NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Special Reliability Assessment:
Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System

November 2017

RELIABILITY | ACCOUNTABILITY




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Errata

August 30th, 2018: Table 1.3 has had the values for East Texas, Oklahoma, and Louisiana updated. Additionally, the Northeast area has been added to the table.

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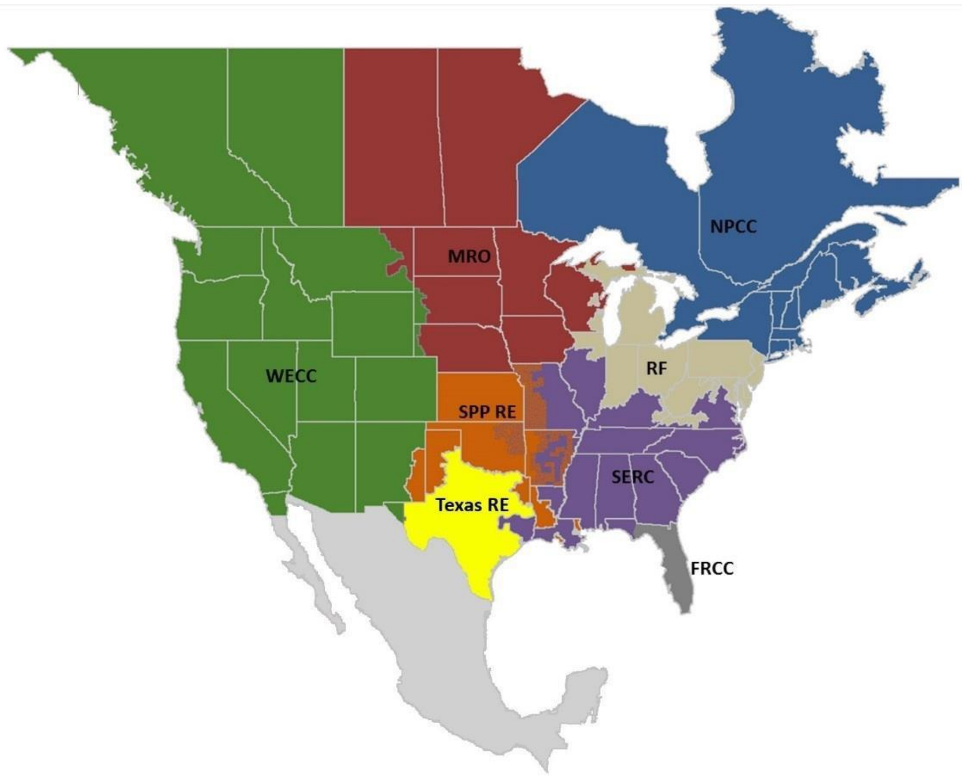
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security 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 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

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Executive Summary

This assessment provides an analysis of the potential impacts to BPS reliability as a result of a large disruption on the natural gas system. As reliance on natural gas to meet electric generation requirements increases, additional planning measures, and risks must be considered to better understand the implications of the complex interdependency between the natural gas system and the BPS.

North America is experiencing a large shift in its electric generating resources with ongoing retirements of coal-fired and nuclear capacity coupled with growth in natural gas, wind, and solar resources. Regulatory rulings and state renewable portfolio standards are significant drivers for the development of more renewable energy resources while historically low natural gas prices and other factors are contributing to a large increase in the development of natural-gas-fired resources. Some areas within North America now meet their peak electric demand with greater than 60 percent of that sourced from natural-gas-fired electric generation.

This growing interdependence of the natural gas and electric infrastructure has resulted in new operational and planning reliability challenges. For example, the Aliso Canyon natural gas storage facility leak underscored not only the reliance on natural gas to meet electric demand but also how the disruption of a key natural gas infrastructure component can impact BPS reliability. In addition to natural gas storage, pipelines, compressor stations, and liquefied natural gas (LNG) facilities are also critical components of the natural gas infrastructure that the electric industry relies on to meet its load-serving obligations. While the natural gas industry has demonstrated a high degree of reliability, the natural gas leak at Aliso Canyon raised awareness of the BPS's dependency on natural gas infrastructure and calls for a closer look at the facilities that support fuel deliveries to electric generation.

This assessment identifies major clusters of natural gas generation and conducts a screening analysis to determine at a high level whether there are further issues that need investigation.

Key Findings

NERC's assessment identifies the following key findings:

- **Natural gas facility disruptions can have varying impacts depending on geographical location and overall infrastructure dynamics.**
  Disruptions to natural gas facilities that impact BPS reliability are highly dependent on a variety of area-specific issues, including the amount and distance from natural gas supply sources, the amount of natural-gas-fired generation commonly connected to the pipeline system, resilience and preparation measures, and market and regulatory requirements. For example, in New England and Southwest California–Arizona, an outage of nearly any major natural gas facility (e.g., one interstate pipeline, key compressor station, or LNG terminal) during electric summer or winter peak conditions would likely lead to some level of electric generation outages. In contrast, the pipeline system in areas such as Texas–Oklahoma–Louisiana is highly interconnected, resembles more of a grid structure, is close in proximity to many supply sources, and is less vulnerable to transportation disruptions.

- **NERC's power flow simulation demonstrates that 18 out of 24 groups of gas-dependent generators studied experience transmission challenges during an extreme event.**
  NERC conducted a power flow simulation screening assessment that evaluated the electric transmission system under extreme conditions that were based on the loss of significant electric generation due to failures of natural gas facilities within a relatively local area. The analysis identified approximately 40 "clusters" of natural gas generation representing at least 2,000 MW within a 200 mile radius. After applying criteria for dual fuel or service by multiple pipelines, there were 14 clusters that met the criteria for further examination and were included in the power flow study. Within these 14 clusters, 19 groups

of generation were selected for screening. As well, five other groups were screened based upon the potential impact they would experience due to the loss of a large natural gas storage facility. A power flow simulation was conducted on these 24 groups of generation facilities. There were 18 out of 24 groups of generation facilities identified where transmission upgrades or operational procedures may be necessary to mitigate extreme generator outages.

- **The demand for natural gas storage has increased significantly and has altered the traditional operations of these facilities in order to meet electric demand along with the traditional demands of the natural gas industry.**
  The operational characteristics of some natural gas storage facilities throughout North America have evolved in recent years to accommodate increased natural gas demand. Whereas depleted reservoirs have traditionally operated in a seasonally cyclical manner of injections and withdrawals, the new paradigm of year-round injections and withdrawals has introduced new operational conditions to natural gas storage facilities. In particular, some storage facilities are providing intraday flexibility to support natural gas generation cycling. This is largely caused by the need to offset wind and solar variable energy production. Regulators and market operators need to consider potential fuel reliability and security impact when developing new or revised regulations or market rules regarding generation dispatch and natural gas availability.

- **Aliso Canyon has different characteristics than most traditional natural gas storage facilities.**
  The Aliso Canyon natural gas storage facility outage is a relatively unique situation; rather than being located on the interstate natural gas pipeline system, Aliso Canyon is located within the SoCalGas distribution footprint. The unique demands of the SoCalGas system and its reliance on this storage field differs significantly from typical storage located on the interstate pipeline system and upstream of the local distribution companies. Given Southern California’s high reliance on natural gas generation, increasing ramping requirements to offset variable energy resource production, reducing oil back-up inventory due to environmental regulations, and the changing of local policies, the Aliso Canyon outage poses additional reliability concerns in Southern California.

- **Firm natural gas pipeline transportation, in addition to dual fuel capability and ample infrastructure, provide the highest level of reliability for natural gas delivery.**
  Firm fuel agreements from supply source to burner tip provide the highest level of reliable natural gas delivery. However, pipelines are not typically constructed or planned using “N-1” or other similar reliability requirements. The more natural gas infrastructure is put in service, the more resilient the totality of that infrastructure. Pipeline systems in restructured wholesale electric market areas generally have less firm transportation agreements for natural gas supply, pipeline transportation, and underground storage service compared to systems in vertically integrated markets.

- **Many mitigation strategies have been and can be employed to reduce potential impacts of a natural gas disruption.**
  Electric transmission upgrades, dual fuel capability, electric power imports, the addition of incremental and diverse generating resources, firm fuel agreements, and battery storage can serve as key strategies to mitigate the risks from the disruption of natural gas infrastructure. However, there is presently a decline in the number of dual fuel units as many new projects are foregoing the added cost of developing dual fuel capability lessening its use as a mitigation strategy.

- **Natural gas supply sources have become more diversified, reducing the likelihood of natural gas infrastructure outages affecting electric generation.**
  Most forced outages of natural gas infrastructure are human-caused, such as damage to pipelines from excavation. However, natural events (including earthquakes, hurricanes, other weather events, LNG import/export dynamics) could affect both supply and operations. With the increase in shale production in other areas of North America, the risk of Gulf of Mexico hurricanes impacting natural gas deliveries to electric generation has been significantly reduced.

- **Recent FERC Orders continue to promote natural gas/electric coordination.**
  FERC Orders 787 and 809 have supported natural gas/electric system coordination by increasing the synchronization of operations between the two industries.

- **Comprehensive planning by Planning Coordinators can significantly increase system resilience.**
  NERC Planning Coordinator studies show that comprehensive planning and evaluation of significant risks on the natural gas system can result in a significant increase in available resilience measures to maintain reliability. Planning Coordinators that have documented these studies have found success in working with state regulators when requesting support for additional resilience measures (e.g., oil inventory, new natural gas generation is dual fuel capable, etc.).

Recommendations

NERC makes the following recommendations:

Regulators and Policy Makers

- **During the planning process, system planners should work with regulators to incorporate expeditious consideration of air permit waivers, which may be needed for resilience purposes; dual fuel, back-up pipeline capacity, and/or alternative sources of supply should be required in areas with significant risk.**

  Dual fuel capability increases generation reliability and resilience, but it is currently limited by various federal, state, and provincial laws and regulations that restrict the duration power plants can run on oil. Temporary air permit waivers may be needed from environmental agencies in advance of an event of a sustained natural gas infrastructure disruption. Furthermore, the necessity for air permit waivers should be incorporated in resilience planning initiatives when they are required.

- **Regulators should consider fuel diversity as they evaluate electric system plans and establish energy policy objectives. Additionally, regulators and policy makers should expedite licensing of new transmission and natural gas facilities to diversify and distribute risk.**

- **Cyber and physical security needs to be diligently considered by regulators.**

  Federal regulators and agencies should work with natural gas pipeline operators and evaluate potential cyber and physical security vulnerabilities on the natural gas system's infrastructure and control facilities. Policy makers should ensure gas infrastructure is as secure from cyber and physical threats as the grid it supplies. Additionally, gas industry regulators should be engaged to establish cyber security standards that match those of the NERC reliability standards.

- **The Department of Energy (DOE) should have the Energy Information Administration (EIA) collect data that quantify and assess the use of dual fuel storage for natural-gas-fired generation and whether that storage has inventory.**

Industry

- **NERC registered entities should consider the loss of key natural gas infrastructure in their planning studies.**

  Entities should assess and develop criteria to evaluate large-scale BPS reliability impacts due to loss of pipelines, LNG, compressor stations, or natural gas storage facilities in the extreme event list as detailed in the Transmission Planning NERC Reliability Standard (TPL-001-4).[1] The criteria should also consider capacity and energy limitations, including seasonal replenishment requirements. Pipeline systems should be planned with the equivalent of N-1 to assure deliverability in the event of a pipeline, LNG, or storage

[1] http://www.nerc.com/files/tpl-001-4.pdf

outage. Where areas were identified in this assessment of needing more granular analysis, planners in those identified areas should be tasked with reviewing this work, assessing the more detailed implications, and where appropriate developing contingency plans to mitigate potential natural gas interruptions, and report back to NERC on what has been done.

- **Owners and operators of dual fuel capable generators must ensure operability of secondary fuel.**

  Generator Owners and Operators of units with dual fuel capability should maintain and regularly test operational capabilities and back up fuel inventories at units to ensure that dual fuel capable units provide adequate resilience in the event of a natural gas outage.

- **Natural gas and electric industries must continue to advance coordination as the electric industry continues to become a larger percentage of total natural gas throughput.**

  The natural gas and electric industries should increase coordination and information sharing of nonpublic operational information to promote reliability and interdependent system integrity. This coordination should include cyber and physical security as well. Additionally, as our power supply becomes increasingly dependent on natural gas, industry must ensure this just-in-time fuel is as reliable and secure as the power plants that need the fuel to operate.

NERC

- **NERC should enhance its reliability guidelines and/or standards.**

  NERC, with industry's support, should enhance its Reliability Guidelines and/or Standards as necessary to include additional planning and operating requirements for analyzing disruptions to the natural gas infrastructure and their impacts on the reliable operation of the BPS. The standards should include developing and deploying mitigation plans to address reliability risks caused by outages of significant natural gas infrastructure.

- **NERC should enhance its Generator Availability Data System (GADS) database.**

  The NERC GADS database should be modified to provide additional information on duration as well as frequency and cause codes for natural gas outages so that a more specific causality can be formulated around natural gas generator outages. This information should be used to work toward mitigation of common causes of failure.

This assessment, which builds on earlier NERC assessments, identifies the need to further improve coordination between the electric and natural gas industries to support the electric system's reliability and resilience. Differing regulatory frameworks and requirements increase the complexity between the interdependence of the two industries. Inter-industry coordination is needed at the regional level due to existing significant operational differences, regulatory rules, and market structures.

Chapter 1: Background

NERC has conducted previous assessments on natural gas and electric interdependence, including the *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power*[2] and its 2011 *Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependencies in the United States*.[3] In 2016, NERC conducted a special assessment, titled *Operational Risk Assessment with High Penetration of Natural Gas Generation*,[4] underscoring increased operational risk with an increase in natural-gas-fired generation.

Despite substantial progress in coordination between the electric and natural gas industries, the growing reliance on natural gas continues to raise the need to identify and mitigate the risks that result from the growing interdependence of the industries. This assessment focuses on the adequacy of the natural gas infrastructure to support the sustained delivery of natural gas to electric generation. The large growth in natural gas use for electric generation is discussed in this chapter along with an overview of potential increased risks to bulk power system (BPS) reliability.

Previous NERC Reliability Assessment Key Findings and Recommendations

Key Findings

The following are key findings from previous NERC Reliability Assessments:

- Natural gas use is expected to continue to increase in the future both in absolute terms and as a share of total power generation and capacity. Unlike coal and fuel oil, natural gas is not easily stored on-site; as a result, real-time delivery of natural gas through a network of pipelines and bulk natural gas storage is critical to support electric generators.
- Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user natural gas peak heating demand during cold winter weather—critically affects the ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).
- While extremely rare, disruptions in natural gas supply and/or transportation to power generators have prompted industry to seek an understanding of the reliability implications associated with increasing natural-gas-fired generation. Contracts for firm natural gas supply and transportation affect the risk profile of each power plant (or group of power plants).
- Natural gas generation is expected to play a growing role in offsetting the variability and uncertainty associated with renewable resources. As variable generation increases, swings in variable generation may call for dispatch of natural gas-fired generation at a larger and less predictable rate.

Recommendations

Policy makers, market operators, and asset owners should consider factors that reduce risk, such as the following:

- **Maintaining Alternative Fuel Capabilities:** Evaluate capabilities across generator fleet, maintain back-up fuel inventories at key stations, and annually test fuel switching capability

[2] http://www.pnucc.org/sites/default/files/NERC%20Phase%20II%20Accomodating%20an%20Increased%20Dependence%20201305.pdf
[3] https://www.columbiagrid.org/client/NERC%20Gas%20Study.pdf
[4] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf

- **Enhancing Market and Regulatory Rules:** Provide additional incentives for behavior and investments that support reliability and resilience
- **Evaluating Single Points of Disruption:** Assess reliability under extreme conditions, loss of major pipeline infrastructure, or supply
- **Continuing Pipeline Expansion:** Keep pace with generation expansion and increasing electricity production
- **Limiting Exposure to Production Area Failures:** Increase resilience by maintaining alternative supply chains and paths
- **Maintaining Situational Awareness:** Maintain awareness of pipeline conditions and the potential unavailability of generators
- **Communicating Risks to Policymakers:** Share and clarify results and conclusions of studies that evaluate electric reliability
- **Maintaining Fuel Diversity**: Maintain fuel diversity in order to provide resilience to common-mode failures

Reliability Guideline on Gas and Electrical Operational Coordination

The NERC Operating Committee is establishing a Reliability Guideline on Gas and Electrical Operational Coordination. The guideline provides operational practices that should increase system resilience and adaptability during extreme conditions. The guideline provides insights on establishing gas and electric industry coordination mechanisms; preparation, supply rights, training, and testing; establishing and maintaining open communication channels; and best practices for intelligence and situational awareness.

