Natural Gas Supply Disruption: An Unlikely Threat to Electric Reliability

Behind the Trump administration's ongoing arguments for bailing out coal and nuclear plants is the specter of fuel supply shortages at natural gas plants as a major vulnerability on the nation's power grid. We previously found bulk power market interventions, as proposed by the administration, would not improve electric reliability because the majority of service disruptions occur elsewhere on the grid. Still, federal officials warn the nation's diminishing coal fleet and increasing reliance on natural gas pose new threats and the Federal Energy Regulatory Commission (FERC) is under pressure to prioritize resilience. Here we assess the potential implications of a disruption to natural gas supply. Specifically, we consider the impact of an unprecedented disruption of the flow of natural gas from the entire length of a pipeline. We find that should such a disruption occur in any one of the five FERC-regulated wholesale electricity markets in the Eastern Interconnection, there would still be sufficient levels of generating capacity to meet peak demand and maintain reliable electric service.

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The US Electric Power System: Reliability First

Regulators require electric system operators to keep reserves of electric supply available to ensure reliable and resilient operations even when demand is at its highest. To comply with reliability standards mandated in the Energy Policy Act of 2005, each North American Electricity Reliability Corporation (NERC) region makes sure that they have adequate generating and demand-side resources to meet peak demand. In other words, the NERC regions must demonstrate resource adequacy. In the event that an individual power plant falls offline unexpectedly, this surplus generating capacity—commonly referred to as a "reserve margin"—provides a buffer against potential disruptions. Reserve margins are based on assumptions about underlying factors such as peak load growth and imports from nearby regions.[1,2] Regulators usually set the level for these reserve margins between 10% and 17% of peak demand with the goal of minimizing bulk power service disruptions experienced by customers to no more than 0.03% of the year.[3]

Demand for electricity follows seasonal patterns, typically peaking in hot summer months when customers need air conditioning and to a smaller extent in winter months for electric heating. Outside these seasonal peaks, even more excess capacity is available, allowing large thermal generators to schedule maintenance during spring and fall (shoulder) months when demand is usually at its lowest.

Figure 1 shows the distribution of hourly electricity demand as a percentage of the peak for each region from July 2015 through June 2019. In all five regions, we find demand is at 95% or more of the peak during less than 0.05% of hours, and demand is more than 90% of the peak during around 1% of hours. This implies that electricity markets only experience peak demand during a few hours of the year. These few hours are when reserve margins are most important. The majority of the hours of the year are between 50-70% of the annual peak load.

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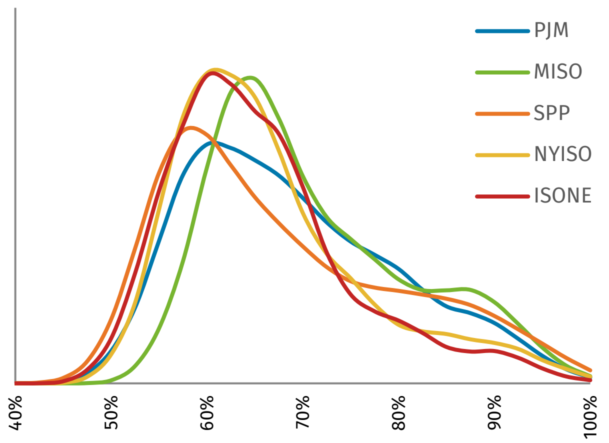
FIGURE 1

Distribution of hourly demand as a percent of maximum demand in each region[i]

Probability

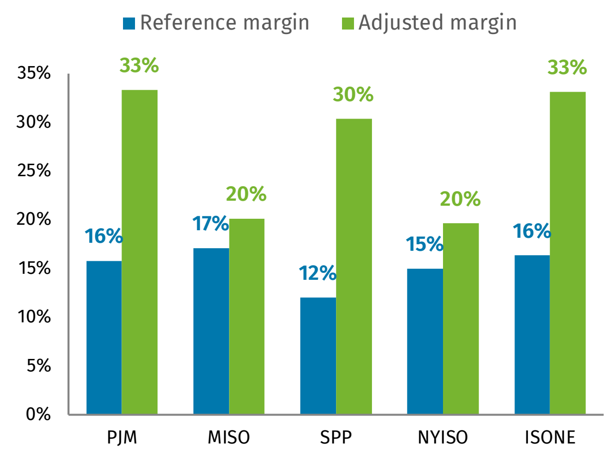


Source: EIA-930

FIGURE 2

Adjusted and reference capacity margins in 2021

Percent of peak load



Source: NERC Long-Term Reliability Assessment, EIA

Most regions that we focus on in this report have far more extra capacity—the actual reserve margin—than is needed to satisfy their regulated or "reference" level of reserve margin (Figure 2). Even under peak demand conditions, the regions we focus on in this report have more spare capacity than the minimum required to meet reliability requirements. This analysis focuses on the ability of each region to meet its total capacity reference reserve margin requirements as a proxy for resource adequacy.[ii]

