Power plant – gas grid dependence

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Abstract

This thesis contributes new knowledge about the effect of the gas grid on the power generation sector and how this effect could inform grid generation resource planning.

In chapter 2, I explore how reliability event reporting standards for operators of the natural gas grid compare to the requirements for power generators. Informed by a quantitative comparison of the numerical thresholds of reporting for gas grid and power generator failure events, I recommend a new reporting requirement for the gas grid that will bring it into line with the requirements for gas-fired power plant operators.

In chapter 3, I examine why gas-fired power plants in the United States have failed because of fuel shortages. I analyze six years of data from a database of power plant failures called the Generating Availability Data System (GADS). Using pipeline scheduling data, I identify areas of the natural gas grid where enough pipeline space may be available so that increased priority fuel contacts could help mitigate fuel shortages at gas-fired power generators.

Chapter 4 examines the economics of distributed fuel storage as a mitigation option for gas shortages at power plants in areas of the U.S. where pipeline space was not historically available. I estimate the additional costs required for New England gas-fired generators to install either distributed compressed natural gas

(CNG) storage or oil dual fuel capabilities as fuel security measures at power plant sites. I construct fuel shortage mitigation supply curves using the cost estimates I develop. I also calculate simple payback periods of mitigation options using the cost estimates and foregone energy and capacity revenue stream estimates. I compare the costs of fuel storage options to those of battery storage and demand response incentives.

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Chapter 1 Introduction and Motivation

In 2008, the large-scale deployment of horizontal drilling and multi-stage hydraulic fracturing technologies at shale formations in the United States unlocked access to a vast pool of natural gas resources. Natural gas production accelerated so rapidly in some regions that in the following year, U.S. natural gas prices at the Henry Hub fell sharply from over $12 per million British thermal units (MMBTU) to just under $3/MMBTU in 2009. In the ten years since 2009, prices have remained mostly within the $2-5/MMBTU range at the Henry Hub. In the Eastern U.S., prices for gas produced in the Marcellus and Utica basins have been consistently $0.50-$1/MMBTU lower than the reference prices at Henry Hub (U.S. Energy Information Administration, 2019c).

Many experts agree that this period of depressed natural gas prices will last for a while. Just how long it will last is a topic hotly debated in the scientific community (see for instance Hughes, 2013).

As with the periods in the 1990s and early 2000s with natural gas price depressions, this new "natural gas boom" has brought about a build out of natural gas power plant capacity. In 2009, when the gas price fell substantially, gas-fired power plants provided 23% of U.S. electric power generated. In 2018, it provided approximately 35% (U.S. Energy Information Administration, 2019a).

On-peak capacity at natural gas power plants in North America increased from 360 GW to 432 GW over the same period (North American Electric Reliability Corporation, 2018).

This increase in natural gas' share of the power generation mix has brought about many advantages and technical challenges.

On the one hand, gas-fired power plants have played a key role in recent reductions of the carbon dioxide emissions of the power sector in the U.S. In this respect, natural gas generators provide a two-sided benefit – 1) at the power plant site, gas-fired generators produce lower carbon emissions per MWh than coal power plants (U.S. Energy Information Administration, 2017) and 2) the fast-ramping capabilities of natural gas power plants allow them to technically complement intermittent renewable energy alternatives like wind and solar better than some of their counterparts (e.g. coal and nuclear plants; Bird, et al., 2013).

On the other hand, a dramatic shift in the generation mix to any one fuel source, like natural gas, creates a dependence between critical infrastructures. In this case, the real-time reliability of the power generation fleet in some regions of the United States is, to some degree, tied directly to the natural gas grid's ability to deliver necessary fuel supplies.

This power plant – gas grid dependence was evident in the Northeast and Mid-

Atlantic during the early 2014 southward shift of the North polar vortex. In January 2014, frigid temperatures created a tug-of-war over the gas molecules in the regional pipeline network that pitted residential customers trying to heat their homes against power plants trying to supply much-needed electrons to the grid. In the PJM Interconnection, approximately 22% of power plant capacity was unavailable during the height of the "polar vortex." Roughly a quarter of the total was due to gas fuel unavailability.

To maintain reliability of the electricity system, grid operators meticulously plan for emergency situations in many ways. One line of defense on the generation side is to procure power plant capacity above and beyond what forecasts predict the peak demand for electricity will be. But when the system becomes heavily dependent on power plants that share a fuel supply infrastructure, such as gas generators in New England, demand shocks like the 2014 "polar vortex" test the limits of these emergency protocols.

While New England did not experience any blackouts during January 2014, the nearly 1,200 MW of simultaneous gas shortage failures contributed to the grid operator coming within 44 Megawatts (MW) of completely using the 620 MW of capacity it procured above their reserve requirement in case of emergency situations (ISO New England, 2014). For insight on how close ISO New England came to a deficiency in its reserve requirement, according to operational data from 2018, 44 MW is less than one third the capacity of the average natural gas generating unit in New England (U.S. Energy Information Administration, 2019b).

In this thesis, I expand our current knowledge of the effect of the gas grid on the power generation sector to inform grid generation resource planning.

In chapter 2, I explore the reliability event reporting standards for operators of the natural gas grid as they compare to the requirements for power generators. To do this, I explore multiple databases of failure event reports and the legislative language underlying those databases. I quantitatively compare numerical thresholds of reporting for gas grid and power generator failure events for the most comprehensive databases currently available. I recommend an additional reliability event reporting requirement for the gas grid that will bring it into line with the reporting requirements for gas-fired power plant operators.

In chapter 3, I examine why gas-fired power plants in the United States have failed because of fuel shortages. To do this, I analyze six years of data from a database of power plant failures provided by the North American Electric Reliability Corporation (NERC) called the Generating Availability Data System (GADS). I develop a systematic data matching process between GADS and various datasets from the U.S. Energy Information Administration that include key fuel supply information for power plants such as the plant's natural gas delivery contract status. To my knowledge, this is the first analysis of this type using actual power plant failure data that covers the conterminous United States. Using pipeline scheduling data, I identify areas of the natural gas grid where enough pipeline space may be available so that increased priority fuel contacts could help mitigate fuel shortages at gas-fired power generators.

Informed by the results of chapter 3, chapter 4 examines the economics of distributed fuel storage as a mitigation option for gas shortages at power plants in areas of the U.S. where pipeline space has not been historically available. With the GADS data for New England gas-fired power plants, I estimate the additional costs required for generators to install either distributed compressed natural gas (CNG) storage or oil dual fuel capabilities as fuel security measures at power plant sites. I examine CNG and oil dual fuel options at the system-level by constructing supply curves using estimates I develop for what fuel security measures would cost per MWh of generation at the affected units. I also examine mitigation options from the private-sector perspective by calculating simple payback periods of mitigation options using the cost estimates and foregone energy and capacity revenue stream estimates.

While focused mainly on the short-term, this work is important for both short-term and long-term power system planning. The case study in Chapter 4 of New England is especially important with respect to planning horizons because political opposition has created delays in natural gas infrastructure expansion into the region (see Gilmer, et al., 2017). These hurdles could make fuel storage on-site at generators a longer-term solution in New England than in other regions of the U.S.

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Chapter 2 A comparison of gas grid and power generation reliability reporting standards[1]

Abstract

According to data from the U.S. Department of Transportation, hundreds of times each year the natural gas pipeline system fails. Data from the North American Electric Reliability Corporation suggest that sometimes these pipeline failures shut down electric power plants. Assessing the reliability implications of these pipeline failures is difficult because the numerical thresholds for pipeline failure reporting are misaligned with those for power plant failures. Pipeline incidents that are severe enough to trigger a mandatory power plant outage report should be reported. Furthermore, Congress should replicate what it did for electric power and charter the establishment of a national natural gas pipeline reliability organization. This organization should provide public access to and analysis of pipeline reliability data that are not deemed a threat to national security.

[1] A shortened version of this paper was published as: Freeman, G. M., Apt, J., & Dworkin, M., (2018). The gas grid needs better monitoring. *Issues in Science and Technology*, 34 (4), 79-84.

2.1 Introduction

We are familiar with large scale *electric grid* outages such as the September 8, 2011 Southwest blackout that hit San Diego at rush hour, and the August 14, 2003 Northeast blackout. Less familiar are failures in the U.S. *natural gas pipeline system*. But they occur.

According to data from the North American Electric Reliability Corporation, fuel-starvation outages at gas power plants happened at an average rate of a thousand events per year between January 2012 and April 2016. Fuel shortage failures affected one in five natural gas plants in the USA during those four years (North American Electric Reliability Corporation, 2019a).

Because data on the reliability of the natural gas pipeline system are almost impossible for anyone to find, our team spent a year meticulously combing through the reports filed by power plants – not pipelines – to count these outages. To our knowledge this is the first time anyone has done this.

Unlike electric power generator failures, in most states, gas pipeline outages are either not recorded or not available without a Freedom of Information Act request. Being able to analyze and predict both system's reliability characteristics is essential to reducing the likelihood of huge monetary losses like the $3.6B in increased electricity costs experienced in New England during the Polar Vortex of 2014 (Mohlin, et al., 2017).

Roughly half of the electricity traded in New England's bulk power market is generated by natural gas power plants. Electricity prices on wholesale markets are set in a uniform price auction to supply enough power to meet expected demand. In such an auction prices are set by the highest bid submitted by the power plants needed to generate electricity for the grid during any given hour. In New England the market price is set by a natural gas power plant almost three quarters of the time. This provides a direct pass-through of natural gas costs into the bids in the power market. Usually that results in reasonably low prices. But when the gas system experiences an outage or a major pressure drop, scarcity can drive prices to extremely high levels (Mohlin, et al., 2017).

Here's why. To avoid the added expense of reserving permanent space on the few pipelines that pump gas into New England from elsewhere, many power plant operators buy gas on the secondary spot market (sometimes called the capacity release market). The secondary gas market is set up so companies that own permanent capacity on pipelines can sell the portion of their reserved pipeline capacity that they do not need at unregulated prices. It is typically less expensive for power plants to buy firm gas supplies from the secondary market than to buy permanent capacity on the pipeline itself as shown in Figure 2.1. (Mann-Whitney U-Test, fuel cost at plants that used long-term firm pipeline contracts > fuel cost at plants that used the spot market to procure firm pipeline space, p-value << 0.001) (U.S. Energy Information Administration, 2018c).