The guideline provides examples of proactive measures that should be taken to prepare for the potential of adverse conditions on the pipeline system. For example, preparing the gas and electric system for coordinated operations benefits from early assessments and activities to ensure that system operators are prepared and can effectively react when real-time events occur. Activities that increase system resilience include developing a detailed understanding of where and how gas infrastructure interfaces with the electric industry, such as the following:

- Identifying each pipeline (i.e., interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
- Identifying the level and quantity of pipeline capacity service (i.e., firm or interruptible, primary or secondary) and any additional pipeline services (e.g, storage, no-notice) being used by each natural-gas-fired generator.
- Developing a model of the non-electric generation load that those pipelines and local distribution companies (LDCs) serve and will protect when natural gas curtailments are needed.
- Identifying natural gas single-element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most natural-gas-side contingencies will not impact the electric grid instantaneously they can be far more severe than electric side contingencies over time; this is because natural gas contingencies may impact several generation facilities. When identifying natural gas system contingencies, the electric entity should consider what the natural gas operator will do to secure its firm customers including the potential that the natural gas system will invoke mutual aid agreements with other interconnected pipelines; this may involve curtailment of non-firm electrical generation from the unaffected pipeline to aid the impacted pipeline.

- Understanding how natural gas contingencies may interact with electric contingencies during a system restoration effort.

Increasing Use of Natural Gas

NERC's *2016 Long-Term Reliability Assessment*[5] reported that natural gas generation is the leading fuel type for capacity additions. Since 2008, the amount of natural gas generation capacity in NERC's footprint has increased by 86 GW—from 336 GW to 422 GW—and is expected to substantially increase over the next ten years. In addition, the use of natural gas generation to serve electric load is increasing. Natural gas combined-cycle units have increased from 43 percent of peak load requirements in 2011 to 56 percent in 2016. The upward trends in both the net generation and the natural-gas-fired combined-cycle annual capacity factor highlight natural gas' growing contribution to meet base load demand, which is a shift from historically serving peak and intermediate loads. For example, Florida, California, and Texas, now rely on natural gas to meet the electric generation requirements of over 60 percent of their on-peak demand. **Table 1.1** shows natural-gas-fired generation as a percentage of on-peak demand in NERC assessment areas.

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity

	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
FRCC	35,583	39,598	66.19%	69.05%
WECC-CAMX	40,299	42,536	68.39%	68.23%
Texas RE-ERCOT	45,842	51,867	60.34%	63.26%
NPCC-New England	14,331	16,308	48.17%	52.33%
WECC-SRSG	16,530	16,774	51.24%	51.84%
WECC-AB	8,514	8,514	52.02%	51.79%
SERC-SE	30,256	30,262	48.53%	46.88%
MRO-SaskPower	1,835	2,087	42.90%	43.97%
SPP	30,413	29,446	45.92%	45.22%
SERC-N	19,250	21,160	37.96%	40.68%
MISO	59,566	60,026	41.74%	42.26%
NPCC-New York	16,030	16,708	41.07%	41.98%
PJM	66,760	76,335	35.80%	38.71%
WECC-RMRG	6,695	6,914	36.36%	38.51%

[5] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity				
	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
WECC-NWPP-US	20,860	20,565	34.67%	34.80%
SERC-E	15,762	17,754	30.67%	32.25%
NPCC New York	6,568	7,340	22.99%	24.91%
NPCC-Maritimes	856	856	12.56%	12.66%
MRO-Manitoba Hydro	311	404	5.51%	6.33%
WECC-BC	434	442	3.45%	3.48%
NPCC-Québec	570	570	1.33%	1.33%

Figure 1.1 shows natural-gas-fired generation in aggregate along select major natural gas pipeline systems in North America underscoring the significant critical mass of natural-gas-fired generation and its dependence on the natural gas pipeline system.

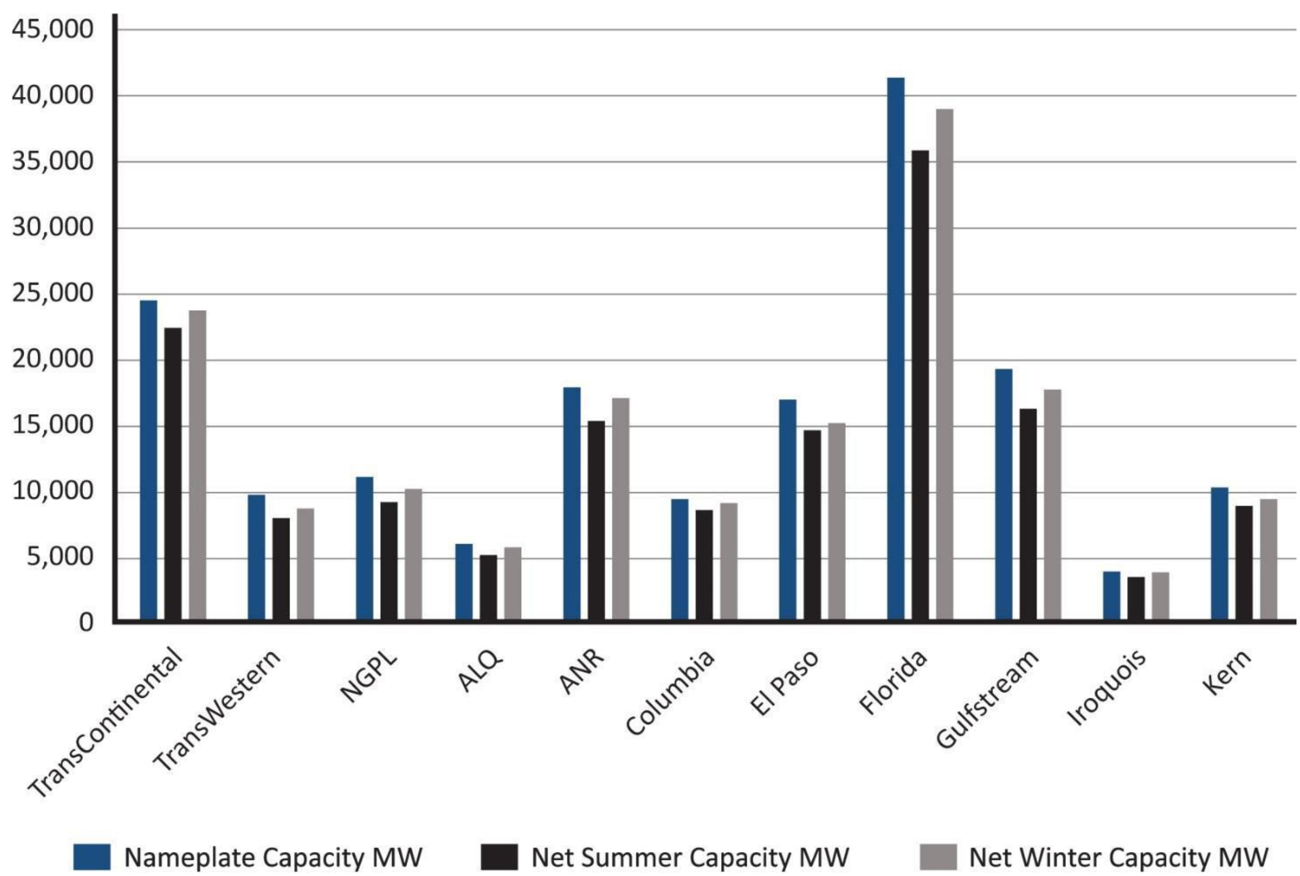

Figure 1.1: Directly Connected Electric Generation on Selected Pipelines

The large growth in natural gas use for electric generation can in part be attributed to its low cost coupled with the reduction in coal use resulting from regulatory rulings in the United States, such as Mercury and Air Toxics Standards and the Cross-state Air Pollution Rule as well as Canadian coal regulations. Natural gas production has increased significantly and is coupled with a decline in natural gas prices, both resulting from newly discovered shale formations and drilling technological advances, such as hydraulic fracturing. **Figure 1.2** shows the decrease in natural gas prices, which has largely contributed to the trend in increased natural-gas-fired electric generation. **Figure 1.3** depicts the large increase in North American natural gas production since the 1990's, which has also been a driving factor in the large increase of natural-gas-fired generation.

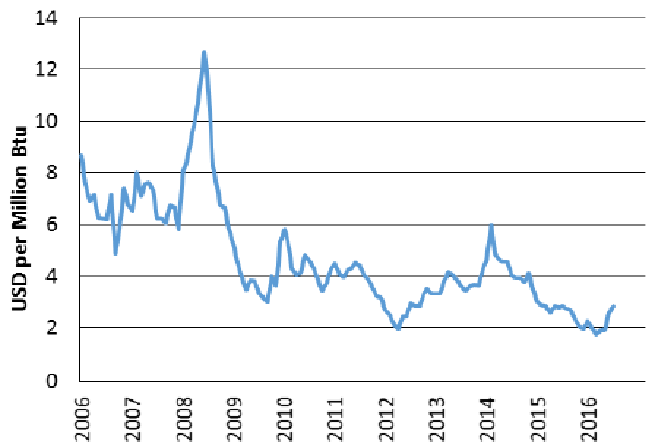

Figure 1.2: U.S. Natural Gas Prices

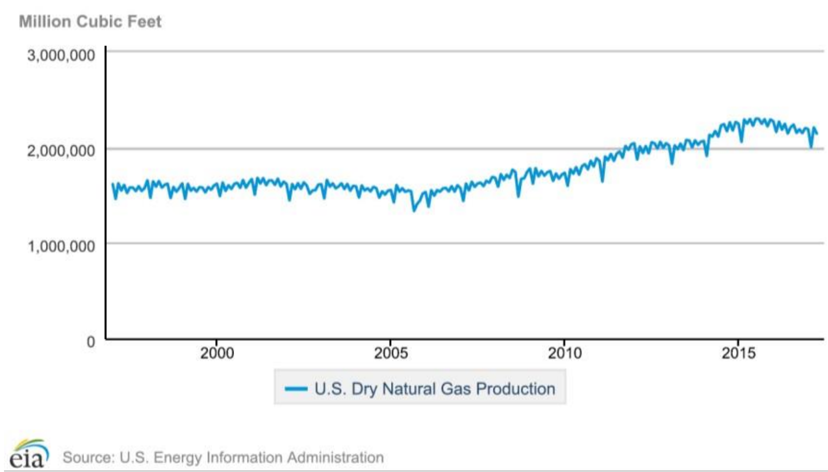

Figure 1.3: U.S. Natural Gas Production

Regional Risk Profiles

Natural gas generation and its impacts on BPS reliability are diverse and varied across North America. Some of the differentiating factors in various areas that are important to understand prior to a deeper analysis are described below in **Table 1.2**.

Table 1.2: Differentiating Factors	
Area	**Risk Description**
Northwest	The northwest does not have significant natural gas storage but also has less reliance on natural gas generation. This area is able to bring in Canadian natural gas supplies as well as domestic supplies in order to meet its natural gas needs.
Southern California and Arizona	This area has a high degree of dependence on storage, notably the Aliso Canyon storage facility. Ramping needs, due to an increased penetration of distributed energy resources and utility-scale solar photovoltaic, have made storage needs more significant in this area. Limited dual fuel capability adds additional reliability concerns to the reliance on natural gas infrastructure in this area. Natural gas storage may be limited geographically in Arizona due to its proximity to a sole source aquifer for water use.
East Texas, Louisiana, and Oklahoma	This area benefits from significant levels of natural gas production and a well-developed system of both interstate and intrastate natural gas pipeline facilities. Additional production area storage facilities provide added deliverability to the area.
Southeast	The southeast has significant amounts of storage, production, and pipeline capacity. A sizable amount of electric generation in this area is backed by firm contracts as well as having dual fuel capability.
Florida	Florida relies heavily on natural gas generation with close to 70 percent of its peak requirement relying on natural-gas-fired generation. Firm fuel and dual fuel capabilities provide effective mitigation for this area. Florida has no market area storage and relies on out-of-area supply to meet their demand requirements and out-of-area storage facilities to mitigate supply disruptions or extreme peak conditions
New England	New England has no storage facilities while relying significantly on natural gas and liquefied natural gas supplies. It has limited infrastructure compared to the demand of natural gas in the area for electric generation. Disruption to any of the major trunk lines or deliveries would likely force generation out of service. Under peak conditions demand may not be served; however, under light load conditions some of these outages can be managed by system operators. Lack of firm transportation by electric generators in this area contribute to its risk profile.

Canadian Natural Gas Market

Some areas within Canada rely significantly on natural gas in order to meet peak electric demand requirements. SaskPower, for example, sources 42 percent of its peak generation from natural-gas-fired generation. Conversely, Québec, partly due to its abundance of hydro assets, currently has no natural-gas-fired electric generation. Canada, similar to the United States, also relies on underground natural gas storage facilities to meet deliverability requirements of natural gas for electric generation. Presently, Canada has approximately 10 underground natural gas storage facilities with working capacity of 440 billion cubic feet (bcf) and deliverability of 7 bcf per day. The majority of Canada's natural gas is transported on a Trans-Canada pipeline that carries natural gas through Alberta, Saskatchewan, Manitoba, Ontario, and Quebec. As a result, Canadian markets are particularly vulnerable to any supply disruptions on the Trans Canada pipeline.

Aliso Canyon Storage Facility Outage

The Aliso Canyon underground storage facility, one of more than 400 storage facilities in the United States, experienced a significant leak in 2015 resulting in a temporary closure of this facility. This closure underscores the potential reliability issues resulting from a reliance on a particular generation fuel type. The Aliso Canyon outage has also accentuated the need for a better understanding of risks associated with the growing dependence on natural gas and the need to take appropriate actions to assess and mitigate those risks.

While the natural gas industry has demonstrated a high degree of reliability that includes a system of natural gas pipelines, compressor stations, storage, pipeline looping, and liquefied natural gas deliverability, the Aliso Canyon storage facility shut-down in Southern California in the winter of 2015 underscores the significant threats that a single point of disruption can pose to the reliability of the BPS. The rapid increase in the growth of reliance on natural gas for electric generation necessitates that system planners and operators fully understand their exposures to a potential natural gas disruption and have contingency plans in the event of disruption.

In July 2017, the Division of Oil and Gas and Geothermal Resources (a division of the state of California Department of Conservation) and the California Public Utilities Commission concurred that natural gas injection may resume at the Aliso Canyon storage facility. Since the leak was plugged 17 months prior, significant improvements and upgrades had been made to infrastructure, testing, operations, and monitoring to ensure safe operations. The facility will operate at a significantly reduced storage capacity and injection pressures.[6]

Considerations for Bulk Power System Reliability

Natural-gas-fired generation mostly relies on "just-in-time" fuel delivery from the natural gas industry. Disruptions to the fuel delivery can lead to multiple electric generating units becoming unavailable. This is compounded as multiple plants are connected through the same natural gas infrastructure. Disruptions to the fuel delivery results from adverse events that may occur such as line breaks, well freeze-offs, or storage facility outages. Similarly, the pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor driven compressors). In consideration of potential risks associated with pipeline systems, NERC has identified natural gas generators that are dependent on major trunk lines or are restricted to one pipeline connection in various areas. These are described in **Table 1.3** below.

