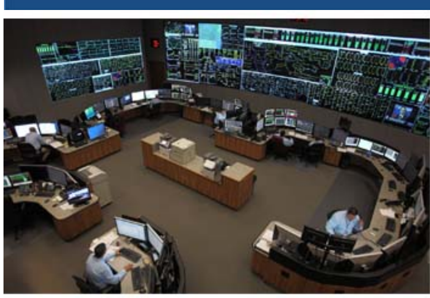
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Short-Term Special Assessment

Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation

May 2016

RELIABILITY | ACCOUNTABILITY

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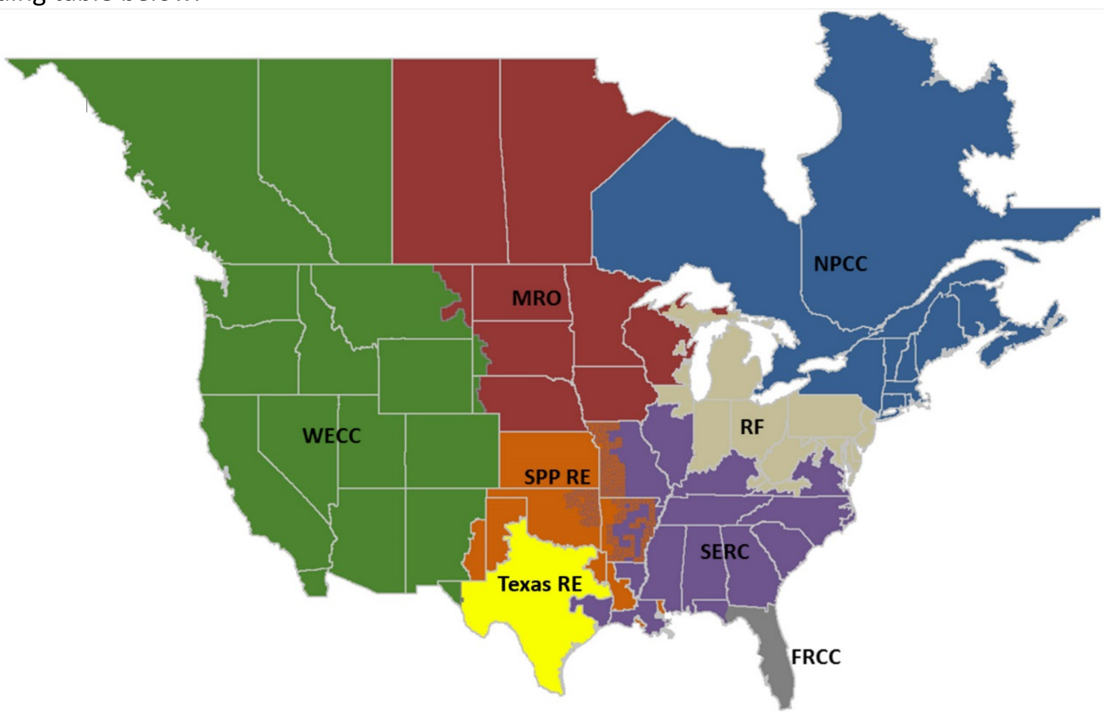
Preface

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, 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 serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Errata

8/23/2016

Modified tables and charts for all areas to align Dual-Fuel Capacity and Gas-Fired Capacity (non-Dual-Fuel) with corresponding values.

Executive Summary

NERC continues to assess the increasing risk of fuel disruption impacts on generator availability from the dependency of electric generation and natural gas infrastructure. In the past, NERC conducted two special assessments on gas-electric interdependencies; a primer highlighting key considerations in 2011[1] and a detailed framework for incorporating risks into reliability assessments in 2013.[2] As highlighted in a number of NERC long-term reliability assessments, substantial progress has been made in the last five years to improve coordination between natural gas pipelines, gas distribution companies, and electric industries. Even so, there are remaining concerns and opportunities to address on this subject.[3]

Until recently, natural gas interdependency challenges were most experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, a recent outage of an operationally-critical natural gas storage facility in Southern California—Aliso Canyon—demonstrates the potential risks to BPS reliability of increased reliance on natural gas without increased coordination between the two industries. The risk associated with Aliso Canyon, which may result in controlled load shedding, is expected to persist through the 2016 summer season, and potentially into the 2016/2017 winter and 2017 summer seasons. The challenges faced in California represent a series of risks that have been layered into the system over the past decade: significant dependency on a single and just-in-time delivery fuel source, specifically for ramping capability to meet load and generation variability; reduced amount of baseload and dispatchable resources; increased amounts of variable and distributed resources; increasing need of system flexibility; gas system dependency on storage to maintain operating pressure; and a lack of clear understanding of natural gas operational characteristics and potential impacts on BPS operations.

Understanding the interdependencies and operational differences between the two industries is critical to mitigating reliability risks going forward. The unavailability of the Aliso Canyon storage facility is the most recent example of the potential risks to BPS reliability posed by increased dependence on natural gas. Over the next several months, mitigation measures will be put into place by state regulators and the electric and gas utilities; however, these measures will not completely address challenges emerging from the reduction in resource adequacy. Even with mitigation measures in place, system operators from both the electric and gas industries in California are facing a major challenge this summer. CAISO studies identified 14 days of potential electric service interruption if natural gas constraints affect the Los Angeles basin generating facilities.[4] Further study is needed to address any additional risks to the reliable operation of the BPS until further is known about the operation of the Aliso Canyon storage facility.

As growth in natural gas demand increases from the electric sector, pipeline transportation constraints, storage limitation, and contingencies on gas infrastructure will have a greater impact on gas-fired generation. Overdependence on a single fuel type increases the risk of common-mode or single-point-of-failure disruptions as experienced during recent extreme weather events, like the 2014 Polar Vortex.[5] Disruptions in natural gas supply and delivery to generators have prompted the gas and electric industries to further examine reliability implications associated with an increasing dependence on the natural gas infrastructure needed to support electric generation. The gas and electric industries operate under different regulatory structures and rules that affect how infrastructure is planned, built, maintained, and operated.

[1] NERC 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States; December 22, 2011

[2] NERC 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power; June 5, 2013

[3] NERC Reliability Assessment and Performance Analysis

[4] California Public Utilities Commission: Aliso Canyon Risk Assessment Technical Report; April 5 2016

[5] NERC 2014 Polar Vortex Review

As dependence on natural-gas-fired generation increases in North America, the coordination efforts between natural gas pipelines and bulk power electric industries become more important and impactful to system reliability. For example, the relationship between gas availability and low temperatures further challenges the electric industry's ability to manage extreme weather conditions, particularly when conditions affect a wide geographic area and there is less support available from neighboring systems. Additionally, strain may be experienced during the summer months as electric peak loads occur during the same time frame that gas storage demands are being managed and pipelines undergo maintenance. These extreme weather events should serve as early indicators of more frequent impacts if natural gas supply and transportation are surpassed by the demand from natural gas-fired units that continue to predominantly rely on non-firm gas service.

This assessment identifies potential reliability considerations that should be addressed to maintain the reliable operation of the BPS through an operational risk analysis. It provides a short-term perspective by using the latest resource and demand projections from industry.[6] The assessment focuses on areas with natural gas generation penetrations of greater than 40 percent, so the NPCC-New England (ISO-NE), NPCC-New York (NYISO), ERCOT, and WECC-CA/MX assessment areas were selected for evaluation.

NERC examined the changing resource mix within these areas and determined how much gas-fired generation has been added and how much is anticipated to serve peak load during the next 18–24 months. Scenarios were then created using either NERC GADS[7] performance data or existing industry analysis to develop a range of assumptions around potential forced outages and unit unavailability. This assessment is not a prediction of the upcoming seasonal reliability, but rather provides sensitivity and extreme case evaluations to better understand the risk to BPS reliability.

The key findings of this assessment are:

1. Assessment areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability.
2. Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system.
3. High levels of coordination between natural gas and electric system operators enable higher efficiency, higher resilience, and increased situational awareness and preparedness.

NERC recommends the following:

1. Planners and operators should continue accounting for the risks from extreme weather events and plan to ensure resource adequacy as a result of potential gas-fired generator outages. NERC's 2015 *Winter Reliability Assessment*[8] outlined these operational challenges, what winter preparedness activities have been introduced, and what additional improvements are needed.
2. NERC, in collaboration with the Planning and Operating Committees, should establish guidelines for future reliability assessments to evaluate both short- and long-term fuel availability, generation operational characteristics, and other related risks.[9] Resource and transmission planning should account for the potential of large, common-mode single-contingency-type disruptions to natural gas pipelines

6 NERC 2015 Long-Term Reliability Assessment
7 Generating Availability Data System (GADS)
8 NERC 2015-16 Winter Reliability Assessment
9 NERC 2015 Long-Term Reliability Assessment

and associated facilities, specifically for compression stations, well-head supply, and gas storage. These system states need to be simulated, studied, and assessed continuously.