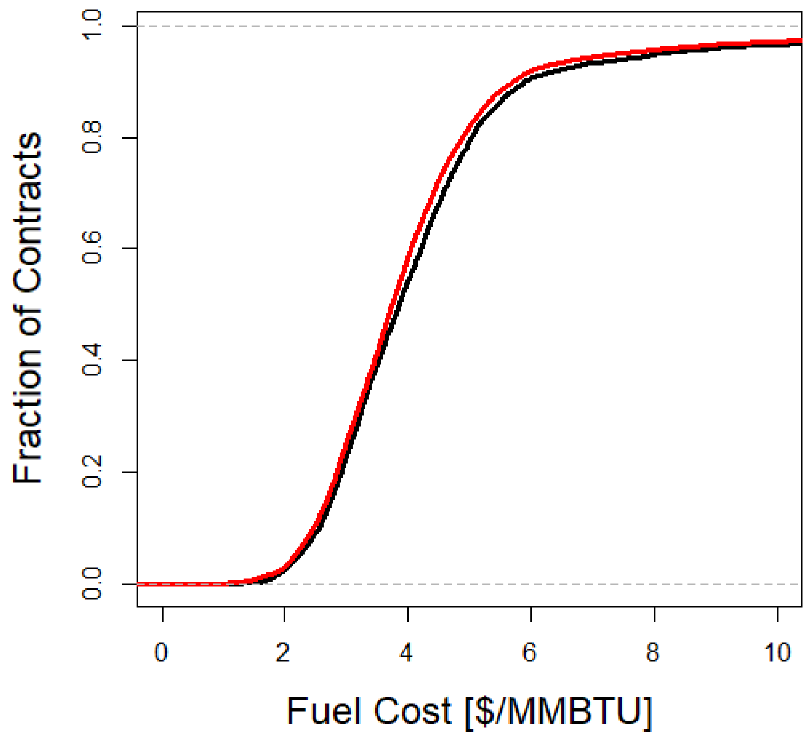

Figure 2.1. CDF comparison of fuel costs at power plants that held long-term firm pipeline contracts (black) and fuel costs at plants that procured firm pipeline capacity through the spot market for their fuel supplies (red) between 2012 and 2016 (U.S. Energy Information Administration, 2018c).

But, when demand for gas spiked due to heating loads during the Polar Vortex, the supply of pipeline space available on the secondary market was not adequate to fulfill power plant demand and higher cost oil power plants were forced to pick up the slack. The consequences of these events were astronomical wholesale electricity price increases from a weighted average of around $50/MWh to almost $500/MWh (see Figure 2.2) (Babula, 2014 and U.S. Energy Information

Administration, 2018e).

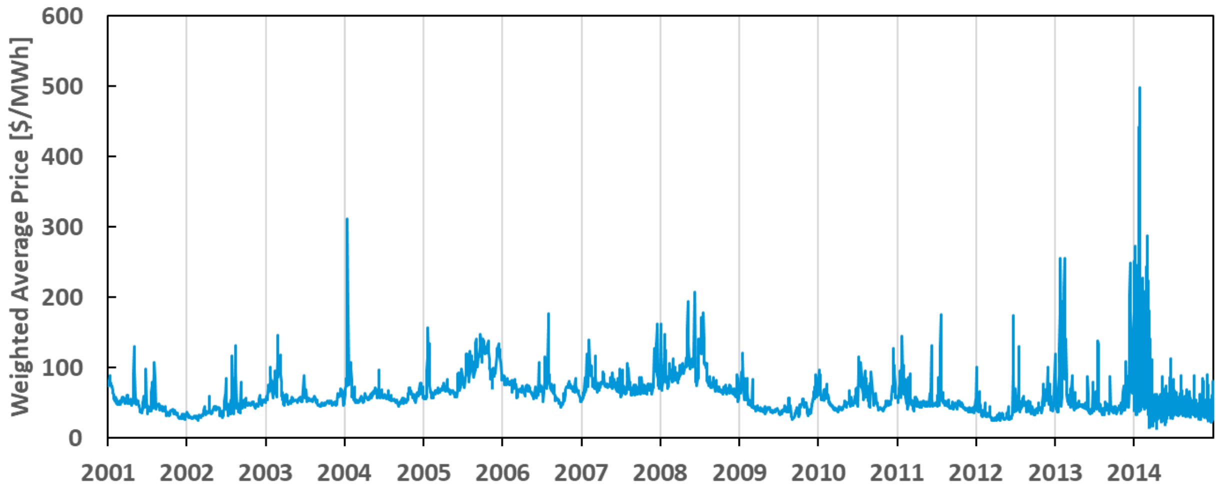

Figure 2.2. Weighted average price of wholesale electricity traded at the New England Mass Hub 2001-2015 (U.S. Energy Information Administration, 2018e).

Only by combining accurate data from the gas system with existing data on power plant outages can we understand the situations where extreme temperatures cause demand for both gas and electricity to skyrocket, driving up prices on the spot markets and causing this sort of snowballing financial debacle.

An operational failure on a key pipeline serving an area like Algonquin in New England would similarly starve power plants of gas supply creating the same sort of financial meltdown. When these natural gas pipeline failures occur, there is no central source to which they are reported.

For power system reliability, it is important to know how often, where and why pipeline failures occur. This is because power plant operators are limited in the measures they can take to prepare themselves for gas interruptions.

Depending on the characteristics of the power plant, storing backup gas supplies at the generator site may be an impractical mitigation strategy because the required tank farm to hold compressed gas for just one day's power plant operation would increase the plant's footprint by 5-10%, and that doesn't even consider the ancillary equipment required to support the gas storage (See Calculations). The added equipment and land requirement may prove to be an economic impediment from taking this mitigation approach (we will examine this in chapter 4). Liquefied natural gas storage, even for a few hours' worth of plant operation, is very expensive. And underground storage at the plant is equally impractical for most plants. Another option is fuel-switching. But, only one quarter of gas power plants can switch to oil without halting operation and about 40% of those plants report restrictions to the duration of their secondary fuel operation because of "storage limitations." These on-site storage limitations can include limited-volume fuel tanks, air permit limits[2], or other unspecified limitations to the plant switching fuel. The EIA does not specify a numerical threshold on reporting storage limitations, this is left to the discretion of the

[2] Plants must obtain an air permit that at least meets federal emissions guidelines before they can operate. The air permitting process is carried out at the local level using the federally approved implementation plan of the plant's locality (typically state, sometimes county). However, locality permitting guidelines can be more difficult to achieve than the minimum federal standards. How difficult it is to obtain an air permit depends on a large number of factors including, but not limited to, plant design and size, and locality non-attainment status. The U.S. Environmental Protection Agency's current goal is to issue air permits for all new projects within 6 months of receiving applications by the year 2022. Historically, the varying stringency of the approved local implementation plans has created a permitting time period that could range anywhere between 6 months and several years (Appleyard, 2017).

respondent (U.S. Energy Information Administration, 2018c).

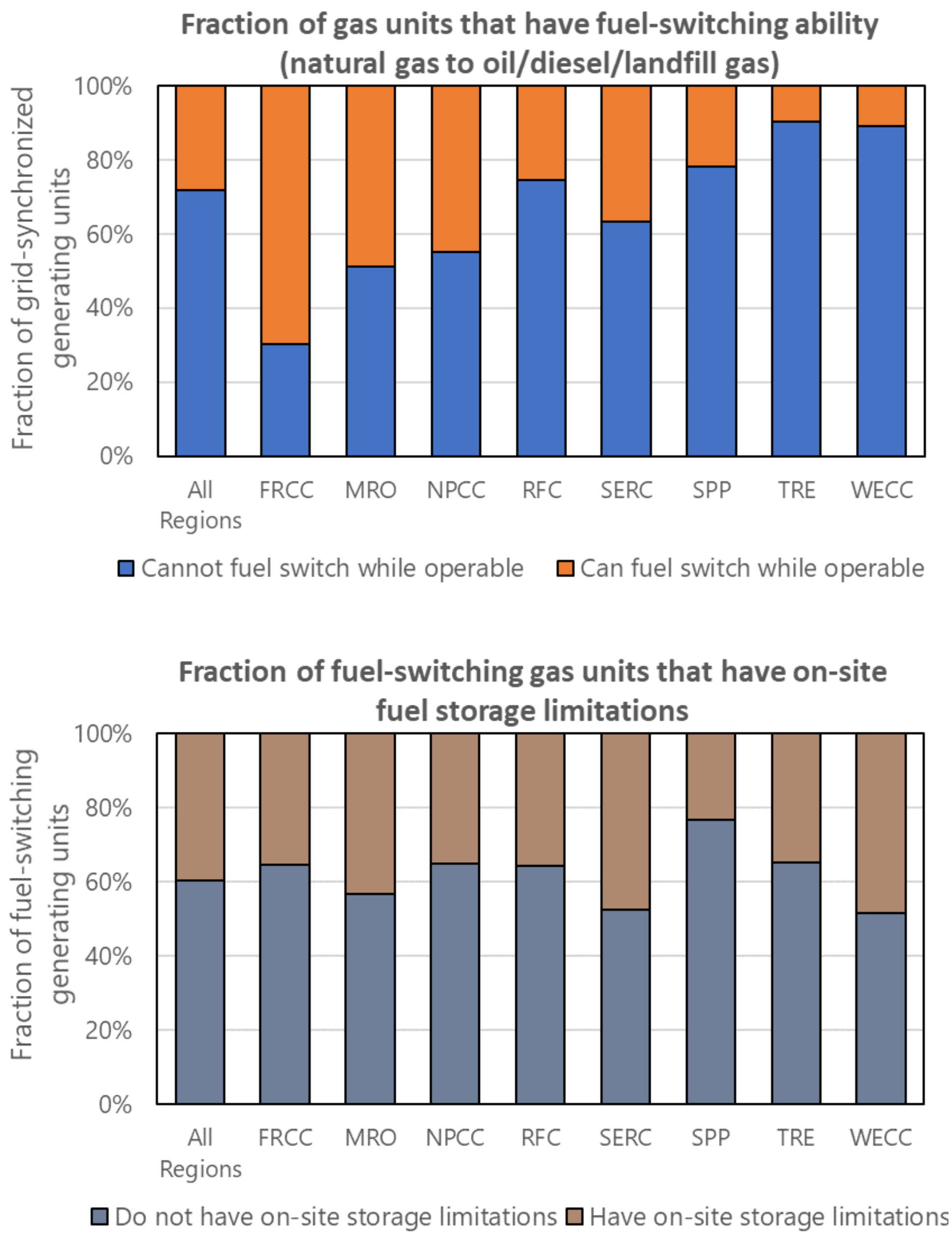

Figure 2.3. Stacked percentage bar charts of the fraction of generating units that are able to fuel switch (top) and the fraction of fuel-switching units that have on-site secondary fuel storage limitations (bottom) - 2016. These limitations include air permit, fuel tank volume or other unspecified limitations (U.S. Energy Information Administration, 2018b).

The plants that do not have fuel-switching abilities are tied to the real-time reliability of the natural gas network. When emergency situations arise on the natural gas grid, pipeline operators turn to a load-shedding protocol that outlines the order in which customers will have their gas supply turned off. The shedding of load restores operational stability to the gas grid in situations of high stress.

On the other side of the gas meter, however, as pipeline operators carry out their load-shedding procedure to restore stability to the gas grid and shut off fuel supplies to gas power plants, the burden of meeting demand for electricity is shifted to other power plants. If the generation shifting creates a large enough stress on the electricity network, other power plants sometimes fail, creating further instability on the electric grid.