Table 1.3: Natural Gas Supply Characteristics by Area

Region	Number of Generators with One Connection	Generation Capacity with One Connection (MW)	Number of Major Supply "Trunk" Lines Serving Area
Northwest	16	4,963	24
Southern California and Arizona	20	11,430	13
East Texas, Louisiana, and Oklahoma	40	17,965	60
Southeast	68	46,124	35
Florida	38	31,049	7
Middle Atlantic	22	12,244	9
New England	35	13,103	6
Northeast	49	21,903	20

As natural gas generation transitions from a "peaking" resource to a more "baseloaded" resource, a disruption of the delivery of natural gas resulting from a single loss of a natural gas infrastructure facility exposes the electric industry to a much greater level of risk and loss of resilience.

There are two important and distinct reliability risks associated with natural gas supply that need to be considered in BPS planning (see **Figure 1.4**). The first is Interruption Risk. When electric generator customers do not procure "firm" supply and transportation for their fuel, their service is likely to be interrupted when firm customers schedule their full entitlements—particularly in constrained pipeline areas such as New England. This report does

[6] http://www.conservation.ca.gov/dog/pages/AlisoCanyon.aspx

not assess these more "typical" interruptions that may impact individual generators based on their fuel service agreements.

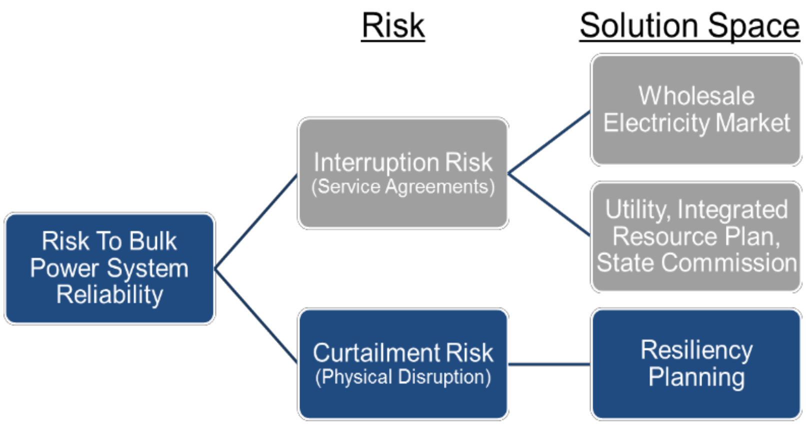

Figure 1.4: Natural Gas Disruption Risk Paradigm

The second is Curtailment Risk, which occurs when "firm" service is disrupted through a *force majeure* event. Curtailments occur when facility outages impact the scheduled flow of natural gas for any reason.

Understanding the distinction between these two risks is important due to their solutions being very different. For example, electric generation with "firm" fuel service agreements can still be curtailed but can be off-set by dual fuel capability.

Interruption Risk is generally considered in NERC's annual reliability assessments. Through the assessments, NERC puts a spotlight on generator availability risks that may be impacting their ability to meet peak seasonal demand. However, issues related to generator interruptions are likely to be resolved through integrated resource plans, state or provincial regulatory requirements, and implementation of mitigation strategies—such as dual fuel capability and electricity markets (where they exist). Each of these solutions has a mechanism to consider the reliability needs of the system.

For this assessment, NERC focused on Curtailment Risk, which involves resilience planning. Resilience planning is generally defined as preparatory actions to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive events. These activities often are supplemental to "normal" planning activities but serve to provide awareness and mitigation of potential risks to both industry and regulators. **Figure 1.5** demonstrates the paradigm between reliability and fuel assuredness.

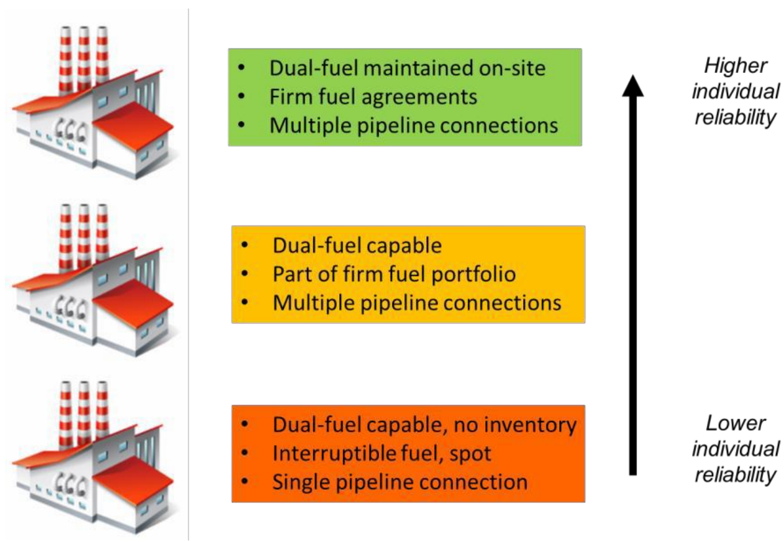

Figure 1.5: Generalized Risk Profiles and Generator Vulnerabilities

Chapter 2: Assessment Objectives and Approach

This assessment evaluates impacts to the bulk power system reliability as a result of fuel delivery disruptions resulting from the loss of major natural gas infrastructure facilities (e.g., storage facilities, key pipeline segments, liquefied natural gas terminals). Electric power system and transmission screening analysis provides insights on transfer capability as a result of a large loss of generation. Additionally, the assessment offers recommendations for reducing bulk power system exposure to natural gas infrastructure disruptions through planning and preparation.

An advisory group comprised of electric industry experts provided guidance to NERC throughout this assessment activity. NERC, in coordination with the Regional Entities, Argonne National Laboratory, and industry experts identified natural gas storage facilities and major pipelines that, if inoperable, could have an impact on electric reliability. The location of generation affected, dual fuel capability of resources, and electric transmission system adequacy are considered in this assessment. This assessment also uses data acquired from Transmission Planners and Planning Coordinators as well as from public sources.

Objectives

The assessment's objective are as follows:

- Identify natural gas infrastructure facilities that are important for the operation of large amounts of generation capacity
- Assess current studies performed by industry that evaluate large disruptions to natural gas facilities
- Evaluate the transmission system given the loss of generation from natural gas supply disruptions
- Make recommendations on mitigating natural gas infrastructure risks to bulk power system reliability

Approach

Steps I, II, and III

This assessment is structured in the following three steps:

Step I: Assessment of Existing Studies
- Gain understanding of existing planning approaches
- Highlight and promote best practices

Step II: Evaluation of Gas Storage Facilities
- Evaluate large storage facilities tightly coupled to electric generation (>2GW)
- Measure reliability implications of these outages

Step III: Identify Generation Clusters
- Identify areas with highly dense natural gas generation
- Determine vulnerabilities and risk factors

Step I – Appendix E.
Step II - Chapter 4.
Step III - Chapter 5.

The assessment process involves evaluating the electric system's ability to operate reliably under a variety of scenarios in which natural gas infrastructure is significantly disrupted. This includes disruptions to facilities that have not occurred historically but can conceivably materialize due to a variety of reasons, including (but not limited to) natural events, accidents, or regulatory action.

Chapter 3: Reliability Considerations, Risk Factors, and Previous Studies

Electric Reliability

NERC defines the reliability of the interconnected bulk power system (BPS) in terms of the following two basic and functional aspects:

- **Adequacy**: 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 Reliability:** The ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.

Note: Fuel adequacy is a function of fuel security. For example, if an electric generator does not have fuel, it is not available to generate electricity, which reduces the capability of the system.

Reliability Considerations for Natural Gas Generation

Natural-gas-fired generation mostly relies on "just-in-time" fuel delivery from the natural gas industry. Disruptions to the fuel delivery can quickly lead to multiple electric generating units becoming unavailable. This is compounded where multiple plants are connected through the same natural gas infrastructure. Disruptions to the fuel delivery results from adverse events that may occur such as line breaks, well freeze-offs, hurricanes, floods, storage facility outages, or infrastructure attacks. Similarly, the pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors). Whereas the ability to use alternate fuel provides a key mitigation effect, only 27 percent of U.S. natural-gas-fired generation capacity added in 1997 and later is "dual fuel."[7]

Factors Impacting the BPS's Risk Exposure

The following inputs can be used by Planning Coordinators and Transmission Planners to ascertain the natural gas generation fleet's potential exposure to Curtailment Risk:

[7] Testimony of the Foundation for Resilient Societies By Thomas S. Popik, June 19, 2017

Fuel Service Agreements	• What level service does each generator maintain?
Alternative Fuel Capabilities	• What are the fuel-firing capabilities of the unit? Is back-up oil maintained on-site? Is it tested?
Pipeline Connections	• How many direct connections are available to the generator and are they served by different supply sources?
Market and Regulatory Rules	• What are the regulatory obligations under a force majeure? What tools exist to prepare and plan for a large disruption?
Vulnerability to Disruptions	• What is the generation fleet's risk profile as it relates to reliance on natural gas storage and limited transportation sources?
Pipeline Expansion	• Where growth in natural gas generation is occurring, is pipeline expansion also occurring?

Increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas supply and delivery. Strategies—such as storage, firm fuel contracting, alternate pipelines, dual fuel capability, generators using other fuel sources with on-site fuel availability, sufficient pipeline capacity to support normal and emergency operations, access to multiple natural gas basins, or additional electric transmission lines from other areas—can help mitigate and manage potential risks to reliability. An important mitigation approach includes high levels of coordination between the electric and natural gas industries, which can lead to a more resilient bulk power system and increased situational awareness of potential fuel supply shortages. Regional solutions will likely include a mix of mitigating strategies, increased natural gas and/or electric infrastructure, electric market products, a diverse fuel mixture, and dual or back-up fuel capability

Assessment of Existing Studies (Step 1)

NERC reviewed previous studies conducted by Argonne National Laboratories, Eastern Interconnection Planning Collaborative (EIPC), ERCOT, Southern Company, and Columbia Grid Reports as well as the Aliso Canyon Risk Assessment Technical Reports. From the review of these reports and key lessons learned, NERC has developed the following key takeaways and recommendations.

Key Takeaways

The results of the survey conducted by NERC identified several key findings several key findings that may be useful as the electric and natural gas industries identify ways to assess the impacts of potential extreme disruptions. The following are some key takeaways from the survey:

- The importance of an assessment of interdependence varies by company and Region due to individual resource mix, topology, and the availability of dual fuel generation capacity.
- Several companies are already either conducting studies or developing processes that will lead to studies to assess natural gas infrastructure disruptions.
- The identification of wide-area transmission impacts (i.e., voltage and thermal constraints) due to loss of a large natural gas underground facility or a segment of a pipeline are typically not studied; the majority of the focus is put on resource adequacy and resource availability. Transmission reliability and contingency analysis in the event of loss of a major pipeline/storage facility is paramount in developing mitigation plans and emergency operational procedures.

- Many respondents indicated that there were no natural gas storage facilities within their systems to evaluate. However, the loss of a large natural gas facility can impact electric generation downstream and beyond the boundaries of a Planning Coordinator. Determining whether natural gas system outages could create a regional or local electric reliability risk will warrant a coordinated and detailed analysis among neighboring Planning Coordinators.
- Electric Registered Entities, in coordination and collaboration with their neighbors and natural gas sector, should determine which power plants would be affected in the event of a disrupted natural gas facility. Alternative fuel capability, mitigation plans, emergency operating procedures, evolving ramping capability requirements to manage VERs, and the wide-area reliability impacts to the BPS should be further studied.

Recommendations

Comprehensive studies by Planning Coordinators that assess specific disruptions to important natural gas facilities should identify and characterize adverse impacts to electric reliability. These disruptions are typically beyond the "design basis" of the power system required by NERC Reliability Standards as well as any regional or local planning requirements; because of this, these reliability risks are generally not incorporated into the planning requirements. In many cases, the resulting reliability impacts are due to a lack of capacity on existing infrastructure. As the BPS relies more heavily on natural gas generation, policy makers and regulators need to be aware of these risks—how likely they are as well as the potential impact. While many pipeline-related infrastructure impacts can be rectified within a week or two, natural gas storage facilities, as observed with Aliso Canyon, can be out for significant periods of time.

The recommended approach for Planning Coordinators can be broken down in the following four general steps:

1. Identify potential natural gas system contingencies and their frequency of occurrence.
2. Assess the impacts for each of the identified contingencies in terms of duration and amount of natural gas supply disrupted.
3. Apply the contingency disruptions to the natural gas supply capabilities to calculate the impact on total natural gas supplies and, more specifically, the amount of natural gas available to electric generators.
4. Determine the transmission systems ability to transport power to load under these extreme conditions.

With this information, policy makers, regulators, and industry can effectively identify and determine solutions that help support reliability depending on their individual risk tolerances.

A further description of these studies is outlined in Appendix E: Assessment of Existing Studies.

Chapter 4: Evaluation of Natural Gas Storage Facilities

Step II

Step I of NERC's study approach was an assessment of existing studies which can be found in Appendix E. This chapter (which is Step II of NERC's study approach) provides an evaluation of natural gas storage facilities. It documents the second part of NERC's assessment approach and details methods, assumptions, and results from the evaluation of natural gas storage facilities and the identification of coupled clusters of generation.

Natural Gas Storage

Underground storage of natural gas is an integral component of the natural gas supply chain, but its function is different from the other components of that supply chain, which are production, pipeline transportation, and distribution. Storage serves as a substitute for natural gas production, but the location of a storage facility can also provide operational flexibility for the natural gas delivery infrastructure. There are 385 underground storage facilities in the lower 48 states with a total of 4,688 bcf of working natural gas design capacity.[8] As a substitute for production, storage enables local distribution companies to offer natural gas to consumers throughout the year with reliable service and stable prices. Natural gas storage enables companies to adjust for daily and seasonal fluctuations in demand throughout the year while natural gas production remains relatively constant year-round. For those generators that rely on storage, a storage outage could result in potential supply shortages. Without storage, customers (including electric generators and residential users) would be faced with potential supply shortages. Not all natural gas storage facilities are designed for "rapid turn" to service the power sector. Rapid turn is found in salt domes, which have a greater ability to inject and withdraw throughout the year than depleted reservoirs do providing salt dome storage facilities with greater ability to handle the swings and non-ratable takes of electric generators.

Following the events at Aliso Canyon, federal officials (including members of Congress), sought to understand and identify opportunities to improve the overall safety and environmental impacts of natural gas storage infrastructure. To support these efforts, the federal government, formed an Interagency Task Force on Natural Gas Storage Safety in April 2016. Detailed in the Final Report of the Interagency Task Force on Natural Gas Storage Safety,[9] the analysis identified a small number of underground natural gas storage facilities other than Aliso Canyon that have the potential to affect energy reliability. As the electric and natural gas industries become more interdependent, it was also recommended that electric power system planners and operators, working with their natural gas counterparts, should study and understand the electric reliability impacts of prolonged disruptions of large-scale natural gas infrastructure (e.g., storage facilities, processing plants, key pipeline segments and compressor stations, liquefied natural gas terminals). They should share their analyses with State and Federal officials to ensure that policy makers fully understand the risks to electric reliability and can develop appropriate mitigation policies and strategies. In summary, the task force concluded that, while incidents at U.S. underground natural gas storage facilities are rare, the potential consequences of those incidents can be significant and require additional actions to ensure safe and reliable operation over the long term.

In November of 2016, NERC formed an advisory group comprised of Planning and Operating Committee members, electric industry experts, select natural gas sector association representatives, and Regional Entity staff to perform a special reliability assessment[10] on the screening of single points of disruption to natural gas infrastructure. The loss or disruption of the natural gas infrastructure could directly affect the operations, reliability, and resilience of the North American bulk power system. The growing interdependence has created more frequent reliability

[8] Underground Natural Gas Working Storage Capacity.

[9] Ensuring Safe and Reliable Underground Natural Gas Storage

[10] The Special Reliability Assessments are intended to be topic-driven around specific risks (e.g., drought, fuel availability, natural gas, electric interdependency) to the bulk power system (BPS). See NERC Rules of Procedure (Section 800).

challenges in recent years in which power generators have to curtail electricity production due to fuel unavailability. Interdependency issues often become more pronounced during extreme weather events, electric system outages, or natural gas supply disruptions. [11, 12, 13, 14]

Data Gathering, Methods, and Assumptions

Argonne National Labs conducted an assessment that identified 12 underground natural gas storage facilities that can potentially have a significant impact on electric generation capacity if they become inoperable. **Table 4.1** provides an overview of these underground natural gas storage facilities. NERC used this assessment and added additional five natural-gas-fired generation facilities to develop further analysis that analyzes risks associated with losing a group of natural gas-fired electric generation facilities simultaneously due to a lack of natural gas deliverability.

