Percent	Percent	Percent	Percent	Percent	Annual Difference
Anticipated Reserve Margin	22.5%	40.6%	20.9%	36.2%	23.8%	22.1%	23.5%	1.4%
Prospective Reserve Margin	22.5%	40.6%	20.9%	36.2%	23.8%	22.1%	23.5%	1.4%
Reference Margin Level	15.0%	11.0%	15.2%	14.0%	15.7%	15.4%	15.4%	0.0%

Highlights

- The availability of the Aliso Canyon Natural Gas storage facility remains an item of focus for electric reliability within the Western Interconnection, particularly in Southern California.
- Due to below-average hydroelectricity supplies and reduced generation, capacity to serve consumers will be tight in high-load periods, especially during evening hours when solar power dissipates. This assessment found a 50 percent chance that the CAISO will need to declare a Stage 2 Emergency at least for one hour this summer.
- Other than described above, there are no significant issues of note for the upcoming summer season.
- WECC staff remains focused on the potential loss of electric generation from inverter-based solar resources, following voltage disturbances.

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.
- *2017 Long-Term Reliability Assessment* data has been used for most of this 2018 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, or total internal demand, for the summer and winter of each year.
- Total internal demand projections are based on normal weather (50/50 distribution) and are provided on a coincident 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 are expected to 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 percentile:

$$\text{Anticipated Reserve Margin} = \frac{(\text{Anticipated Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

$$\text{Prospective Reserve Margin} = \frac{(\text{Prospective Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

Reference Margin Level: The assumptions of this metric vary by assessment area. The reference margin level is typically based on load, generation, and transmission characteristics for each assessment area, and in some cases, the reference margin level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the reference margin level. In some cases, the reference margin level will fluctuate over the duration of the assessment period, or it may be different for the summer and summer seasons. If one is not provided by a given assessment area, NERC applies a 15 percent reference margin level for predominately thermal systems and 10 percent for predominately hydro systems.

On-Peak Expected Capacity Generation Mix: generation mix is aggregated from 2017 Long-Term Reliability Assessment data. Fuel types with nominal quantities were aggregated together as fuel types, renewables, other renewables, or other fuels.

Renewable Nameplate Capacities: these charts include renewable on peak and nameplate (de-rated and expected on peak added together) capacities.

Errata

July 1, 2018

Page 6: Added clarification on reserve margin key findings for Texas RE-ERCOT and natural gas deliveries in Southern California

Page 9: Added additional information on the Texas RE-ERCOT reserve margin changes from May 2017 to Summer 2018

Page 14: Updated impacts of natural gas storage facilities and pipeline impacts in Southern California

Page 25: Updated SERC load forecast data

Page 28: Updated WECC resource data and associated reserve margin calculations