Having enough operable generating capacity to meet peak demand is necessary, but not alone sufficient, to ensure electricity reliability across the entire grid. The bulk power system also includes transmission infrastructure–the system that moves electricity from power plants to local distribution systems. NERC has developed transmission planning requirements to ensure reliable operation over a wide range of system conditions and contingencies, including the loss of one or more system elements (such as specific transmission lines).[4] A reliable, interconnected transmission grid allows electricity to flow from one zone or region to meet demand during peak loads or if a large generator is forced offline.[5] While this report focuses on generation resource adequacy, local reliability depends on being able to generate enough power, move electricity across the transmission network, and then send it across the distribution network to customers.[6]

A Recent Shift Towards Gas Generation

The prevalence of natural gas is at the center of the Trump administration's argument that coal and nuclear plants must be prevented from exiting the market. It claims that too much dependence on natural gas will leave the nation vulnerable to pipeline disruptions. In 2007, coal and nuclear power plants combined made up 44% generating capacity nationwide and contributed more than two-thirds electricity generation in the US.[iii] About 70 gigawatts (GW) of coal plants and 4 GW of nuclear have retired since then, reducing the combined share of coal and nuclear to just over 30% of total US capacity and 47% of total US generation (Figure 3). Coal power plants in the US tend to be older, and most units have been operating for 40-50 years.[iv] Power plants that have retired since 2010 were older and less efficient than the rest of the fleet.[7] At the same time, persistently cheap natural gas and improved turbine efficiency have driven an increase in efficient combined-cycle generating capacity. Meanwhile, dramatic cost reductions in wind and solar photovoltaics (PV), as well as state and federal policy support, drove a near doubling of renewable capacity from 131 GW to 221 GW over the 2007-2017 period.

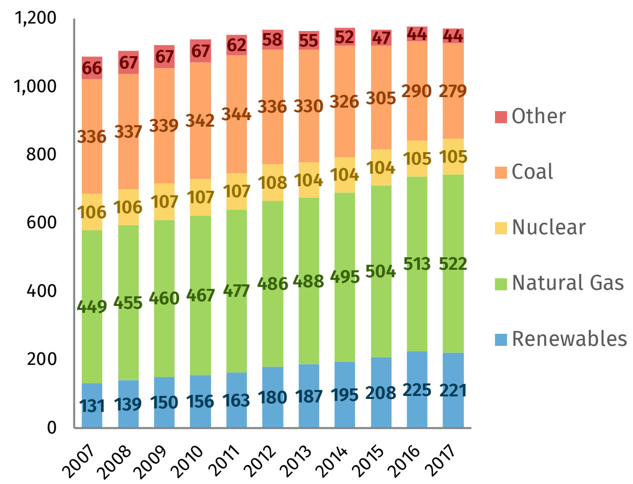
[i] Demand at or greater than 95% (90%) of peak happens in PJM 0.3% (1.0%), MISO 0.3% (1.3%), SPP 0.4% (1.2%), NYSIO 0.2% (0.8%), and ISONE 0.3% (0.7%) of hours. Data from EIA-930.

[ii] We use data on anticipated reserve margins from the most recent NERC Long Term Reliability Assessment (LTRA), and update it to include the latest planned retirements and additions. EIA publishes information on the natural gas pipelines that serve each power plant, which generators are able to burn fuel oil as a backup to natural gas, and the generating capacity of every power plant. By combining data from these sources, we can estimate how large of a disruption to the natural gas transmission system might be necessary to cause resource adequacy issues on the electricity grid.

[iii] Capacity values are from EIA AEO 2010. Generation values are from EIA-923.