Under current reporting requirements it is possible to get only an incomplete picture of the frequency of these kinds of interdependent natural gas/electricity infrastructure failures. One typical event affected pipeline operations in the Midwest in the second half of May 2017. During that event, caused by maintenance, a pipeline operator alerted its power plant customers that it reserved the ability to limit their hourly gas deliveries to one-sixteenth of their scheduled amounts (Energy Transfer, 2018). If this had occurred during a period of high demand for electricity, or as an unanticipated outage, the consequences could have been a blackout.

2.2 Gas-electric interdependence

In February 2011, an extreme weather event hit the Southwestern United

States chilling local temperatures to as low as 30 degrees below zero. The temperature dropped so low in places that water vapor at natural gas wellheads froze, restricting flow from production areas to the residents of the area. Simultaneously, regional power plants failed to keep up with electricity demand due to inadequate planning for the unexpected cold weather. The Electric Reliability Council of Texas (ERCOT) reported that over the first four days of February, 152 individual generator units at 60 power plants in Texas didn't provide the electricity they promised, triggering the initiation of rolling blackouts. More than 75% of the units reporting forced outages in Texas relied directly on natural gas as their primary fuel source. On the first night of the event, more than 8,000 MW of power generation unexpectedly dropped offline; that was 12% of the entire installed capacity of the ERCOT electricity grid (Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, 2011 and U.S. Energy Information Administration, 2018b).

Further compounding the problem, a segment of the regional pipeline system that shipped natural gas from the production wells in Texas, that were not frozen, to markets in New Mexico and further West relied on Texas grid electricity to power its compressor stations. When the rolling blackouts started, the electric compressor stations shut down, and the gas pressure in the regional pipeline system fell starving customers in New Mexico of much-needed natural gas for heating. When all was said and done, 28,000 natural gas customers in New Mexico were forced to find other ways to protect themselves and their families from the bitter cold (Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, 2011).

An internet search yields newspaper coverage and government hearing documents related to the February 2011 incident; but these events are absent from publicly available incident databases. The gas service interruptions do not appear in the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Accident and Incident Database, the only readily-accessible central database of significant incidents on both inter- and intrastate pipelines available at the time (Pipeline and Hazardous Materials Safety Administration, 2018a).

Failures of electric generators or the grid are reported to state utility commissions, the federal government, and to the North American Electric Reliability Corporation. It is of serious concern that we know much less about outages in the growing natural gas infrastructure. In this regard, there should be a level regulatory playing field. But there is not.

As of 2017, data from the Homeland Infrastructure Foundation-Level (HIFLD) Database detailed that only about 5% of natural gas transmission compressor stations nationwide were powered solely by electricity (U.S. Department of Homeland Security, 2017). The natural gas outage in New Mexico emphasized the gas grid's reliance on the steadfast operation of the electric compressor stations to provide critical heating fuel supplies. The fact that we have good data on failures in only one of these networks (electricity) puts us all at risk.

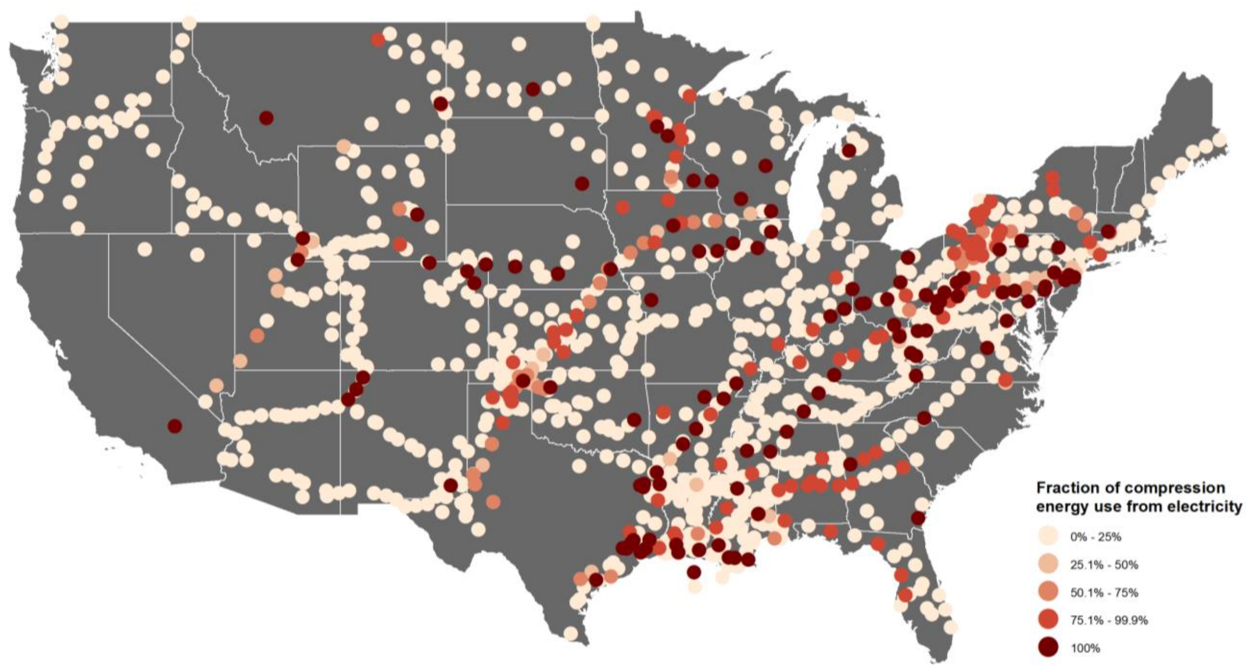

Figure 2.4. Map of natural gas compressor stations on transmission pipelines in the U.S. The red color ramp represents the fraction of compression energy use from electricity. All of the darkest red dots are compressor stations that used 100% electricity for compression in 2017 (U.S. Department of Homeland Security, 2017).

We should be concerned not only about pipeline outages, but also about the USA's huge seasonal natural gas storage facilities. The purpose of gas storage is to provide operational reliability during the months of high gas demand by pumping gas into storage during low-demand periods then pumping gas back out into the pipeline network when it is needed. Special geological formations such as depleted gas fields, aquifer reservoirs, and salt caverns are used to store the seasonal natural gas.

When large storage facilities fail, they wreak havoc on fuel supply stability for power generators. In October 2015, a seven-inch injection well casing at the Aliso Canyon natural gas storage field in Southern California failed, creating the largest natural gas leak in United States history. Nearly four months passed as the operator and emergency responders worked to contain the leak. A joint task force consisting of representatives from the California Public Utilities Commission, Energy Commission, Independent System Operator, and the Los Angeles Department of Water and Power convened to discuss measures to prevent possible power outages in the summer caused by shortages of gas supplies for power plants (California Public Utilities Commission, et al., 2016). The result was the expedited approval of over 100 MW of battery storage projects including the 20 MW, 80 MWh Mira Loma project estimated to cost California ratepayers between $20 and $40 million (Pyper, 2017).

As with the New Mexico event, the Aliso Canyon event also received significant media coverage, but there is no database entry in PHMSA or anywhere else (Pipeline and Hazardous Materials Safety Administration, 2018a). PHMSA did not gain jurisdiction over gas storage facilities until almost a year later.

2.3 Partial gas failures are also a problem

Complete natural gas outages are not as common as failures that drop the pressure in the pipeline. Power plant facilities are designed to receive natural gas from pipelines at a contracted pressure and volumetric flow rate based on available pipeline capacity and their generator equipment specifications. For example, two common natural gas turbines built by General Electric (GE), the 50-megawatt (MW) model LM6000 and the 85-megawatt 7EA, require incoming natural gas pressures of 290 and 675 pounds per square inch (psi), respectively (General Electric, 2018). The Natural Gas Supply Administration reports that natural gas is typically transported in interstate pipelines at pressures between 200 psi and 1,500 psi (Natural Gas Supply Administration, 2018). The lowest pressure interstate pipelines require power plant operators to maintain additional on-site compression equipment to run either model of the GE turbines. Pressure reductions on the lowest pressure interstate pipelines add stress to these on-site compressors. Even for the highest-pressure pipelines, a 55% drop in pressure would put a generating unit using the 7EA at risk of operational failure. An event causing an 80% reduction would put the LM6000 at risk of operational failure.

The problem is that it is hard to tell using public information when these pressure reduction events occur. The closest we can get from the pipeline side is through notices posted online by gas pipeline operators informing their customers a day or two ahead of time when they anticipate the need to impose physical constraints to protect the operation of their systems. These pipeline Operational Flow Orders (OFOs) can be issued because of an imbalance between scheduled or actual injections and consumption, pipeline or compressor failure, maintenance, weather, or any other unforeseen situation. Volumetric gas shortages and system pressure situations that do not necessarily create a complete outage can also trigger an OFO. Pipeline operators enforce OFOs by charging an additional fee for any volume of gas a customer moves on the pipeline in excess of the amount they scheduled the previous day. It is possible to search each pipeline's bulletin board website for OFOs as an estimate of how often situations that could create pressure reductions occur, but doing this is so time consuming that no comprehensive study has been done. Furthermore, the availability and frequency of these notices is pipeline specific.

To get an idea of how often OFOs occur, we studied the pipeline with the largest number of natural gas power plants closely connected to it, Transcontinental (U.S. Energy Information Administration, 2018b). For this major pipeline, 21 OFOs were issued between August 2014 and April 2016. That's about once a month (Williams Corporation, 2018). We know that during at least

6 of these OFOs, an actual gas imbalance was present within a Transcontinental zone where gas power plants reported failures due to fuel shortages. Ninety five percent of the 290 power plant failure events were due to interruptible fuel supply contracts that allowed Transcontinental to turn off gas supply to those power plants first to stabilize the pipeline system. The remaining 5% of failures affected more than 900 MW of capacity at 4 power plants in the Northeast (North American Electric Reliability Corporation, 2019a).

From the power plant side, the closest we can get to a ballpark estimate of the number of partial outages on the gas pipeline network is through reports of fuel-starvation power plant de-rating (partial outage) events. According to data from the North American Electric Reliability Corporation, nationwide, these fuel-related, partial outages at gas power plants happened at an average rate of 230 events per year between January 2012 and April 2016 (North American Electric Reliability Corporation, 2019a).

But lax reporting requirements make it impossible to know the specific cause of these plant failures reported as lack of fuel. Did the plants fail to adequately schedule their gas supplies in the day-ahead gas market? Was there actually a physical pipeline failure? Or, something else entirely? The whole picture is murky, at best.

2.4 We need a level regulatory playing field

Recent lessons in interdependency between the gas and electric grids are a call to action to better align data availability of both grids' operational characteristics. We need commensurate reporting requirements for both systems. This is not a new message. In 2013, the North American Electric Reliability Corporation (NERC) released phase II of its special reliability assessment report entitled "Accommodating an Increased Dependence on Natural Gas for Electric Power." NERC identified a lack of "compiled statistical data on gas system outages that would be the equivalent to [the electricity plant Generating Availability Data System (GADS)] databases." NERC called upon the natural gas transmission sector to work with them on recommendations for data to be included in a central pipeline outage database with the purpose of conducting reliability analyses of the dual-grid system (North American Electric Reliability Corporation, 2013).