3. System operators should enhance coordination strategies to address potential fuel supply interruptions due to unforeseeable conditions. Good utility practices and procedures, particularly in New England, enable high efficiency, higher resilience, and better situational awareness and preparedness.[10] These practices should be shared and considered as more gas-fired generation is added.

4. NERC and WECC will work with respective entities to conduct a joint meeting whereby all involved entities will identify high-level reliability risks associated with the loss of the Aliso Canyon storage facility and develop mitigating strategies to ensure reliability.

5. The electric industry has taken positive steps to address coordination between the electric and natural-gas industries by developing good utility practices, operating procedures, enhanced communications between electric and natural gas industries, and collaboration with state and federal regulators to ensure electric reliability.[11] NERC recommends continued efforts to more fully comprehend the risks and potential mitigation measures, such as dual-fuel capability and firm delivery contracts, to address the risks from reliance and interdependency between these two industries.

[10] ISO-NE Rules and Procedures

[11] NERC 2015 Long-Term Reliability Assessment

Introduction

Short-Term Special Assessment (STSA) Approach

This assessment evaluates four areas in the North American footprint; ISO-NE (Chapter 1), NYISO (Chapter 2), ERCOT (Chapter 3), and WECC-CA/MX (Chapter 4). The assessment provides an overview of electric reliability by analyzing potential generation supply risks in terms of unavailable natural gas for fueling electric generation. This short-term assessment investigates the state of natural gas-electric interdependency using a deterministic operational risk analysis for the next 18 months and includes four upcoming seasons: Summer 2016, Winter 2016/2017, Summer 2017, and Winter 2017/2018.

The NERC Summer 2015[12] and Winter 2015[13] reliability assessments introduced this operational risk analysis, which evaluates past performances of resources to identify operational sensitivities for serving peak load. This approach provides a snap-shot view of a particular system by examining at-risk outages and an extreme natural gas availability scenario. The remaining available resources are then compared with normal (50/50)[14] and extreme (90/10)[15] peak load forecasts. This deterministic approach includes performance data but does not account for capacity and load relief programs, such as voltage reduction, passive demand response programs, or other emergency operating procedures.

Data for the peak load forecasts, anticipated capacity, and net firm import capabilities were obtained from NERC's 2015 LTRA.[16] Net firm imports do not include the potential maximum transfer capability based on daily dispatch and system topology. In reality, the transfer amount can be larger or smaller, depending on parameters such as market conditions, transmission availability, and area needs.

Figures I.1 and I.2 provide a breakdown of the individual components used for this analysis and what a potential capacity deficiency risk may look like. NERC used data from its Generator Availability Data System (GADS) to model generator outages pertaining to gas-fired and non-gas-fired outages to determine seasonal at-risk capacity; this method is further explained in Appendix A. The capacity determined to be at-risk is classified as follows: average forced non-gas outages, average forced gas outages, and maximum forced gas outages.

Peak load forecasts in excess of the anticipated capacity that is not considered at-risk, indicate a potential for capacity deficiencies. However, there are additional procedures available to system operators to mitigate this prior to shedding load. An additional scenario was introduced to this analysis that compared the total anticipated capacity to a specific natural gas unavailability type event for an area, such as loss of a gas pipeline by force majeure, compression and/or gas storage issues, or any circumstance that would prevent a gas-fired generating plant from obtaining fuel. This scenario was analyzed separately from the at-risk capacity to avoid potential double counting of gas-fired generator outages.

[12] NERC 2015 Summer Reliability Assessment; May 2015

[13] NERC 2015-16 Winter Reliability Assessment; December 2015

[14] Load projections are based on a 50/50 peak demand forecast; also referred to herein as net internal demand. Values represent the baseline values for each season, each with a range of possible outcomes based on probabilities around the baseline or midpoint. Projections are provided on an assessment area basis and are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, RC, assessment area, or BA.

[15] NERC requested a load projection based on the 90th percentile probability. In general, this means that the severe load forecast is expected to reach this higher level once in every 10 years.

[16] NERC 2015 Long-Term Reliability Assessment; December 2015.