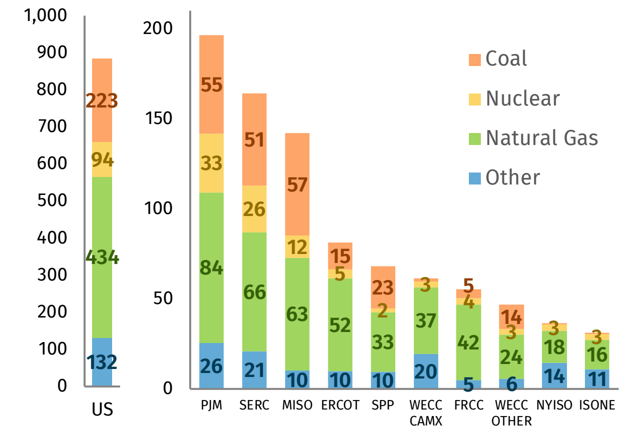
[iv] As of 2017, EIA calculated a capacity weighted average age of 39 years. EIA. (2017). [Most coal plants in the United States were built before 1990](https://www.eia.gov/todayinenergy/detail.php?id=30812). Energy Information Agency. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=30812.

FIGURE 3
US Generating capacity by fuel from 2007-2017
Gigawatts of net summer capacity



Source: Rhodium US Climate Service

FIGURE 4
Anticipated 2021 availability-adjusted generating capacity by fuel
Gigawatts



Source: Rhodium US Climate Service. Note: Other includes wind, solar, hydro and petroleum.

While all kinds of capacity count towards reserve margins for planning purposes, the value of different types of resources may be adjusted to reflect historical performance and availability. For example, coal capacity may be assigned a lower capacity value to reflect unexpected historical outages due to freezing coal piles in winter and other disruptions.

In 2021, we estimate that coal and nuclear will continue to make up around 35% of total US capacity, while natural gas will represent half of total US capacity (Figure 4). The capacity values in Figure 4 are based on NERC's 2018 Long Term Reliability Assessment (LTRA).[8] LTRA capacity values have been updated to include recently announced capacity additions and retirements, plus the upper bound of projected retirements in the Rhodium US Climate Service Taking Stock 2018 scenarios.[v] These capacity values are lower than those in Figure 3 because NERC lowers power plant capacity values to account for historical forced outage rates.[vi] Looking at the nation's bulk power markets, we estimate that, in 2021, coal and nuclear retirements, as well as natural gas capacity additions, will lead gas to become the single largest resource type in all markets on a capacity basis (Figure 4).

Focusing on the Bulk of the Electric Grid

In this report, we focus on five large, FERC-regulated competitive power markets that represent 60% of current customers and the bulk of the nation's coal and nuclear capacity. PJM Interconnection (PJM), the Midcontinent Independent System Operator (MISO), the Southwest Power Pool (SPP), the New York Independent System Operator (NYISO), and ISO New England (ISONE), shown in Figure 5, were home to 58% of total US electric generation in 2017, including 65% of existing coal capacity and 64% of existing nuclear capacity. We excluded the California Independent System Operator (CAISO) from this analysis because of the lack of significant coal generating capacity.

FIGURE 5
Electric power markets covered in this analysis

Source: Rhodium US Climate Service

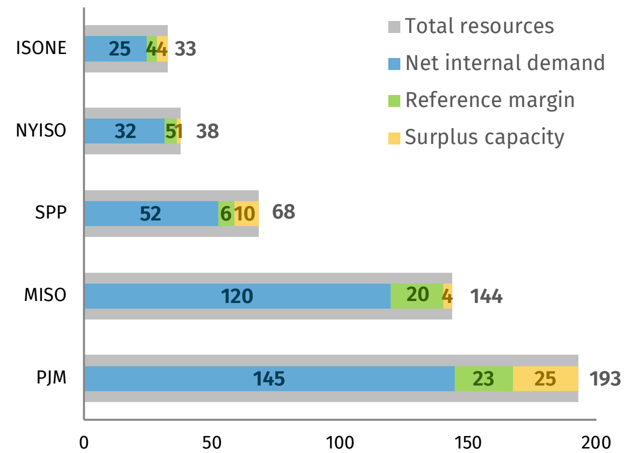
[v] We assume that the LTRA only includes retirements and additions announced through March 2018. These are supplemented with retirements and additions from the January 2019 EIA-860m and retirements from Rhodium's Taking Stock 2018.
[vi] NERC uses adjusted capacity values provided by each reliability area. Thermal power plants are adjusted by a historical forced outage rate (EFORd), and renewable resources are adjusted by a historical capacity factor value for the region. To simplify the analysis across regions, we use the full net summer capacity for thermal retirements and additions not included in the LTRA and adjust wind/solar capacity additions using values specific to each region.

