NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2017 Summer Reliability Assessment

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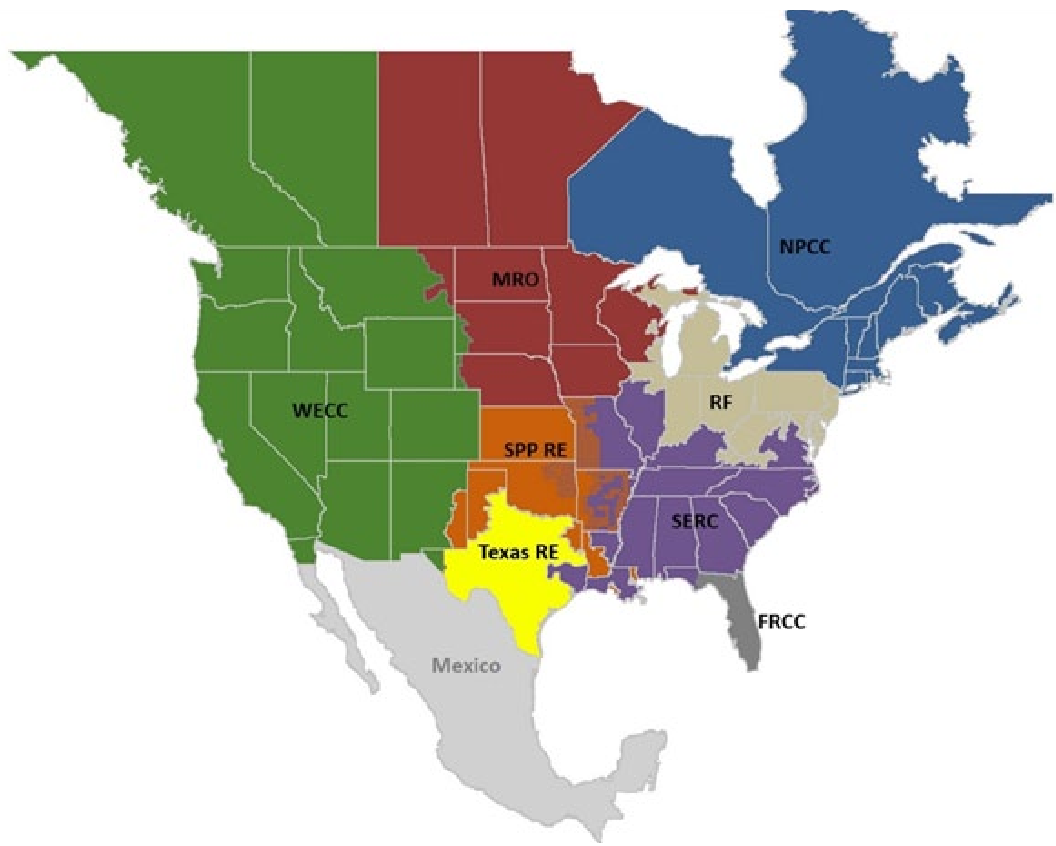
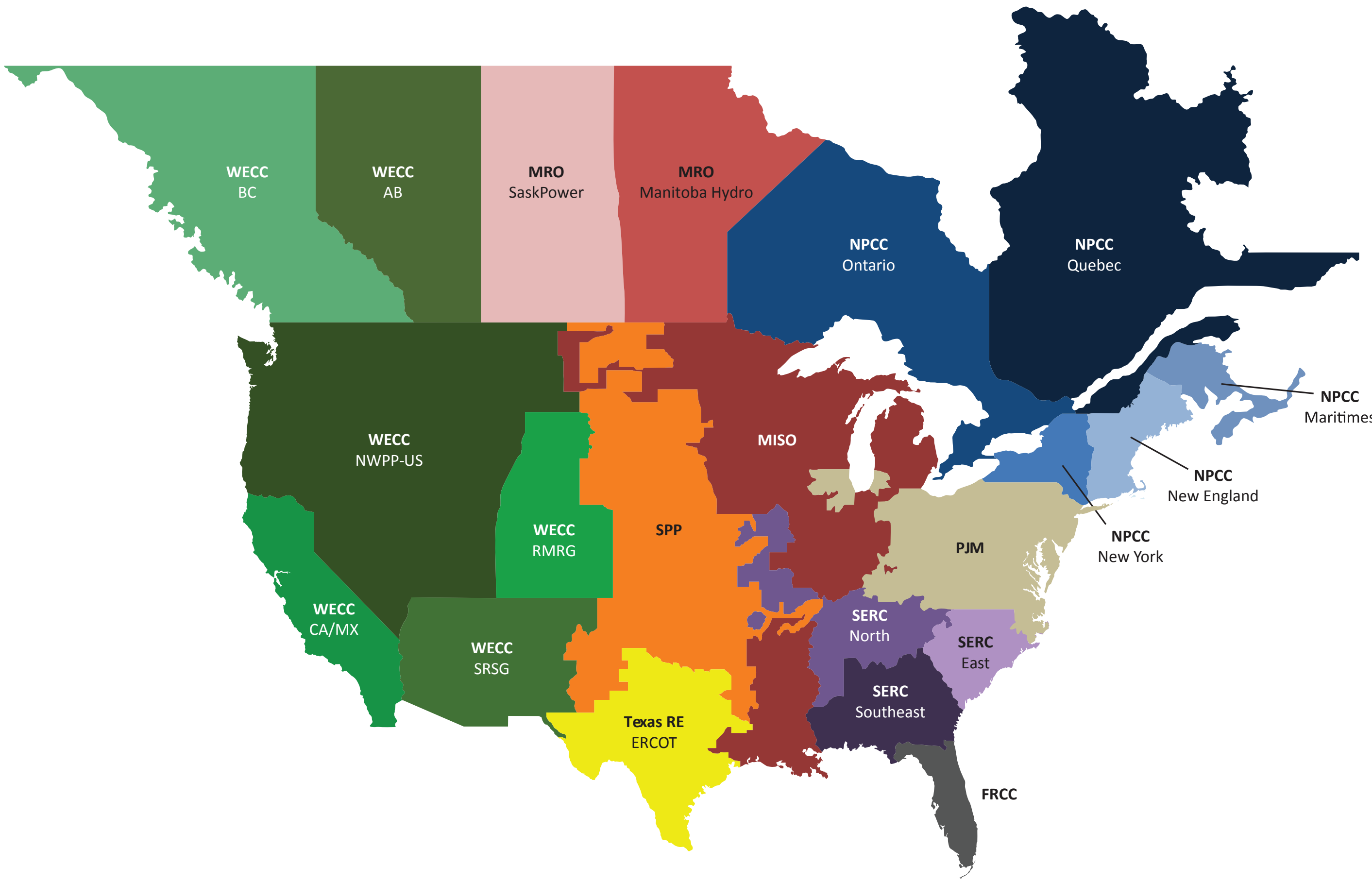
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California in Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serve more than 334 million people. The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map below. The assessment areas are shown on page 4. Refer to the *Data Concepts and Assumptions Guide* for more information.





FRCC—Florida Reliability Coordinating Council
- FRCC

MRO—Midwest Reliability Organization
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

SPP RE—Southwest Power Pool Regional Entity
- SPP

Texas RE–Texas Reliability Entity
- ERCOT

NPCC—Northeast Power Coordinating Council
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF—ReliabilityFirst
- PJM

WECC—Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

SERC—SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

About This Report

The objectives for NERC's Summer Reliability Assessment (SRA) are to identify, assess, and report details about the reliability of the North American BPS and to make recommendations as necessary. The SRA identifies potential summer resource deficiencies and operating reliability concerns, determines peak electricity demand and supply changes, and highlights unique regional challenges. The SRA represents the results of collaborative efforts involving the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff to develop sound technical bases for understanding these potential concerns, changes, and challenges. The SRA is intended to enable entities to better anticipate and respond in ways that ensure BPS reliability. The SRA also provides an opportunity for the industry to discuss their plans to ensure reliability for the upcoming summer period.

Key Findings

NERC had identified several key findings for this summer through the assessment of resource adequacy, management of renewables, impacts from the Aliso Canyon underground storage facility outage, frequency ride-through capabilities of solar inverters, and impacts from the 2017 solar eclipse. They are as follows:

- Most assessment areas demonstrate resource adequacy by maintaining sufficient Anticipated Resources to meet their planning Reference Margin Levels for this summer. The Anticipated Reserve Margin for NPCC-New England falls to 14.88 percent, which is below their Reference Margin Level of 15.10 percent for this summer.

- Relatively large differences between actual and predicted variable energy resource outputs can present operational challenges if sufficient flexible resources(dispatchable) are not available to make up or absorb these differences in outputs. This is especially challenging for systems that have a significant level of capacity with operational constraints that limit their ability to quickly change their output up or down.

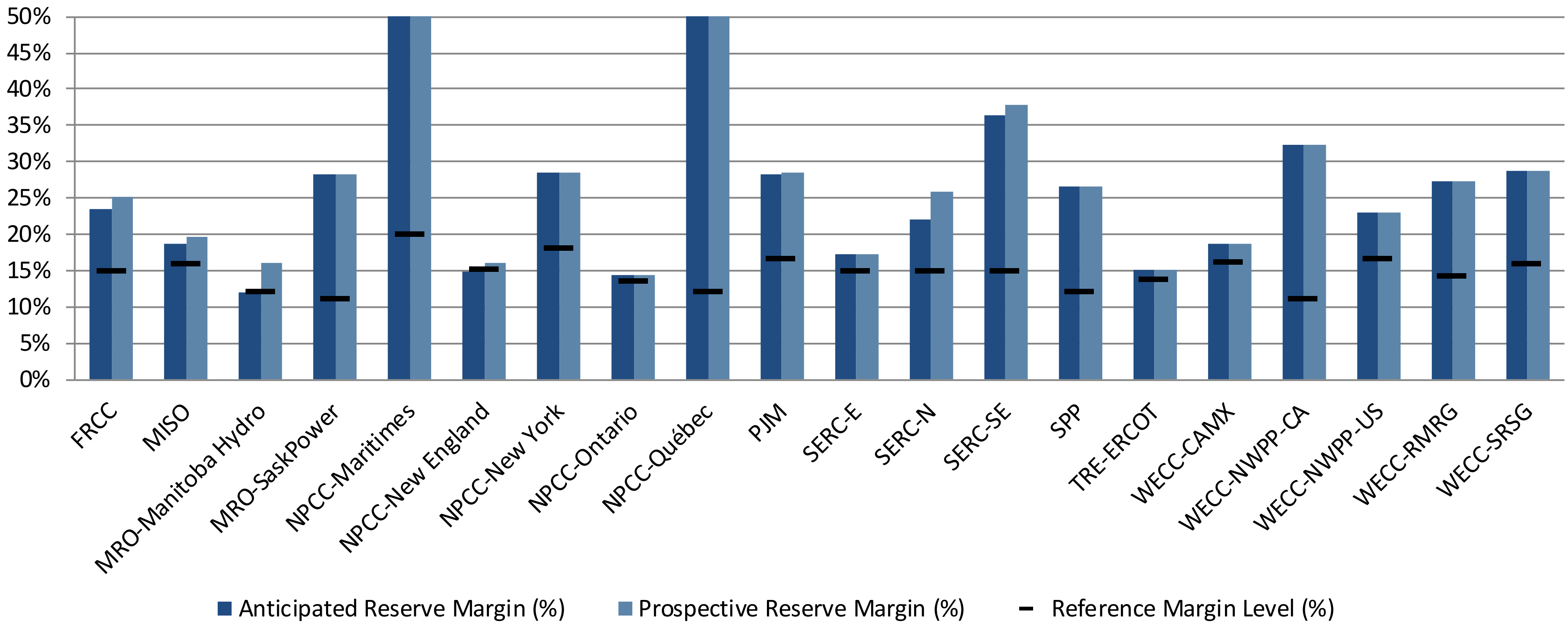
- For the upcoming 2017 summer season, WECC does not anticipate any new reliability issues associated with the Aliso Canyon outage in Southern California; however, natural gas withdrawal capability is still limited in the area as a result of this outage. CAISO continues to coordinate plans with the impacted gas company and neighboring BA and RC to minimize risk to the bulk power system. Additionally, CAISO plans to leverage an abundance of must-run hydro resources this summer to alleviate natural gas constraints in Southern California.