Table 4.1 Major Underground Storage Facilities

UGS Rank	Underground Storage Facility (UGS)	UGS Type	Maximum Daily Deliverability (Mcf/d)	Nameplate Capacity At-Risk (MW)	Distance of Farthest Plant (Miles)	Number of Plants At-Risk
1	Storage Facility XYZ	Salt Cavern	2,665,000	13,800	490	19
2	Storage Facility XYZ	Salt Cavern	2,500,000	13,700	480	17
3	Storage Facility XYZ	Depleted Reservoir	550,000	9,100	270	14
4	Storage Facility XYZ	Salt Cavern	3,200,000	9,200	340	14
5	Storage Facility XYZ	Salt Cavern	2,300,000	9,000	240	16
6	Storage Facility XYZ	Depleted Reservoir	1,860,000	7,820	40	16
7	Storage Facility XYZ	Depleted Reservoir	1,680,000	7,600	50	18
8	Storage Facility XYZ	Salt Cavern	765,000	3,800	290	5
9	Storage Facility XYZ	Depleted Reservoir	275,000	3,600	330	6
10	Storage Facility XYZ	Depleted Reservoir	800,000	3,400	350	7
11	Storage Facility XYZ	Salt Cavern	2,400,000	2,500	320	6
12	Storage Facility XYZ	Depleted Reservoir	1,555,000	2,200	170	4

The U.S. Natural Gas Storage Risk-Based Ranking Methodology and Results report,[15] published by Argonne National Laboratory, summarizes the methods and models developed to assess the risk to energy delivery from the potential loss of underground natural gas storage facilities located within the United States. The U.S. has a total of 418 existing storage fields of which 390 are currently active. Argonne National Laboratory has developed three distinct models to estimate the impacts of a disruption of each of the active underground natural gas facilities on their owners and operators: 1) local distribution companies (LDCs), 2) directly connected transporting pipelines and thus on the customers in downstream States, and 3) third-party entities and thus on contracted customers expecting the natural gas shipment and measured impacts across all natural gas customer classes.

[11] A Primer of the Natural Gas and Electric Power Interdependency in the United States
[12] Accommodating an Increased Dependence on Natural Gas for Electric Power. Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System
[13] Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation
[14] NERC 2014 Polar Vortex Review
[15] https://anl.app.box.com/s/ki95gqa3xzein3h11ef2sst4xq4qgdho

For the electric sector, the impacts were quantified in terms of natural-gas-fired electric generation capacity potentially affected from the loss of an underground natural gas storage facility. All models and analyses are based on publicly available data.

Figure 4.2 illustrates the three underground storage supply-to-customer processes that were modeled. The consequence of an underground gas storage (UGS) disruption was estimated using Excel-based models developed internally by Argonne specifically for its assessment. In each model, a compensated mode is run in which mitigation measures are assumed to be implemented whenever a supply shortfall is estimated. Such mitigation measures include increased withdrawals from unaffected UGS facilities owned by the UGS operators, additional contributions from liquefied natural gas storage facilities (if available), raised output from natural gas production fields, and increased contributions from other interstate transmission pipelines via interconnection points.

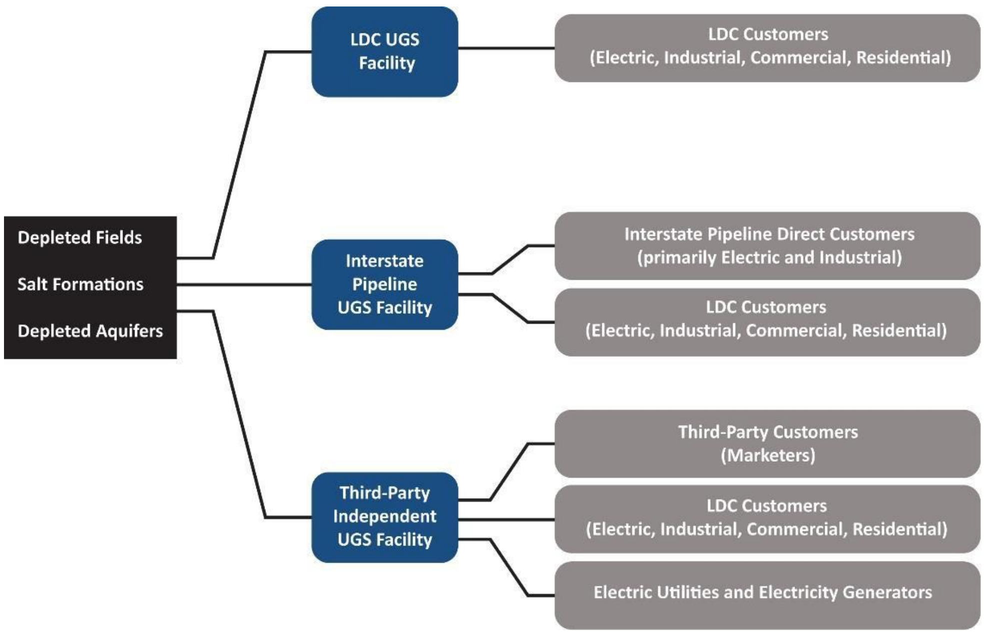

Figure 4.2: Underground Storage Supply-to-Customer Processes

The process for determining at-risk power plants from underground natural gas facility disruptions uses information on the maximum daily storage quantity of natural gas that each UGS facility is obligated to store and supply for a shipper (i.e., electric utility, LDC, marketer) under each contract. The overall procedure to determine the potentially affected power plants is as follows:

1. NERC used the FERC Index of Customers to determine which organizations (e.g., natural gas LDCs, natural gas marketer, electric utility, interstate transmission natural gas pipeline) have contracted with a given UGS company for natural gas supply.
2. Data from EIA Form 923 was used to establish the natural gas supplier to each electric power plant and the type of supply and transport contracts (firm, interruptible) and to identify which power plants could be affected by a disruption in natural gas supply for a given UGS facility.
3. NERC used data from EIA Form 860 to establish the natural gas pipeline(s) connected to each natural-gas-fired generator and the FERC Index of customers is then examined to determine whether the pipeline has a storage or asset management contract (and what type of contract), which could be affected by a disruption of a given UGS facility.
4. Based on the above, compensated supply-demand models specific to each UGS owner type (i.e., LDC, Interstate Pipeline, Third Party) determine the total electric capacity that is potentially affected by the

disruption of natural gas supply from a UGS facility.

5. NERC then developed a list of potentially affected power plants for each UGS facility that identifies the supplier, type, potentially affected electric capacity (MW), and natural gas contract. The estimated shortfall in natural gas supply from a given UGS facility is compared with the monthly consumption of each natural-gas-fired generator that receives natural gas during each month. It is assumed that power plants with interruptible contracts will be affected before those with firm contracts. In addition, the power plants closest to the UGS facility will be disrupted first as power plants farther away from the UGS facility may have a higher probability of finding another source of natural gas.

Chapter 5: Identification of Generation Clusters

Step III

This chapter (which is Step III of NERC's study approach) identifies large generation clusters that would be most susceptible to a natural gas disruption. This was conducted to determine vulnerabilities and risk factors necessary to consider in resilience planning.

Background

In addition to the underground natural gas facility interruptions to electric generation availability, NERC identified approximately 40 generation clusters in 7 main geographical areas. Each cluster represents at least 2 GW of natural-gas-fired power plants. See **Figure 5.1**.

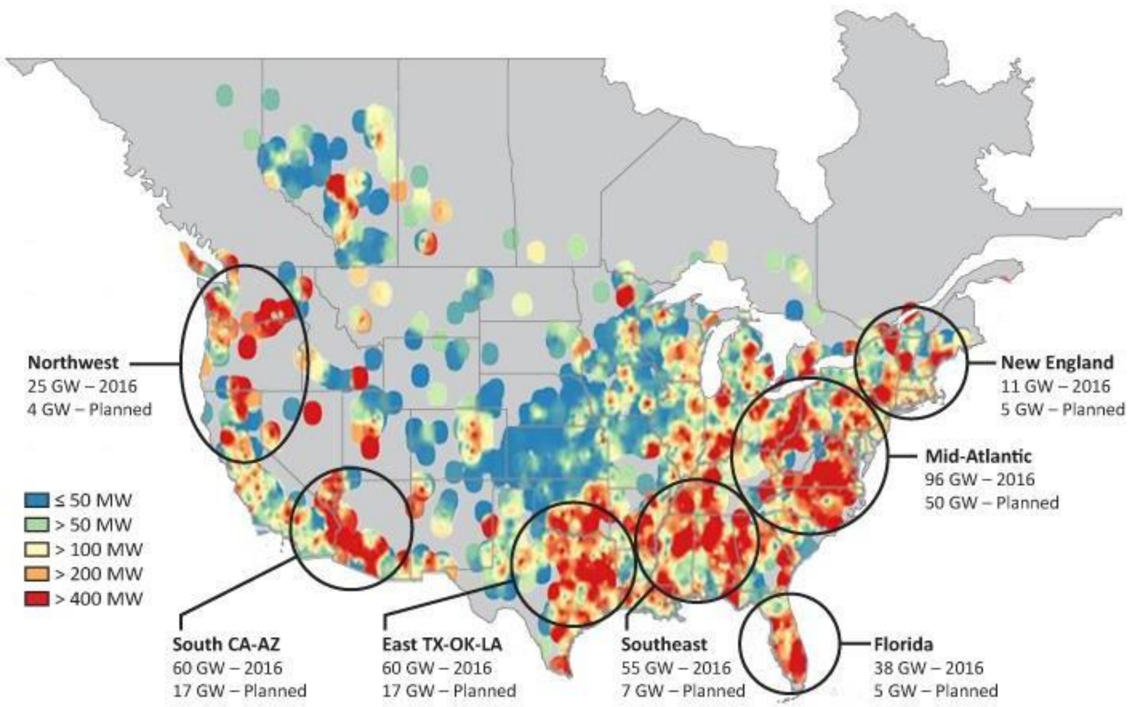

Figure 5.1: Natural Gas Generation Clusters

A data request was sent to Generator Owners/Operators, Balancing Authorities, and/or Planning Coordinators through the Regional Entities to collect information, including dual fuel capability/capacity, seasonal generating capacity, fuel contract type, power system model bus number, and natural gas pipeline connectivity. Not all of the generating plants identified within a cluster were BES elements (e.g., behind the meter, industrial generation for internal processes) and were not modeled.

The assumptions considered in the identification are as follows:

- All generation with an alternative source of fuel was assumed available (with no fuel-switching down time period). This generation's dispatch was modified to reflect the generating capacity with the secondary fuel burn.
- All generation and transmission facilities are on-line and available to serve load.

- Non-hydro renewable generation (solar and wind) was dispatched at their de-rated capacity at peak demand.
- Based on available data when this study was performed, this study does not consider the addition of new pipeline capacity.[16]

The generation was reviewed with the natural gas industry members serving on the NERC Technical Advisory Group to ensure the identified generation is connected to a segment of a pipeline. The identification excluded Aliso Canyon and areas where Planning Coordinators have performed extensive assessments to re-dispatch electric generation to evaluate loss of natural gas facilities.

From the originally identified 40 clusters, 14 clusters met the criteria (2 GW or more are at risk of being lost, excluding alternative fuel generation capacity) for power flow screening. Within the clusters there were some where multiple pipelines fed the generation fleet within the identified geographical area. In some instances there were more than one set of generating stations identified within a cluster that met the screening criteria of 2GW or greater that were supplied by one pipeline. In aggregate, 19 groups of generation were selected within the 14 clusters in addition to the 5 groups of natural-gas-fired generation from the loss of a large natural gas underground natural gas storage facility for further power system analysis. Results of this screening are included in the next chapter.

[16] The assessment was conducted using existing case studies that may not include recent incremental projects, such as the Sabal Trail and Florida Southeast Connection pipelines, which went into service in Florida in the summer of 2017.

Chapter 6: Transmission Power Flow Screening

Using the information provided by Argonne National Laboratory as well as the information received from Planning Coordinators, NERC conducted a transmission power flow screening.

In addition to the 19 sets of generation that met the criteria (as described in the previous chapter), an additional five sets of generating stations that were not captured during the geographical location assessment performed by NERC were also included. These five sets were identified as being vulnerable to a loss of underground storage as assessed in Chapter 4 above. from the Argonne National Laboratory analysis due to loss of an underground natural gas storage facility that were not captured during the geographical location assessment performed by NERC. These 24 sets of potential electric generation outages greater than 2 GW were selected for the power flow screening.

Steady-State Power System Screening Approach

The screening process examined if the system could support the import of replacement power equal to the loss of generation that resulted from a natural gas supply disruption. The screening process undertook an extreme scenario of a large natural gas supply disruption combined with peak load conditions during a non-coincident peak. The screening analysis is intended to provide NERC, Regional Entities, and Planning Coordinators insights as to where more granular evaluation of the transmission system is needed.

The analysis determined if the transmission system is capable of meeting demand using the existing system and resources or if reliance on neighboring systems can support the required deliverability of resources.

NERC's study is limited to existing interconnection-wide models, such as the Multi-Area Modeling Working Group (MMWG) and WECC interconnection models. Therefore, NERC can only perform a screening analysis since more detailed models with known operational procedures also need to be evaluated.

The study approach used replacement power that was first sourced from the Planning Coordinator area and then from the neighboring systems. The screening was performed with DSA Tools and is shown in **Figure 6.1** and summarized below:

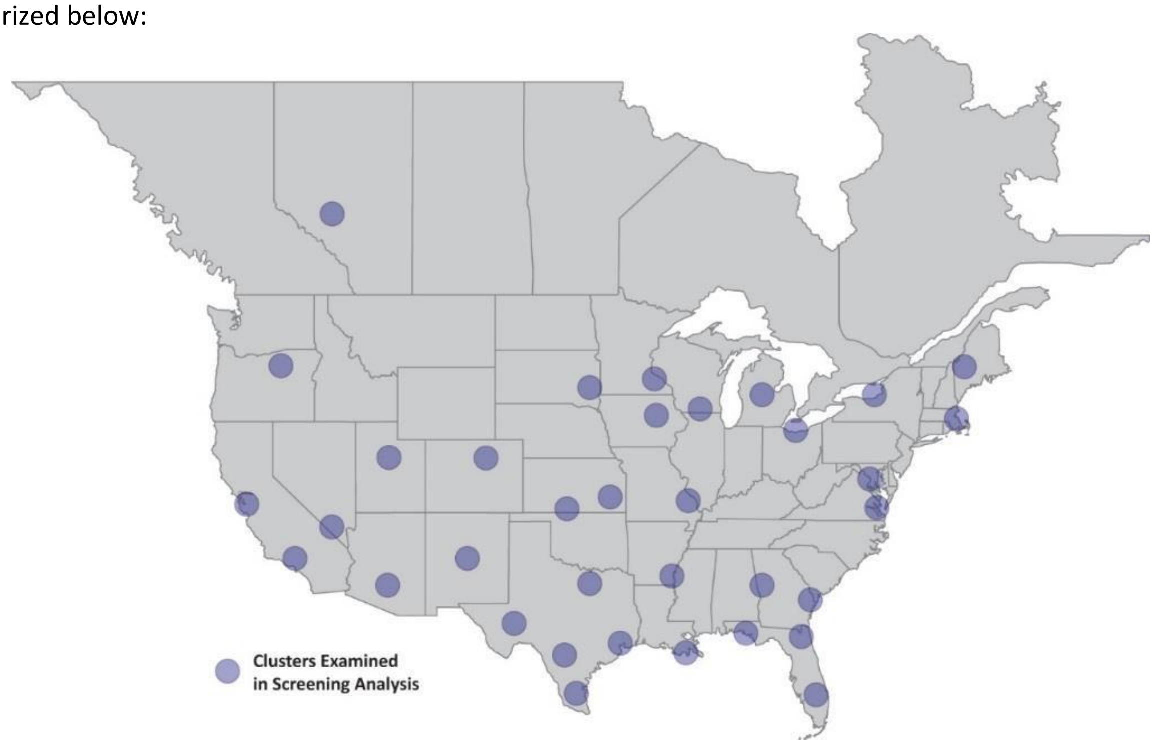

Figure 6.1: Clusters Examined in Screening Analysis

- Reliance on generation capacity internal to a Planning Coordinator area:
  - Non-natural-gas-fired generation (source) is set to increase their output to the maximum generating capacity within the Planning Coordinator area.
  - The natural-gas-fired generation (sink) impacted by the loss of a natural gas facility is scheduled to be reduced to minimum capacity and turned off if the minimum is reached.
  - Generation was transferred from other sources as impacted natural-gas-fired generation was reduced in increments of 5 MW and a power flow solution was obtained.
  - The transfer was continued until the impacted natural-gas-fired generation reached zero output or the system could no longer support the delivery of the makeup power.
- Reliance on neighboring Planning Coordinators to transfer power:
  - In the event that generation capacity internal to a Planning Coordinator area reaches its maximum capacity before the impacted natural-gas-fired generation reached zero output, an interface area is defined at the Planning Coordinator boundaries and transfers are allowed.
  - The transfer continued until thermal limits at tie-lines are reached or voltage criteria is violated.