Through 2021, these markets are where nearly three-quarters of planned or projected coal capacity retirements and 100% of planned or projected nuclear retirements are expected to occur. Even with these announced closures, we estimate that all markets maintain enough surplus generation resources to put reserve margins well above planning levels (Figure 6). Looking ahead, MISO and NYISO will have the smallest amount of surplus capacity above their reference margin in 2021.

FIGURE 6

Anticipated total resources, net internal demand, reference margin, and surplus capacity in 2021

Gigawatts



Source: NERC LTRA, EIA

Natural Gas Pipeline Disruptions Are Rare

While coal and nuclear plants keep fuel stockpiles on-site, natural gas is delivered by pipeline to power plants as needed for power generation, with almost no on-site storage. The Trump administration asserts that this just-in-time delivery makes natural gas resources inherently more vulnerable to disruptions and that the increasing dominance of this fuel could be cause for concern. In response, it's worth taking a look at what sort of events can limit or disrupt the flow of natural gas, how common these events have been historically, and how these pipeline disruptions might affect resource adequacy margins in large electric power markets. We are not the first ones to consider this issue. Several Regional Transmission Organizations (RTOs) and the Department of Energy (DOE) have assessed the interface between the electric power and natural gas systems and the implications for bulk power resource adequacy.[9]

Both planned and unplanned events can restrict or eliminate the flow of natural gas through a pipeline, causing a disruption in the normal supply of gas. Planned events, such as maintenance that has been coordinated with customers, are unlikely to affect bulk power system resource adequacy. Unplanned events range from the loss of a compressor station, which would reduce the available throughput of a natural gas pipeline, to the severing or rupture of a pipeline. The most severe disruptions can reduce or eliminate the flow of natural gas through a section of pipeline for several months.[10]

Based on an analysis of data from the Pipeline and Hazardous Materials Safety Administration (PHMSA), we find the US natural gas system typically deals with a handful of disruptions every month that last a day or more. Despite these disruptions, deliverability to end-use sectors, including electric power generators, is rarely impacted because of the redundancy built into the system. The power system has witnessed occasional disruptions to natural gas supply due to cold weather events. Cold winters increase competition between users of natural gas as demand rises for heating, which can reduce the availability of supply for users without firm contracts. PJM routinely reports on how its system faired in these events.

The largest natural gas supply-side disruption occurred during the Polar Vortex of January 2014—a winter so extreme that PJM experienced 8 out of its top 10 winter peak demand days of all time.[11] On the day with the tightest power supplies, natural gas power plant outages totaled 9.3 GW, 5% of total PJM capacity at the time. The event marks the largest natural gas supply shortage on record. It resulted in a similar magnitude of natural gas plant outages as the pipeline disruptions we model in this analysis. Though this is helpful for context, we note that the Polar Vortex overall put much more pressure on the power system at the time than is likely in a full pipeline disruption. In addition to the 9.3 GW of capacity forced offline due to lack of natural gas supply, an additional 30.9 GW of outages were caused by cold temperature equipment failures and frozen coal stockpiles. Despite losing 22% of total capacity due to these factors, PJM maintained "a reliable power supply for consumers" during this event.[12]

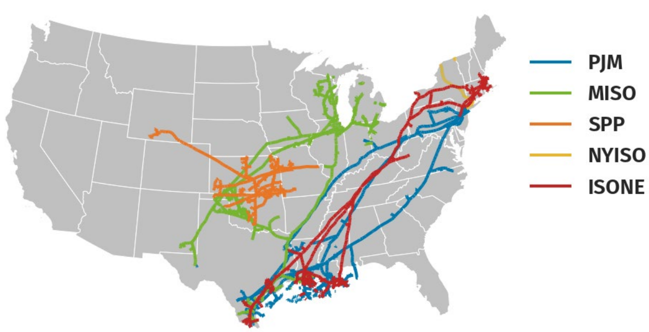
After the 2014 Polar Vortex, RTOs such as PJM and MISO took steps to further improve performance during cold weather operations. PJM adopted new capacity performance rules, which helped reduce the number of forced outages in PJM during the January 2018 cold snap to nearly half of what was experienced in the 2014 Polar Vortex.[13] MISO credits its improved market outcomes between the same two events, including a smaller difference in day-ahead and real-time pricing,[vii] with enhancements such as better electric-gas market coordination.[14] Poor coordination between natural gas and electricity markets can lead to situations where natural gas power plants are unable to easily access spare pipeline capacity, reducing available generating capacity and increasing electricity prices.[15]