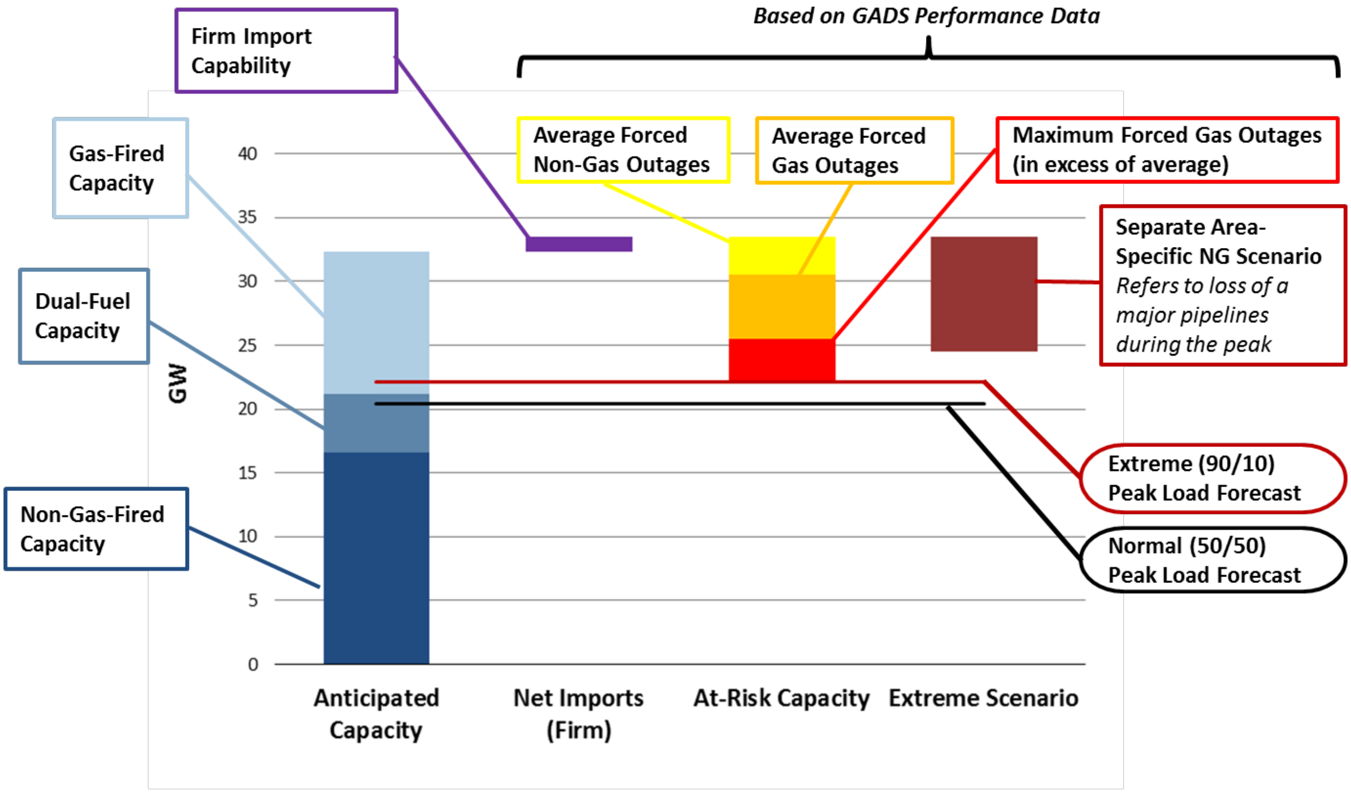


Figure I.1: Operational Risk Analysis - Component Breakdown

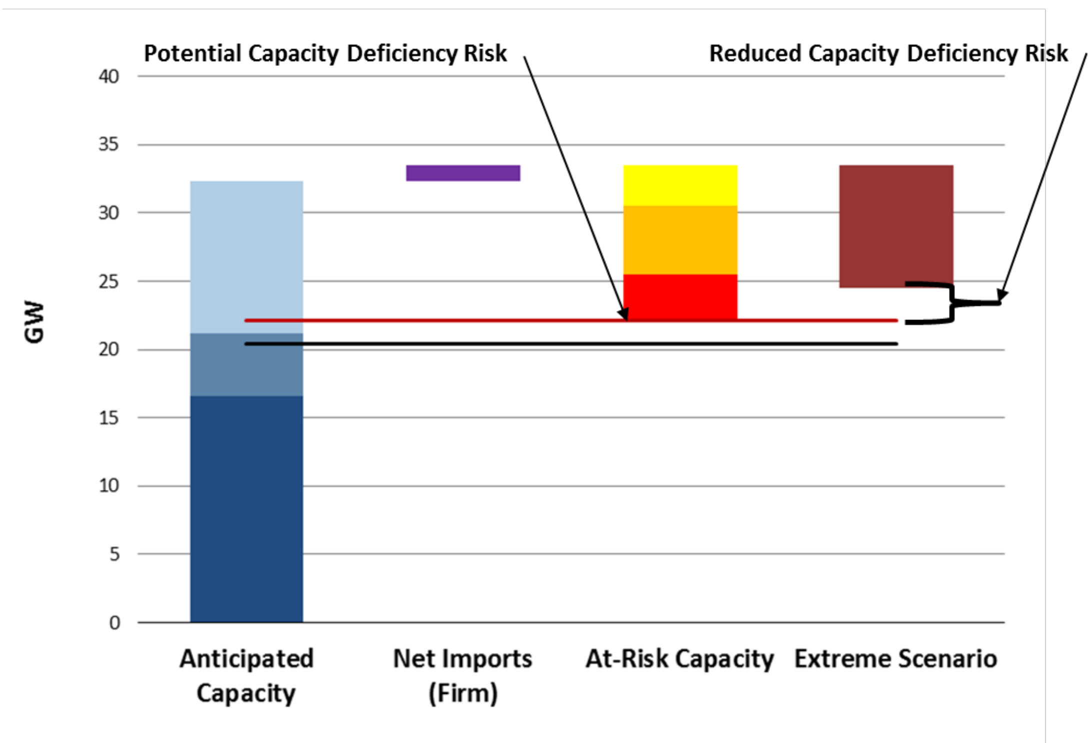


Figure I.2: Operational Risk Analysis – Interpreting Results

Chapter 1 – Independent System Operator of New England (ISO-NE)

Operational Risk Analysis - Natural Gas

Table 1 – ISO-NE Operational Risk Data

Load Projections	2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	26,147	20,433	25,801	20,444
90/10 Peak Load Forecast (Reduced by Available DR)	28,485	21,122	28,174	21,132
Anticipated Capacity				
Total Capacity	30,862	32,715	30,095	32,375
Net Imports (Firm)	1,516	1,491	1,167	1,167
Non Gas-Fired Capacity (MW)	17,410	17,596	15,902	16,568
Dual-Fuel Capacity	4,216	4,576	4,230	4,590
Gas-Fired Capacity (non-Dual-Fuel)	9,236	10,543	9,964	11,217
Gas-Fired + Dual Fuel Capacity (MW)	13,452	15,119	14,193	15,807
Gas-Fired Capacity (% of Total On-Peak)	44%	46%	47%	49%
At-Risk Capacity				
Average Outages of Non Gas-Fired Generation	473	1,261	473	1,261
Average Outages of Gas-Fired Generation	337	316	337	316
Maximum Outages of Gas-Fired Generation	1,806	3,354	1,806	3,354
Extreme Scenario	4,365	4,365	4,365	4,365

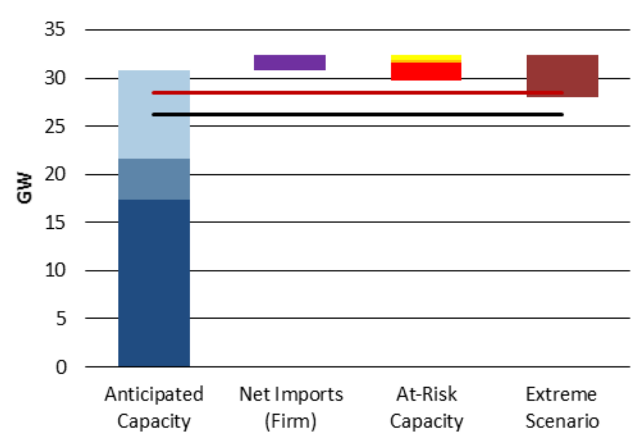


Figure 1.1: ISO-NE Summer 2016 Gas Operational Risk

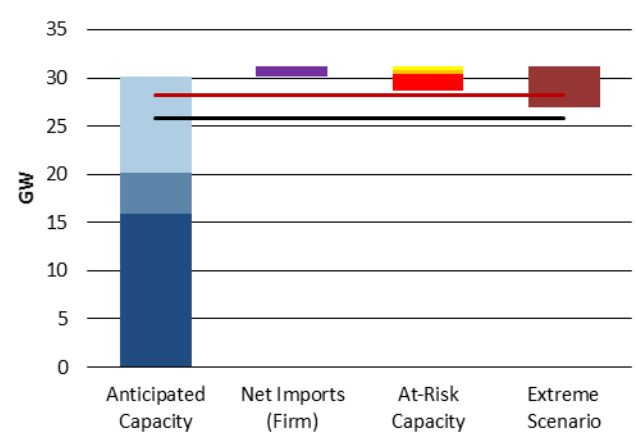


Figure 1.2: ISO-NE Summer 2017 Gas Operational Risk

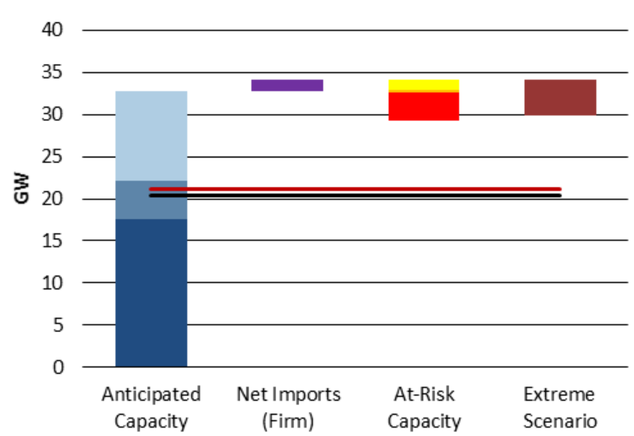


Figure 1.3: ISO-NE Winter 2016/17 Gas Operational Risk

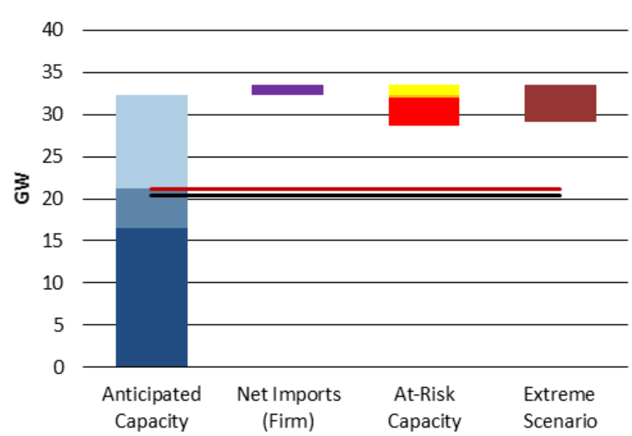


Figure 1.4: ISO-NE Winter 2017/18 Gas Operational Risk

Key Takeaways and Assumptions

- ISO-NE extreme scenario numbers are based on an extreme loss of a major pipeline supplying the area. In this particular case, the extreme scenario number is total capacity (100 percent) of the gas pipeline minus 50 percent of the dual-fuel capacity in the area. This analysis assumes that a conservative 50 percent or more of the dual-fuel units will be available to support reliability for an unexpected loss of a natural gas pipeline. ISO-NE has various programs in place to test the fuel-switching functionality for all dual-fuel units on an annual basis and, in an ideal scenario, more than 50 percent of the affected units would switch fuels and stay online.
- Prior studies by ISO-NE show that potential force majeure events would not cause a sudden loss of fuel to generators located on the affected pipeline, and based on pipeline conditions at the time, would take between several minutes to hours to impact pressure and flow to downstream customers. Theoretically, this provides ample time for both generator owners and system operators to start implementation of remedial actions to supplement the upcoming loss of generation.
- Based on this extreme scenario analysis, ISO-NE might experience tight operational conditions for the 2016 and 2017 summer seasons from the loss of a major gas pipeline that supplies the area. ISO-NE has emergency operating procedures in place to address this extreme scenario.