Screening Results

The results of the screening indicate that 18 out of 24 groups of generation facilities would experience voltage and stability issues in the absence of additional operational remedies when (>2GWs) of natural-gas-fired generation were to be disrupted. This is shown in **Figure 6.2**.

Figure 6.2: Clusters Where Power Flow Issues were identified

Recommendations

DOE, NERC, and its Registered Entities should collaborate to confirm with plant owners and operators which power plants would be affected, whether they have existing dual fuel capability (with available alternative fuel) or other mitigation options, and what the reliability impact is to the bulk power system, considering a variety of conditions and sensitivities. Coordination between electric sector utilities and Registered Entities should be expanded to include assessments where reserve sharing facilities are available, where maintenance of large generation/transmission facilities could impact import capabilities, and where generation availability can span within a large area.

Chapter 7: Liquefied Natural Gas and Other Supply Disruptions

In addition to the potential for natural gas pipeline disruptions and natural gas storage disruptions, liquefied natural gas (LNG) disruptions and other supply disruptions can pose reliability challenges to the bulk power system. LNG can either be a source or a demand on the natural gas system. The location of LNG facilities within the natural gas pipeline system and distances between wellheads, import facilities, and electric generating stations need to be considered.

Potential Loss of Liquefied Natural Gas Supplies

Due to pipeline constraints, LNG imports in New England during the winter heating season (or to supplement natural gas supplies in response to a pipeline contingency) are critical to maintain bulk power system reliability. In other areas, the potential for a dramatic increase in the volumes of LNG exported from the United States has raised concern over its impact on the natural gas markets in the US—in particular the impact on the power generation market where natural gas fueled generators are being used to replace aging coal fired plants to provide more electricity to meet increasing overall demand.

Shortages of natural gas led to the building of LNG importation facilities in the 1970s. Subsequent global trade changes led to dramatic reductions in LNG importation into the US followed shortly after the year 2000 by increased demand for more natural gas. Mothballed LNG importation facilities were reactivated and new importation facilities were built to meet this new shortage of natural gas in the U.S. Increased natural gas production has led to a reduction in the price of natural gas, which has boosted the demand in industrial and electric power markets. **Figure 7.1** shows current LNG plants that are connected to natural gas pipeline systems.

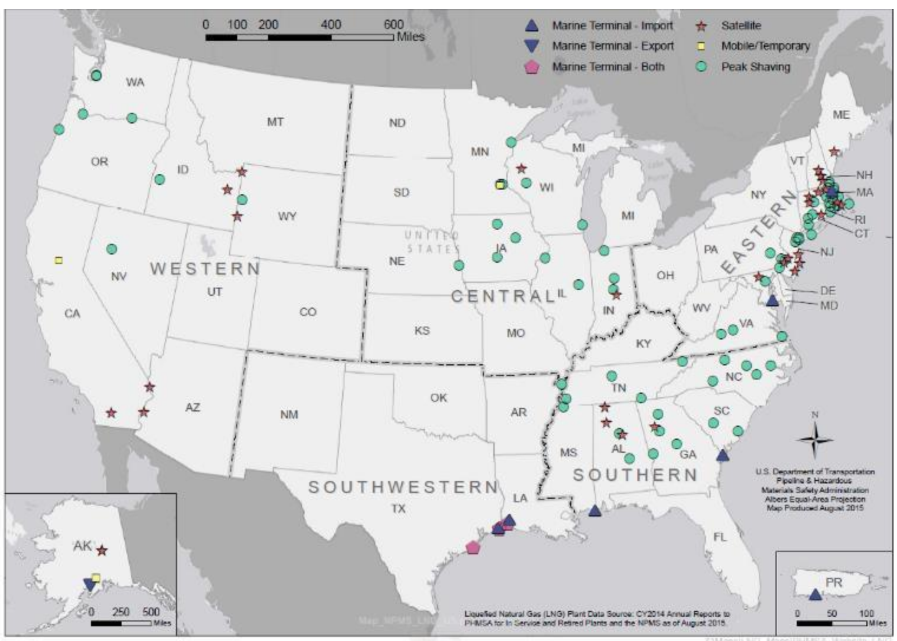

Figure 7.1: U.S. LNG Plants Connected to Natural Gas Pipeline Systems

Similarly, LNG is beginning to play a larger role in Canada in meeting peaking needs as well as serving to export natural gas to the United States. The Canaport LNG facility in Saint John, New Brunswick, has a maximum send out of 1.2 bcf/day enabling it to supply deliveries to the Northeast United States as well as within Canada.

Regional Natural Gas Supply Chain Impacts

The location of natural-gas-fired generation facilities in relation to the pipelines that transport natural gas to their facility is a critical part of the analysis of the impact on power generation during any significant outages in the natural gas supply chain. The location of LNG facilities within that natural gas pipeline system is just one component that must be considered.

With the locations of shale natural gas formations being remote from the traditional areas of natural gas production, there are shifts in the direction of flow of natural gas through the existing and proposed natural gas pipeline systems that will impact the reliability of natural gas supply across the United States. Historically, there was a long chain of natural gas pipelines that moved natural gas north from the Gulf of Mexico as far as New England. Now, a major source of natural gas is located at the midpoint known as the Marcellus shale production zone. Thus, natural gas no longer has to flow from the Gulf to the Northeast and New England with Marcellus volumes satisfying much of the demand. The natural gas produced in the Gulf areas can now, to a greater degree, stay in that area to support increased power generation and the growth/expansion of industrial markets. Similar shifts are occurring or will occur in other areas of the United States.

New England and Northeast Natural Gas Markets

In the New England area, there is a higher degree of concern with the limited natural gas system flexibility to address the interstate pipeline constraints. This means there are fewer options for alternate sources of natural gas supply should any part of the natural gas supply system experience a major outage other than increased imports from LNG facilities.

LNG remains an important fuel for New England, providing from 20 percent to over 40 percent of design-day supply in the winter for several local natural gas organizations. Without these LNG supplies, there would not be enough natural gas available for electric generation on a winter peak design-day even with the natural gas pipeline systems operating at full capability. LNG provides about 8 percent of New England's total annual natural gas supply. There is no underground storage located in New England primarily due to geologic unsuitability. LNG is thus an important part of the Region's supply and deliverability network. There are liquefaction and satellite storage tanks in localities in the Region that are owned and operated by the LDC. In 2016, according to the Northeast Gas Association (NGA), the LNG storage capacity in New England among the LDCs was 16.1 bcf.

Just as a disruption on a natural gas pipeline could impact delivery of U.S. natural gas supplies to New England, a disruption at an LNG import terminal, or a pipeline serving that terminal, would limit LNG supplies serving the Region. Due to New England’s inadequate pipeline capacity and its reliance on LNG in order to meet peak day natural gas requirements, ISO New England has implemented significant measures to reduce risk of a loss of bulk power system reliability. ISO New England has developed the following actions to date:

- Non-Market Enhancements:
  - ISO New England has developed a systematic plan of coordination between ISO New England and the pipeline operators. Changes to the ISO New England Information Policy allows communications with pipeline operations staff about specific generators.
  - ISO New England maintains situational awareness of the natural gas system using newly developed tools that monitors the capability and demand on the natural gas system. This includes evaluating a generator's daily natural gas arrangements versus expected natural gas requirements to meet the generator’s daily schedule. Oil and coal inventory surveys are also conducted monthly and are updated weekly or daily during times of high demand.
- Market Enhancements:

- ISO New England implemented enhancements to its energy and ancillary services markets to better reflect the intra-day price volatility of natural gas and operating reserve deficiencies
- FERC Order 809 providing more flexibility for scheduling natural gas as well as adding a new intraday nomination cycle has served to mitigate some the electric and natural gas interdependency concerns.
- ISO New England will be implementing a pay-for-performance incentive in its forward capacity market. This is designed to provide stronger incentives for resources to perform during shortage conditions.

Until the pay-for-performance incentives go into effect on June 1, 2018, ISO New England has implemented a winter reliability program. This winter program is designed to provide the incentive for generators to increase their fuel inventories prior to the winter.

Even with these enhancements, the deficiency of infrastructure (combined with a lack of natural gas firm transportation for electric generation) exacerbates the effects of a single point of disruption. The natural gas system in New Jersey, New York, and New England is expected to become more constrained in the coming years. In addition, the planned and targeted closures of nuclear plants in the Northeast will increase the demand for natural gas to fuel the electric generation needed to address the emerging supply gap.[17]

[17] US Chamber of Commerce Institute For 21st Century Energy: Energy Accountability Series

Chapter 8: Other Contributing Factors to Natural Gas Disruptions

It is necessary to identify the types of contingencies that can occur in the natural gas system's infrastructure and to compile data on their frequencies, duration, and consequences that can be used in reliability assessments. There are a wide range of events that could result in the loss of natural gas service, including physical/operational, technical/cyber, natural, and man-made causes.

A list of some of the potential natural gas system vulnerabilities includes the following:

- Physical/Operational
  - Mechanical or operational malfunction of a specific natural gas system equipment, such as a compressor station
  - Pipeline leakage or burst due to stress or corrosion cracking
  - Storage well degradation or failure due to scaling, water penetration, or other factors
  - Pipeline capacity outages due to scheduled construction, maintenance, and testing
- Technical/Cyber
  - SCADA system malfunction
  - Electrical failure of supporting computer and control systems
  - Database corruption
  - Hacking or tampering with supporting software and information for control systems
  - Failure or malfunction of operational flow control systems
- Natural
  - Damage to compressor stations from flooding
  - Damage to pipelines due to flooding, erosion, river scouring
  - Damage to facilities due to hurricanes or high winds
  - Well freeze-offs in production and storage systems
  - Damage to facilities due to earthquakes
- Man-made
  - Damage resulting from terrorist activities
  - Pipeline damage due to excavation
  - Damage due to negligence

Physical and Cyber Protection

NERC and the American Gas Association have launched a new grid and energy delivery security partnership that takes advantage of the growing interdependency and collaboration of the natural gas and electricity industries. Under this partnership, staff from the Downstream Natural Gas Information Sharing and Analysis Center (DNG-ISAC) have joined the Electricity Information Sharing and Analysis Center (E-ISAC) in Washington, D.C., to improve coordination on potential security risks related to critical electricity and natural gas pipeline infrastructure.[18] The partnership between the E-ISAC and the DNG-ISAC builds on the long-standing efforts of the natural gas and electricity industries to address supply interdependencies by developing a robust information exchange on shared security risks.

Threats to bulk power system reliability increase as physical and cyber threats grow, underscoring the need for additional coordination between the natural gas and electric industries in regards to physical and cyber security. NERC recommends that natural gas industry regulators should be engaged to establish cyber security standards that match those of the NERC reliability standards.

[18] NERC, AGA Launch Security Information Sharing Effort

Chapter 9: Conclusion

North America is experiencing a large shift in its electric generating resources with ongoing retirements of fossil-fired and nuclear capacity coupled with growth in natural gas, wind, and solar resources. With this, it is becoming even more important to evaluate system resilience and effective operational coordination particularly when some fuels are being relied on more than others. The Aliso Canyon natural gas storage facility outage in Southern California underscores not only the reliance on natural gas to meet electric demand but also how the disruption of key infrastructure can impact bulk power system reliability.

Whereas increased synchronization between natural gas and electric industries incremental resources (e.g., battery storage and transmission upgrades, dual fuel capability, diverse resources, storage, and increased incentives to secure firm transportation) can serve to mitigate risks, entities should assess and develop criteria to evaluate bulk power system potential reliability impacts due to a loss of a pipeline, liquefied natural gas facility, or storage facility.

The electric and natural gas industries should continue to increase coordination, particularly with the increased threats of cyber and physical attacks. Additionally, it is important that Generator Owners seek necessary air permit waivers and a protocol for calling on those in the event that alternate fuel is necessary. As natural-gas-fired generation continues to grow, particularly in order to meet peak demand, regulators and policy makers should evaluate existing natural gas industry standards, including cyber and physical standards, and evaluate whether those standards should be mandatory.

NERC’s power flow analysis determined that many areas in North America could incur power flow and stability issues if they were to experience significant losses of natural gas infrastructure. This accentuates the need for system operators and planners to conduct their own system studies around loss of pipeline infrastructure and to develop contingency plans.

More transparent data and more thorough data analysis is needed to formulate key decisions around the bulk power system reliability. NERC should expand its GADS data base to provide more specific cause codes for natural gas outages so that more precise causes can be determined in order to formulate adequate remedies to reduce outages.

Appendix A: Overview of Natural Gas Storage—Aliso Canyon Outage

Background and Overview

In October 2015, a natural gas leak was detected in one of the Aliso Canyon underground natural gas storage facility wells[19] in southern California. The facility is one of the largest natural gas storage facilities in the United States, serving approximately 11 million customers and providing fuel to 18 power plants with approximately 10 GW of capacity. The natural gas pipeline and storage network in California that includes the Aliso Canyon facility is different from other Regions, so impacts of the Aliso Canyon facility shutdown would not be duplicated elsewhere. Nevertheless, this storage outage underscores the potential effects that a single point of disruption can have on bulk power system reliability.

Through November and December 2015, SoCalGas worked to stop the leak, and the amount of working natural gas storage in Aliso Canyon was reduced from 86 bcf to 15 bcf. SoCalGas sealed the leak in February 2016; however, additional injection of natural gas into the facility was prohibited pending a comprehensive inspection of the 114 storage wells at the facility.

A technical assessment group was formed to study and identify risks posed to electric and natural gas reliability as a result of the loss of Aliso Canyon.[20] The group conducted a study of potential risks and developed an action plan that outlined a number of mitigation measures. In response to the potential operational concerns, entities led by the California ISO (CAISO), California Public Utility Commission (CPUC), California Energy Commission (CEC), and the Los Angeles Department of Water and Power (LADWP) prepared and implemented coordinated operating plans.

The unavailability of Aliso Canyon significantly impacted system operations during Summer 2016 and Winter 2016/2017. However, due to mild weather and other factors that resulted in reduced electricity demand, there was no loss of load during this time. Increased hydroelectric generating availability further mitigated potential impacts in system operations during the summer of 2017.

A second study[21] on Aliso Canyon is expected to be issued by the CEC in December, 2017, to fully address how the CAISO has worked with utilities and other parties to address the 2016–2017 events.

2016–2017 Seasonal Operations Overview

Summer 2016

Through extensive coordination among operating entities, there were no electric load interruptions as a direct result of unavailability of the Aliso Canyon storage facility. The summer temperatures were mild with the exception of system peak demand on June 20, 2016. In addition, outages caused by wildfires did not impact major transmission paths and were mitigated adequately through real-time system operations. During the summer season, there were three natural gas curtailment incidents with no impact to electric generation availability. Flex Alerts[22] were used successfully to change consumer behavior and reduce demand at key times.