Power Markets Have More Than Enough Capacity

Even though data shows the natural gas system has been incredibly reliable at delivering fuel to industrial, residential, commercial, and electric power customers, the Trump administration claims that enough risk exists to justify power market intervention on behalf of coal and nuclear assets to maintain resource adequacy. Here we consider what might happen if an unprecedented event were to occur: a large disruption forces one of the major gas pipelines shown in Figure 7 to become completely unavailable during peak electric load in one of the five regions considered in this analysis. We assess if a large natural gas transmission disruption could reduce available generating capacity below the reference margin for individual regions while taking into account anticipated generator retirements and additions through 2021.

FIGURE 7

The most critical interstate natural gas pipelines serving each region



Source: EIA, Rhodium Group analysis

For each of the regions described above, we calculate the generating capacity of natural gas power plants that rely exclusively on a single pipeline and don't have the capability to switch to an alternative fuel (such as diesel) that can be stored on site.[viii] ISONE has the highest percentage of natural gas generating capacity at plants that are dependent on a single pipeline for fuel (74%), and NYISO has the lowest (36%), with the other three regions between 61% and 67%. The total generating capacity at power plants with a single pipeline connection can be considered a rough and somewhat conservative measurement of the generating capacity directly lost if all gas were to stop flowing through the entire length of that pipeline.

To determine which pipelines are most critical to resource adequacy, we rank each based on the total natural gas generating capacity of all power plants that rely solely on that pipeline for fuel in each region. We assume that if a power plant is connected to more than one pipeline, then enough gas could be re-routed through other pipelines to supply it. Each generator with multiple pipeline connections is assumed to be available unless it is connected solely to the two largest pipelines in a region. The interconnected nature of pipeline networks would, in reality, make it very difficult to shut down all gas flow for the entire length of a major interstate pipeline, sometimes spanning over 1,000 miles.

Based on the assumptions described above, we estimate anticipated reserve margins in 2021 for each region based on retirements of coal and nuclear plants and then after accounting for lost capacity due to the complete disruption of the largest pipeline and second largest pipelines in each region.[ix] Losing all generating capacity dependent on the most critical pipeline in a given region would not be enough to threaten resource availability in any of the five regions (Figure 8). In the even more unprecedented event of losing two most critical pipelines serving the region, we find PJM, SPP, NYISO, and ISONE would still maintain enough capacity to meet their reference reserve margins, while MISO's reserve capacity would drop to 13% (1.8 GW below the reference level of 17%). Our findings are in line with those of PJM that there is no eminent threat and that issues arise only in if the most extreme scenarios come to fruition.[16]

[vii] Large differences in day-ahead and real-time prices "are usually due to congestion or reserve scarcity associated with load uncertainty or forced outages". MISO (2018).

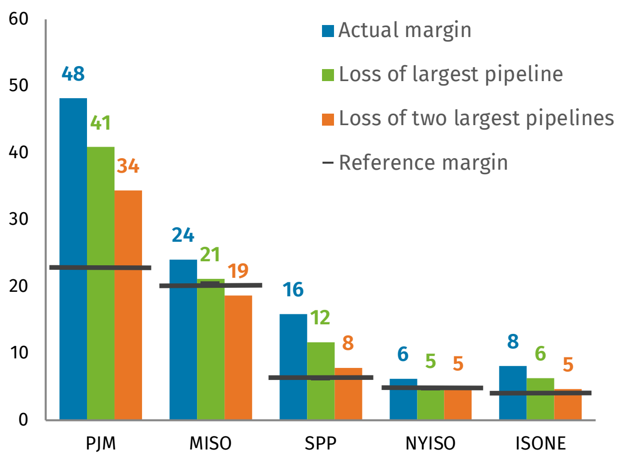
[viii] EIA-860 lists up to three pipelines (interstate or intrastate) and one local distribution company (LDC) to which every power plant is connected. We count the net summer generating capacity of power plants that connect to only a single inter- or intrastate pipeline.