- The 2017 Summer Reliability Assessment presents no anticipated impacts to reliability on the BPS due to the 2017 solar eclipse.

- The first known major loss of utility-scale solar resources occurred in California on August 16, 2016, as the result of a transmission system disturbance initiated by a fire induced fault. The solar invertor technology did not operate as expected and failed to provide frequency ride-through capability. This event highlights on-going challenges with the interconnection of invertor based technologies to operate reliably, and additional steps will be taken to inform industry, manufacturers, and planners to ensure they are aware of this risk to the BPS.

Resource Adequacy

The Anticipated Reserve Margin is the primary metric that is used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak load.[1] Large year-to-year changes in anticipated resources or forecasted peak load (total internal demand) can greatly impact Planning Reserve Margin calculations. Most assessment areas have sufficient Anticipated Reserve Margins that meet or exceed their planning Reference Margin Level for the 2017 summer as shown in the figure below.



Summer 2017 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

The Anticipated Reserve Margin for NPCC-New England falls to 14.88 percent, below their Reference Margin Level of 15.10 percent. This projected shortfall in Planning Reserve Margins is primarily due to approximately 700MW of delayed new resources that were expected to be available to serve load for this summer.[2] These resources were included in NERC's *2016 LTRA*,[3] which projected an Anticipated Reserve Margin of 20.32 percent for the 2017 summer; this is a decrease in 5.44% in projected Anticipated Reserve Margins for the 2017 summer between two assessments. During extreme weather, there is an increasing risk of operational issues when reserve margins are tight. If forecasted summer conditions materialize, New England

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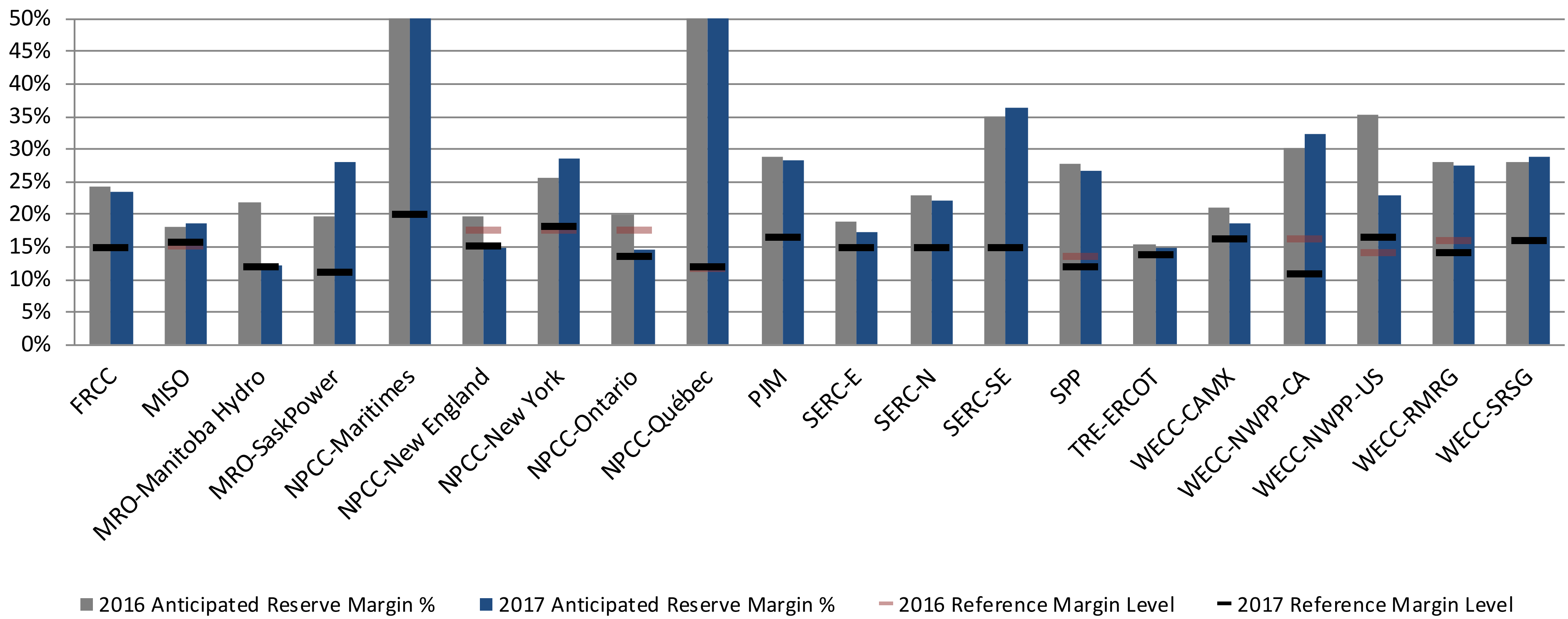
[1] Refer to *Data Concepts and Assumptions Guide* for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.
[2] ISO New England: Managing Power Grid Operations This Summer; April 26, 2017
[3] NERC 2016 Long-Term Reliability Assessment; December 2016

may need to rely on import capabilities from neighboring areas as well as the possible implementation of emergency operating procedures (EOPs). These actions are anticipated to provide sufficient energy or load relief to cover the forecasted deficiency in operable capacity.

NERC's *2015 LTRA*[4] discussed the observed tightening of reserve margins in several assessment areas. Similarly observed have been changes to the resource mix as some areas have diminishing resource diversity and flexibility. Even if an assessment area is showing sufficient Planning Reserve Margins, operational issues need to be monitored in light of these two observations to ensure resource adequacy. The figure below shows the relative change from the *2016 Summer Reliability Assessment* to the 2017 summer. 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. Additional details concerning specific areas of interest to NERC are provided in the individual assessment area highlights.



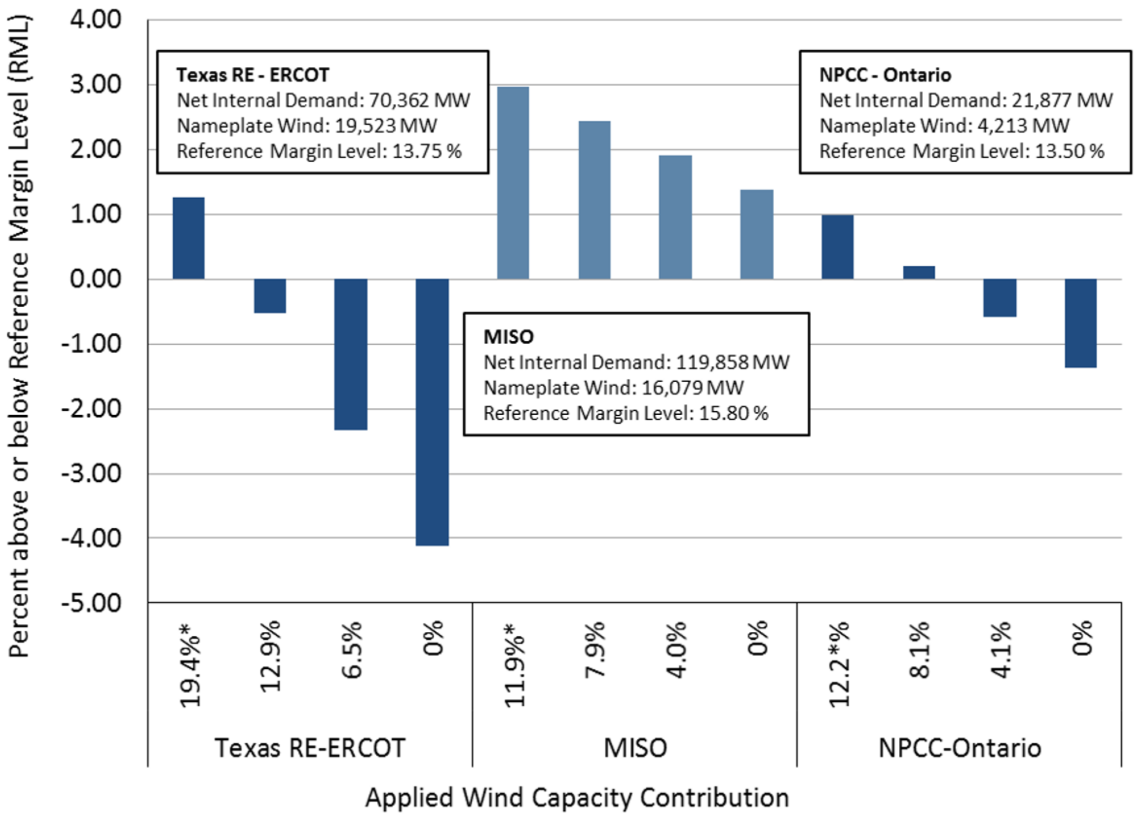
Summer 2016–2017 Anticipated Reserve Margins Year to Year Change

[4] NERC 2015 Long-Term Reliability Assessment

Assessing how areas are accounting for their resources is a fundamental part of understanding an assessment area's Planning Reserve Margins. The capacity contribution of variable energy resources (VERs) differs greatly from that of conventional generation. Conventional generation uses typical summer and winter ratings while capacity contributions from VERs, such as wind generation, are a statistical representation based on historical operational experience.

For example, the figure to the right shows three assessment areas with different amounts of wind generation. These three assessment areas were chosen for this analysis based on being geographically distinct and having a high degree of installed wind capacity. Assessment areas within the ERO footprint have differing methods for calculating their assumed on-peak capacity contributions from wind; these may include a probabilistic analysis or rolling averages of historical values.[5, 6]

Each column illustrates how the reserve margins for these areas would change with reduced amounts of assumed on-peak capacity contributions from their wind resources; values are reduced by thirds from their original assumed capacity contribution. Lower assumed on-peak capacity contributions reduce the reserve margin that could cause some assessment areas to fall below their Reference Margin Level.