19 Owned by Southern California Gas Company (SoCalGas)

20 The technical assessment group consisted of members from the California Public Utility Commission (PUC), California Energy Commission, California ISO, Los Angeles Department of Water and Power (LADWP) and SoCalGas.

21 "CCST study" led by California Energy Commission with California Council on Science and Technology. The scoping description gives the report name as "Long-Term Viability of Gas Storage Study". The study has participation from multiple agencies including California Air Resources Board, Division of Oil and Gas and Geothermal Resources with the Department of Conservation and is expected to be issued by late December, 2017. Details may be found at.

22 California ISO Flex Alerts

During the Aliso Canyon outage, CAISO and SOCalGas modified several tariffs to allow the natural gas company to push selected electric generation up in curtailment priority to help maintain both natural gas and electric system reliability. Tariff changes and improved coordinated planning between the CAISO and So CalGas provided the flexibility needed to avoid unserved electric load due to the unavailability of the Aliso Canyon Storage facility.

Winter 2016/2017

On January 24 and 25, 2017, due to increased system demand driven by cold weather conditions, SoCalGas began withdrawing natural gas from Aliso Canyon to support reliability of the Region's natural gas and electricity systems with no electric service curtailments. Over the two days, approximately 50 MMcf of natural gas was withdrawn, leaving 14.8 bcf of working natural gas inventory in the field.

SoCalGas did issue curtailment watches each day from January 23 through January 26, 2017, and CAISO used their generation natural gas constraint nomogram in the day-ahead market to limit natural gas usage in the Southern California Edison and San Diego Gas and Electric areas. The nomogram limits the use of generating resources in the impacted area reducing their output to conserve natural gas supply in preparation for potential shortfall in real-time operations.

Summer 2017

On July 19, 2017 the California Department of Conservation announced that injections would be able to resume at Aliso Canyon. Following months of rigorous inspection and analysis of wells at the Aliso Canyon natural gas storage facility and the implementation of multiple new safety protocols, state engineering and safety enforcement concluded the facility would be safe to operate and could reopen at a greatly reduced inventory capacity in order to protect public safety and prevent an energy shortage in Southern California.

Under Senate Bill 380 (SB 380), the Division of Oil, Gas and Geothermal Resources and the California Public Utilities Commission were required to concur that the facility was safe before natural gas injection could resume. This will continue to limit the withdrawal capacity of these facilities, resulting in reduced natural gas availability to meet both natural gas and electric generation needs.

The National Oceanic and Atmospheric Administration forecasted a warmer than normal Summer 2017 in California and increased risk of fire with thick undergrowth fed by spring rains. Compared to Summer 2016, the electric generation was less reliant on Aliso Canyon due to hydroelectric generation availability in both northern California and the Pacific Northwest, dual fuel capability in the LA basin, increased non-natural-gas-fired generation and transmission resources, and incremental participation in the western Energy Imbalance Market (EIM).

Through coordination and cooperation among operating entities in southern California, there were no load interruptions during Summer 2017. The CAISO, SoCalGas, LADWP, Peak Reliability Coordinator, and Western Electricity Coordinating Council continued to communicate through Peak-day calls, weekly calls with Peak Reliability Coordinator, and daily natural gas coordination calls with SoCalGas.

2016 and 2017 Technical Assessments

Summer 2016 and Winter 2016/2017 Assessment Summary

In April 2016, a technical assessment group released the Aliso Canyon Risk Assessment Technical Report,[23] which provided findings from analysis of the potential natural gas and electric system reliability impacts. The report outlined four key factors that contributed to reliability risks during the Summer 2016 operating season:

- Rapid ramping of electric generation that exceeds the dynamic capability of the natural gas system

[23] Aliso Canyon Risk Assessment Technical Report

- Mismatches between scheduled natural gas and actual demand
- Planned and unplanned outages on the natural gas storage and delivery system, outside of Aliso Canyon
- Interruptions in natural gas supply to California (e.g., very cold weather in the east)

In May 2016, the Technical Assessment Group also created an Aliso Canyon Action Plan[24] that presented measures[25] to mitigate the risk of large natural gas curtailments that could result in electricity interruptions. The five mitigation plan categories are as follows:

- Prudent use of Aliso Canyon
- Tariff changes
- Operational coordination
- Demand-side reduction for natural gas and electricity
- Reduction of natural gas maintenance outages

Summer 2017 Assessment Summary

The Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment was released in May of 2017.[26] The assessment report outlines the study work and findings related to potential risks to southern California electric reliability with reduced natural gas availability within the SoCalGas system. Based on the hydraulic modeling conducted, the maximum natural gas send-out that SoCalGas facilities (excluding Aliso Canyon) can support is 3.638 bcf per day (bcfd) of which 2.2 bcfd is available for electricity generation. This assumes ideal conditions with 100 percent receipt point utilization and storage capability. Studies conducted by the CAISO and LADWP indicated that 1.47 bcfd during peak conditions would meet expected electric demand.

Mitigation measures detailed in the Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment[27] are as follows:

- **Battery Storage:** The outage of Aliso Canyon drove the expedited procurement of nearly 100 MW of battery storage in the Southern California Edison and San Diego Electric and Gas footprints. LADWP has expedited its beacon 20 MW battery project, which should be operational in 2018.
- **Transmission Capacity:** Several transmission upgrades made over the last year will provide additional reliability to the transmission system feeding southern California. Some of the larger improvements include the 500 kV Vincent-to-Mira Loma line, phase shifters installed in the Imperial Irrigation District footprint, synchronous condensers installed in the SCE and SDGE footprints, and series reactors installed by Pacific Gas and Electric (at their Midway substation).
- **Solar Capacity:** LADWP recently brought 144 MW of solar on line bringing their total to approximately 1 GW. They plan to bring an additional 106 MW on-line in Summer 2017.
- **Dual fuel capability:** In 2016, LADWP secured temporary variances that allow the burning of diesel fuel at three of its plants (totaling approximately 1.3 GW). These variances permit the burning of diesel fuel under specific conditions as a last resort (i.e., as a last step to prevent a rolling blackout).

During peak demand or system element contingencies, additional generation may be needed to meet electric reliability. If natural gas supply cannot accommodate additional generation, southern California entities may need

[24] Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin
[25] Aliso Canyon Mitigation Measures May 19, 2017
[26] Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment
[27] *Ibid.*

to rely on assistance from neighboring Balancing Authorities. This assumes ample supply outside southern California and adequate transmission capacity to move that power into the southern California system. A reduction of import capability will require more natural gas supply to meet the energy shortfall. If that natural gas is not available from other SoCalGas facilities, natural gas may have to be withdrawn from Aliso Canyon. A reduction in import capability or demand response in southern California coupled with a reduction of natural gas storage withdrawal or flowing natural gas supply may result in electric load shedding.

California's Underground Natural Gas Storage Facility Current Status

The CPUC has ordered other SoCalGas underground natural gas facilities to upgrade the wells (particularly at Honor Rancho and La Goleta) and to store natural gas in preparation for the summer season.

The recent unavailability of Aliso Canyon has increased the coordination and communication between operating entities in both the electric and natural gas industries. The cooperation between electric entities is paramount to ensure the reliability of the Bulk Electric System. The coordination has also expanded beyond the impacted entities throughout the Western Interconnection.

The Aliso Canyon outage underscores the possibility that this outage may be more than an isolated incident. With the large increase in natural gas generation and the reliance on natural gas storage to meet those needs, natural gas storage is paramount to the reliability of the bulk power system

Appendix B: Natural Gas System Operations

Most areas in the United States and Canada are served by many different pipeline systems that are relied on to transport natural gas into and out of each area. The North American natural gas pipeline network is a highly integrated system with many connections that enable the transfer of natural gas between the different pipeline systems. In addition, there are numerous connections with natural gas utilities and natural-gas-fired power plants that receive natural gas. In many cases, multiple connections from multiple pipelines create both flexibility and reliability in natural gas deliveries. Further, underground natural gas storage is connected to the pipelines supporting reliable natural gas delivery. Market area natural gas storage makes it possible for firm peak month and peak day deliveries to be satisfied with a greater degree of certainty and reliability. Natural gas utilities further augment underground storage supplies with storage from above-ground facilities, most notably liquefied natural gas peak shaving, and propane-air facilities. In short, the natural gas infrastructure is extensive and diverse, making the system for serving firm loads very reliable. Nevertheless, contingencies that negatively impact natural gas service can and do occur. On rare occasions, these contingencies threaten firm service. More often, these contingencies may reduce the capacity available for interruptible service that many generators use that the pipeline has no contractual obligation to provide and only is available when firm shippers are not using their capacity.

Natural gas production, transmission, and distribution systems have inherent attributes that provide for a high degree of reliability and resilience. Unlike electricity, which travels near the speed of light and flows along a path of least resistance, natural gas moves by pressure. Natural gas moves through a transportation system with the use of compressors that reduce the volume and pressurize it, allowing the molecules to travel long distances. Compressors are placed at regular intervals to continue the forward movement. As a result, natural gas physically moves slowly through a pipeline at speeds up to 30 mph and its flow can be controlled. The slower speed of natural gas movement along a pipeline allows time for pipeline operators to control the flow of natural gas and to adjust their operations in the event of a disruption. As a result of these characteristics of natural gas and the natural gas transportation system, a failure at one point on the system typically has only a localized effect.[28] However, even a local effect can cause some disruption of power generation.

Another important characteristic of natural gas is its ability to be stored after production. Natural gas is most commonly stored underground in depleted aquifers and oil and natural gas fields as well as in salt caverns. Not all states have geology suited for natural gas storage in depleted aquifers or oil and natural gas wells. Increasingly some states are reluctant to use water aquifers for natural gas storage. Natural gas can also be stored above ground in storage tanks as liquefied natural gas for use at import and export facilities and at peak shaving plants or as compressed natural gas for industrial and commercial uses. Although storage is important as a supply cushion, it also provides important operational flexibility in the event of constraints in the pipeline and distribution network because storage facilities are widely dispersed on those networks. According to an April 2017 Interstate Natural Gas Association of America survey of 51 interstate pipelines, over the ten-year period (2006–2016), pipelines delivered 99.79 percent of firm delivery contractual commitments to their firm shippers. However, this is not a guarantee that contractual commitments to shippers prevent all single point disruptions. Further, until recently, the electric sector was not as reliant upon natural gas nor was the sector using as many variable energy resources that require frequent ramping of generation during the Electric Peak demand.

The wide geographic dispersion of production areas may reduce the vulnerability of the supply to localized weather events. Additionally, most natural gas production now occurs in onshore areas with offshore production making up only 5 percent of total natural gas production as compared to 20 percent in 2004.[29]

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[28] More detail about the physical, operational characteristics of the natural industry segments can be found in the Appendices to the 2011 Southwest Cold Weather Event report prepared by the staffs of FERC and NERC. Report on Outages and Curtailments During Southwest Cold Weather Event of February 1-5, 2011 (August 2011), Appendices 8-10 ("Southwest Cold Weather Report").

[29] EIA – Natural Gas Monthly December 2007 and Natural Gas Monthly April 2017: https://www.eia.gov/naturalgas/monthly/pdf/table_07.pdf.

The natural gas transportation network is comprised of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the event of a physical disruption. In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop for planned maintenance or minor disruption. This leaves parallel loops in service. In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to shippers (at least outside the affected segment). The use of line pack in the pipelines can be used if needed to provide operational flexibility as noted in the Southwest Cold Weather Report.[30]

However, line pack is not a substitute for storage facilities for multiple baseload natural-gas-fired power plants in a region. As noted previously, because of the inherent characteristics of natural-gas and the interconnected pipeline system, operators can control and redirect the flow around an outage in one segment. The existence of geographically dispersed production and storage, and its location on different parts of the pipeline and distribution system, also provides flexibility for operators to maintain service in the event of a disruption on parts of the transportation and distribution system. These attributes have all positively contributed to the natural gas system's historic reliability and resilience.

State statutes and public utility regulations may allow a local distribution company (LDC) to curtail services to some customers in the event of extreme situations for reasons that include the need to maintain the operational integrity of the system and/or to maintain natural gas service to designated high priority customers, including "essential human need" customers. Historically, these regulatory requirements give the highest priority for the reliability of service to residential and commercial customers without short-term alternatives. As a result, a generator that relies on an LDC distribution system (particularly on an interruptible basis) as part of the generator's fuel supply chain needs to take into account these regulatory obligations of the LDC and, for example, plan for the use of alternate fuels, maintain on-site fuel storage (such as liquefied natural gas or compressed natural gas), or contract for a higher level of service from the LDC (such as firm transportation or emergency service).

[30] Southwest Cold Weather Report at 68-70.

Appendix C: Natural Gas Industry Regulatory Construct

Following FERC orders 436[31] and 636,[32] the natural gas industry has not been vertically integrated, and each distinct industry segment has been subject to a different regulatory construct. The industry consists of three general segments: 1) upstream natural gas production, gathering, and processing, 2) pipeline transportation and storage, and 3) local distribution.[33] Price regulation for natural gas sold by producers was removed in the Wellhead Decontrol Act of 1989, which was followed later by FERC's removal of all price regulation for the sale of natural gas in the wholesale market. Gathering and processing are also not subject to price regulation by the Federal Government. However, the price and terms and conditions of the interstate transportation and storage of natural gas continue to be regulated by FERC. Pure intrastate transportation and storage of natural gas is subject to state regulation and Public Utility Commissions. The local distribution of natural gas by local distribution companies (LDCs) is also subject to state regulation. All pipelines are subject to safety regulation by the U.S. Department of Transportation, Pipeline and Hazardous Safety Administration, or state agencies.

FERC's regulation of interstate transportation and storage is contract-based. The pipeline or storage companies' contract with its shipper customer, and how the shipper nominates service under that contract, determines the scheduling and curtailment priorities in the event of a pipeline restriction or *force majeure* event. FERC regulations preclude interstate pipelines from undue discrimination in providing service based on the classification of customers. This means that the identity of the customer, whether it is an LDC, electric generator, or a producer, cannot have any bearing on priority of service. In addition, the pipeline is required to honor all firm service contracts as long as there has been no *force majeure* event.[34]

Pipelines schedule capacity based on nominations, and when necessary, restrict service based upon the type of service contracted. There are two main types of service that pipeline and storage operators provide: 1) firm service: whereby a shipper pays a monthly reservation charge to the pipeline, which entitles it to transport or store a certain quantity of natural gas daily assuming the shipper nominates the quantity and it delivers to the pipeline the equivalent amount of natural gas at the receipt points specified in the contract, and 2) interruptible service: which is a lower quality service provided by the pipeline when it has available capacity that is either not under firm contracts or not being used that day by firm transportation customers. Within firm service, many pipelines and storage facilities provide no notice service; no notice service allows for the highest level of firm service that a customer can contract. It allows for the reservation of pipeline capacity throughout the 24-hour natural gas day. This reservation of capacity allows for the electric utility or customer to nominate its firm service on a primary basis throughout the day offering the highest level of flexibility available on a pipeline.

Under the FERC regulations,[35] a firm service shipper is entitled to "segment" its capacity daily and utilize other delivery points within the path to its delivery point if capacity is available, which are called "secondary firm points." Once scheduled by the pipeline, the transportation capacity to secondary receipt and delivery points is as firm as primary firm. Primary firm service shippers receive the most reliable service because they have the highest priority when scheduling and are the last to be curtailed in *force majeure* situations. Secondary firm service shippers are next in priority for scheduling, but once scheduled, they are curtailed pro rata with other firm service. Interruptible shippers, if scheduled, can be bumped by higher priority firm shippers; interruptible shippers are also curtailed first before any firm shippers. Many environmental laws and regulations limit oil use for electric generation.

[31] 1985 FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling consumers to negotiate prices directly with producers and contract separately for transportation

[32] FERC Order No. 636

[33] A more detailed diagram of the natural gas industry segments appears at the end of these comments.

[34] FERC natural gas regulations define "service on a firm basis" as a service that is "not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm services." 18 C.F.R. § 284.7(a) (3).

[35] 18 C.F.R. § 284.7(d).