NERC's message has been heard in the academic community. Currently, academic teams across the country, ourselves included, are exploring the issues presented in the special reliability assessment. But nothing has been done in the ensuing four years to fix the data misalignment. We just don't know how vulnerable we are, and we don't know where to apply management attention to reduce the vulnerabilities.

Here, we explore the current federal reporting standards relevant to quantitative analysis of the reliability of the dual-grid system as they exist today and recommend a path of development for the central database recommended by NERC.

2.5 A Tale of Two Thresholds

For electric generators, the GADS Data Reporting Instructions outline specific, numerical thresholds for mandatory reporting. Events causing any power plant with nameplate capacity of 20 megawatts (MW) or greater (the vast majority of all plants) to fail at startup, to be completely unavailable unexpectedly, or to be unable to provide the full amount of power the plant promised to the grid must be reported. Power plant “de-rating” reports are mandatory for all events causing the equivalent of 2% or more of the power plant’s “net maximum capacity (NMC)” to be unavailable for 30 minutes or more. A cause identification code is included with every power plant failure report (North American Electric Reliability Corporation, 2019b). Between January 2012 and April 2016, over 1,000 failure events per year were reported by gas power plant operators claiming lack of fuel from the gas pipeline network (North American Electric Reliability Corporation, 2019a). The data from these reports are confidential, but aggregate data that is fine for measuring reliability has been published (Murphy, et al., 2018).

Reliability events for gas pipelines, on the other hand, are reported to various entities, but with reporting thresholds that vary by jurisdiction. The Federal Energy Regulatory Commission (FERC) has jurisdiction over operation of interstate pipelines; PHMSA for interstate and intrastate pipeline safety; and the state Public Utility Commissions (PUCs) for intrastate pipeline networks – mostly for local distribution companies. According to high-level mapping data provided by the Energy Information Administration, roughly 60% of natural gas power plants with capacity of 20 MW or larger are within five miles of an interstate pipeline (U.S. Energy Information Administration, 2018d). The remaining 40% are likely fueled by smaller, intrastate pipeline systems. Therefore, it is important that reliability data are available for both interstate and intrastate pipelines. Because the natural gas grid in the U.S. does not have a central reliability organization like the electricity grid does, compiled data sources that are sufficient to model interdependencies between the two complete systems are hard to find.

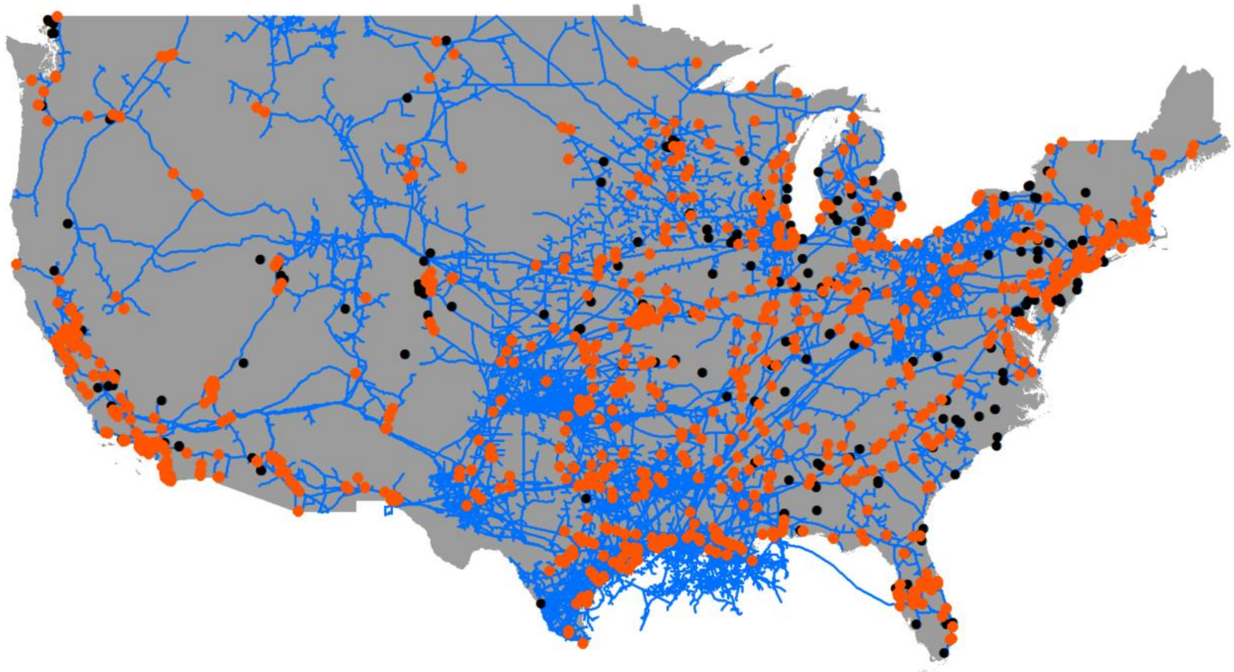

Figure 2.5. Map of contiguous U.S. natural gas pipelines and all 20+ MW gas-fired power plants. Orange markers indicate power plants within a 5-mile distance of transmission pipelines and black markers indicate power plants further than 5 miles from transmission pipelines.

One promising data source that could meet the needed criteria is outlined in 18 CFR § 284, Subpart I. The regulation states that FERC, through Form 588, requires "emergency transaction" reports from pipeline operators. An emergency transaction occurs as a result of "any situation in which an actual or expected shortage of gas supply would require an interstate pipeline company, intrastate pipeline, local distribution company, or [pipeline that is not under FERC jurisdiction due to stipulations in the Natural Gas Act] to curtail deliveries of gas or provide less than the projected level of service to any customer." The reporting requirements of the regulation could be read to require transaction records for both complete gas curtailment events (“curtail deliveries of gas”) and partial gas curtailment events (“provide less than the projected level of service to any customer”).

But this is only one way to read the rule. By our interpretation of the definition of an emergency transaction, the FERC-588 reports should capture the data that are needed to study reliability, but they don’t. The filings under FERC-588 and other gas pipeline emergency reports are available on FERC’s eLibrary website. Searching the eLibrary for emergency filings using the keywords “interrupt,” “outage,” or “curtail” produces 32 results from 17 unique pipeline events between 2012 and 2015. Most of the events were for gas flow diversions to avoid pipe segments taken out of service for maintenance. In these cases, the emergency transactions were brokered to avoid gas interruptions to customers (Federal Energy Regulatory Commission, 2018).

Unfortunately, despite the fact that multiple delivery-failures have occurred, only one report over the period details a service interruption that could have affected a power plant located on the pipeline. Thus, the FERC-588 data are no help in understanding the reliability of the natural gas system.

In January 2016, a 30-inch steel transmission pipeline in the Southwest ignited due to a rupture of the pipe material. The explosion caused service to be interrupted on the pipeline for 35 days as repairs were made. While crews at a western gas distribution utility worked to fix a leaky valve in July 2016, they accidentally struck a 4-inch plastic main, causing the gas to ignite. Extensive system damage occurred, 30 people were evacuated, and gas service was shut down for a day. In March 2011, a gas gathering line in the Gulf of Mexico was struck by a dredging operation and knocked out of service for over 250 days (Pipeline and Hazardous Materials Safety Administration, 2018a).

Not one of those events were reported to FERC.

As the FERC data are not very informative, the most comprehensive, easily accessible, centralized source remaining that captures both inter- and intrastate pipeline data is the Pipeline and Hazardous Materials Safety Administration (PHMSA) Natural Gas Distribution, Transmission & Gathering Accident and Incident Database. The one service interruption in the FERC data is also captured by the PHMSA database. These data have been gathered since 1970 and are filed by the pipeline operator. The data are compiled and catalogued with a description of each pipeline incident and its subsequent root-cause investigation. PHMSA makes these data available publicly on their website. The thresholds that trigger a mandatory report to PHMSA are outlined in 49 CFR § 191.3. They include an event that results in both a release of gas or hazardous liquid from the pipeline and at least one of the following:

1. “A death, or personal injury necessitating in-patient hospitalization;

2. Estimated property damage of $50,000 or more . . . excluding the cost of gas lost or;

3. Unintentional estimated gas loss of three million cubic feet or more.”

The legislative language also calls for any event that is “significant in the judgment of the operator, even though it did not meet the [previous] criteria . . . of this definition” to be reported. As PHMSA is a safety-centered organization, the thresholds focus on safety-related metrics; however, some of the fields on the forms that pipeline operators and investigators submit to PHMSA after an incident investigation capture important reliability metrics such as the system component affected, shutdown time, and the primary cause (Pipeline and Hazardous Materials Safety Administration, 2018a).

An analysis of the 673 PHMSA accident and incident reports for distribution, gathering and transmission pipelines between 2012 and 2015 shows that approximately 80% of reports met at least one of the automatic report conditions while 20% did not. The 131 reports that did not meet at least one threshold can be viewed as those “judged significant” by the pipeline operator. But, as mentioned in the section “Gas-electric interdependence”, the serious events at Aliso Canyon and in New Mexico are omitted from the data available on PHMSA’s website. This leaves us to wonder how many other “significant” events are missing from these data, or even what a "significant" event is judged to be.

The only way we can effectively study interdependent reliability is if the standards for reporting pipeline outages and power plant failures are sufficiently equivalent. In comparing the GADS and PHMSA reporting thresholds, it is evident that the language for reporting outage events at power plants is far more stringent than for gas pipeline outages. Again, this is probably because PHMSA's mission is safety, but there is no central reliability organization for the gas network.

As a quantitative example of this misalignment, if we assume that a 460 MW combined-cycle natural gas power plant (the median size of such plants – U.S. Energy Information Administration, 2018b) was designed to continuously provide its net maximum capacity and it does so 60% of the time, a little better than the EIA's reported 2015 operational average of 56.3% (U.S. Energy Information Administration, 2018a), the plant would consume the equivalent of between 1.6 and 1.9 million cubic feet of natural gas per hour at 60°F and atmospheric pressure (gas flow at these conditions is referred to in units of "standard cubic feet per hour," or "scf/h") (U.S. Energy Information Administration, 2018f – see calculations). That means that an unintentional release of 3 million cubic feet of gas to the atmosphere represents just under two hours of the power plant's full operation. Recall that for electricity-side reporting at this power plant, a complete power plant outage of any duration or a de-rating event equivalent to just 2% of the plant's capacity for 30 minutes or more must be reported; 2% of the power plant's capacity operating for 30 minutes would consume between 26,000 and 32,000 cubic feet of gas at 60°F and atmospheric pressure, a volume 100 times less than the PHMSA volumetric release threshold (See calculations).