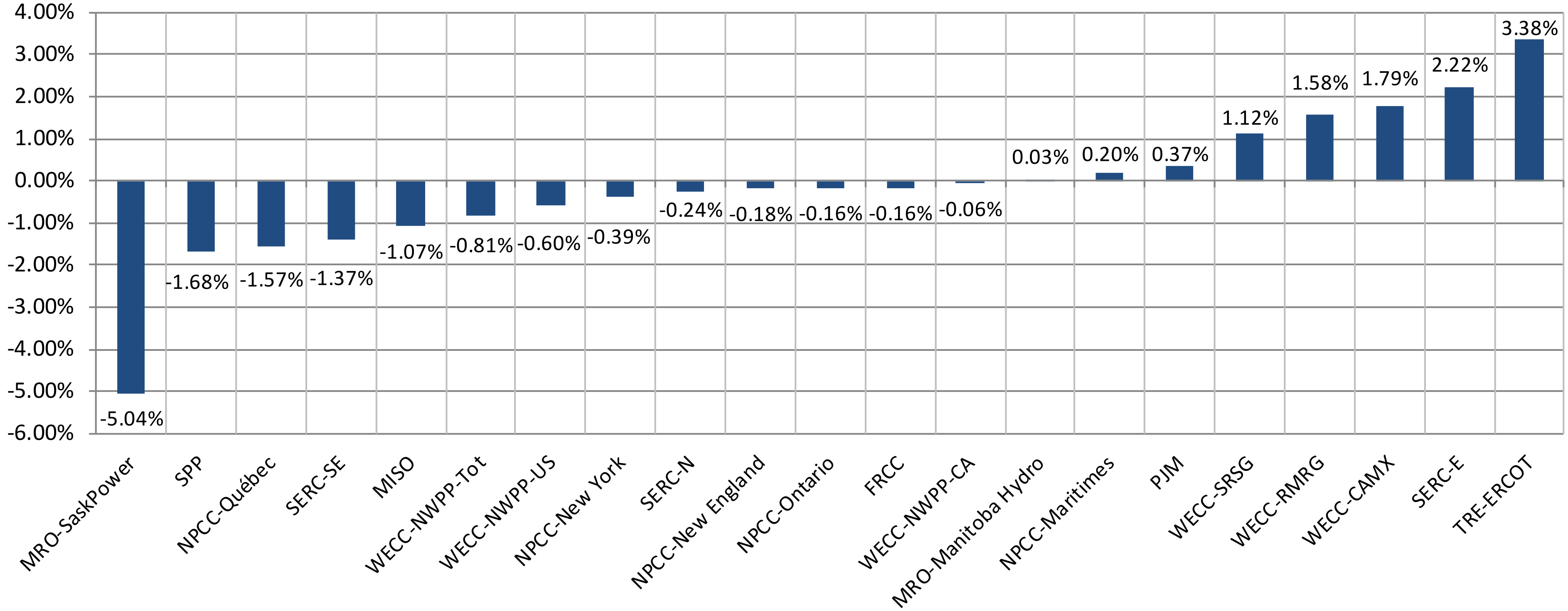
Percent Deviation from Reference Margin Level for Different Wind Capacity Contributions

***represents the on-peak wind capacity contribution assumed in the 2017 SRA**

[5] ERCOT: Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2017

[6] MISO: Planning Year 2017-2018 Wind Capacity Credit; December 2016

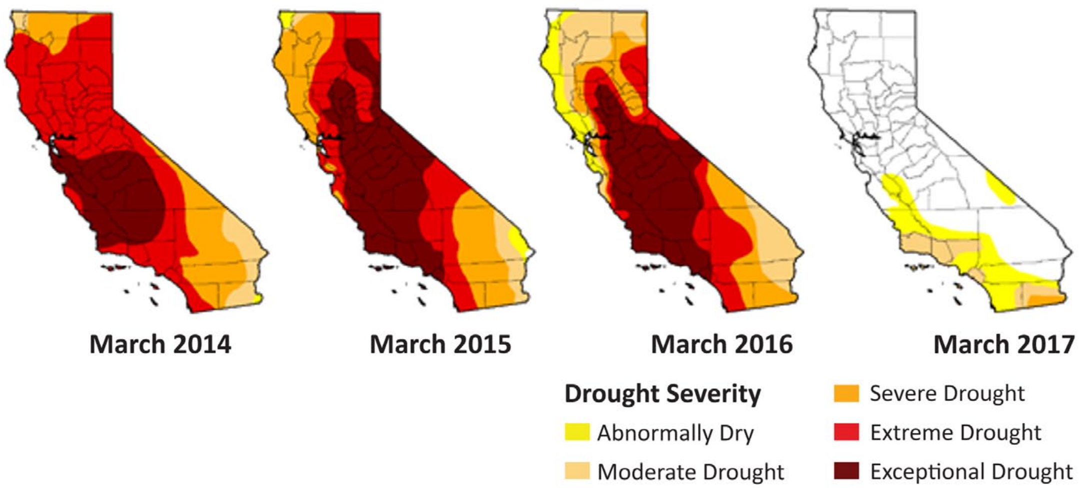
Changes to total internal demand between years can be due to a variety of reasons, but can be summarized to the following: forecasted load growth and changes to load forecast methods and assumptions. While the data collected for total internal demand are projections based on a normal weather (50/50) forecasts, higher values due to more extreme weather are possible during peak load conditions. These more extreme weather events are considered during operational planning when developing week-ahead load forecasts to ensure that sufficient resources will be online and available to serve load. Systems must be flexible enough to accommodate large changes to load forecasts in both long-term and short-term planning.



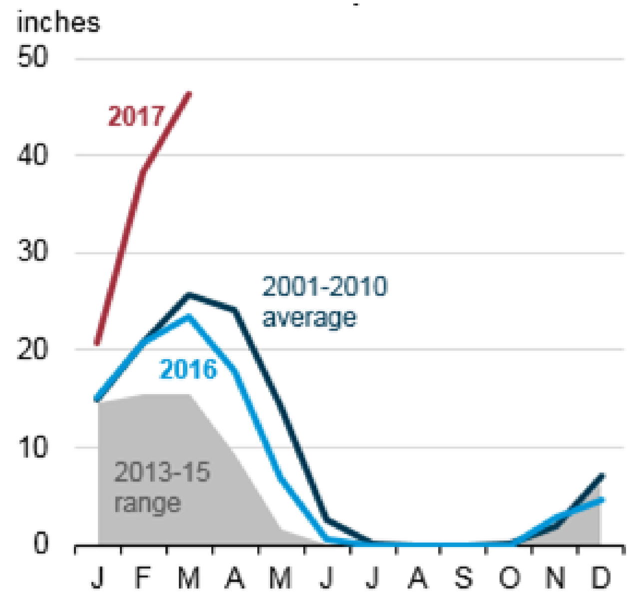
Total Internal Demand 2016–2017 Net Change

Renewable Management

The management of renewable generation is a necessary component of short-term system planning and operations. Variable energy resources (VERs) without access to energy storage devices will generate energy directly on the system. This requires operational management of dispatchable resources to match the changes to both load and VERs on the system. A sufficient amount of other dispatchable resources must be flexible enough to meet these changes or operations may need to curtail generation from wind or solar resources to maintain system stability. Curtailments to wind or solar generation may also be due to other system issues, such as over-generation concerns during a light-load time period or potential thermal overloading on transmission lines due to transmission constraints. Substantial increases in rainfall and snowpack levels in California have essentially removed most drought conditions from the state. The figures below from the Energy Information Administration show the rapid decrease in drought severity since March of 2016.



EIA: California Drought Status[7]



EIA: California Snow Water Equivalent[8]

Managing both VERs and the possibility of must-run hydro may present the area with additional operational issues during light load conditions, including a potential increase in cycling baseload generation during off-peak conditions. WECC staff is monitoring operational challenges that may emerge during the upcoming summer season. The runoff from heavy snow pack levels in northern California, in conjunction with abundant solar generation during afternoon hours, could create hours with over-supply of electric energy. California currently operates through over-supply conditions during most afternoon hours and this combination of system conditions would increase the amount of over-supply the state creates. Operations in the area will continue to monitor these situations to mitigate any potential risk to reliability.

[7] EIA: Record precipitation, snowpack in California expected to increase hydro generation in 2017

[8] Ibid

Aliso Canyon

Prior to the 2016 summer operating season, WECC conducted an independent assessment of potential impacts to the electric system that could result from potential fuel limitations in Southern California due to the Aliso Canyon issues from both a resource adequacy and a powerflow perspective.[9] Given the change in drought conditions from 2016 to 2017 and the renewed availability of hydro resources, WECC considered the 2016 work a "worse-case" scenario from the resource adequacy perspective, so the studies performed in 2016 were still valid and not repeated in 2017.

In 2016, WECC also conducted a series of power system contingency analyses to understand how the entire interconnection would perform under different stressors. Overall, the studies showed no major interconnection-wide impacts but did reveal important operational considerations for Southern California. Using its powerflow stability model, WECC assessed the potential operational impacts to the Western Interconnection broadly and Southern California specifically. This was done using a baseline for comparison as the 2016 "Heavy Summer Base Case," a model of the interconnection that assumes high summer loads and moderate power transfers to reflect a stressed system scenario. WECC then created two comparison cases to reflect potential conditions in Southern California, one with all the natural gas generation in the L.A. Basin at minimum output and one with it all turned off. These cases were chosen specifically because they are expected to emphasize potential negative study results, making them worse-case bookends. WECC then tested these cases by applying a number of contingencies to focus on the following indicators of system health:

- **Generation availability and unit stability:** With low generation in the L.A. Basin, would there be sufficient resources elsewhere to replace the generation?
- **Overloading of transmission lines:** Assuming the resources are available, can they be imported without causing overloading of transmission lines and exceedances of WECC transmission path ratings?
- **Voltage stability:** With low generation in the L.A. Basin, would there be sufficient voltage support in the area to maintain acceptable transmission and distribution voltages?

There were four takeaways from the contingency analyses:

- There is a minimum amount of generation that must be online in the L.A. Basin to provide voltage support to the local system and allow power to be imported. Without this generation, there is a high likelihood of voltage collapse within the L.A. Basin and risk to the interconnection if such a collapse is not quickly isolated. LADWP and CAISO have the detailed tools to determine the minimum level of generation that must remain on-line for system stability and have estimated 1300 MW to be the "must-run" capacity to support transmission import capability. WECC's analytics affirmed that this is a reasonable estimate.
- The generation facilities capable of producing reactive power to provide voltage support include the natural gas facilities in the L.A. Basin. Some of these units are dual-fuel units and were designed with the capability to burn distillate. The ability to run these plants on an alternative fuel other than natural gas will help ensure adequate minimum levels of generation when gas supply is scarce.
- The location of on-line generation within the L.A. Basin is critical to stability. Certain combinations of on-line units can lead to poor voltage support or additional stress on the transmission system in the L.A. Basin area due to unusual or abnormal power flows. CAISO is in the best position to determine the correct units to run in real time based on the actual operating configuration of the system.