ISO-NE Summary

- About 8.2 GW of proposed generation is natural gas fired, representing about 60 percent of the new capacity being installed by Summer 2016.[17]
- The area has limited natural gas pipeline capacity, despite the tremendous growth in natural gas-fired generating capacity. This, coupled with growing demand from the heating sector, results in existing pipelines running at or near maximum capacity most of the time, particularly so in winter.[18]
- Extreme demand scenarios are evaluated annually and serve as the basis for ISO-NE's winter reliability programs that have been in place since Winter 2013/2014. The primary focus of the extreme winter weather scenarios is to assess the potential unavailability of natural gas to fuel generators when temperatures are lower than normal.
- The ISO-NE long- and short-term outage coordinators evaluate and account for gas-fired generation that may be at risk in determining seasonal operable capacity margins. ISO-NE would balance stressed system conditions with real-time supplemental commitments and the use of emergency procedures as needed.
- Fuel surveys are in place to request fuel inventory, availability and switching information from generators that are listed as dual-fuel generators. The fuel surveys solicit information concerning applicable time to switch fuels, testing requirements, power output/air permit limitations, and other operational limitations, such as startup capability on alternative fuels and ramping capability, simultaneous fuel operation (burning both oil and gas at the same time), and environmental restrictions. There are also provisions to allow for cost recovery of successful dual-fuel commissioning and testing. This provision is in effect until 2018 and provides for annual testing, verification, and availability requirements.[19]
- To measure at-risk gas generation and improve situational awareness, ISO-NE has developed a gas utilization tool (GUT) that assists control room operators in the evaluation of current and next-day operating plans. The tool uses data gathered from the electronic bulletin boards (EBBs) of gas pipelines serving New England and visualization with estimated scheduled deliveries based on historical nominations for local distribution companies, commercial and industrial loads. The tool provides an

[17] ISO-NE 2016 Regional Electricity Outlook; January 2016
[18] ISO-NE Natural Gas Infrastructure Constraints
[19] ISO-NE Market Rule 1 - Appendix K - III.K.5 "Winter Reliability Solutions 2015-16, 2016-17 and 2017-18 Winter Seasons" 01/28/2016

estimation of the remaining natural gas pipeline capacity available for use by the New England power sector along with a forecast of natural-gas-fired generation at risk.

- The FERC-approved Winter Reliability Program[20] has been critical to maintaining power system reliability and, until forward capacity market incentives are implemented in 2018, the program will continue to help address several challenges that could have an impact on generation during the winter operating period.
- ISO-NE and the regional natural gas sector have had on-going communications and coordination since 2005. After the cold snap of January 2004, the regional natural gas sector, as represented through the Northeast Gas Association (NGA)[21] in concert with ISO-NE, began to co-chair the Electric/Gas Operations Committee (EGOC). The EGOC is open to all parties, but primarily consists of representatives from the electric sector (i.e., ISO-NE, NYISO, and PJM) and the regional gas sector (i.e., pipelines, LDCs, LNG, and fuel suppliers, etc.).[22] EGOC meetings usually take place both pre- and post-season, and the 50th meeting of the committee will take place this May. This relationship has improved understanding, education, training, and communications for both industries within New England.

[20] FERC Docket No. ER15-2208-000 Winter Reliability Program - ISO-NE; September 11, 2015
[21] Northeast Gas Association
[22] ISO-NE Electric/Gas Operations Committee

Chapter 2 – New York Independent System Operator (NYISO)

Operational Risk Analysis – Natural Gas

Table 1: NYISO – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)		32,512	23,639	32,655	23,603
90/10 Peak Load Forecast (Reduced by Available DR)		35,763	26,003	35,920	25,964
Anticipated Capacity					
Total Capacity		39,399	41,747	39,114	41,462
Net Imports (Firm)		1,147	-	1,555	404
Non Gas-Fired Capacity (MW)		23,507	24,259	23,222	23,974
Dual-Fuel Capacity		12,111	13,403	12,111	13,403
Gas-Fired Capacity (non-Dual-Fuel)		3,781	4,086	3,781	4,086
Gas-Fired + Dual Fuel Capacity (MW)		15,892	17,489	15,892	17,489
Gas-Fired Capacity (% of Total On-Peak)		40%	42%	41%	42%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		1,124	1,052	1,124	1,052
Average Outages of Gas-Fired Generation		378	632	378	632
Maximum Outages of Gas-Fired Generation		1,434	2,387	1,434	2,387
Extreme Scenario		2,871	2,871	2,871	2,871

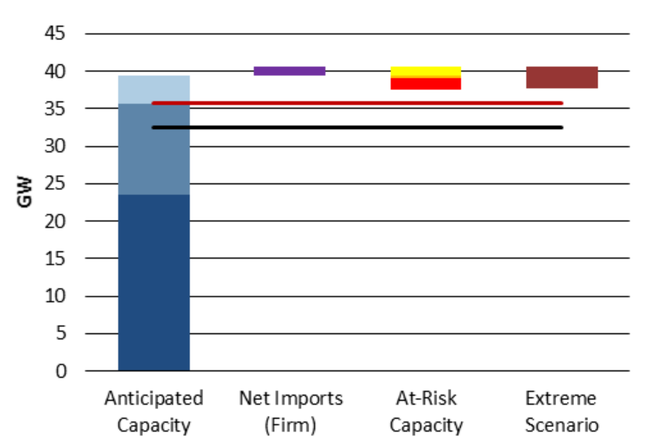


Figure 2.1: NYISO Summer 2016 Gas Operational Risk

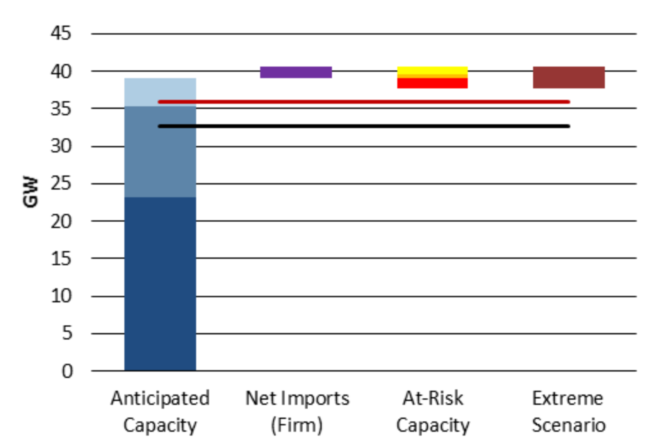


Figure 2.2: NYISO Summer 2017 Gas Operational Risk

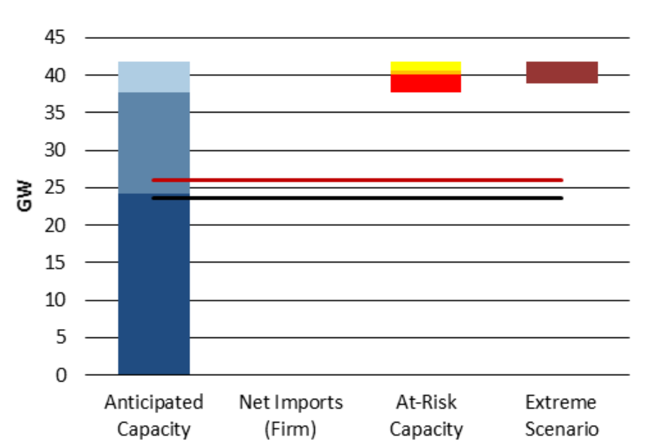


Figure 2.3: NYISO Winter 2016/17 Gas Operational Risk

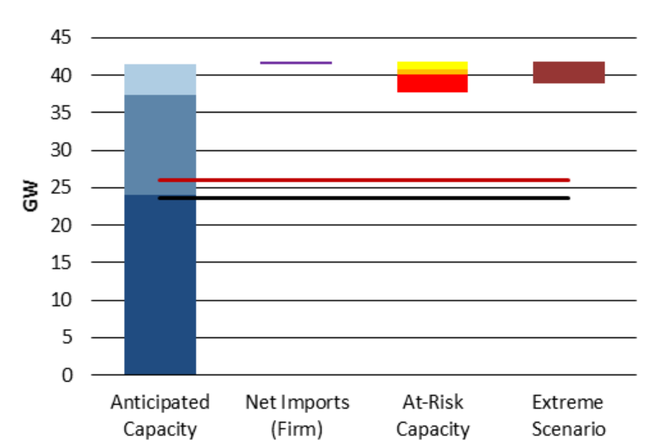


Figure 2.4: NYISO Winter 2017/18 Gas Operational Risk

Key Takeaways

- While the New York region does rely on natural gas as one of its predominant fuel sources, the region has more than one gas pipeline feeding generating plants and supplying firm customers.
- Hence, based upon the operational risk metrics, the New York region is not projected to experience tight operational margins for upcoming seasons.