[ix] For some of the pipelines, it would be nearly impossible to disrupt all natural gas flow to customers with a single event. For example, the ANR Pipeline, which serves power plants in MISO, spans 14 states and sources gas from Texas and Oklahoma, the Gulf Coast, and storage facilities in Michigan. We split the ANR pipeline into two segments due to its unique layout, separating the Northern and Southwest zones from the Southeast zones. TransCanada. (2014). *System Map ANR Pipeline Geographic Location*. Accessed at https://anrpl.com/documents/pipeline_map.pdf.

FIGURE 8

The largest possible effect on reserve margins from losing all natural gas capacity exclusively dependent on a single pipeline

Gigawatts



Source: NERC LTRA, EIA, Rhodium Group analysis. Note: Actual margin reflects available capacity adjusted to reflect historical performance and resource availability.

Electric Power System Resilience

The resilience of electric generators in the face of a fuel supply disruption, whether it is due to an unlikely large natural gas pipeline disruption, extreme weather events, or more routine supply disturbances, depends on several factors unique to each individual power plant and natural gas supply configuration. Here we walk through a non-exhaustive list of factors that can increase system resiliency in the event of a fuel supply disruption, including pipeline redundancy, dual-fuel capabilities, and natural gas storage.

Demand-side resources

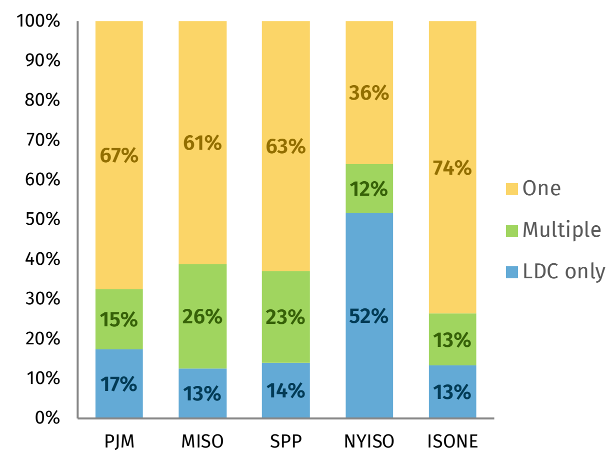
Losing generating capacity is only an issue if the remaining capacity is insufficient to meet demand. But demand is not immutable; it can be managed through energy efficiency, demand response, and distributed energy resources. These demand-side resources are a critical part of ensuring that customers are served by a reliable and resilient electricity grid.[17]

Pipeline redundancy

Unless it is dual-fueled, a natural gas power plant depends on real-time natural gas delivery to generate electricity. Therefore, any disruption that stops natural gas from flowing to power plants will reduce the generating capacity within a region. Because some power plants connect to more than one pipeline and others procure gas through a local distribution company (LDC) that may be served by multiple pipelines, not all power plants connected to a pipeline would be affected by a potential disruption. Over half of the generating capacity in NYISO obtains gas from the LDC. Local distribution companies themselves undergo internal planning processes to ensure that adequate supply is available (Figure 9). Including LDC connected generators is outside the scope of this analysis. ISONE has the largest percentage of capacity (74%) dependent on a single pipeline leading them to need extra redundancy elsewhere in the fuel supply and generation systems.

FIGURE 9

Percent of natural gas capacity that receive gas from one pipeline, from multiple pipelines, or exclusively from a local distribution company



Source: EIA, Rhodium Group analysis

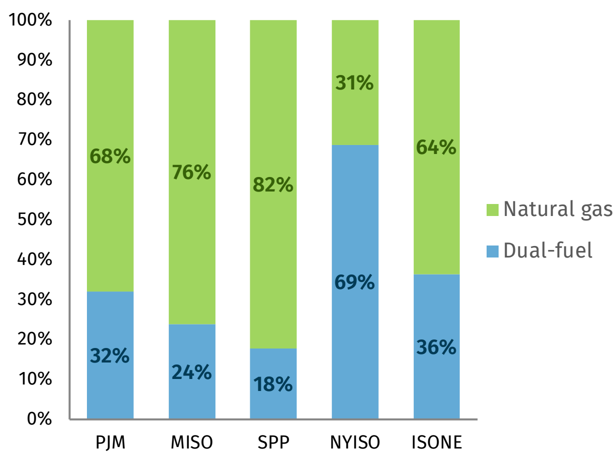
In addition to power plants having multiple pipeline connections, the natural gas transmission system is an extensive interconnected network with the ability to route gas through multiple pathways around disrupted segments.[18] Some pipelines have increased their capacity in a single right of way through a process called pipeline looping, where multiple physical pipelines run parallel with each other.[19] This increases the capacity and resilience of the pipeline system and is currently how natural gas supply disruptions are easily routed around to ensure adequate supply to the end-use sectors. Because of this design, disrupting the flow of natural gas at one point in a pipeline may not shut down gas flow for all downstream segments. 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.