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[9] Aliso Canyon Risk Assessment Technical Report; April 5, 2016

- Communication and collaboration among the affected entities is critical. This situation highlights the interdependency of the gas and electric infrastructures and operating protocols. The high level of communication and information sharing that occurred in 2016 between the entities will need to be closely managed and continued throughout the 2017 summer until the Aliso Canyon natural gas storage facility can be further utilized

The 2016 study assumed all normally operating transmission lines in the L.A. Basin and the rest of the interconnection are in service. The study also assumed availability of the additional generating resources used in the simulations. If either transmission or generation capacity is limited for any reason (e.g., a fire that takes out multiple transmission lines or unforeseen events that result in the unavailability of major generating resources, such as gas constraints or unscheduled maintenance), the additional stress to the Western Interconnection could result in negative impacts that were not identified. As with the resource adequacy work, WECC reviewed the 2016 work and determined that it was still valid and relevant for 2017. The availability of the Aliso Canyon Natural Gas storage facility remains an item of concern for electric reliability within the Western Interconnection and, more specifically, southern California.[10] SoCal Gas is still prohibited from injecting gas into the storage facility, and it is not known when injections will be allowed to resume. The absence of Aliso Canyon is not expected to have an impact on reliability during the upcoming summer season due to the anticipated abundance of hydroelectric generation. WECC staff will continue to monitor and participate in activities related to the Aliso Canyon Natural Gas storage facility and identify any potential impacts to electric reliability.

2017 Solar Eclipse

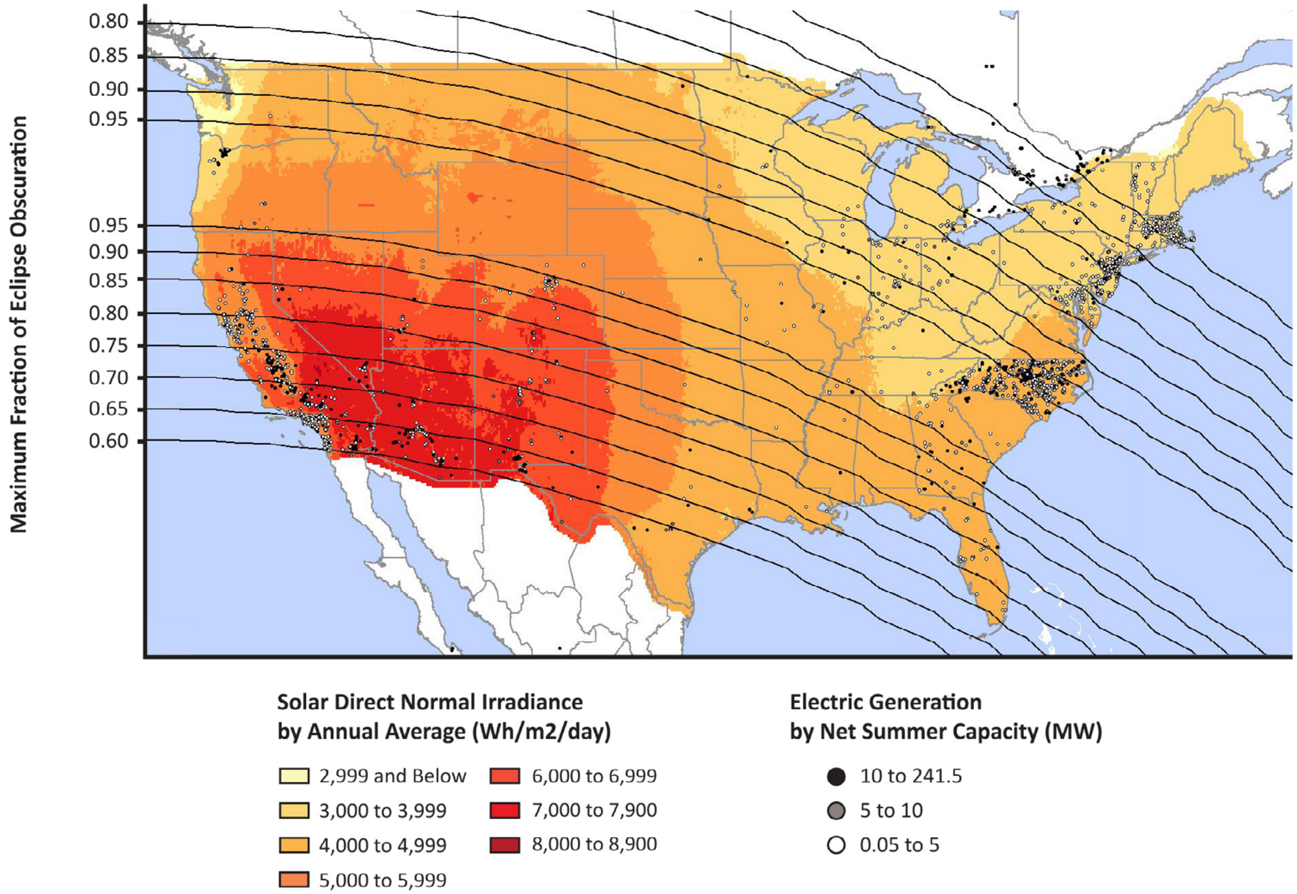
A total solar eclipse is a predictable event that impacts solar generation over a very short time period. NASA has predicted a total solar eclipse with a path that will directly affect North American bulk power system operations on August 21, 2017. Total solar capacity (distribution and transmission connected) in the U.S. has increased from 5 MW in 2000 to 42,619 MW in 2016. As the number of photovoltaic generators on the power system increases, the risk created by solar eclipses to reliable system operations will increase as well.

Therefore, NERC performed a solar eclipse wide-area assessment in order to evaluate potential reliability consequences of the total solar eclipse on the BPS. A whitepaper on the assessment was released in April 2017.[11] The NERC whitepaper provides a review of the European assessments on the 2015 eclipse and provided the applicable lessons learned in the white paper. The whitepaper focused specifically on impacts of system loading and potential reliability implications when an area experiences a large reduction of photovoltaic generator capacity due to a total solar eclipse.

Additionally, the white paper's study produced results on an extreme case scenario basis (i.e., perfect weather conditions that allow for total obscuration of the sun and a heavily loaded system (i.e., peak load conditions)). On the next page is a map of the United States with direct normal irradiance shaded, the eclipse band layers marked on the map by a series of parallel lines, and the locations of utility-scale photovoltaic systems shown by white, gray, and black circles.

[10] California ISO: Aliso Canyon gas-electric coordination

[11] NERC: A Wide-Area Perspective on the August 21, 2017 Total Solar Eclipse; April 2017



United States map showing direct normal irradiance, eclipse bands, and the locations of transmission photovoltaic generators

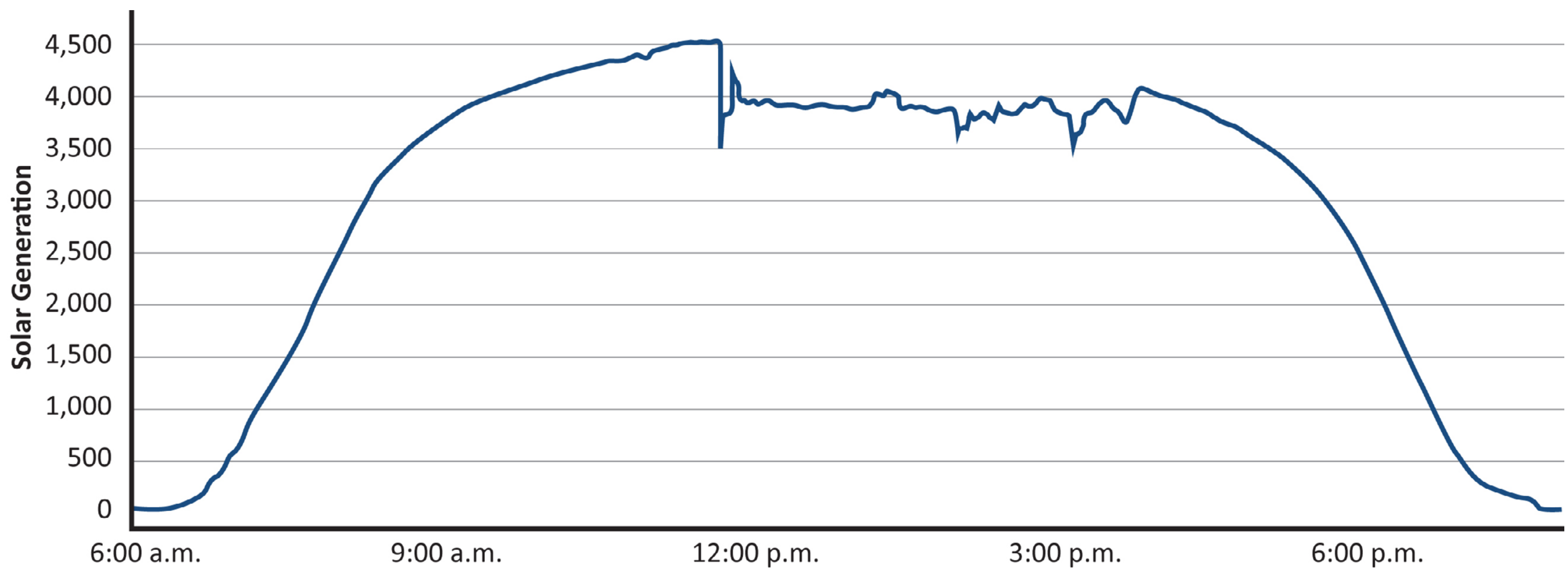
The above figure shows the observed gap between the eclipse bands, the gap band is the path of totality of the eclipse. This gap includes the center line and the northern and southern limits of total obscuration, but the center line of the eclipse is not explicitly drawn within the band to avoid confusion. In the map, the two states with visible concentrations of utility solar were identified as California and North Carolina. California and North Carolina will experience the greatest impact to photovoltaic resources and system operations; however, the analysis performed in the study showed no reliability impacts to BPS operations. It is recommended that utilities in all states perform detailed studies and retain necessary resources to meet the increased and varying load. For areas with high penetrations of solar resources, there may be a need for advanced resource/generator coordination during the August 21, 2017, system operating day when operators may need to plan to schedule non-photovoltaic resources (or arrange imports) to be available in order to address ramp issues which will result from the sudden perceived varying load and the abrupt varying utility photovoltaic generator conditions.

Seven years after August 21, 2017, North America will again experience a total solar eclipse on April 8, 2024. As the industry continues to advance and modify the power system to meet customer needs by adding photovoltaic generators, the effect of eclipses on the BPS due to the system's increased dependence on intermittent solar resources will become more relevant. Controllable system resources that help to balance the electrical characteristics are necessary for the BPS. Future detailed studies and coordination may be needed to ensure the effect of astronomical events on the behavior of wide-area BPS facilities can be predicted and the expected system reliability maintained.