NYISO Summary

- For 2015/16 Local Distribution Companies (LDCs) have adequate capacity, but remains congested due to residential and commercial customer demand.[23]
- The NYISO Market Mitigation and Analysis Department[24] performed on-site visits of several generating stations (totaling 14,901 MW) to discuss past winter operations and preparations for Winter 2015/2016. Their visits focused on units with low capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, and the causes of failed starts, programs to improve performance, and programs to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel-switching capabilities to improve winter operations.[25]
- Generators connected to LDC in NYISO have strict dual-fuel requirements. Some New York LDCs require dual-fuel capability under their Electric Generation Service classifications. LDCs generally reserve the right to inspect the facility and may require customers to prove the backup generation and fuel storage capability of the facility. Penalties for non-compliance, discoverable either through inspection or failure to switch to a backup fuel during an interruption, are generally tied to the price of a backup fuel.[26]
- In NYISO, eleven generators hold firm mainline transportation contracts. Four of these contracts are for volumes sufficient to fuel the full plant capacity, the others range from approximately one-third to three-fourths of plant capacity. Seven of the contracts are held by generators which are ultimately served by LDCs; the character service of the last leg of the transportation path is currently unknown. In National Grid's (NGrid) Long Island service territory, for example, generators can negotiate a limited-curtailment or "quasi-firm" character of service. Such arrangements typically have a temperature trigger or a specified number of days of curtailment rights, thereby assuring the generation company of firm service during the remainder of the year.[27]
- New and planned pipeline expansions will enable additional Marcellus gas to flow into the New York Control Area (NYCA) Levitan & Associates, Inc., "NYCA Pipeline Congestion and Infrastructure Adequacy Assessment," New York Independent System Operator, September 2013.[28]

[23] New York Public Service Commission - Winter Fuels Outlook: Natural Gas Supply for the 2015-2016 Winter Season; October 27, 2015
[24] NYISO Market Mitigation and Analysis Department
[25] NPCC Reliability Assessment for Winter 2015-16 - Final Report; December 1, 2015
[26] EIPC Gas-Electric System Interface Study - Final Draft; April 4, 2014
[27] Ibid
[28] NYCA Pipeline Congestion and Infrastructure Adequacy Assessment; September, 2013

Chapter 3 – Texas Reliability Entity (TRE)/Electric Reliability Council of Texas (ERCOT)

Operational Risk Analysis - Natural Gas

Table 1: ERCOT – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	—	67,657	51,935	68,514	52,797
90/10 Peak Load Forecast (Reduced by Available DR)	—	74,423	57,129	75,365	58,076
Anticipated Resources					
Total Resources		78,141	79,696	80,033	84,155
Net Imports (Firm)		392	835	392	835
Non Gas-Fired Capacity (MW)		32,274	31,408	33,466	31,929
Dual-Fuel Capacity		6,225	6,433	6,225	6,433
Gas-Fired Capacity (non-Dual-Fuel)		39,642	41,855	40,342	45,794
Gas-Fired + Dual Fuel Capacity (MW)		45,867	48,288	46,567	52,227
Gas-Fired Capacity (% of Total On-Peak)		59%	61%	58%	62%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		2,275	2,741	2,275	2,741
Average Outages of Gas-Fired Generation		583	861	583	861
Maximum Outages of Gas-Fired Generation		1,705	8,782	1,705	8,782
Extreme Scenario		3,500	5,000	3,500	5,000

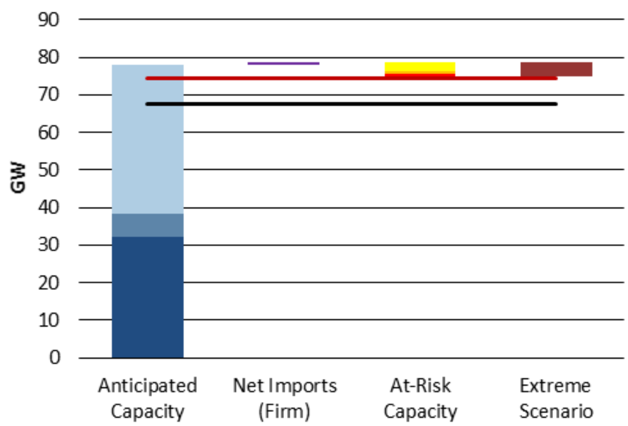


Figure 3.1: ERCOT Summer 2016 Gas Operational Risk

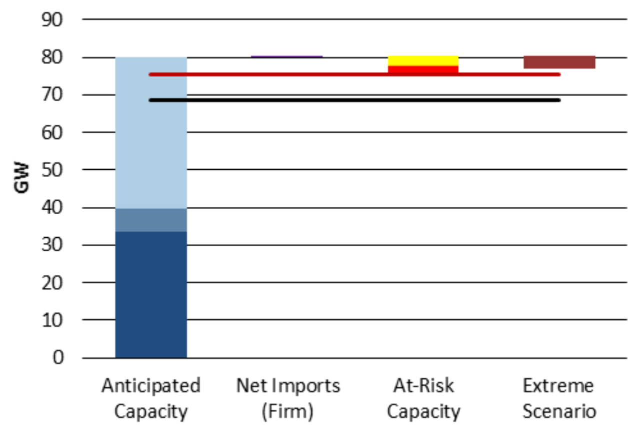


Figure 3.2: ERCOT Summer 2017 Gas Operational Risk

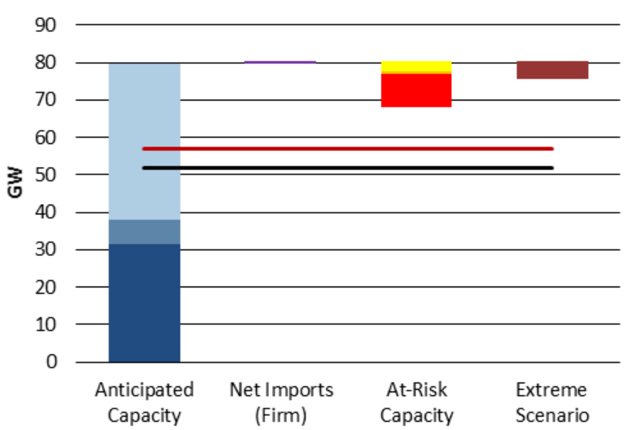


Figure 3.3: ERCOT Winter 2016/17 Gas Operational Risk

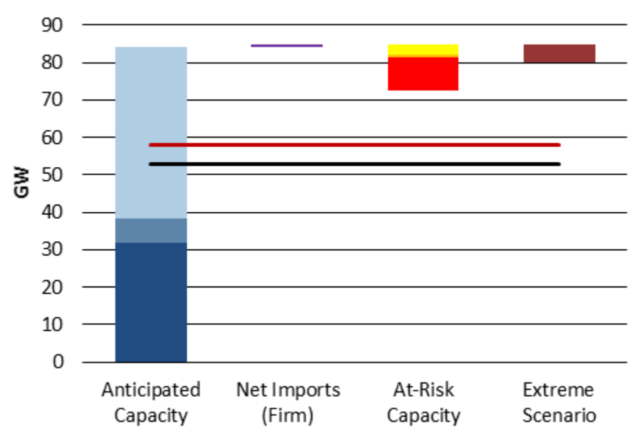


Figure 3.4: ERCOT Winter 2017/18 Gas Operational Risk

Key Takeaways

- Loads in Texas tend to be higher in summer compared to the winter season, leading to tighter margins in the summer.
- Texas has various emergency operating procedures in place to address high loads, such as load responsive assets.