But power plants are fueled by high-pressure natural gas supplies. Volumetric flow rate and pressure of the gas moving within pipelines are tied together. If we further assume that the above power plant is made up of GE 7EA turbine units operating at an incoming gas pressure of 675 pounds per square inch (psi), in one hour, the plant would consume roughly 40,000 cubic feet of gas at pressure (General Electric, 2018). And, a 2% derating for 30 minutes only represents roughly 600 cubic feet of gas consumption at pressure, 5,000 times less than the PHMSA threshold! (See calculations)

This simple example helps illustrate why we think it is wrong that the only numerical, operational threshold for automatic gas pipeline incident reporting to the most comprehensive database is the volume of gas released. Gas volume released, while important for financial, environmental, and safety reasons, is inadequate for system reliability analysis. Fluctuations in system pressure, or similarly volumetric flow rates, are the important system variables for gas system reliability as they characterize a pipeline company's ability to serve loads. Furthermore, as the language specifies, the explicit thresholds currently need be reported only if they occur simultaneously with an unintentional release of gas or hazardous liquid (Pipeline and Hazardous Materials Safety Administration, 2018a). Important reliability events without releases of gas from pipelines, such as reductions in operating pressure of the gas system, are left out of these explicit definitions. In the absence of more encompassing data, reliability analysts working with the PHMSA data are left to rely on the events that the operator judges to be "significant."

Perhaps more appropriate data are collected through other means and have been used internally for reliability assessments of the gas grid. We have not seen any hints or reasons to believe this is the case, but even if it is, an internal assessment isn't as good as having an open community reliability analysis. An open community reliability analysis would provide regulators and the many stakeholders of the gas grid with valuable information while also reducing the administrative burden of completing these analyses in-house. State agencies, academic institutions, trade organizations, businesses using gas for emergency backup generators, and large natural gas consumers – like power plants – should be provided access to pipeline reliability data that are not deemed a threat to national security. For power plants, these data are crucial for both siting of new power plants and existing capacity bid planning. Access to data that can capture events on both interstate and intrastate pipelines with the potential to affect the bulk power network should be provided outside the walls of government so experts across the country can analyze the reliability of the interdependent gas and electric grid systems on a level playing field.

2.6 First steps in the right direction

In September 2013, the National Association of Pipeline Safety Representatives (NAPSR), an organization with ties to the National Association of Regulatory Utility Commissioners (NARUC), released a document titled "Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations." Within the report, NAPSR identified that state regulators had 308 enhanced reporting initiatives in place that would require pipeline operators to report safety conditions above and beyond those required by federal standards. They also identified that 33 states had various types of enhanced reporting standards with specific reference to the regulation underlying the PHMSA reporting thresholds. These enhanced standards included lowered property damage thresholds, outpatient injury reports, and other modifications to the CFR § 191.3 language (National Association of Pipeline Safety Representatives, 2013).

One important set of initiatives identified by NAPSR are those that require pipeline operators to report outages affecting a specific number of customers, outages of a specific duration, or complaints of gas delivery pressure issues. At the time that the compendium was released, 20 states had one of these categorical reporting standards in place (National Association of Pipeline Safety Representatives, 2013).

The problem is that each of these 20 states has its own reporting thresholds with varying stringency. For instance, Pennsylvania requires reports of all gas outages affecting the lesser of 2,500 customers and 5% of total system customers (Commonwealth of Pennsylvania, 2018). Florida requires reports of outages affecting the lesser of 500 customers and 10% of total gas meters on the pipeline network (State of Florida, 2018). Washington requires reports of outages affecting more than 25 customers (Washington State Legislature, 2013). Wyoming requires reports of all service interruptions of any size (Wyoming State Legislature, 2018).

The state reports appear to be a step toward solving one piece of the reliability puzzle. But only three states, New Hampshire, Rhode Island, and Washington were listed by NAPSR as having a reporting requirement for system pressure issues (National Association of Pipeline Safety Representatives, 2013). As discussed in the section "Partial gas failures are also a problem", system pressure fluctuations without a complete gas outage can shut down gas turbines. One proactive state, Maine, requires reports of all gas interruptions longer than a half hour that affect other utilities' critical facilities (State of Maine, 2005).

Data accessibility is also state-specific. Some states, such as Wyoming and Pennsylvania make the records they collected publicly available on their state information portal websites (if you know what search terms to use to find these data - Wyoming State Legislature, 2018 and Commonwealth of Pennsylvania, 2018). In other states, the data from the records are referenced only as footnotes in annual pipeline safety reports or simply unavailable, requiring a Freedom of Information Act request to access the records.

2.7 A path forward

To properly manage an increasingly interdependent gas and electricity system, the federal government should build on the states' efforts in updating the reporting thresholds for natural gas pipeline incidents to better align with the power plant outage standards and create a national standard. We recommend that pipeline incidents of sufficient size to trigger a mandatory power plant outage report should be reported. This additional threshold should be a specific requirement of pipeline systems with active firm supply contracts with power plants. This recommendation is based on the agreement between the pipeline and the power plant that a firm contract implies – there will be no unplanned curtailment of natural gas service unless necessary in an emergency.

Construction of any new standards should be based on the average amount of natural gas heat input required to produce a unit of electricity (the power plant heat rate) and modified to correspond to the most stringent power plant outage standards. The new standard should also be periodically revisited or updated to account for technological advances.

For pipelines with firm gas service contracts to serve power plants of over 20 MW nameplate capacity, events that reduce the pipeline's ability to serve the plant by their respective pressurized equivalent of 25,000 standard cubic feet per hour (scf/h) should be reported. Pipelines with firm service contracts in place to serve power plants with nameplate capacity of 20 MW or less should report events that reduce the pipeline's ability to serve the plant by 900 scf/h. These thresholds are based on the average heat rates of an advanced combined-cycle power plant and a baseload distributed generation plant, respectively. They are scaled to represent 2% of the median plant's net maximum capacity in each category, the power plant reporting threshold (U.S. Energy Information Administration, 2018b).

During the development and implementation of this new standard, stakeholders of both the electric and natural gas industries should be consulted. We recommend that representatives from the American Gas Association, Gas Technology Institute, National Association of Pipeline Safety Representatives

(NAPSR), Pipeline and Hazardous Materials Safety Administration (PHMSA) and the North American Electric Reliability Corporation (NERC) should be consulted. During meetings with these groups, a key topic of discussion should be to better define what "an event that is significant in the judgment of the [gas system] operator" should include for natural gas pipeline incident reporting and to whom certain types of significant events should be reported. Additionally, care should be taken to identify the least amount of information required to complete operational interdependency analyses. Pipeline operators closely guard their data for internal use. The new standard should be crafted in a manner that preserves proprietary trade secrets while also identifying the information that must be collected to conduct reliability analysis of the whole pipeline network.

We also recommend that the government use the New Mexico and Aliso Canyon events as the impetus to follow the electricity sector's example by designating a central entity to oversee the reliability of the natural gas delivery system. After the 2003 Northeast electric blackout, through the Electric Policy Act of 2005 (EPAct 2005), Congress authorized FERC to appoint an Electric Reliability Organization (ERO) with authority to require mandatory reliability and reporting standards for electricity utilities throughout the United States. Congress should replicate what it did for electric power for the gas network.

The PHMSA data discussed earlier comes from an organization with the mission of "protect[ing] people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives" (Pipeline and Hazardous Materials Safety Administration, 2018b). Because safety is PHMSA's core mission, their data are unsuitable for conducting a thorough reliability analysis of the natural gas network. Instead, the effort to organize a central, NERC-like gas reliability organization could be spearheaded by a group with ties in both industry and government (for example, NAPSR).

Experts at NERC should provide guidance to the gas reliability organization. NERC's involvement in the early stages of this effort could provide not only important lessons learned during its own establishment, but the foundation for a collaborative relationship between NERC and its gas counterpart. In a country that produces the largest share of its electricity from natural gas, it is critical to coordinate reliability issues between the two grids.

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2.9 Appendix A: Supporting calculations

The table below outlines the assumptions and sources for the estimated land footprint increase at a 460 MW combined-cycle gas power plant created by storing one day worth of CNG onsite. The calculations follow the table detailing how storage volume requirements were estimated.

Table A.1. Inputs and assumptions used to estimate the land requirements for on-site CNG storage at an illustrative 460MW combined-cycle natural gas power plant.

Input	Min	Max	Source Notes
Land Footprint of Power Plant	20 acres	40 acres	(Natural Gas Supply Association, 2016)
Time Period for Storage	1 day		Assumption
Gas Volume Required for Storage Period	38MMcf	46MMcf	Calculation (From following section)
Storage Tank Capacity	170,000 scf		Equipment vendor – FIBA (modular, skid-mountable size)
Storage Tank footprint	44 ft x 8 ft		Equipment vendor – FIBA (modular, skid-mountable size)
Number of tanks required	220	270	Calculation
Total footprint for storage tanks	**1.8 acres**	**2.2 acres**	**Calculation**

As a numerical comparison of pipeline failure reporting standards from PHMSA and the GADS power plant availability database, we computed the hourly consumption of natural gas by a 460 MW conventional combined-cycle power plant operating at 60% capacity factor based on heat rate assumptions used in the U.S. Energy Information Administration's Annual Energy Outlook (U.S. Energy Information Administration, 2018f).

$$
\begin{aligned}
Q_{HHV} &= CF \times Capcity \times Heat\ Rate \div HHV \\
&= 0.6 \times 460MW \times \left(\frac{1{,}000\ kW}{1\ MW}\right) \times \left(\frac{6{,}600\ BTU}{kW-h}\right) \times \left(\frac{1\ scf\ of\ NG}{1150\ BTU_{HHV-gross}}\right) \\
&= 1.6\ MMcf/h
\end{aligned}
$$

$$
\begin{aligned}
Q_{LHV} &= CF \times Capcity \times Heat\ Rate \div LHV \\
&= 0.6 \times 460MW \times \left(\frac{1{,}000\ kW}{1\ MW}\right) \times \left(\frac{6{,}600\ BTU}{kW-h}\right) \times \left(\frac{1\ scf\ of\ NG}{950\ BTU_{LHV-gross}}\right) \\
&= 1.9\ MMcf/h
\end{aligned}
$$

The most stringent of the GADS reporting thresholds is the requirement for operators to report partial outage events equivalent to 2% reduction from maximum capacity for 30 minutes or more. We computed the equivalent volume of natural gas that 2% of a theoretical 460 MW combined cycle power plant's capacity would consume in a half hour.

$$
\begin{aligned}
V_{HHV} &= CF \times Capcity \times Heat\ Rate \div HHV \\
&= 0.02 \times 460MW \times \left(\frac{1{,}000\ kW}{1\ MW}\right) \times \left(\frac{6{,}600\ BTU}{kW-h}\right) \times \left(\frac{1\ scf\ of\ NG}{1150\ BTU_{HHV-gross}}\right) \\
&\times 0.5h = 26Mcf
\end{aligned}
$$

$$
\begin{aligned}
V_{LHV} &= CF \times Capcity \times Heat\ Rate \div LHV \\
&= 0.02 \times 460MW \times \left(\frac{1{,}000\ kW}{1\ MW}\right) \times \left(\frac{6{,}600\ BTU}{kW-h}\right) \times \left(\frac{1\ scf\ of\ NG}{950\ BTU_{LHV-gross}}\right) \\
&\times 0.5h = 32\ Mcf
\end{aligned}
$$

These figures are based on natural gas flow at standard conditions. Natural gas combustion turbines require elevated incoming gas pressure. We use the OEM recommended inlet pressure of a common General Electric turbine (675 psi) to approximate the volume of pressurized pipeline gas required to trigger the smallest of mandatory power plant failure reports. By Boyle's Law approximation:

$$V_2 = \frac{P_1 V_1}{P_2} = \frac{14.7psi(29{,}000ft^3)}{675psi} \approx 600ft^3$$

Lastly, we use data from the Energy Information Administration's Form 860 database to recommend pipeline service reduction reporting standards equivalent to the most stringent power plant de-rating reporting thresholds using the equations above.