Solar Inverters

On August 16, 2016, smoke from the Blue Cut wildfire in San Luis Obispo County, California resulted in the tripping of two 500kV lines in the active fire area. There was a noticeable frequency excursion with Peak RC reporting the loss of over 1,000 MW across multiple renewable resources in the CAISO BA following these line outages. CAISO, SCE and Peak, confirmed that no conventional generators tripped and that all the resources that were lost practically instantaneously were utility-scale renewables, primarily solar.

While not a qualifying event in the ERO EA Process, the occurrence was significant and unusual enough that the ERO requested an event report and worked with the engineers and planners at CAISO and Southern California Edison, to better understand this first known major loss of renewable resources due to a transmission system disturbance.



Total Solar Generation in the CAISO Balancing Authority on August 16, 2016

The tripping of the first 500 kV line was due to smoke from the fire creating a fault and the line clearing as designed. The second 500 kV line tripped as a result of a smoke induced fault, again by design, and cleared within three cycles. Before that fault cleared, the transient caused by the fault was experienced at the 26 nearby solar farms (thus the aggregate over 1,000 MWs of generation) and subsequently caused the inverters to stop injecting ac current within two cycles.

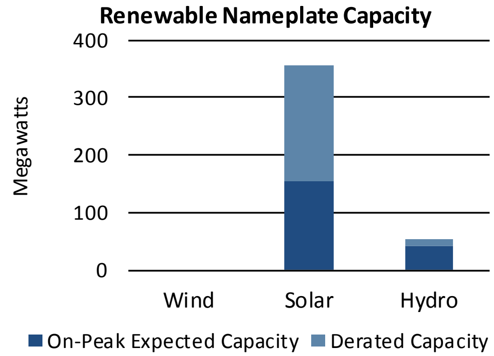
- Many of the inverters stopped outputting power before the fault cleared, indicating that the faulted condition alone created the condition that caused the response as opposed to post-fault system response (transient stability).
- Many inverters calculated frequencies at the inverter terminals that are well outside of the values that would be expected for a normally cleared fault. Many inverters calculated a system frequency in the range of 57 Hz during the fault.
- A thorough analysis of the event and the operating characteristics of the related equipment is underway.

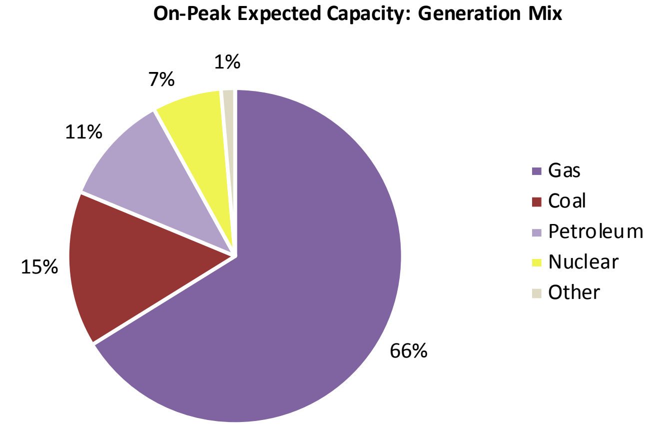
This event provides an observable reference to the challenges discussed in the *Essential Reliability Services Task Force Measures Framework Report*.[12] Inverter based resources have different operating characteristics than those that are synchronously connected to the BPS. To be reliably integrated, these operating characteristics will require proper planning, design, and coordination. Maintaining reliability is embodied in the predictability, controllability, and responsiveness of these operating characteristics. Analyses of these emerging technologies and their penetration levels must be done to allow for effective planning and to provide system planners and operators the flexibility to modify real-time operations for the reliability of the grid. The ERO will produce lessons learned and technical references from information gathered from this and similar events.

[12] NERC:Essential Reliability Services Task Force Measures Framework Report; November 2015

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 Balancing Authorities with 45 registered entities (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 over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.

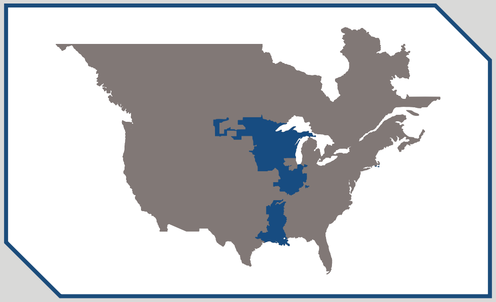




FRCC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	47,654	47,580	-0.2%
Demand Response: Available	2,924	2,922	-0.1%
Net Internal Demand	44,730	44,658	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	53,110	53,403	0.6%
Tier 1 Planned Capacity	1237	467	-62.2%
Net Firm Capacity Transfers	1,260	1,252	-0.6%
Anticipated Resources	55,607	55,122	-0.9%
Existing-Other Capacity	505.1	744	47.3%
Prospective Resources	56,112	55,866	-0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.32%	23.43%	-0.9
Prospective Reserve Margin	25.45%	25.10%	-0.3
Reference Margin Level	15.00%	15.00%	0.0

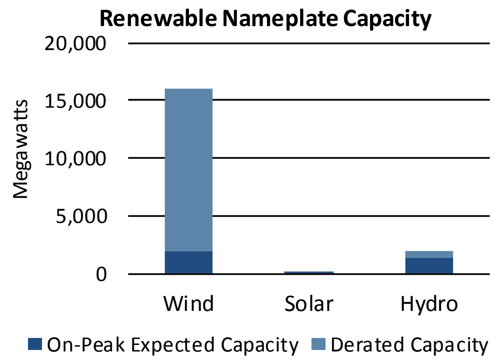
Highlights

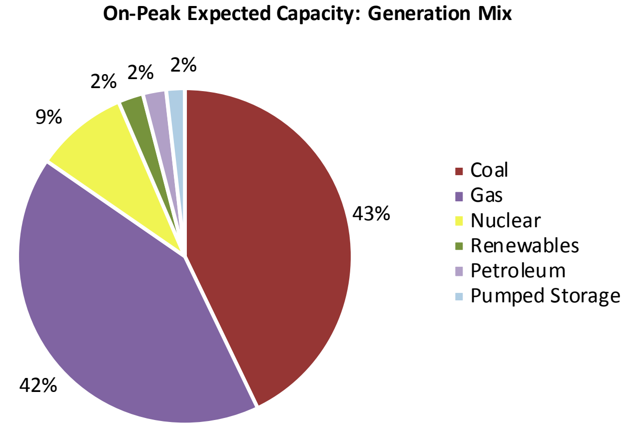
- FRCC anticipates that it will maintain reliability on its system during the upcoming season.
- FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess peak load under anticipated system conditions. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria can be mitigated under expected conditions.



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.

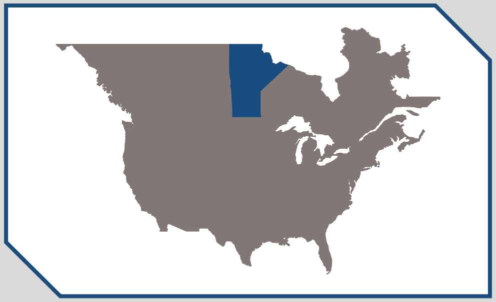




MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	126,081	125,002	-0.9%
Demand Response: Available	4,923	5,144	4.5%
Net Internal Demand	121,158	119,858	-1.1%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	142,343	142,398	0.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	627	-45	-107.2%
Anticipated Resources	142,969	142,353	-0.4%
Existing-Other Capacity	1351.4	1,151	-14.8%
Prospective Resources	144,321	143,504	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.00%	18.77%	0.8
Prospective Reserve Margin	19.12%	19.73%	0.6
Reference Margin Level	15.20%	15.80%	0.6

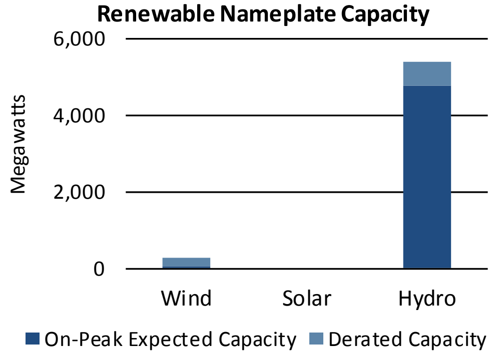
Highlights

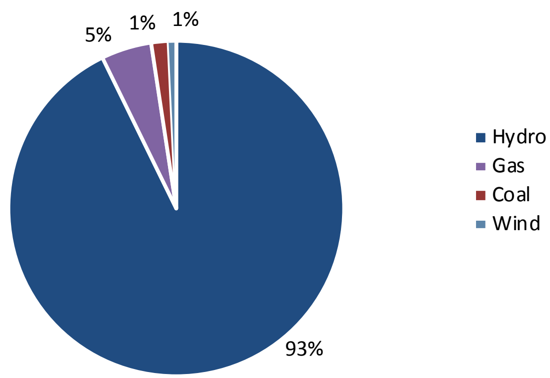
- MISO anticipates that it will maintain reliability on its system during the upcoming season.
- Compared to last season, a greater amount of MISO's reserves are made up of demand response resources. This increases the likelihood of operators needing to call on these resources during emergency operating conditions. All demand response resources are expected to perform when called upon, so this does not pose any reliability issues.



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.

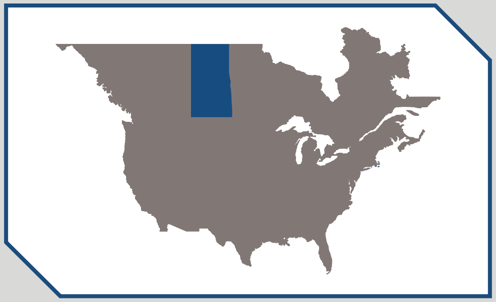




MRO - Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,312	3,313	0.0%
Demand Response: Available	0	0	0.0%
Net Internal Demand	3,312	3,313	0.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,435	5,149	-5.3%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-1,396	-1,435	2.8%
Anticipated Resources	4,039	3,714	-8.1%
Existing-Other Capacity	108.6	130	19.7%
Prospective Resources	4,148	3,844	-7.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.96%	12.10%	-9.9
Prospective Reserve Margin	25.24%	16.03%	-9.2
Reference Margin Level	12.00%	12.00%	0.0

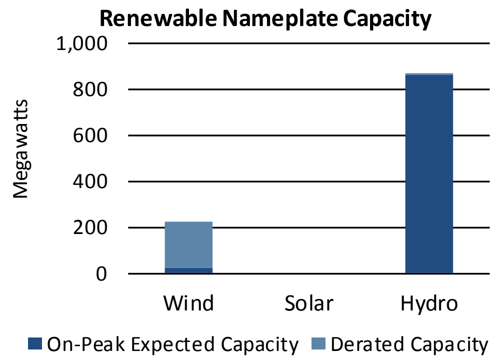
Highlights

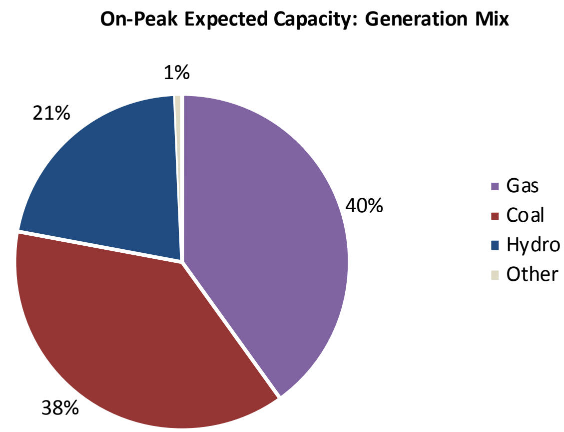
- Manitoba Hydro anticipates that it will maintain reliability on its system during the upcoming season.
- The main cause of changes in Existing-Certain Capacity from 2016 to 2017 SRA are scheduled planned outages.