Dual-fuel capabilities

In the unlikely event of a natural gas supply shortage, a large portion of natural gas plants can also use oil-fired generation for back-up. Figure 10 shows that dual-fuel capable gas capacity ranges from 18% of total gas capacity in SPP to as much as 69% in NYISO. During times of tight winter natural gas supply, PJM, NYISO and ISONE, in particular, have been known to switch their dual-fuel units to oil-fired generation and could have fuel on-site year-round to increase the resiliency of their systems.[20] In its 2018 fuel security study, PJM did find that oil tank replenishment rates could be limited at smaller generators (less than 100 MW) due to restricted truck receiving and offloading capabilities.[21] This means that during an extended natural gas supply disruption, some dual-fuel facilities may not be able to generate as often as they would otherwise be dispatched.

FIGURE 10

Percent of natural gas power capacity that can burn both gas and fuel oil (dual-fuel) or only natural gas



Source: EIA, Rhodium Group analysis

Natural gas storage

In addition to the vast network of pipeline connections and the distribution of different production points that feed into the pipeline system, an array of natural gas storage is located throughout the country. Unlike electricity, natural gas is a physical commodity that can be stored for long periods. The amount of natural gas in storage varies throughout the year and is usually between 1,000 to 4,000 billion cubic feet (Bcf).[22] For reference, the US daily natural gas burn in 2018 for all end-uses was approximately 80 Bcf.[23] Though this analysis did not quantify withdrawals from natural gas storage, data shows that, on average, several weeks of natural gas demand exists in storage throughout the country. Depending on where a hypothetical natural gas pipeline disruption occurs, significant natural gas supply from storage may be available for back-up.

Focus on the Real Reliability Crisis

Rather than examining dozens of different scenarios, we look at what sort of natural gas pipeline disruption would be necessary to reduce available capacity below reference margins in each region in the most extreme event. It is important to remember that electricity reliability is only impacted if the available capacity is unable to meet demand. Reference margins already account for contingencies and assume that some generators will be offline. Additionally, they are conservatively based on the annual anticipated peak. Daily demand is less than peak demand 95% of the time, meaning in those hours, additional excess supply is available to meet demand. The impacts of a natural gas pipeline disruption will depend on circumstances like the location of the disruption, whether the pipeline is looped (multiple parallel pipelines), where it interconnects with other pipelines downstream of the disruption, and whether it connects to any storage reserves downstream of the disruption. If delivery from the primary pipeline is not possible, the plant might be able to rely on a second pipeline for natural gas or burn fuel oil if it is dual-fuel. Only under unprecedented circumstances, where demand is at or near peak and more than one gas pipeline is completely disrupted, will an electric power region have to deal with insufficient resources.

Based on our analysis, we find that natural gas fuel supply disruptions will not bring available generating capacity below reference margins in large competitive power markets in the Eastern Interconnection, even when we account for announced and projected retirements through 2021. In the unlikely and unprecedented event of a disruption to the largest natural gas pipeline in each region, all of the regions considered in this analysis will continue to have generating capacity that exceeds their reference margins. There is no need to shore up retiring coal or nuclear plants in an effort to maintain these same reference margins.

If regulators' goal is to address reliability, they need to respond to the high-probability threats and situations of the transmission and distribution system that are likely to turn the lights off for US homes and businesses. As the data shows, distribution disruptions and extreme weather are by far the leading cause of US power outages[24] and these are becoming more frequent and damaging with climate change according to the Third National Climate Assessment.[25] Policy attention and resources would be better devoted to addressing these real threats to reliability.

Disclosure Appendix

This research was prepared for the American Petroleum Institute and is part of a two-report series. The research was conducted independently by Rhodium Group, LLC. The findings and views expressed in this note are the authors' alone. The authors would like to thank Gillian Giannetti, Natural Resources Defense Council; Robbie Orvis, Energy Innovation; Michael Panfil, Environmental Defense Fund; Sarah Ladislaw, Center for Strategic and International Studies; and Avi Zevin, Institute for Policy Integrity for comments and feedback on an earlier version of this report.

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