3. What causes natural gas fuel shortages at power plants?

Abstract

Using 2012–2018 power plant failure data from the North American Electric Reliability Corporation, we examine how many fuel shortage failures at gas power plants were caused by physical interruptions of gas flow as opposed to operational procedures on the pipeline network, such as gas curtailment priority. Through a data matching process between the failure events, generator characteristic data and pipeline reporting, we find that physical disruptions of the pipeline network account for no more than 5% of the MWh lost to fuel shortages over the six years we examined. Gas shortages at generators have caused correlated failures of power plants with both firm and non-firm fuel arrangements. Unsurprisingly, plants using the spot market or interruptible pipeline contracts for their fuel were somewhat more likely to experience fuel shortages than those with firm contracts. We identify regions of the Midwest and Mid-Atlantic where power plants with non-firm fuel arrangements may have avoided fuel shortage outages if they had obtained firm pipeline contracts. The volume of gas needed by power plants to fuel the lost MWh in those regions was only a small fraction of the total volume delivered to potentially non-essential commercial and industrial pipeline customers in those regions.

3.1 Introduction

Natural gas provided 23% of U.S. electric power generated in 2009; ten years later it provides 35% (U.S. Energy Information Administration, 2019a). In North America, on-peak power capacity at natural gas units has increased from 360 GW to 432 GW over the same period. The North American Electric Reliability Corporation (NERC) projects further additions of natural gas generating capacity of 45 GW over the next decade (North American Electric Reliability Corporation, 2017b).

The reliable operation of these gas units depends on the availability of natural gas delivered by the gas pipeline network. Between January 2012 and March 2018, on average, there were over a thousand failures each year of large North American gas power plants due to unscheduled fuel shortages and fuel conservation interruptions (North American Electric Reliability Corporation, 2019). During the peak of the January 2014 Northeast cold weather event, 9,700 MW of forced outages in PJM (a large U.S. regional transmission organization) were due to natural gas shortages (PJM Interconnection, 2014), a little less than 14% of the operable gas capacity in PJM at the time (U.S. Energy Information Administration, 2018).

Here we examine the causes of these lack-of-fuel outages at natural gas power plants in North America. The pipeline network itself may fail. Or the network may be intact, but there may not be enough natural gas to supply the demand by all customers. In that case, residential customers have the highest priority in the U.S. (to ensure they can heat their homes), followed by customers that have purchased firm gas supply contracts.

Most previous published research on this topic is in the form of technical reports from reliability organizations or regional transmission organizations (RTOs). In a 2013 special report, NERC identified a need to develop risk-based approaches, conduct assessments, and enhance data sharing and planning coordination between the gas and electricity industries (North American Electric Reliability Corporation, 2013). Another study conducted for a consortium of RTOs located in the Eastern Interconnection included a scenario-based approach to assess whether the gas pipeline network was robust enough to support future electricity generation needs. They modeled single-point pipeline failures and found that, in the region under study, power plants were distributed among multiple pipeline systems and the effect of a single-point failure was limited (Eastern Interconnection Planning Collaborative, 2014).

In response to these reports, the academic community produced mathematical models of the integrated natural gas and power systems. In Shahidehpour et al. (2005) modified an IEEE test system to show that gas-electric interdependency could be influenced by gas supply capabilities, generator and pipeline characteristics, operational procedures and volatile gas and electricity market prices. Correa-Posada and Sánchez-Martín (2015) used a mixed-integer linear program formulation to highlight the importance of gas travel velocity and gas pipeline line pack for providing the flexibility required to support large fractions of natural gas power generation. Chertkov et al. (2015) developed a partial differential equation model of natural gas pipeline flow and concluded that pressure fluctuations on the gas grid could cause issues for power generators. While admitting that combined optimization of the gas and electricity systems "may not be possible in practice," Zlotnik et al. (2017) explored coordination of the two grids using multiple best-case scenario optimization models. In 2016, Devlin et al. developed a coupled unit commitment and gas flow model for Britain and Ireland to show that gas supply network bottlenecks could greatly increase short-run costs for generators. Pambour et al. (2017) developed a coupled transient, hydraulic gas system model and AC-Optimal Power Flow model that showed both that disruptions of supply on the gas network could cause load shedding on the electricity grid and that outages at non-gas power plants could cause increased demand on the gas grid for gas-fired power plants.

Here we examine an historical database of fuel shortage and conservation interruption failures at all gas-fired power plants of over 20 MW in North America from 2012-2018. Our primary goal is to identify how many of these fuel shortage failures were caused by physical interruptions of gas flow as opposed to operational procedures on the pipeline network, such as gas service curtailment priority. For the latter cause, we wish to answer the policy question, “Are there regions in which generators could mitigate fuel shortage failures by switching to firm pipeline contracts?”

We find that (1) physical disruptions of the pipeline network account for no more than 5% of the MWh lost to fuel shortages over the six years we examined; (2) fuel shortages have caused correlated failures of gas power plants that held both firm and non-firm gas contracts; (3) unsurprisingly, plants holding non-firm contracts were somewhat more likely to experience fuel shortages than those with firm contracts; and (4) large areas of the PJM, MISO and SPP assessment areas may have been able to support the migration of power plant gas supply from non-firm arrangements to long-term firm contracts because there was room to flow more gas through the regional trading hubs at the times of non-firm fuel shortage events and the volume of gas needed by power plants to fuel the lost MWh in those regions was only a small fraction of the total volume delivered to local commercial and industrial customers in those regions.

The remainder of this paper is organized as follows. In section 2, we provide a summary of the source materials in this analysis. In section 3, we briefly explain our data processing and analysis methods. In section 4, we highlight the key quantitative results from this analysis. We conclude in section 5 with a summary and discussion of implications for policy.

3.2 Materials

We use four broad categories of data: failure data for large gas power generators, failure data for the natural gas pipeline network, generator characteristic data to identify the contract status and pipelines fueling the failing power plants and pipeline scheduling data to examine the effect of pipeline supply and demand.

3.2.1 North American Electric Reliability Corporation Generating Availability Data System

In 2006, the U.S. government designated NERC as the country's electric reliability organization. NERC implemented mandatory reporting requirements for power plant reliability events in January 2012. For 2012, all generating units with nameplate capacities greater than 50 megawatts (MW) were required to report reliability events to the Generating Availability Data System (GADS). In January 2013, the capacity threshold was lowered to 20 MW, its current level. Wind and solar power plants and power plants of capacity less than 20 MW are not required to report to GADS at this time.

We filtered the GADS dataset to include only unscheduled outages, de-ratings (partial outages) and startup failures reported by natural-gas-fired combustion turbine generating units, combined-cycle generating units and combined-cycle blocks[1]. We chose unscheduled events because they happen with little-to-no notice and are the events considered in resource adequacy modeling. We next filtered events to only include fuel shortage and fuel conservation interruption causes (codes 9130, 9131 and 9134[2]). Pre-processing of the data, to ensure that we excluded events when plants were unavailable due to economic reasons (reserve shutdown) and that reported information was valid, followed the same procedure as in Murphy, et al. (2018) using the ABB Velocity Suite tool (2019).

The resulting filtered subset spans January 2012 through March 2018 and is comprised of an average of 1,043 event reports per year across 328 unique, gas-fired power plants located in all eight NERC regions[3].

3.2.2 U.S. Energy Information Administration Annual Electric Generator Data

We used 2012-2017 EIA Form 860 data to identify the pipeline(s) connected to each power plant. We used two items from the EIA-860 survey, 16a and 16b, to do this. Item 16a reads: "If this facility … has a pipeline connection to a Local

[1] An individual GADS reporting unit that consists of the pair of a combined cycle's combustion turbine and the associated steam turbine. Some operators report the combustion turbine and steam turbine as separate generating units, some do not.

[2] Code 9130 is an outage due to lack of fuel during when "the operator is not in control of contracts, supply lines, or delivery of fuels." Code 9131 is an outage due to lack of fuel during when an interruptible supply of fuel is part of the fuel contract. And, Code 9134 is a fuel conservation outage event (North American Electric Reliability Corporation, 2017a).

[3] We present results here at the interconnection level and the NERC region level based on the NERC region that the generating units reported as having belonged to when the event report was logged. NERC regions are evolving: SPP has become distributed among WECC, MRO, and SERC; similarly FRCC will no longer be a NERC region as of July 2019.

Distribution Company (LDC), provide the name of the LDC." Item 16b reads: "If this facility … has a pipeline connection other than to a Local Distribution Company, provide the name(s) of the owner or operator of each natural gas pipeline that connects directly to this facility or that connects to a lateral pipeline owned by this facility."

The overall EIA-860 database includes generator-level information about operational power plants and their associated equipment. All plants with total, grid-connected generator nameplate capacity of 1 MW or greater are required to complete form EIA-860 (U.S. Energy Information Administration, 2018). Over the six-year study period the EIA-860 data contain information about approximately 3,800 natural gas generators with nameplate capacity of at least 20 MW (the NERC reporting requirement).

We couple the EIA-860 data with natural gas fuel receipt data from 2012-2017 EIA Form 923. These data allow us to determine under which contract status (firm, interruptible or spot market) each power plant procured their natural gas fuel supplies during the times of the fuel shortage failures reported to NERC. The data include monthly fuel receipt information for 993 different natural gas power plants[4] across the U.S. The reporting threshold for EIA-923 is identical to EIA-860 (U.S. Energy Information Administration, 2019b).

[4] A plant can contain multiple natural gas generators in one location. The EIA 923 data are reported at the plant level as opposed to the EIA 860 data which are reported at both the plant and generator level.

3.2.3 Natural gas pipeline failure data

To determine whether fuel shortage failures at power plants occurred during physical failures on the natural gas pipeline network, we examined two sources of pipeline failure data.