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.

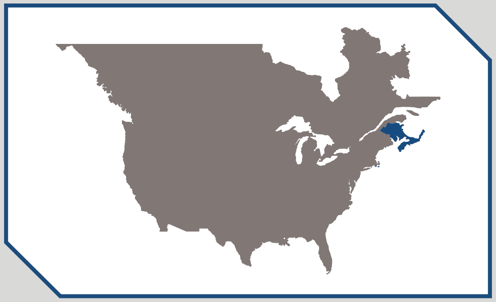




MRO - SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,482	3,353	-3.7%
Demand Response: Available	205	241	17.6%
Net Internal Demand	3,277	3,112	-5.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	3,894	3,964	1.8%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	3,919	3,989	1.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,919	3,989	1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.59%	28.17%	8.6
Prospective Reserve Margin	19.59%	28.17%	8.6
Reference Margin Level	11.00%	11.00%	0.0

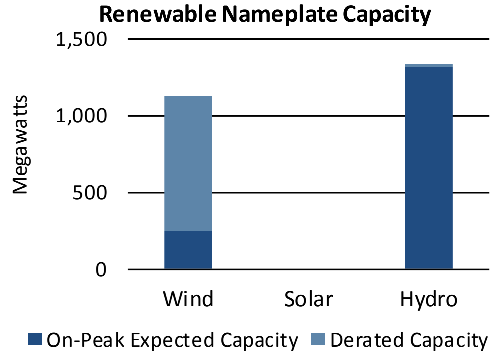
Highlights

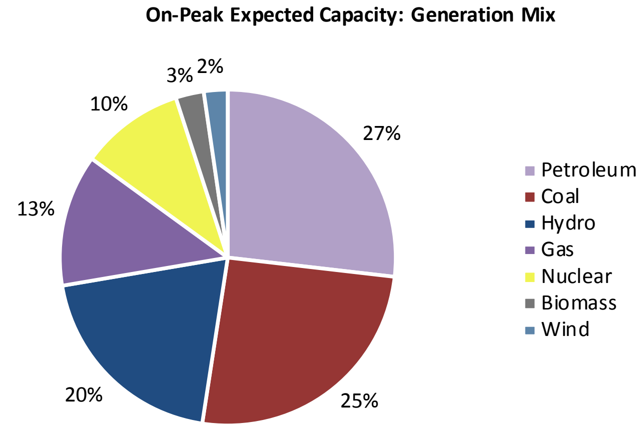
- SaskPower anticipates that it will maintain reliability on its system during the upcoming season.
- There are no known operational challenges anticipated for the upcoming season.



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.





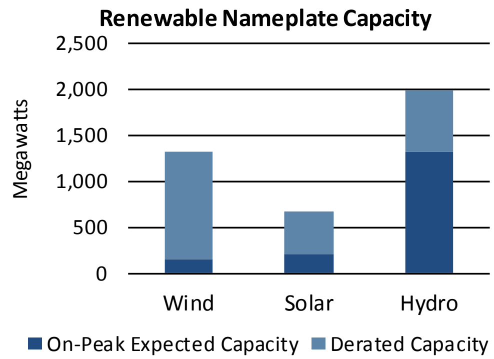
NPCC - Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,307	3,320	0.4%
Demand Response: Available	362	369	1.9%
Net Internal Demand	2,945	2,951	0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,398	5,636	4.4%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	5,398	5,636	4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,398	5,636	4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.29%	90.99%	7.7
Prospective Reserve Margin	83.29%	90.99%	7.7
Reference Margin Level	20.00%	20.00%	0.0

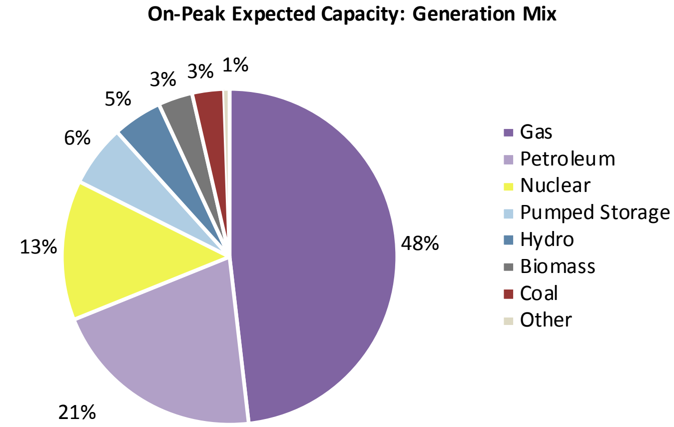
Highlights

- Maritimes anticipates that it will maintain reliability on its system during the upcoming season.
- There are planned upgrades on the 345 kV transmission system, but since the Maritimes is a winter peaking system these transfer limitations are not expected to impact reliability.
- If conditions were to change due to unplanned transmission or generator outages, operating adjustments would be addressed by Operations Engineering by a Short Term Operating Procedure (STOP) for the New Brunswick Power Control Room.

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 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.

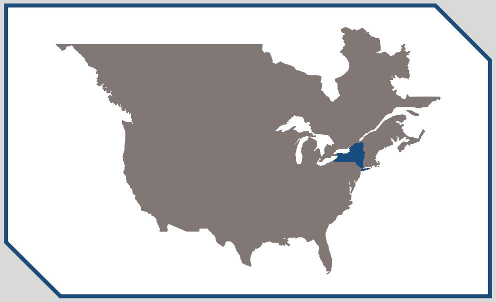




NPCC - New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	26,704	26,482	-0.8%
Demand Response: Available	557	382	-31.4%
Net Internal Demand	26,147	26,100	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	30,196	28,738	-4.8%
Tier 1 Planned Capacity	33	0	-100.0%
Net Firm Capacity Transfers	1,062	1,246	17.3%
Anticipated Resources	31,291	29,984	-4.2%
Existing-Other Capacity	290	315	8.6%
Prospective Resources	31,581	30,299	-4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.67%	14.88%	-4.8
Prospective Reserve Margin	20.78%	16.09%	-4.7
Reference Margin Level	17.60%	15.10%	-2.5

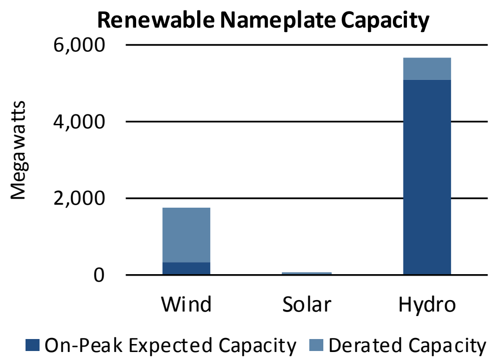
Highlights

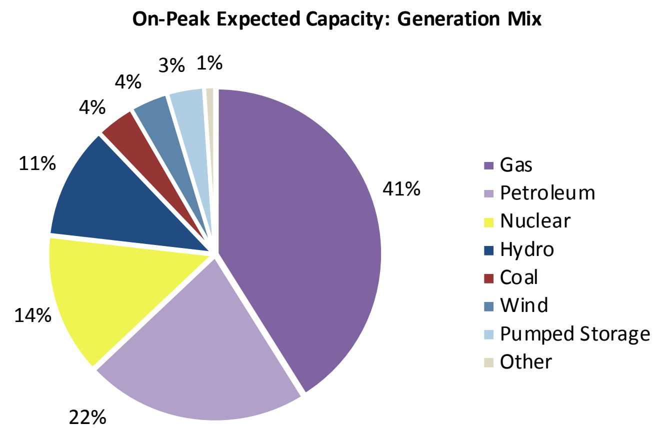
- The New England net margins represent factors such as 1,246 MW (23 percent) of net import with respect to approximately 5,400 MW of full import capability, and two generator delays in commissioning with a combined capacity supply obligation (CSO) of 674 MW.
- If forecasted summer conditions materialized, New England may need to rely on import capabilities from neighboring Areas, as well as the possible implementation of emergency operating procedures (EOPs). These actions are anticipated to provide sufficient energy or load relief to cover the forecasted deficiency in operable capacity.



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.

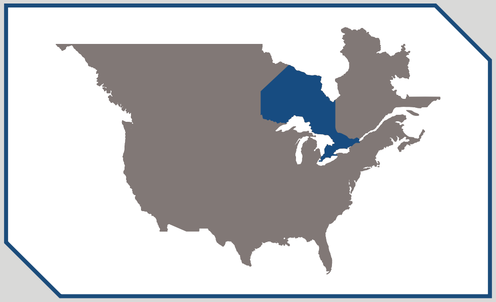




NPCC - New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	33,360	33,178	-0.5%
Demand Response: Available	1,248	1,192	-4.5%
Net Internal Demand	32,112	31,986	-0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	38,535	38,581	0.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	1,769	2,533	43.2%
Anticipated Resources	40,304	41,114	2.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	40,304	41,114	2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.51%	28.54%	3.0
Prospective Reserve Margin	25.51%	28.54%	3.0
Reference Margin Level	17.50%	18.00%	0.5

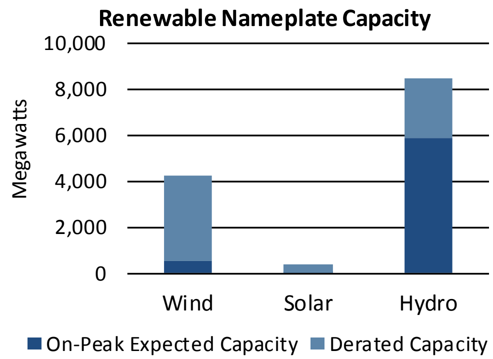
Highlights

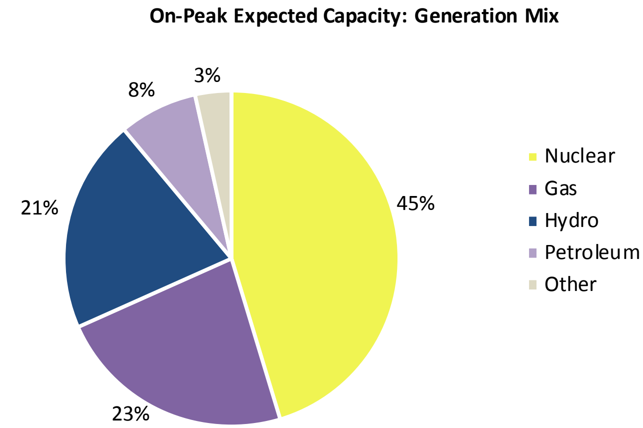
- High capacity factors on certain New York City peaking units could result in possible violations of daily NOx emission limits if they were to fully respond to the NYISO dispatch signals; this could occur during long duration hot weather events or following the loss of significant generation or transmission assets in NYC.
- In 2001, the New York State Department of Environmental Conservation (DEC) extended a prior agreement with the New York Power Pool to address the potential violation of NOx and opacity regulations if the NYISO is required to keep these peaking units operating to avoid the loss of load.



NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

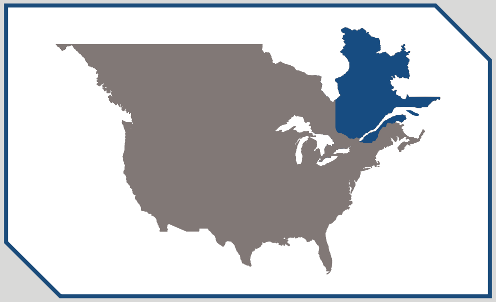




NPCC - Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	22,587	22,614	0.1%
Demand Response: Available	674	737	9.3%
Net Internal Demand	21,913	21,877	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	25,940	24,692	-4.8%
Tier 1 Planned Capacity	370.235	354	-4.5%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	26,310	25,045	-4.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,310	25,045	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.07%	14.48%	-5.6
Prospective Reserve Margin	20.07%	14.48%	-5.6
Reference Margin Level	17.55%	13.50%	-4.1

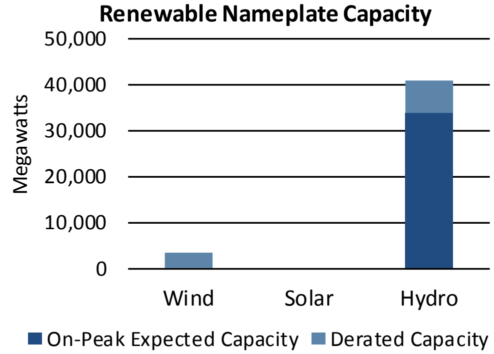
Highlights

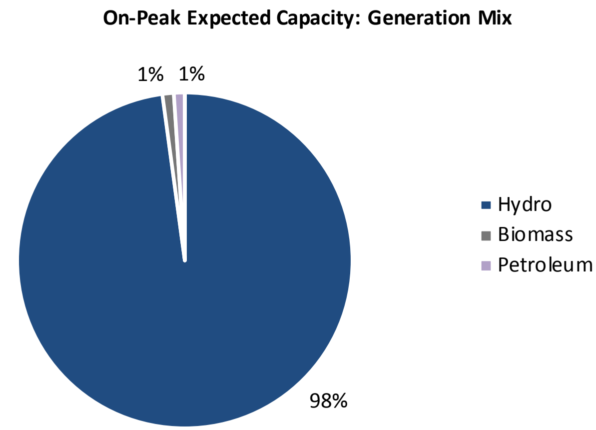
- If extreme weather conditions materialize, the IESO may need to reject some generator maintenance outages to ensure that Ontario demand is met during the summer peak.
- High voltages in southern Ontario continue to present operational challenges during periods when the level of transfers on the 500 kV system are reduced. To address this issue on a more permanent basis, the IESO requested Hydro One to install additional high voltage reactors at Lennox TS with a target in-service date of Q4 2020.



NPCC-Québec

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC sub region 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 or radial generation or load to and from neighboring systems.

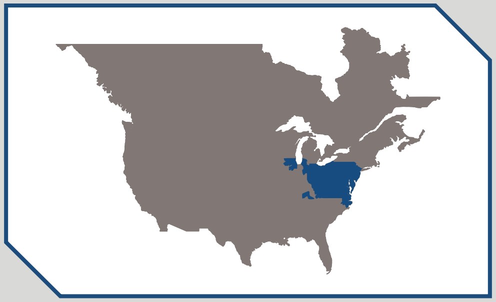




NPCC - Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	20,833	20,506	-1.6%
Demand Response: Available	0	0	0.0%
Net Internal Demand	20,833	20,506	-1.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	34,048	34,478	1.3%
Tier 1 Planned Capacity	0	5	0.0%
Net Firm Capacity Transfers	-1,947	-1,855	-4.7%
Anticipated Resources	32,101	32,628	1.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,101	32,628	1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.08%	59.11%	5.0
Prospective Reserve Margin	54.08%	59.11%	5.0
Reference Margin Level	11.60%	12.00%	0.4

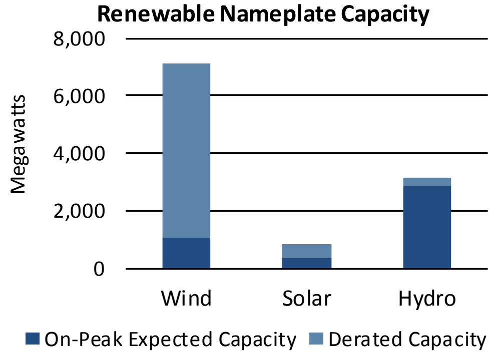
Highlights

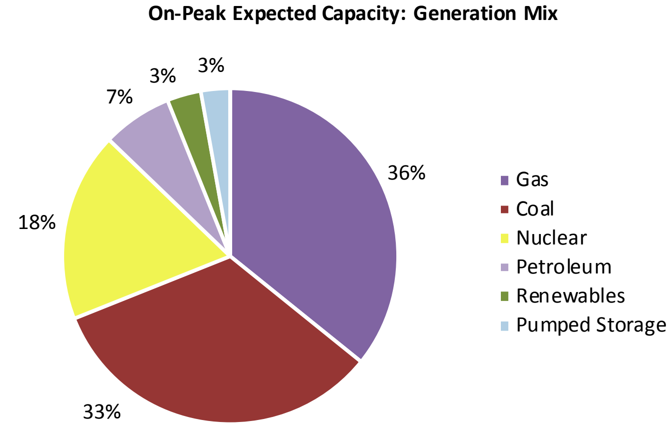
- Québec predicts that it will maintain resource adequacy system is winter peaking. Québec area expects to be able to provide assistance to other areas if needed, up to the transfer capability available.
- Most transmission line, transformer and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems.



PJM

PJM Interconnection is a regional transmission organization (RTO) 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.

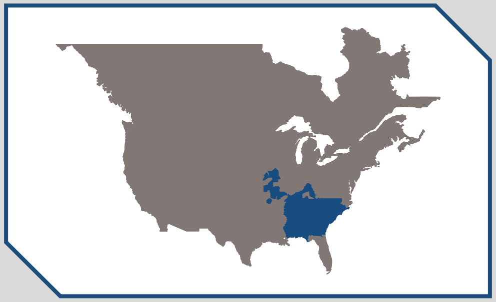




PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	152,131	152,999	0.6%
Demand Response: Available	8,777	9,120	3.9%
Net Internal Demand	143,354	143,879	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	179,360	179,695	0.2%
Tier 1 Planned Capacity	0	734	0.0%
Net Firm Capacity Transfers	5,353	4,304	-19.6%
Anticipated Resources	184,713	184,734	0.0%
Existing-Other Capacity	0	319	0.0%
Prospective Resources	184,713	185,053	0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.85%	28.40%	-0.5
Prospective Reserve Margin	28.85%	28.62%	-0.2
Reference Margin Level	16.40%	16.60%	0.2

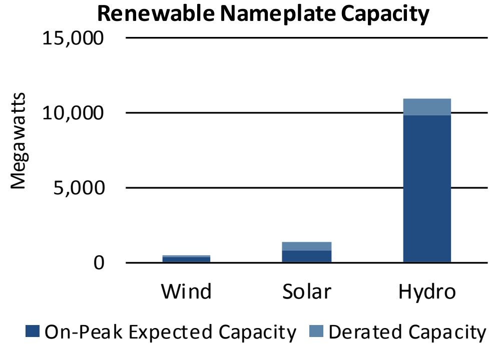
Highlights

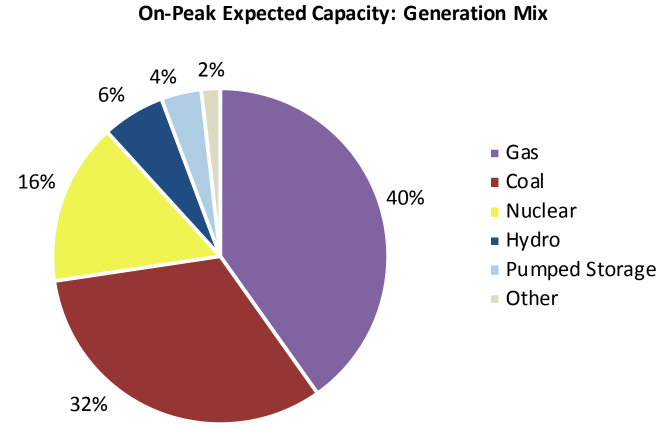
- Anticipated Reserve Margin is 28%, which is above the PJM Reserve Requirement of 16.6%.
- Forecasted load growth is lower than it has been in previous years.
- Coal capacity retirements and introduction of new natural gas capacity continues.



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: Alcoa Power Generating, Inc.–Yadkin Division , 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.

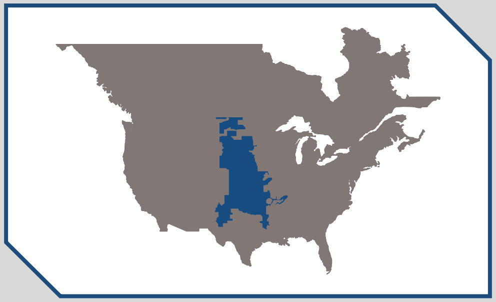




SERC Resource Adequacy Data						
Demand, Resource, and Reserve Margins	**SERC-E**	**SERC-N**	**SERC-SE**	**2016 SRA SERC Total**	**2017 SRA SERC Total**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	44,408	41,978	46,423	131,994	132,809	0.6%
Demand Response: Available	1,355	1,714	2,165	4,640	5,234	12.8%
Net Internal Demand	43,053	40,264	44,258	127,354	127,575	0.2%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	50,145	49,193	61,437	161,532	160,776	-0.5%
Tier 1 Planned Capacity	84	1,002	220	1,875	1,306	-30.3%
Net Firm Capacity Transfers	214	-1,070	-1,313	-3,133	-2,169	-30.8%
Anticipated Resources	50,443	49,126	60,344	160,274	159,913	-0.2%
Existing-Other Capacity	42	1,603	648	2,361	2,294	-2.9%
Prospective Resources	50,485	50,729	60,992	162,635	162,207	-0.3%
Planning Reserve Margins	**Percent (%)**	**Percent (%)**	**Percent (%)**	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.17%	22.01%	36.35%	25.85%	25.35%	-0.5
Prospective Reserve Margin	17.26%	25.99%	37.81%	27.70%	27.15%	-0.6
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	0.0

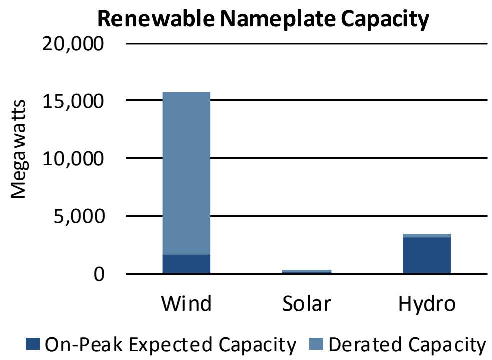
Highlights

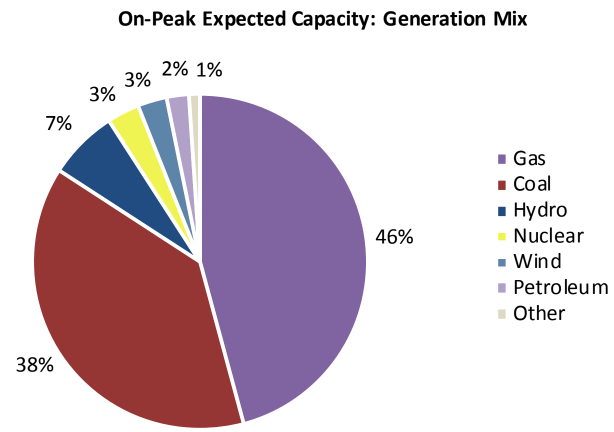
- SERC expects similar summer conditions as compared to 2016 and anticipates that it will maintain system reliability through drought or high temperatures.
- SERC continues to evaluate reserve margins for its assessment area to ensure the deliverability of resources within its footprint. SERC is working to increase awareness of data reporting inconsistencies between NERC and the Regions, particularly regarding the installation of distributed renewable resources.