Texas RE and ERCOT Summary

- Natural gas, at 48.3 percent, continues to be the dominant fuel used to generate electricity in the ERCOT area, followed by coal at 28.1 percent. In 2015, wind moved from fourth to third, at 11.7 percent, providing about 40.8 million MWh during the year. Wind surpassed nuclear power, which increased slightly from 2014; nuclear power provided 39.4 million MWh, or 11.3 percent of total energy used.[29]
- Texas is the largest producer of natural gas in the U.S. and also has the highest number of miles of natural gas pipeline.[30] There has been extensive pipeline construction over the last 10 years as a result of development of unconventional gas supplies in the Barnett and Eagle Ford shale areas. The ERCOT area has sufficient natural gas supply infrastructure to support gas-fired generation requirements for the next 18 months and beyond. Intrastate pipelines predominantly serve electric generators in ERCOT, with 13 pipeline systems supplying gas. Seven interstate pipelines also provide gas supplies for the area. The majority of gas-fired generators (60 percent based on a generator survey) have access to multiple pipeline interconnections with various supply receipt options and most are able to acquire supplies in excess of their peak needs.
- Gas supply disruptions are most likely to occur during extended periods of cold weather during the winter season, while hurricanes and pipeline outages represent a lower and more localized supply disruption risk. To assess cold weather-related supply disruption risks, ERCOT developed gas curtailment scenarios for its winter *Seasonal Assessment of Resource Adequacy* (SARA) reports.[31] These scenarios consist of expected and extreme levels of capacity reduction resulting from temperature-driven natural gas curtailments at power plants. These curtailments are based on low winter temperatures reaching certain thresholds at which outages and derates are expected to occur based on natural gas transportation restrictions. Data for scenario development comes from regional low temperature assumptions and an "Hourly Power Plant Transportation Restriction Plan" for a local distribution company that serves northern Texas, as well as generation owner surveys and ERCOT operator event logs for gas curtailment-driven generation capacity reduction events. For its Winter 2015/2016 SARA report (Figure 3.5), ERCOT includes about 1,500 MW of gas curtailment outages/derates for typical temperatures at the time of the winter peak load hour, and an additional 1,060 MW of outages/derates, assuming that extreme cold temperatures occur during the peak load hour. Based on these potential capacity reduction levels and the assumed threshold amount of operating reserves needed to avoid energy emergency alerts, ERCOT concluded that gas curtailments due to cold weather represent a low risk to system resource adequacy during the winter months.
- Generators in the ERCOT area are required by protocols to notify ERCOT any time their fuel suppliers make them aware of issues that might limit their operation. ERCOT operations staff also issues various weather emergency preparedness notices that may include requests for real-time information on resource fuel capabilities. Since 2015, ERCOT has been working directly with the natural gas pipelines and local distribution companies to identify critical loads for gas supply and provide ERCOT operators with advance warning for gas curtailment actions.

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[29] ERCOT Press Release - "Energy use in ERCOT Region grows 2.2 percent in 2015"; January 15, 2016

[30] EIA - U.S. State Rankings: Natural Gas Marketed Projections, 2014

[31] ERCOT - Seasonal Assessment of Resource Adequacy for the ERCOT Region - Winter 2015/2016; November 2, 2015

- ERCOT issues a "Unit Alternative Fuel Capability" survey in the fall of each year to generator owners, intended to ascertain details on fuel usage and deliverability (firm versus non-firm), alternative fuel sources, the latest fuel-based unit curtailments, and the number of hours to transition to an alternative fuel.
- ERCOT has also implemented a rigorous winter preparedness testing mechanism for generating plants with exposure to extreme weather.

Seasonal Assessment of Resource Adequacy for the ERCOT Region
Winter 2015/2016 - Final
Release Date: November 2, 2015

Forecasted Capacity and Demand

Operational Resources (excluding wind), MW	68,063	Based on current ratings reported through the unit registration process
Switchable Capacity Total, MW	3,702	Rated capacity of resources that can interconnect with other regions and are available to ERCOT
less Switchable Capacity Unavailable to ERCOT, MW	(470)	Based on survey responses of Switchable Resource owners
Mothball Resources, MW	0	Based on seasonal Mothball units plus Probability of Return responses of Mothball Resource owners
Private Use Network Capacity Contribution, MW	4,433	Average capability of the top 20 hours in the winter peak seasons for the past three years
Non-Coastal Wind Resources Capacity Contribution, MW	2,287	Based on 18% of rated capacity for non-coastal wind resources per Nodal Protocols Section 3.2.6.2.2
Coastal Wind Resources Capacity Contribution, MW	622	Based on 37% of rated capacity for coastal wind resources per Nodal Protocols Section 3.2.6.2.2
RMR Resources to be under Contract, MW	0	No RMR resources currently under contract
Non-Synchronous Ties Capacity Contribution, MW	371	Average capability of the top 20 hours in the winter peak seasons for the past three years
Planned Resources (not wind), MW	7	Based on projected dates provided by developers of generation resources
Planned Non-Coastal Wind, MW	189	Based on projected dates and 18% of rated capacity for non-coastal wind resources
Planned Coastal Wind, MW	136	Based on projected dates and 37% of rated capacity for coastal wind resources
[a] Total Resources, MW	79,341	
[b] Peak Demand, MW	57,400	Peak forecast is based on expected demand and weather conditions for winter 2015
[c] Reserve Capacity [a - b], MW	21,941	

	Forecasted Season	Extreme Peak Load / Typical Generation	Extreme Peak Load / Extreme Generation
Peak Load Adjustment (1)	0	3,434	3,434
Typical Maintenance Outages (2)	4,061	4,061	4,061
Typical Forced Outages (2)	3,756	5,268 (3)	5,268 (3)
Extreme Forced Outages (4)	0	0	4,584
[d] Total Uses of Reserve Capacity	7,817	12,763	17,347
[e] Capacity Available for Operating Reserves (c-d), MW Less than 2,300 MW indicates risk of EEA1	14,124	9,178	4,594

(1) Winter Peak Load Extreme Forecast is 60,834 MW based on the 90th percentile level.
(2) Maintenance Outages and Forced Outages based on average of historical outage data for December, January and February weekdays, hours ending 7 am to 10 am (starting in 2010).
(3) Includes typical outages/derates due to natural gas curtailments during extreme peak load hours.
(4) Extreme Forced Outages include forecasted derates due to natural gas curtailments at low ambient temperatures during extreme peak load hours.

Figure 3.5: ERCOT Winter 2015-16 SARA Report Chart

Chapter 4 – Western Electricity Coordinating Council (WECC) – CA / MX Area

Operational Risk Analysis – Natural Gas

Table 1: WECC CA-MX – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)		52,669	38,213	52,919	38,245
90/10 Peak Load Forecast (Reduced by Available DR)		57,936	42,034	58,211	42,070
Anticipated Resources					
Total Resources		63,748	54,438	65,823	54,445
Net Imports (Firm)		2,296	2,296	2,296	2,296
Non Gas-Fired Capacity (MW)		19,051	8,545	19,241	7,593
Dual-Fuel Capacity		1,497	1,497	1,497	1,497
Gas-Fired Capacity (non-Dual-Fuel)		43,200	44,396	45,085	45,355
Gas-Fired + Dual Fuel Capacity (MW)		44,697	45,893	46,582	46,852
Gas-Fired Capacity (% of Total On-Peak)		70%	84%	71%	86%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		1,027	3,571	1,027	3,571
Average Outages of Gas-Fired Generation		337	484	337	484
Maximum Outages of Gas-Fired Generation		2,658	1,391	2,658	1,391
Extreme Scenario		9,800	9,800	9,800	5,000