3.2.4 Pipeline and Hazardous Materials Safety Administration Incident Reports

The U.S. Department of Transportation (DOT) gathers operator submissions of natural gas pipeline incidents for the distribution, transmission and gathering segments of the gas grid. The thresholds for automatic reporting of incidents to the Pipeline and Hazardous Materials Safety Administration (PHMSA) are outlined in 49 CFR Parts 191 and 195. These sections of the code of federal regulations define an incident as a pipeline event that "… involves a release of gas from a pipeline … and that results in one or more of the following consequences: a death, or personal injury necessitating in-patient hospitalization; estimated property damage of $50,000 or more … excluding cost of gas lost; unintentional estimated gas loss of three million cubic feet or more"; or "any event that is significant in the judgment of the operator" but does not meet the previous thresholds. Pipeline operators must report incidents to PHMSA within 30 days of the event (Pipeline and Hazardous Materials Safety Administration, 2019).

The thresholds established by the DOT through PHMSA are large compared to the thresholds established by NERC for power plant failures. But to date, the

PHMSA database is the only centralized database of failures on all three of the major segments of the gas grid (Freeman et al., 2018). For this reason, we begin our analysis of pipeline failures with the PHMSA database.

We filtered the raw data of PHMSA incident reports for distribution, transmission and gathering pipelines to include only events on onshore pipelines. We further excluded incidents that did not result in a component shutdown and events that had incomplete information about shutdown and restart times. We filtered to events that caused a pipeline component to shut down rather than events that caused service interruptions because we are interested in estimating the upper-bound of the number of power plant failure events caused by pipeline incidents. The resulting, filtered dataset consists of 780 incidents reported by 202 different pipeline operators between 2012 and 2017.

3.2.5 Natural gas transmission pipeline critical notices

We supplemented the PHMSA incident reports with a database of natural gas transmission pipeline critical notices compiled in the ABB Velocity Suite tool (2019). We restrict our sample of pipeline notices to only critical notices that have both a start date and an end date. The data cover 42 out of 46 of the transmission pipeline networks directly connected to power plants reporting to GADS. These 42 pipelines fueled the plants that reported 70% of the 6,200 GADS fuel shortage events between 2012 and 2017.

The pipeline notices include a description of the notice type. We use the notice type field to produce two filtered subsets of the data. One includes only the most extreme, short-notice, critical alerts—force majeure. Force majeure events are pipeline outages that are unexpected and out of the control of the operator. The second includes pipeline notices of seven types: capacity constraint, curtailment, operational flow order, critical period, force majeure, notices regarding capacity that is available on a pipeline, and weather events that affect gas pipeline operations. The immediacy and severity of the additional events included in the second filtered subset are more broadly defined than the set consisting of only force majeure events; our goal is to estimate the upper bound of the number of fuel shortage events at power plants that can be explained by failures on the gas pipeline network that actually impeded the flow of natural gas.

The force majeure subset of pipeline notices during the 6 years examined includes 431 notices posted on the online bulletin boards of 16 different pipeline operators. The second, less restricted, subset includes 16,502 notices posted on the online bulletin boards of 29 different pipeline operators.

3.2.6 Individual pipeline scheduling data

Information about the quantity of natural gas scheduled each day was gathered for the transmission pipeline network across the contiguous U.S. These data were collected from individual pipeline bulletin boards by ABB and made available through the Velocity Suite tool (2019). The natural gas scheduling data include final scheduled quantities for every shipper on 246 pipelines across the U.S.

3.2.7 ABB Velocity Suite Daily Hub Reports

The Velocity Suite also includes a product using the pipeline scheduling data called the Daily Hub Report. These data include information about the utilization of major natural gas trading hubs across the country. We use utilization data for 2012-2017 at 28 different trading hubs throughout the country to examine the conditions on the gas grid during days when fuel shortage failures were reported at gas power plants. A map of the hubs used in this analysis is available in Figure B.1 in Appendix B.

3.2.8 U.S. Energy Information Administration Natural Gas Consumption by End-Use

We use monthly, state-level natural gas consumption data gathered by the U.S. EIA through Form 857 to analyze the fraction of natural gas deliveries by sector during times of fuel shortage failure events at natural gas power plants. These monthly data are publicly available online for years 2001 – present (U.S. Energy Information Administration, 2019c).

3.3 Methods

3.3.1 Matching GADS reports to EIA data

The NERC data do not include details about the pipelines fueling the natural gas units in the GADS sample. In order to analyze how gas pipeline system characteristics have historically affected natural gas fuel shortage failures, we developed a systematic approach to match the NERC failure data to EIA generator characteristic data. This matching process is performed at the plant level and requires four fields from both the GADS and EIA data. The relevant GADS fields are 'Unit Code', 'Utility (Company) Code', 'Regional Entity', and 'Location of Unit (State)' (North American Electric Reliability Corporation, 2017a). The corresponding EIA fields from EIA-860 Schedule 2 are 'Plant Name', 'Utility Name', 'NERC Region', and 'State' (U.S. Energy Information Administration, 2018). The process developed for this matching is given in the supporting material at the end of this chapter. We were able to provide a match for all the power plants in the GADS sample.

3.3.2 Calculating time series of unscheduled, unavailable capacity due to fuel shortages

De-rating (partial outage) events account for up to 28% of all unscheduled unavailable MWh due to fuel shortages and conservation interruptions at gas units depending on the NERC region. Thus, we rigorously account for overlapping de-ratings as a function of other de-rating events that may be underway using the process developed by Murphy et al. (2018).

We construct 30-minute resolution time series using de-rating magnitudes, outages and startup failures. We chose 30 minutes as opposed to hourly time steps to account for short-lived fuel shortage outages and account for spikes in event start and end minutes at 30-minute time steps identified by Murphy et al. (2018). The contribution to unavailable capacity by outages and startup failures is each unit's nameplate capacity during the half-hour periods when those event types are in effect. We aggregate each unit's fuel shortage failure magnitude time series up to the plant level, then to the NERC region level and interconnection level. A map of the NERC regions during our sample period is shown in Figure B.2 in Appendix B.

3.3.3 Matching GADS reports to pipeline failure reports

We match the beginning times of fuel shortage power plant failure events with time windows of pipeline failures to determine if pipeline failures could have caused fuel shortage outages at power plants. We do this by assigning every power plant in the GADS dataset to the pipeline listed first in its direct connection list according to EIA-860. We then match the power plant failure timestamps to PHMSA incidents and bulletin board critical notices on the corresponding pipeline. We buffer start and end times of pipeline failures by two hours to account for small errors in recording of times in the power plant failure data.

3.3.4 Matching GADS to daily natural gas trading hub reports

To assess the historical availability of natural gas for transactions by power plants, we complete a similar process of spatial matching of power plants to gas trading hubs. We use the spatial data enabled by the matching of the NERC data with the EIA-860 data to conduct a simple, straight-line proximity analysis between plants reporting fuel shortage failures and the closest major natural gas trading hub with data available in the ABB Velocity Suite Daily Hub Reports. We then time-match the fuel shortage events' beginning time stamps with the utilization of the nearest gas hub during the day of the event.

3.3.5 Construction of Algonquin Citygates Hub utilization time series

The raw data from the ABB Velocity Suite Daily Hub Reports lacks a major trading hub for the New England region. According to the user guide of the ABB Velocity Suite (2019), the utilization field in the daily hub reports are constructed from the raw pipeline scheduled deliveries data using the equation:

$$Utilization(t) = \left(volume\ flowed_t / \max_{t=1,\dots,t}\{volume\ flowed_t\}\right) \qquad (3.1)$$

Where, t is the sequential day number index in the data. Note that the running maximum in the denominator is the demonstrated peak flowed through the hub.

We use equation one and the scheduling data for delivery points on the Algonquin gas pipeline to reconstruct the Algonquin Citygates hub index according to the Intercontinental Exchange's physical gas hubs method (2019).

To follow the ICE's conventions, we exclude gas deliveries within the J-system. The J-system connects the LNG terminal located at Northeast Gateway in Everett, MA to the Algonquin mainline south of Boston. Unlike the rest of the Algonquin pipeline system, the J-system does not rely on other pipelines for its supply of natural gas.

3.4 Results and Discussion

3.4.1 Fuel shortages and conservation interruptions at natural gas units have caused large, correlated failures at both plants that held firm contracts and plants that did not

Over just the six years of data provided by the GADS sample, large magnitude correlated failures occurred at both firm and non-firm[5] power plants in the U.S. (Figure 3.1). In the Eastern Interconnection, large recurring correlated failures occurred during the winter months of each year and affected multiple power plants. During most of the time period, generators in the Eastern Interconnection employing non-firm fuel procurement strategies were the largest contributors to these correlated failures. This was not the case in the ERCOT and Western Interconnections. In all regions, multiple generators experienced fuel shortages simultaneously while holding long-term, firm fuel contracts but, in ERCOT and the Western Interconnection these firm contract failures sometimes contributed

[5] Non-firm plants are power plants that were either coded as procuring their fuel on the short-term natural gas spot market or utilizing interruptible pipeline contracts at the time of their reported fuel shortage failures according to EIA-923.

up to 100% of the peaks in the respective region's fuel shortage failure timeseries.

We disaggregated the total fuel shortage failures in each interconnection to the individual NERC regions and the individual pipeline systems fueling the failing plants. We find that correlated fuel shortage power plant failures have peaked at more than 5% of total nameplate gas-fired capacity in MRO (5.0%), NPCC (5.5%), RFC (15.5%) and SPP (10.9%). Single pipeline networks fueled plants that simultaneously failed, resulting in the loss of more than 2% of installed gas capacity in those same regions (Figure 3.2).