LDCs are regulated by most states as utilities with an obligation to serve their firm core retail customers. As a result, LDC systems are built to serve their firm core customer base to ensure reliable service to these firm customers and others on a "design day" (or a forecasted peak day load based on historical weather conditions). Natural gas utilities may offer an interruptible "bundled" sales service (which includes commodity supply and the transportation of the supply on the local distribution system) and/or a stand-alone interruptible transportation service for the transportation of customer-owned natural gas on the local distribution system. The LDC systems are sized to serve core customer needs, and as a result the LDC may not be able to maintain interruptible transportation service at all times. During periods of high usage and system constraints, prevalent on the coldest winter days, LDCs may call on interruptible customers to cease natural gas usage temporarily, upon which these customers generally switch to a back-up fuel, such as fuel oil.[36]

The National Energy Board regulates pipelines in Canada, including the TransCanada pipeline, which transports natural gas through Alberta, Saskatchewan, Manitoba, Ontario, and Quebec. The regulatory construct in Canada is similar to that of the United States in which firm transportation carries the highest priority. Natural gas-electric coordination, particularly information sharing between the natural gas generators and natural gas pipeline companies, is also an issue of significant importance in Canada. The Ontario Independent Electricity System Operator (IESO) has supported a broader review of FERC Order 787 to determine if IESO can benefit from similar coordination efforts.[37]

Although not to the same level as many areas in the United States, Canada relies significantly on natural gas in order to meet peak electric demand requirements. SaskPower, for example, sources 42 percent of its peak generation from natural-gas-fired generation. Conversely, Quebec, partly due to its abundance of hydro assets, has no natural-gas-fired electric generation. Canada, similar to the United States, also relies on underground natural gas storage facilities to meet deliverability requirements of natural gas for electric generation. Presently, Canada has approximately 10 underground natural gas storage facilities with working capacity of 440 bcf and deliverability of 7 bcf per day.[38]

[36] The tradeoff for these customers is a discounted rate for the interruptible natural gas delivery service, compared with firm service rates, and the customers enter into these interruptible contractual arrangements with that prior knowledge.
[37] http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/completed/gas-electric-coordination-enhancements
[38] INGAA

Appendix D: FERC Natural Gas-Electric Coordination

Recognizing the increased use of natural gas to generate electricity, FERC has encouraged natural gas-electric coordination.

Stemming from the Southwest outage in February 2011, FERC hosted a series of regional technical workshops and solicitation of written comments to collect input from every sector nationally and in each Region, relevant to electric reliability as show below:

- Electric utilities
- Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)
- Industrial consumers
- State regulators
- Natural gas pipelines, marketers, suppliers, and natural gas distribution companies
- The North American Energy Standards Board (NAESB)

Starting from this and other input, FERC initiated natural gas scheduling rulemakings in order to better synchronize operations between the natural gas and electric industries. FERC followed with various individual actions among the regulated ISO/RTOs. The natural gas rulemakings resulted in Order Nos. 787[39] and 809.[40]

Order Nos. 787 and 809 are described in more detail below:

- Order No. 787 (Communication between power generators and natural gas pipelines):
  - The final rule allows interstate natural gas pipelines and electric transmission operators to share nonpublic operational information to promote reliability and integrity of their systems (ensures robust communications).
- Order No. 809 (Pipeline Scheduling Time Line):
  - The final rule addresses the differences between nationally standardized natural gas pipeline scheduling and regional electric dispatch time lines. The order adopted two proposals submitted by NAESB (after FERC directed work to find consensus) to revise the interstate natural gas nomination time line and make conforming changes to the NAESB standards in FERC's regulations.
  - The revised regulations modify the scheduling practices used by interstate pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers that use multi-party transportation contracts.
  - Effective April 2016, the order shortened the gap between the deadlines for nominations and the start of natural gas flow from those nominations and added a new intraday nomination cycle, all to allow shippers including electric generators to better match their nominations to the dispatch decisions of power markets and to the trading cycles of commodity natural gas markets.
    - FERC had initially proposed to move the start of the "Gas Day" from 9:00 a.m. Cocos Islands Time to 4:00 a.m. Cocos Islands Time to better match the morning ramp-up of generation load.

[39] FERC Order No. 787, Communication of Operational Information between Natural Gas Pipelines and Transmission Operators, (Docket No. RM13-17-000, November 15, 2013)

[40] FERC Order No. 809, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (Docket No. RM14-2, April 16, 2015)

> However, in Order No. 809, FERC decided not to require a change to the start time of the Gas Day, finding that "*there is limited evidence to support the premise in the NOPR that the current start of the Gas Day results in natural-gas-fired generators de-rating during the morning ramp due to exhausting nominated natural gas transportation*." "*In addition, evidence in the record provided through the ISO and RTO data responses did not provide sufficient support for changing the nationwide Gas Day*."[41]

Several observations arose out of the FERC proceeding: ISO-NE and several other grid operators provided data that they believe supported a change in the start of Gas Day. ISO-NE stated that during 2013 and 2014, there were 173 reported natural-gas-fired generator de-rates due to fuel limitations and 67 of those were logged between 3:00 a.m. and 9:00 a.m. Cocos Islands Time. The morning de-rates affected 49 days. In 2013 and 2014, there were 20 natural-gas-fired generator de-rates due to fuel limitations, over 14 days, that had an identified ending time that coincided with the start of the next Gas Day at 9:00 a.m. Cocos Islands Time. While ISO-NE stated that it was not certain the de-rates occurred solely due to the exhaustion of natural gas pipeline nominations given the 9:00 a.m. Cocos Islands Time end time, this is likely the cause. The proceeding highlighted the regional differences and complexities between the natural gas and electric markets and the operational characteristics of both systems and the need for improved GADS reporting so that RTOs have improved information for the causes of de-rates in the future.[42]

The electric markets in the East were stressed during each of the cold weather events in 2014. During these events, electric demand was at historic levels due to the extremely cold weather. New winter peaks were set in MISO, PJM, NYISO, and SPP. During the cold weather events later in January, regional demand in the eastern Regions was high but not at the levels set in early January.[43] However, the latter periods did experience stresses primarily because of higher natural gas prices as a result of historic demand levels, fuel delivery disruptions, and generator outages.[44] Despite the unprecedented performance levels required, the natural gas industry was able to honor all firm fuel supply and transportation contracts.[45]

As part of FERC's ongoing efforts, the Commission asked NAESB in an order on rehearing of Order No. 809 to explore the potential for faster computerized scheduling to provide shippers with more opportunities to reschedule natural gas. NAESB reconvened its natural gas-electric harmonization task force to conduct industry-wide fact-finding. After those discussions concluded, NAESB reported to FERC that no recommendations achieved consensus on standards.[46] During the NAESB deliberation, the importance of pipeline service menus was discussed, but participants recognized that service development has occurred and continues to occur naturally in the marketplace and that it is not within NAESB's scope to recommend such service policy changes to FERC.[47]

Order Nos. 787 and 809 provided a forum for dialogue and proposed regulatory changes to increase natural gas and electric coordination, including a more compatible scheduling paradigm. The industries continue to have

[41] Paragraphs 63 and 64 of Order No. 809.

[42] While these data do not show specifically whether the generators exceeded their firm natural gas transportation schedule for the day, ISO-NE states that the data suggests that the de-rates likely resulted from the exhaustion of natural gas transportation service, because the generators could come back on line at the start of the new Gas Day. Docket No. RM14-2-000

[43] See http://www.ngsa.org/winter-2013-14-market-conditions-frequently-asked-questions/#jumpone .

[44] See FERC Staff Presentation "Recent Weather Impacts on the Bulk Power System" January 16, 2014, http://www.ferc.gov/CalendarFiles/20140116102908-A-4-Presentation.pdf.

[45] See https://www.ferc.gov/media/news-releases/2014/2014-4/10-16-14-A-4-presentation.pdf and "During each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries." Also see https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf at Slide 4.

[46] The July 29, 2016 NAESB Status Report for Submittal to the Commission Concerning FERC Order No. 809 is available at the following link: https://www.naesb.org/pdf4/ferc072916_naesb_order809_status_report.pdf.

[47] Letter to NAESB in FERC Docket No. RM14-2-000.

discussions in various forums as needed regarding areas where further communication and coordination may be useful.

Appendix E: Assessment of Existing Studies

Step I

This appendix (Step I of NERC's study approach) provides an overview of existing studies conducted by industry. The purpose of this is to gain an understanding of existing planning approaches as well as to highlight and promote best practices.

NERC Survey Response Summary

In an effort to understand electric industry efforts in planning to prepare for events similar to the Aliso Canyon outage, NERC conducted a survey of Planning Coordinators in North America. The survey questions were focused on assessments, analysis, and studies conducted within the last five years on evaluating the loss of large natural gas facilities (e.g., storage facilities, key pipeline segments, liquefied natural gas terminals). In addition, the survey also included questions on specific procedures and guidelines to ensure adequate back-up fuel supplies, firm or interruptible natural gas supply and transportation to generating facilities as well as transmission deliverability considerations if assessments resulted in resource shortfalls within the Planning Coordinator area. The goal of the survey was to determine what, if any, natural gas dependent analysis industry planners were performing and to review the methods and assumptions used for supporting studies. The purpose of this section is to provide a high-level summary of the responses to that survey and provide some key takeaways for consideration by the industry. **Figure E.1** provides a breakdown of responses received from Planning Coordinators and Balancing Authorities. This figure demonstrates a significant number of cases where no existing studies or analysis have been performed.

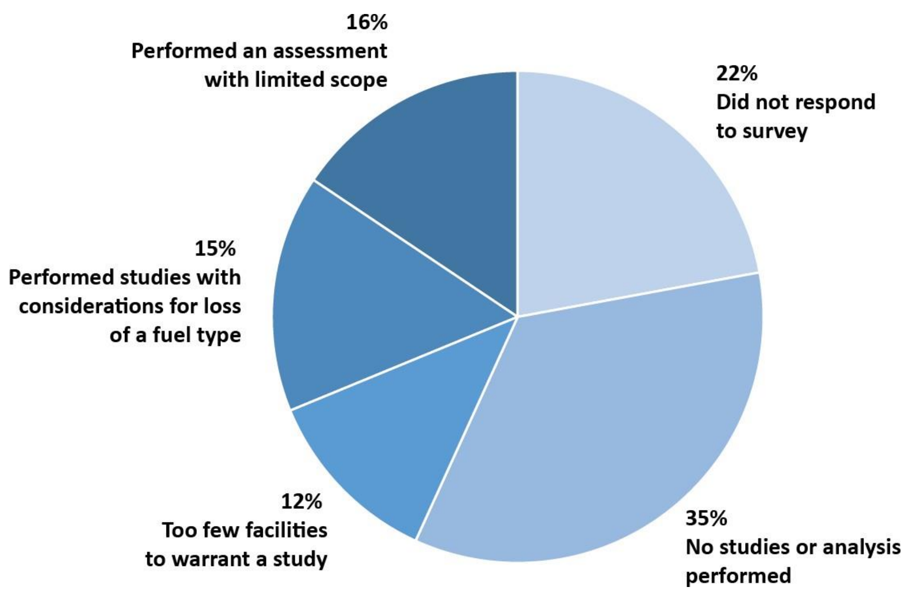

Figure E.1: Planning Coordinator and Balancing Authority Survey

The scope, frequency (i.e., seasonal, per annum, or every 3–5 years), and framework of assessments and studies conducted varies by entity. Most respondents refer to TPL-001-4[48] extreme event category detailed requirements R3 and R4, which evaluate simulations with removal of elements based upon operating experiences that may result in wide-area disturbances or loss of two generating stations resulting from conditions, such as loss of a large natural gas pipeline. The NERC Reliability Standard also require an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) if the analysis concludes there is cascading caused by the occurrence of extreme events.

[48] Standard TPL-001-4 — Transmission System Planning Performance Requirements

Few entities have developed their own assumptions and criteria or participated in a joint effort with neighboring entities where transmission constraints were often a secondary concern in favor of focusing more on issues of resource adequacy. Less than 10 percent of respondents were aware of or anticipated impacts to reliability should their primary source for natural gas be unavailable. Mitigation plans included the following: 1) the reliance on backup fuel for generating resources with dual fuel capability, allowing them to continue to supply electric power to their customers without interruption of service; 2) reliance on importing power from neighboring utilities; and 3) the increase in generation from other types of fuel (e.g., nuclear, hydro, coal).

Summary of Existing Assessments

A summary of existing analyses and results are detailed below. These reports were reviewed for insights into how those studies were conducted and their respective methods and assumptions.

Argonne National Laboratory Pipeline Disruption Analysis

The United States Department of Energy commissioned Argonne National Laboratory to analyze the potential impacts of an abrupt and protracted loss of natural gas deliverability due to some disabling event at each of the Nation's interstate natural gas pipelines. The method ANL used in this analysis required the estimation of the consequences of such a disruption. "Disruption" was defined as the total loss of deliverability at specific locations along the interstate natural gas pipeline for a period of at least a one-month duration, at the time of peak natural gas demand. The consequence analysis was performed using the Argonne-developed *NGfast* tool, which is a natural gas pipeline network model that enables the rapid assessment of impacts from disruptions and flow reductions in the nation's natural gas transmission pipeline network. Impacts were measured in terms of the extent of natural gas volume disrupted, states affected, local distribution companies (LDCs) affected, number and type of customers affected, and amount of natural gas-based power generation capacity affected.[49] All of the monthly data for the years 2014 and 2015 incorporated in *NGfast* were obtained from publicly accessible sources.

Potential Impacts of Interstate Natural Gas Pipeline Disruptions

The consequence of an interstate natural gas pipeline failure is expressed in terms of the number of customers affected per sector and the amount of natural gas flow lost. For the purposes of this study, customers in the electric sector are of particular interest because of the interdependency that exists between the electric and natural gas systems; the principal impacts in the electric sector are expressed in terms of megawatts potentially interrupted due to the lack of natural gas supply.

The analysis indicates that the largest potential impact from the loss of the natural gas supply from interstate natural gas pipeline would be on natural-gas-fired power plants. The impact on downstream residential and commercial customers was estimated to be minimal.

Potential Electric Sector Impacts

It was assumed that an unexpected loss of generation capacity would not affect electric reliability unless the loss is relatively large (2 GW or more).[50] The analysis of the interstate natural gas pipeline network was performed using *NGfast* under the following two sets of conditions:

- **A Worst-Case Scenario:** Assumes that mitigation measures are not available and that the only way to balance supply and demand after a disruption is to shed load. This scenario can be considered highly unlikely as the natural gas sector would apply a range of mitigation measures as available. Mitigation

[49] Edgar C. Portante, Brian A. Craig, Stephen M. Folga, "*NGfast*: A Simulation Model for Rapid Assessment of Impacts of Natural Gas Pipeline Breaks and Flow Reductions at U.S. State Borders and Import Points," *IEEE.org* 1118-26 (S.G. Henderson, B. Biller, M.-H. Hsieh, J. Shortle, J.D. Tew, and R.R. Barton, eds. 2007), http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=4419711 (presented at the 2007 Winter Simulation Conference).

[50] DOE, 2016. *Ensuring Safe and Reliable Underground Natural Gas Storage*, available at https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf, accessed July 13, 2017.

measures typically include additional withdrawals from in-state underground storage, liquefied natural gas facilities, and production fields as well as compensating flows from interconnected pipelines.

- **A Reasonable Best-Case Scenario:** Assumes mitigating measures, such as those suggested above, would be implemented to balance supply and demand after a disruption. This case also considers the abilities of LDCs that are interconnected to multiple pipelines to use their own pipelines and storage to provide alternate service to generators. However, this scenario does not take into account whether the mitigating actions would be cost-effective.

The results for the Worst-Case and Reasonable Best-Case scenarios are shown in **Figures E.2** and **E.3**, respectively. The two figures highlight the interstate natural gas pipelines which, if disrupted, would lead to potential electric sector impacts. The figures also show the states affected and the amount of natural-gas-fired power generation capacity potentially impacted, together with the quantity of the affected electric generating capacity that has co-fuel or dual fuel capability (i.e., the ability to switch from natural gas to another fuel such as distillate fuel oil, if needed).