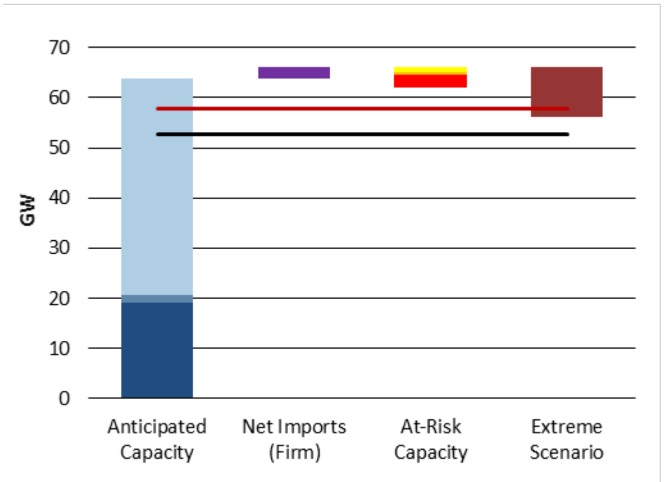

Figure 4.1: CA-MX Sum. 2016 Gas Operational Risk

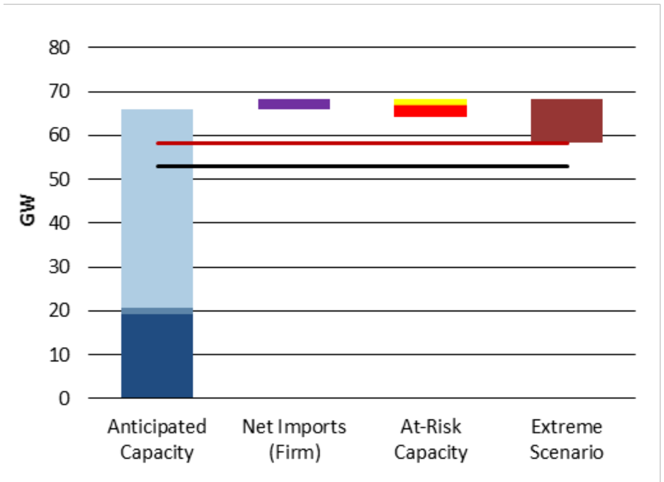

Figure 4.2: CA-MX Sum. 2017 Gas Operational Risk

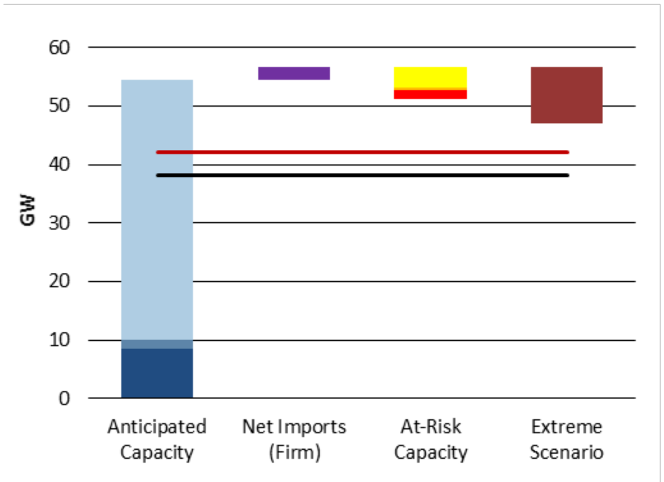

Figure 4.3: CA-MX Win. 2016/17 Gas Operational Risk

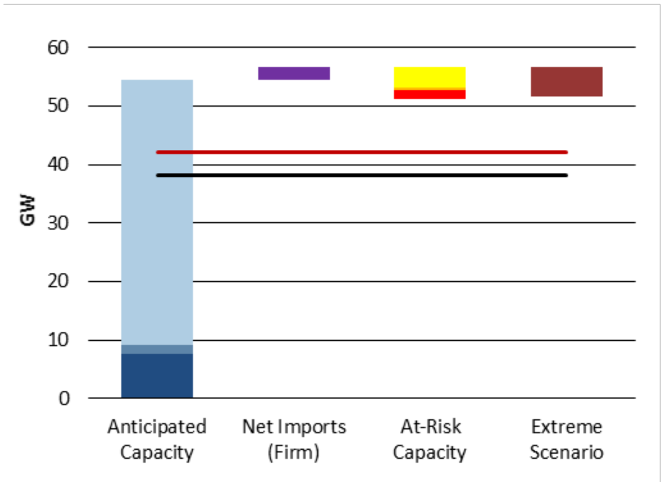

Figure 4.4: CA-MX Win. 2017/18 Gas Operational Risk

Key Takeaways

- Southern California may face reliability challenges in summer 2016, possibly stretching into winter 2016/2017 and summer 2017, due to the reduction of capacity at Aliso Canyon. This is reflected in the Extreme Scenario for summer 2016 and summer 2017, as that scenario included outages of the 17 gas plants in the Los Angeles Basin that rely on Aliso Canyon.
- Operations in Southern California could be further impacted by the loss of import capacity. In both the summer 2016 and 2017 extreme scenario cases, a reduction in net imports would likely result in adverse impacts.
- Overall assessment of the WECC footprint doesn't show any significant adverse impacts for upcoming seasons, except under the Extreme Scenario for summer 2017 and summer 2018. This is due to the review of the CA/MX area in aggregation.
- WECC and CAISO have measures in place to help mitigate this gas supply constraint by increasing imports and relying on CAISO's analysis for Aliso Canyon to shed load when necessary.

WECC Summary

Aliso Canyon

In October 2015, a gas leak was detected at the Aliso Canyon natural gas storage facility in southern California. The Aliso Canyon facility is a critical component of the gas system in the Los Angeles Basin. It is one of the largest natural gas storage facilities in the U.S. and is essential in providing a reliable gas supply to 18 large power plants with approximately 9,800 MW of capacity in the Los Angeles basin. Of its 86 Bcf working gas capacity, only 15 Bcf is being stored currently. There is a moratorium on injection of fuel into Aliso Canyon until all wells at the facility have been checked and appropriate action taken to ensure no further leaks.

A technical Assessment Group comprised of the California Energy Commission, the California Public Utilities Commission, the California Independent System Operator, the Los Angeles Department of Water and Power (LADWP), along with the Southern California Gas Company is analyzing both the gas and electric system impacts associated with the loss of the Aliso storage capability. The central finding of the group's Technical Report is that there are real reliability risks to the electric system associated with the loss of Aliso Canyon. Given the uncertain operating status of Aliso Canyon, the reliability of natural gas supply is likely to be threatened from 23 to 31 days of the year. Risks on the natural gas system have a profound effect on the electric supply system, which relies on natural gas to fuel power generators and provide ramping capability to balance an increasing amount of variable generation in California. Key factors leading to potential curtailments on the electric system include differences between receipts and send out on the gas system, gas system maintenance work, and unplanned outages. On as many as 12 to 21 days, gas service curtailments could be large enough to force the California ISO and LADWP to curtail electricity service to customers across a wide area in the LA Basin. 14 of these days could occur in the summer.

The Technical Assessment Group also created an Aliso Canyon Action Plan[32] that presents measures that would help mitigate, but not eliminate, the risk of gas curtailments large enough to cause electricity interruptions. Considerations in developing mitigation plans for the coming summer and winter include limits to import capability, gas balancing practices, and the use of the remaining 15 Bcf working gas in Aliso Canyon for electric reliability. The measures range from targeted consumer communications, new efficiency and demand response measures, greater operational coordination, tariff changes, and clear direction to Southern California Gas to use the gas currently stored at Aliso Canyon, if necessary to prevent electricity interruptions.

[32] California ISO Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin

In a parallel effort, the CAISO formed a group to look at potential reliability risks to both gas and electricity markets in Southern California due to the limited operation of the Aliso Canyon gas storage facility. Through an expedited stakeholder process, the group created a proposal for tariff changes that addresses gas balancing, electricity and gas scheduling misalignment and market-based mitigation measures.[33] CAISO's proposal identifies ways to mitigate risks that impact the electric system when rapid ramping will exceed the dynamic capability of the gas system (i.e., contingency recovery, renewable generation following, or significant changes in load). In its proposal, CAISO also anticipates needing the flexibility to reduce available transfer capability on Path 26, a set of three 500-kV lines connecting Southern California Edison Co.'s intertie with Pacific Gas and Electric Co. to the north. The proposal stated that flexibility would be needed to ensure sufficient transfer capability to support reliable grid operations. The proposal also includes measures to mitigate risks where planned and unplanned outages on the gas system limit pipeline and storage that impact gas availability.

The outage at Aliso Canyon[34] is the most recent demonstration of how BPS reliability is affected by the increasing interdependency between the electric and natural gas industries. While the mitigation measures being undertaken will help reduce the risk of electricity service interruptions, they do not eliminate the risk. The challenges faced in California represent a series of risks that have been layered into the system over the past decade: significant dependency on a single and just-in-time delivery fuel source, specifically for ramping capability to meet load and generation variability; reduced amount of baseload and dispatchable resources; increased amounts of variable and distributed resources; increasing need of system flexibility; gas system dependency on storage to maintain operating pressure; and a lack of clear understanding of natural gas operational characteristics and potential impacts on BPS operations. Continued coordination between electric and gas industry entities will be critical to mitigating risks and minimizing their impact.

The four most impactful measures to help mitigate risk are: tightening the gas balancing rules; giving generators dispatch information two days in advance so that they can procure gas more accurately; directing the use of the remaining gas in Aliso Canyon to prevent electric service interruptions; and completing inspection of the Aliso Canyon storage facility to allow the resumption of safe injection. The long-term risks associated with Aliso Canyon will not be known until more is known about the longer term operational prospects of Aliso Canyon.

[33] California ISO Aliso Canyon Gas-Electric Coordination - Straw Proposal; April 15, 2016

[34] California Public Utilities Commission: Aliso Canyon Risk Assessment Technical Report; April 5 2016

Chapter 5 – Conclusions

In 2015, natural gas surpassed coal as the predominant fuel for electric generation and is the leading fuel type for capacity additions. Despite substantial progress in coordination between the gas and electric industries, the growing reliance on natural gas continues to raise reliability challenges regarding the interdependence of the industries and the adequacy of gas and electric infrastructure. Both industries have an opportunity to further enhance planning approaches by considering fuel deliverability, availability, and responses to infrastructure contingencies that are unique to each area and integrate them into resource adequacy and other planning and operating practices.

The electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems. The extent of these concerns from Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials vary throughout North America; however, concerns are most acute in areas where power generators rely on non-firm fuel contracts.

Disruptions as experienced during recent extreme weather events, such as the 2014 Polar Vortex, provide clues to the current relationships between gas availability and extremely low temperatures. As gas-fired generation increases, the amount of generation capacity potentially impacted also increases, particularly when conditions affect a wide geographic area and support from the neighboring areas is unavailable. These extreme weather events serve as early indicators of more frequent impacts to the BPS as more natural-gas-fired units continue to rely solely on just-in-time and non-firm fuel sources.