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, Midwest Reliability Organization Regional Entity, and Western Electricity Coordinating Council. 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.

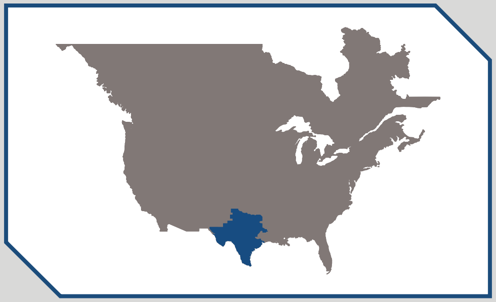




SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	53,430	52,587	-1.6%
Demand Response: Available	785	828	5.5%
Net Internal Demand	52,645	51,759	-1.7%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	67,649	65,092	-3.8%
Tier 1 Planned Capacity	0	67	0.0%
Net Firm Capacity Transfers	-447	369	-182.5%
Anticipated Resources	67,201	65,528	-2.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	67,201	65,528	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.65%	26.60%	-1.0
Prospective Reserve Margin	27.65%	26.60%	-1.0
Reference Margin Level	13.60%	12.00%	-1.6

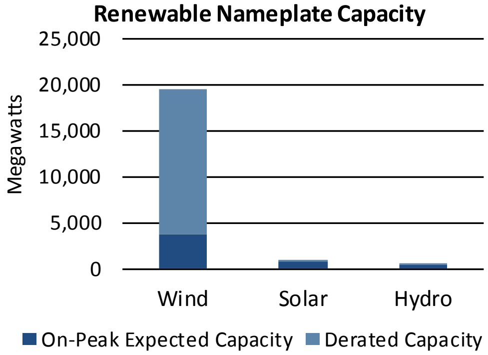
Highlights

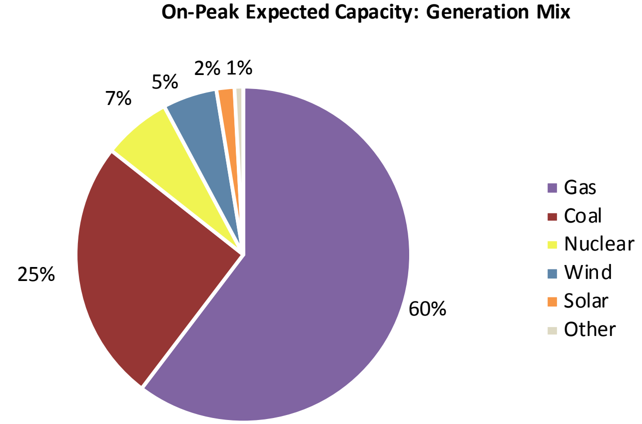
- SPP’s increasing penetration of renewable generation poses operational challenges, which require additional analysis in short-term situations. These challenges, however, are more prevalent in the shoulder seasons and pose less risk for impact during the summer season.
- SPP does not foresee any impacts to resource adequacy for the upcoming summer season.



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. ERCOT is a summer-peaking region that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines, and 566 generation units, and 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 Region.

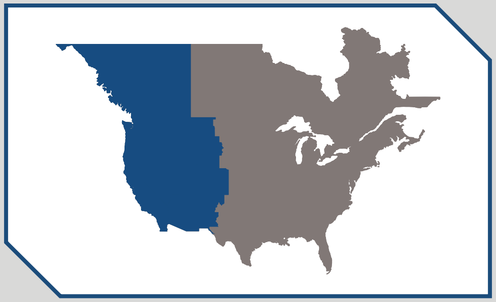


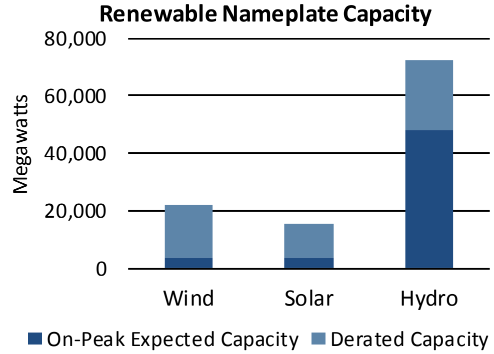


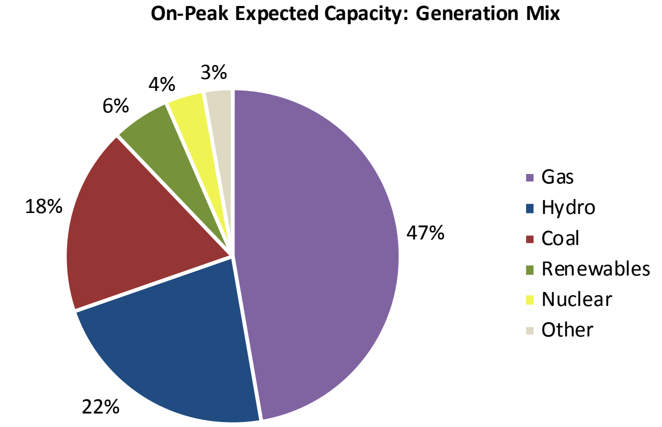
ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2016 SRA**	**2017 SRA**	**2016 vs. 2017 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	70,588	72,934	3.3%
Demand Response: Available	2,525	2,572	1.9%
Net Internal Demand	68,063	70,362	3.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	76,247	77,845	2.1%
Tier 1 Planned Capacity	1247.976	2,937	135.4%
Net Firm Capacity Transfers	1,122	140	-87.5%
Anticipated Resources	78,617	80,922	2.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,617	80,922	2.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.51%	15.01%	-0.5
Prospective Reserve Margin	15.51%	15.01%	-0.5
Reference Margin Level	13.75%	13.75%	0.0

Highlights

- ERCOT expects no system-wide or significant regional reliability issues for the summer of 2017.
- Due to high load growth and the limited number of generating resources supporting the Lower Rio Grande Valley (southern tip of Texas), ERCOT will closely monitor local reliability risks resulting from high import flows and contingency events involving multiple pieces of transmission equipment. ERCOT defined a transmission flow limit, called a Generic Transmission Constraint, to help manage flows across impacted lines.
- To address transmission congestion issues in oil and gas producing regions of West Texas, transmission companies are adding several 138 kV transmission elements in the region. ERCOT is finalizing updates to Congestion Management Plans by June 1.







WECC

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting Bulk Electric System 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 over 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.

WECC Resource Adequacy Data

Demand, Resource, and Reserve Margins	CA/MX	NWPP CA	NWPP US	RMRG	SRSG	2016 SRA Total	2017 SRA Total	2016 vs. 2017 SRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,498	19,340	49,459	12,361	23,357	154,480	154,627	0.1%
Demand Response: Available	1605	0	1413	500	371	3,736	3,889	4.1%
Net Internal Demand	53,893	19,340	48,046	11,861	22,986	150,744	150,738	-0.0%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,513	25,251	56,434	18,262	32,854	188,506	183,062	-2.9%
Tier 1 Planned Capacity	568	324	75	17	29	1,900	994	-47.7%
Net Firm Capacity Transfers	9,894	0	2,602	-3,167	-3,272	0	0	0.0%
Anticipated Resources	63,975	25,575	59,111	15,112	29,611	190,406	184,056	-3.3%
Existing-Other Capacity	0	0	0	0	0	0	0	0.0%
Prospective Resources	63,975	25,575	59,111	15,112	29,611	190,406	184,056	-3.3%
Planning Reserve Margins	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**Annual Difference**
Anticipated Reserve Margin	18.71%	32.24%	23.03%	27.41%	28.82%	26.31%	22.10%	-4.2
Prospective Reserve Margin	18.71%	32.24%	23.03%	27.41%	28.82%	26.31%	22.10%	-4.2
Reference Margin Level	16.14%	10.96%	16.56%	14.17%	15.83%	15.37%	15.40%	0.0

Highlights

- The availability of the Aliso Canyon Natural Gas storage facility remains an item of concern for electric reliability within the western interconnection, and more specifically, southern California.
- The anticipated abundance of hydro generated electricity may be used to displace generation from gas-fired units freeing up more natural gas for the Los Angeles basin area if natural gas availability becomes an issue.
- WECC staff will continue to monitor and participate in activities related to the Aliso Canyon Natural Gas storage facility and identify any potential impacts to electric reliability.

Data Concepts and Assumptions Guide

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 Resiliency.
Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
Operating Resiliency 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 are 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.
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,[13] or total internal demand, for the summer and winter of each year.[14]
Total internal demand projections are based on normal weather (50/50 distribution)[15] and are provided on a coincident[16] basis for most assessment areas.
Net internal demand, used in all reserve margin calculations, and is equal to total internal demand, 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 winter season: (1) unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission must be in effect for the unit; (2) unit must be classified as a designated network resource; (3) 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: • 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 winter season, but do not meet the requirements of existing-certain.

[13] *Glossary of Terms* Used in NERC Reliability Standards
[14] The summer season represents June–September and the winter season represents December–February.
[15] 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.
[16] 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.

Reserve Margins	
Reserve Margins: the primary metric used to measure resource adequacy, defined as the difference in resources (anticipated or prospective) and net internal demand, divided by net internal demand, shown as a percentile.	
Anticipated Reserve Margin =	$\frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
Prospective Reserve Margin =	$\frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
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 may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% reference margin level for predominately thermal systems and 10% for predominately hydro systems.	
On-Peak Expected Capacity Generation Mix – Generation mix is aggregated from 2016 LTRA 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.	