The majority of the potentially affected electric generating capacity has co-fuel backup capability. As expected, the results for the Worst-Case scenario are greater than those of the Reasonable Best-Case scenario. Assuming the industry can deploy all mitigation measures as discussed above, the potentially affected capacity in states in the Northeast, Northwest, and Oklahoma identified in the Worst-Case scenario are reduced in the Reasonable Best-Case scenario, below the 2GW threshold.

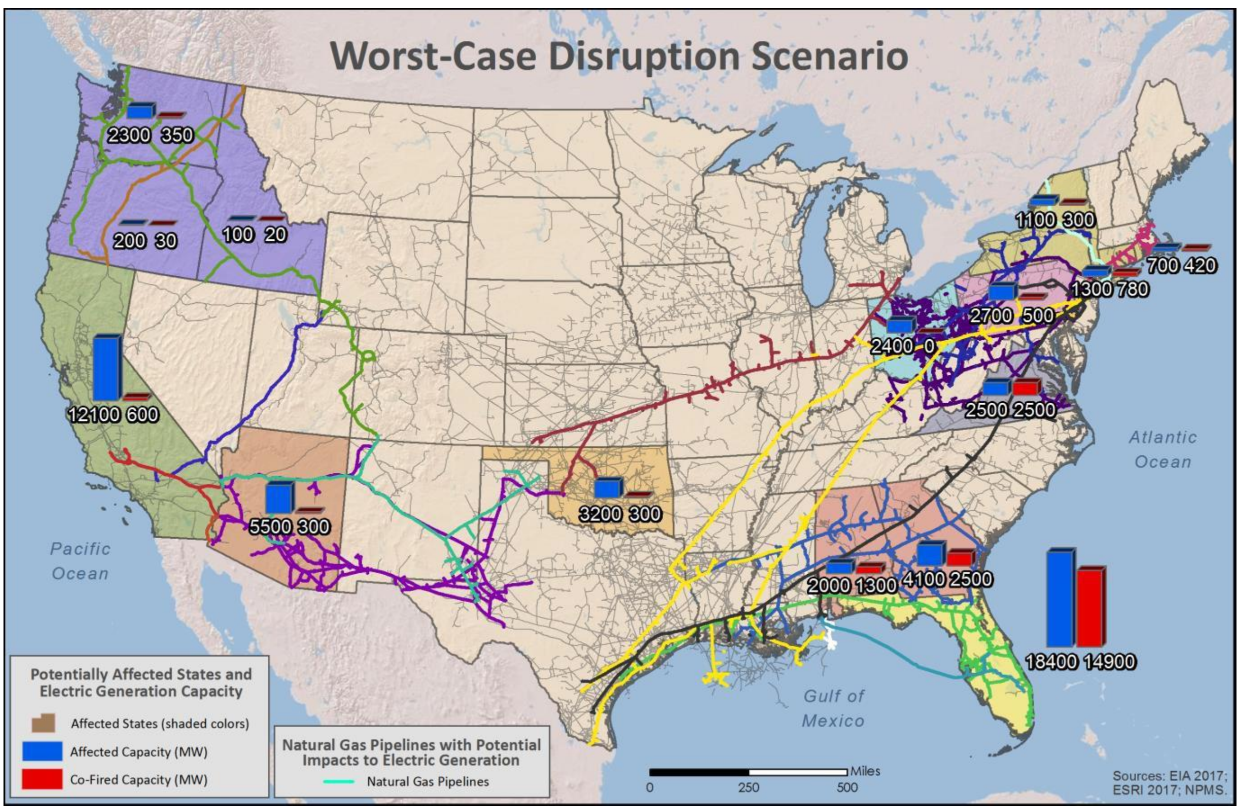

Figure E.2: Summary of NGfast Simulation Results for the Worst-Case Scenario

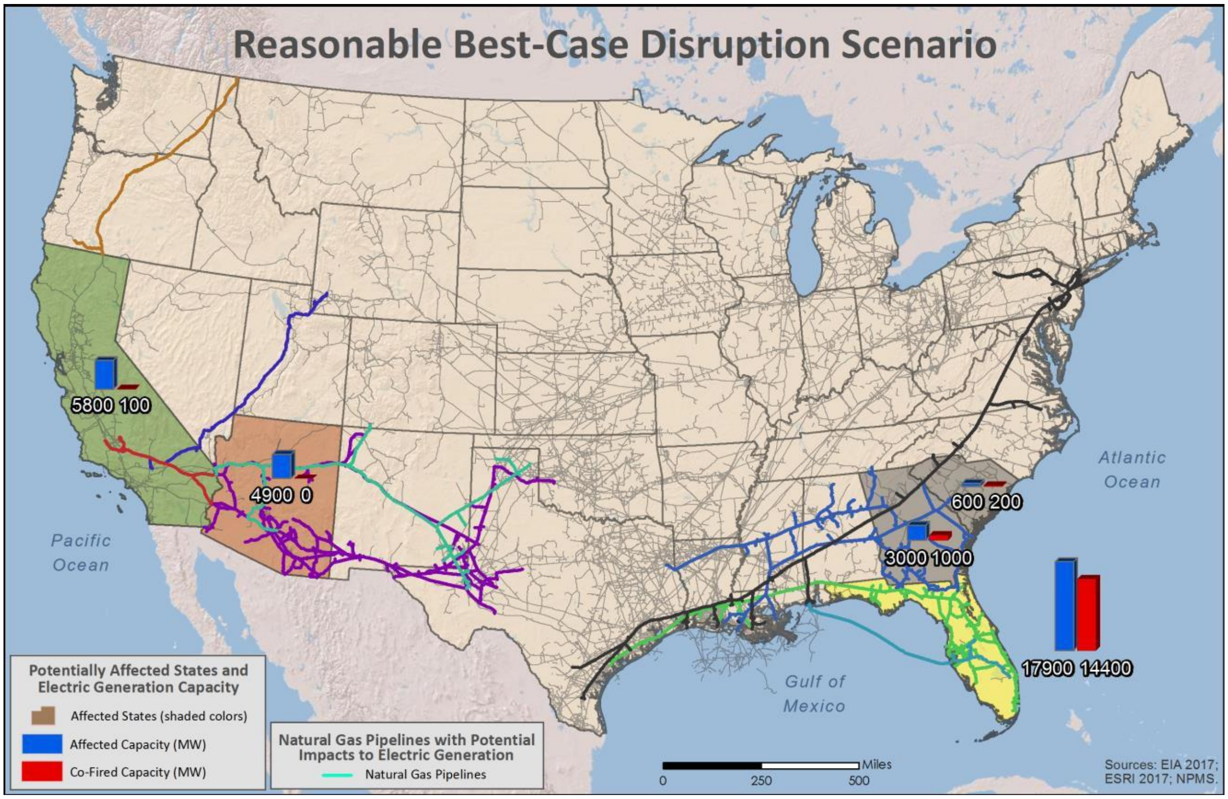

Figure E.3: Summary of NGfast Simulation Results for the Reasonable Best-Case Scenario

EIPC Natural Gas-Electric System Interface Study Summary

The Eastern Interconnection Planning Collaborative Gas-Electric System Interface Study[51] was conducted in 2013 and 2014 with the cooperation of six stakeholders: IESO, ISO New England, MISO, NYISO, PJM, and TVA. The study includes four "Targets." They are as follows:

- **Target 1:**[52] Develop a baseline assessment that includes descriptions of the natural gas-electric system interfaces and how pipeline, storage, and LDC infrastructure impact each other.
- **Target 2:**[53] Identify the specific drivers of the pipeline/LDC planning processes affecting the availability and operational risks borne by natural-gas-fired generators across the study region.
- **Target 3:**[54] Evaluate the current level of operational planning interaction between the bulk electric generation and natural gas supply systems.
- **Target 4:**[55] Assess regulatory, commercial, and operational attributes of the natural gas/electric interfaces affecting the performance of natural-gas-fired generation.

Targets 1 and 2 focused on data-gathering pertaining to the operation and capabilities of the natural gas infrastructure in the Region under study for residential, commercial, and industrial customers. This information was then used to achieve the goal of Target 3, which considered the theoretical loss of a important natural gas pipeline, a important compressor station, or a major liquefied natural gas supply source during a winter and

[51] EIPC - Gas-Electric Documents
[52] Gas-Electric System Interface Study - Existing Natural Gas-Electric System Interfaces
[53] Gas-Electric System Interface Study -Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the electric Systems
[54] Gas-Electric System Interface Study - Natural Gas and Electric System Contingency Analysis
[55] Gas-Electric System Interface Study - Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives

summer peak day in 2018 and 2023. The study allowed dual fuel units to dispatch on their secondary fuel and considered the time necessary to re-dispatch unaffected units. However, *"specific analysis of overall reliability of the electric grid within the Study Region was outside the scope of the Target 3 inquiry."* Of the six study participants, two indicated in their survey response that the results of the EIPC study suggested there are potential reliability impacts for the pipeline contingencies considered. The study indicates that the biggest risk is during the winter for generators who do not have firm natural gas delivery when more natural gas is being utilized by residential customers during these periods.

Columbia Grid Reports (Northwest/Northern California Area)

The Columbia Grid Reports[56] completed in 2012[57] and 2013[58] investigated "*whether large scale limitations in the availability of natural gas to area generation could lead to transmission reliability issues during peak winter loads*." Traditional planning studies assume that the natural gas supply to natural-gas-fired plants is available when needed and is unlimited. The Gas-Electric Interdependencies Study Team was formed to investigate whether this assumption on natural gas availability is appropriate. In addition, if there are situations where the natural gas system may be limited in its ability to deliver natural gas to the power plants, the study team assessed whether these limitations could lead to electric system reliability issues. The focus of the study was to determine whether transmission system changes, or other actions, should be investigated to help protect against limitations in the availability of natural gas to generation in a specified transmission corridor. The study relied upon imports while considering known import limitations. Units with dual fuel capability were allowed to replace the lost natural gas generation but were assumed to have no supply limitations during the period under study. Voltage stability, steady-state voltage, and thermal loading were monitored during the simulations and no performance issues were observed; however, contingency mitigation efforts on overloaded branches and more sensitivity scenarios on the most limiting contingencies were recommended for future assessments.

ERCOT Natural Gas Curtailment Risk Study

The Electric Reliability Council of Texas (ERCOT) study[59] was completed in 2012 and presents the risk of natural gas supply curtailment to electric generators for a 1-year, 5-year, and 10-year time horizon. The study used historical data to implement a probabilistic approach in determining the risks associated with freezing weather, pipeline disruptions, and tropical cyclones as they pertained to the reliability of the natural gas infrastructure in the Region. At least 60 percent of ERCOT's electric generators indicated "interconnects" with more than one pipeline, and the study concluded that this redundancy could help to mitigate the risks associated with a pipeline disruption. The scope of the study did not extend to an analysis of the reliability of the electric transmission network in ERCOT's territory.

Aliso Canyon Risk Assessment Technical Reports

The Aliso Canyon Risk Assessment Technical Reports released in April of 2016[60] and May of 2017[61] were conducted for 2016 summer and 2016/2017 winter seasons and assessed the risks to energy reliability in the Greater Los Angeles and Southern California area without the use of the Aliso Canyon natural gas storage facility. Generating facilities served by Aliso Canyon represent more than half of the local capacity resources in the CAISO and LADWP areas. The assessments determined the minimum level of local generation needed to maintain grid reliability. In the event of a natural gas shortage, imports could be used to meet demand in the area. However, neighboring utilities may not have generation to export as they may be experiencing the same high loading conditions during peak hours, and the import capability may also be limited by the lack of remaining capacity in the tie lines. The analysis considered N-1 transmission contingencies and found that resource adequacy and

56 Gas-Electric Interdependencies Study Team Overview
57 Gas-Electric Interdependencies Status Report
58 Gas-Electric I5 Gas Curtailment Study
59 The Electric Reliability Council of Texas – Gas Curtailment Risk Study
60 Aliso Canyon Risk Assessment Technical Report
61 Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessments

electric system stability issues could result in a supply interruption to load. **Figure E.4** shows the geographic area impacted by Aliso Canyon.

Source: California Energy Commission

Figure E.4: Electric Generation Plants Impacted by Aliso Canyon

Southern Company Natural Gas Dependency and Potential Disruption Analysis

Southern Company's assessment analyzed the potential impacts to the Southern Balancing Authority Area Generation and Transmission System for a hypothetical pipeline failure event between two major supply source pipelines and the generating plants fed from the pipelines. Southern Company's assessment sought to identify potential system impacts due to operating procedures, fuel storage practices, and other mitigation actions Southern Company has established in the event a single pipeline failure were to occur.

This hypothetical pipeline failure event was modeled in a three-stage approach in which Southern Company assesses the transmission system in the following three periods: 1) prior to the pipeline failure event, 2) hours after the pipeline failure has occurred, and 3) days following the pipeline failure until the pipeline is returned to normal service. Southern Company made several assumptions about resource availability at each stage. Transmission constraints were identified based on a single contingency condition at each stage. Southern Company's assessment will be performed at both Summer Peak and Winter Peak load levels for the upcoming peak season. Primarily due to its backup fuel capabilities, Southern Company can maintain reliability on the transmission system for a pipeline disruption event. Southern Company's assessment demonstrates its own steps to prevent an operational problems. However, some power sector companies do not have all of the visibility and controllability into supply, transportation, generation and distribution as Southern Company or other vertically oriented companies do.

Key Takeaways

The results of the survey conducted by NERC identified several key findings that may be useful as the electric and natural gas industries identify ways to assess the impacts of potential extreme disruptions. The following are some key takeaways from the survey:

- The importance of an assessment of interdependence varies by company and Region due to individual resource mix, topology, and the availability of dual fuel generation capacity.
- Several companies are already either conducting studies or developing processes that will lead to studies to assess natural gas infrastructure disruptions.
- The identification of wide-area transmission impacts (i.e., voltage and thermal constraints) due to loss of a large natural gas underground facility or a segment of a pipeline are typically not studied; the majority of the focus is put on resource adequacy and resource availability. Transmission reliability and contingency analysis in the event of loss of a major pipeline/storage facility is paramount in developing mitigation plans and emergency operational procedures.
- Many respondents indicated that there were no natural gas storage facilities within their systems to evaluate. However, the loss of a large natural gas facility can impact electric generation downstream and beyond the boundaries of a Planning Coordinator. Determining whether natural gas system outages could create a regional or local electric reliability risk will warrant a coordinated and detailed analysis among neighboring Planning Coordinators.
- Electric Registered Entities, in coordination and collaboration with their neighbors and natural gas sector, should determine which power plants would be affected in the event of a disrupted natural gas facility. Alternative fuel capability, mitigation plans, emergency operating procedures, evolving ramping capability requirements to manage VERs, and the wide-area reliability impacts to the BPS should be further studied.

Recommendations

Comprehensive studies by Planning Coordinators that assess specific disruptions to critical natural gas facilities should identify and characterize adverse impacts to electric reliability. These disruptions are typically beyond the “design basis” of the power system required by NERC Reliability Standards as well as any regional or local planning requirements; because of this, these reliability risks are generally not incorporated into the planning requirements. In many cases, the resulting reliability impacts are due to a lack of capacity on existing infrastructure. As the BPS relies more heavily on natural gas generation, policy makers and regulators need to be aware of these risks—how likely they are as well as the potential impact. While many pipeline-related infrastructure impacts can be rectified within a week or two, natural gas storage facilities, as observed with Aliso Canyon, can be out for significant periods of time.

The recommended approach for Planning Coordinators can be broken down in the following four general steps:

1. Identify potential natural gas system contingencies and their frequency of occurrence.
2. Assess the impacts for each of the identified contingencies in terms of duration and amount of natural gas supply disrupted.
3. Apply the contingency disruptions to the natural gas supply capabilities to calculate the impact on total natural gas supplies and, more specifically, the amount of natural gas available to electric generators.
4. Determine the transmission systems ability to transport power to load under these extreme conditions.

With this information, policy makers, regulators, and industry can effectively identify and determine solutions that help support reliability depending on their individual risk tolerances.