While gas-electric supply and transportation issues are especially important during the winter season, the summer season presents a separate set of potential reliability concerns that also require ongoing attention. Specifically, the electricity industry must be aware of pipeline and gas distribution company equipment maintenance schedules and promote ongoing coordination to ensure individual generators do not face fuel shortages; principally those that could have been resolved through increased coordination.

Natural gas supply, transportation, and distribution infrastructure adequacy concerns, particularly in certain parts of North America, are causing NERC, industry, and policymakers to refocus attention on the interdependency between natural gas and electricity industries. While coordination efforts between the gas and electric industries continue to improve, the potential still exists for a mismatch between the availability of natural gas delivery and demand from the electric sector. This can be particularly challenging in areas where a significant amount of the capacity and reserve capacity are susceptible to fuel supply interruptions, potentially resulting in more frequent generator outages.

The gas and electric industries have recently made substantial progress to enhance coordination and develop new strategies to address system reliability due to fuel supply concerns. However, additional areas need attention. Specifically, in areas where natural gas constitutes a large portion of the generation mix, system planners need to more thoroughly examine system reliability needs to determine if more firm fuel contracts or dual-fuel capabilities are needed. Fuel availability and deliverability should be specifically considered and integrated into resource adequacy and other planning assessments.

More attention is also needed regarding operational coordination strategies between gas and electric industries. System operators should develop or enhance coordination strategies to address potential fuel supply interruptions, especially prior to anticipated extreme weather events. Generator owners should consider securing on-site, secondary fuel inventories in the event that gas service is curtailed. Operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools should take fuel supply chain risks into account and lead to mitigation measures to assist operators in maintaining BPS reliability. Enhanced training should be considered in light of the increasing need for electric and pipeline/LDC operator communications and coordination.

This short-term assessment focused on four assessment areas within the North American BPS that have a greater than 40 percent level of natural-gas-fired generation thereby relying significantly on natural-gas-fired units as well as the upstream infrastructure (pipelines, compressor stations, natural gas wells, distribution, etc.) necessary to deliver reliable natural gas supply to generating facilities. The assessment determined that all areas generally can meet their natural gas needs over the short-term horizon without relying on emergency operating procedures. WECC CA/MX had the largest risk for reliability issues, demonstrating that in the extreme peak load and the severe scenario, they could experience potential difficulty in meeting their peak demand and operating reserve requirements without initiating emergency operating procedures.

While this analysis determined limited short-term risk in the assessed areas during extreme events, longer term implications emerge as the data shows more outages as a result of fuel supply unavailability as more natural gas-fired generation is installed. The Aliso Canyon gas storage outage demonstrates that even outside of extreme and severe scenario analyses, one gas sector contingency can have an impact on BPS reliability and resource adequacy. This one event, which has the ability to affect up to 9,800 MW of Los Angles-basin generation, underscores the need to identify the need for dual-fuel capability and to develop contingency plans to address the potential effects of a major fuel supply chain contingency.

Appendix A

Method Used to Model Generator Outages

The scope of this assessment includes an analysis of the potential operational risks within the next four peak seasons and across four ISOs: CAISO, ERCOT, ISO-NE, and NYISO. All capacity, demand, and transfer data were obtained from the *2015 Long-Term Reliability Assessment* data set. The extreme weather demand values were assumed by adding 10 percent of the net internal demand on top of the 50/50 peak load forecast. Five years of event data from the Generator Availability Data System (GADS) were analyzed to obtain three classifications of generator outages:

1. Average outages of non-gas-fired generation
2. Average outages of gas-fired generation
3. Maximum outages of gas-fired generation

Mandatory reporting of generator outages to GADS does not include electric generating units below 20 MW nor does it incorporate solar or wind generating capacity outages. Instead, these variable energy resources are assumed to supply a specific capacity contribution across a seasonal peak load hour. This data is presented in relation to the total anticipated capacity which assumes that all other capacity is considered "available" regardless of actual system dispatch or units in reserve/economic shutdown.

Average Outages Methods and Assumptions

- Event data from 2010–2014 were obtained from GADS.
- Only forced outage event types (U1, U2, U3, and SF) were used.
- Events were sorted by their unit type to obtain: Gas-Fired and Non Gas-Fired based events.
- Units were sorted by their physical state location to obtain an approximate area of study: e.g., NYISO outage data was comprised of all units in New York.
- Outage capacity in MW (Unit Rating — Net Available Capacity) was multiplied by the total outage time to calculate the total unavailable energy for each event in MWh.
- The calculated total unavailable energy data were sorted and aggregated together by the starting month for each year.
- Each month's calculated total unavailable energy were average together for all five years to obtain the monthly unavailable energy average; e.g. (Jan 2010 + Jan 2011 + Jan 2012 + Jan 2013 + Jan 2014) ÷ 5 = Averaged January Energy
- Each monthly unavailable energy average was divided by the total number of hours within the data scope to obtain the monthly unavailable capacity average; e.g. Averaged January Energy ÷ (5 $^{\text{years}}$ * 31 $^{\text{days}}$ * 24 $^{\text{hours}}$) = Averaged January Capacity
- Monthly unavailable capacity averages for all months in both seasons were averaged together to obtain the final result of the average outage for any hour within a season; e.g. (Averaged January Capacity + Averaged February Capacity + Averaged December Capacity) ÷ 3

Maximum Outages Methods and Assumptions

- Event data from 2010–2014 were obtained from GADS.
- Only immediate forced outage event types (U1 and SF) were used.

- Events were sorted by their unit type to obtain: Gas-Fired based events.
- Units were sorted by their physical state location to obtain an approximate area of study: (e.g. NYISO outage data was comprised of all units in New York.)
- Outage capacities in MW (Unit Rating — Net Available Capacity) were aggregated by their start date.
- The maximum was obtained for each daily capacity outage aggregation across all five years: e.g. January 1st Maximum = Max of (Jan 1st 2010, Jan 1st 2011, Jan 1st 2012, Jan 1st 2013, Jan 1st 2014)
- The final results used for each season were obtained by taking the maximum daily capacity outage aggregation of all days within the summer and winter months: (e.g., maximum daily outage between June 1st – September 30th)
- The values shown as maximums for the tables and charts are *in excess* of the average gas outages. This was to avoid potentially double counting outages.

Final Results

Summer Outage Data (MW)

Area	Maximum Outages of Gas-Fired Generation	Average Outages of Gas-Fired Generation	Average Outages of Non Gas-Fired Generation
CAISO	2,658	337	1,027
ERCOT	1,705	583	2,275
ISO-NE	1,806	337	473
NYISO	1,434	378	1,124

Winter Outage Data (MW)

Area	Maximum Outages of Gas-Fired Generation	Average Outages of Gas-Fired Generation	Average Outages of Non Gas-Fired Generation
CAISO	1,391	484	3,571
ERCOT	8,782	861	2,741
ISO-NE	3,354	316	1,261
NYISO	2,387	632	1,052

Appendix B

ISO-NE Natural Gas – Electric Operations

The scenario developed for the New England Region assumes a natural gas pipeline "rupture" within the area. This scenario was developed due to the large amount of gas-fired generation located within the ISO New England Balancing Area. Approximately 44 percent of the generating capacity within the area is fueled by natural gas, and gas-fired energy production was approximately 49 percent in 2015.

This theoretical scenario would qualify as a "force majeure" event within the pipeline's tariff structure. As such, pipeline operators would invoke a series of actions to locate and then isolate the break in the pipe to minimize the amount of natural gas escaping to ensure public safety. It should be noted that some pipeline systems within New England have more than one pipeline located within their "rights-of-way." After shutting valves to sectionalize the pipe break and confirming public safety, gas control operators would work to back-feed the pipeline from supply sources located downstream of the break. This would entail maximizing interconnects with other pipelines, interrupting non-firm loads, and maximizing injections of vaporized LNG. Gas control is able to deliver gas to firm customers located upstream of the theoretical pipe-break.

Soon after the pipeline is sectionalized and safety is ensured, gas control operators would then try to restore natural gas deliveries to their firm customers. This force majeure event would mandate that any remaining operational gas pipeline capacity would be pro-rationed among firm customers. All non-firm customers would be immediately asked to curtail their consumption of gas. For New England, this would mean that virtually all natural gas-fired power generators would lose their fuel supplies. Prior studies have shown that the majority of gas-fired power generators within New England rely on capacity release, secondary-firm, and interruptible contracts. Those generators that have functional dual-fuel capability would try to fuel switch to their secondary fuel supply, typically liquid fuels which would include kerosene, jet fuel, and Ultra-Low Sulphur Diesel fuel (ULSD). Power generators that are single fuel (natural gas-only) would have to cease energy production.