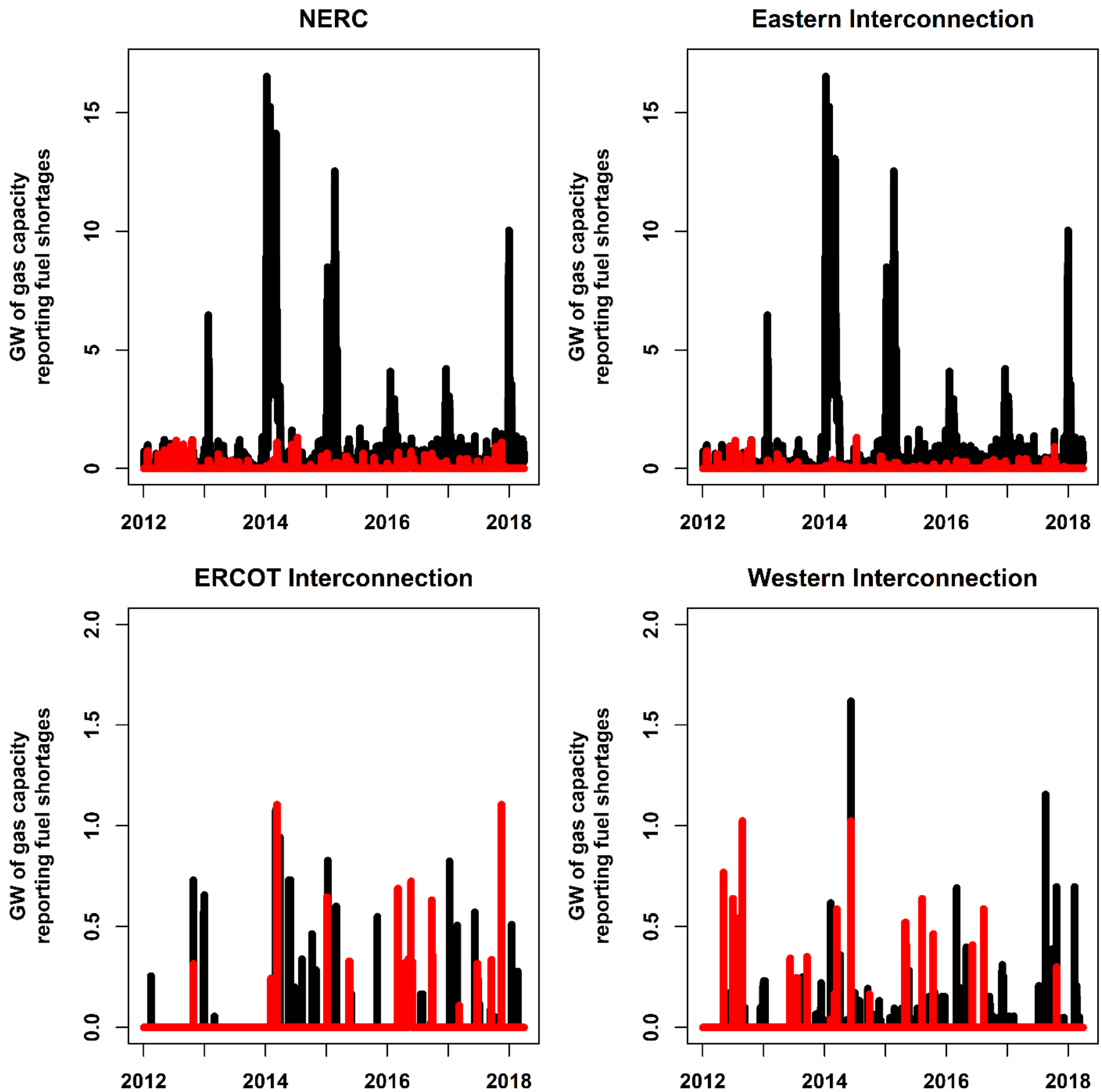

Figure 3.1. Time series plots of gas plant fuel shortage and conservation interruption failure magnitude aggregated by electricity interconnection, grouped by generator contract type. Plots are the sum of all unscheduled lack of fuel outages, de-ratings (partial outages) and startup failures at gas units. The black series is total outage magnitude and the overlaid red series represents outage magnitude at gas plants that held firm contracts at the time of their failures.

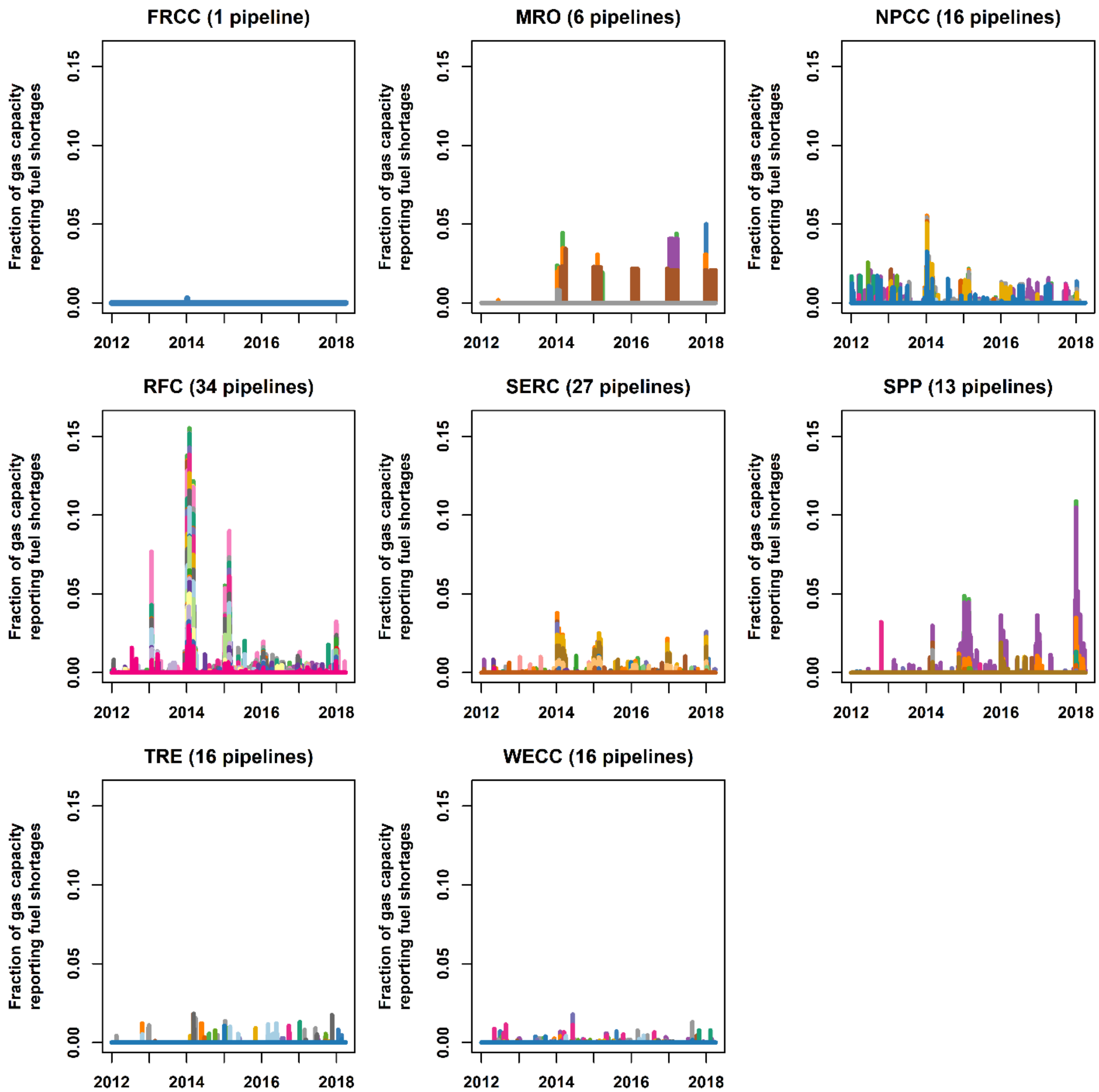

Figure 3.2. Time series plots of gas plant fuel shortage and conservation interruption failure magnitude as a fraction of gas capacity aggregated by NERC region, indicating the pipeline fueling the plant. Each color represents an individual pipeline system. Note: some pipelines span multiple NERC regions and therefore appear in multiple plots.

3.4.2 Gas pipeline failures did not explain the majority of fuel shortage power plant failures

According to data from PHMSA, natural gas pipeline incidents did not coincide with most fuel shortage failure events at natural gas power plants between 2012 and 2017. Only approximately 200 of the 6,200 power plant failure events occurred during a PHMSA incident severe enough to cause a component of the pipeline network to be shut down within the same state as the failing power plant.

Force majeure events that occurred anywhere along the transmission pipelines that directly connected to power plants in the GADS sample explained a maximum of only 9% of the fuel shortage events at those plants (406/4,296). This is an upper bound because we treat force majeure events anywhere along the pipeline network the same. As some pipelines stretch long distances, our estimate may include time-coinciding force majeure declarations far away from the power plant that may not have affected power plant operation. The 9% of events coinciding with force majeure declarations equated to approximately 5% of the MWh lost to fuel shortages over the six years.

The nationwide peak of correlated fuel shortage outages at all natural gas units during force majeure events on their fueling pipelines was 3,075 MW and occurred during the January 2014 Polar Vortex. These 3,075 MW were approximately 19% of the peak of correlated fuel shortage outages during the height of the 2014 Polar Vortex.

However, only approximately 500 of those 3,075 MW were unavailable at plants with long-term firm pipeline contracts. The peak of correlated fuel shortages at gas plants holding long-term firm pipeline contracts during force majeure declarations was 920 MW and occurred in October 2017.

On average, during force majeure declarations, nearly 160 MW of natural gas capacity was unavailable during any 30-minute period in the month of January – the peak month for such outages. But smaller peaks occurred during every month of the year. The month with the second highest average unavailable capacity due to fuel shortages during force majeure was August with nearly 60 MW unavailable during any 30-minute period. This highlights the nature of force majeure events on pipelines – they can be caused by many natural phenomena such as landslides and flooding, not just by cold weather.

The broader subset of critical notices on natural gas pipelines that we aggregated – including capacity constraints, operational flow orders, etc. – explained a maximum of only one quarter of events or about 13% of MWh lost to fuel shortages.

3.4.3 Non-firm plants were over-represented in the fuel shortage failure data

We examined pipeline curtailment priority as a driver of these failures by grouping the power plants in the GADS sample by the pipeline contract status under which >50% of total fuel quantity was purchased between 2012 and 2017. We conducted one-sample proportion tests of the null hypothesis that the proportion of non-firm plants in the GADS sample is equal to the proportion of non-firm plants in the whole EIA-923 database. We find that the proportion of non-firm plants represented in the fuel shortage failure sample ($\hat{p}$ = 0.802) was statistically significantly greater than the proportion in the overall EIA-923 database (p_0 = 0.738) when aggregating over the timeframe 2012 through 2017 (z = +2.21, p-value = 0.014). When we disaggregated the timeframe to individual years, a statistically significant over-representation of non-firm plants was observed for years 2013 (p-value < 0.05), 2014 (p-value < 0.01) and 2015 (p-value < 0.05).

We test for robustness of these results by disaggregating the sample by plant owner and NERC region. We observed no pattern by owner. We observe a significant over-representation of non-firm plants in RFC (p-value < 0.1) and SERC (p-value < 0.05).

We further test robustness by non-parametrically varying the denominator of the proportion test, effectively reducing the sample size holding our estimate constant, to see how small the sample would need to be to no longer produce a statistically significant over-representation at the α = 0.10 level. We find results to be robust to a reduction from the original NERC, RFC and SERC sample sizes of

232, 82, and 44 to sample sizes of 75, 55, and 30, respectively. Summaries of proportion test results are provided in Table 3.1.

Table 3.1. Results of one-sample proportions tests of the null hypothesis that the proportion of non-firm gas plants in the GADS sample is equal to the proportion of non-firm gas plants in the whole EIA-923 database. Result significance is indicated by one-tailed test results in the direction indicated by the sign of the difference of the sample proportion column and the EIA-923 proportion column. '*' indicates significance at the $\alpha = 0.1$ level, '**' indicates significance at the $\alpha = 0.05$ level, and '***' indicates significance at the $\alpha = 0.01$ level.

Region (N)	EIA-923 database non-firm plant proportion (p_o)	GADS fuel shortage plants non-firm proportion ($\hat{p}$)	Number of plants reporting fuel shortages (n)	Smallest sample size required to produce $\alpha = 0.1$ level significant result
NERC (981)	0.738	0.802***	232	75
FRCC (47)	0.404	0.000	1	-
MRO (81)	0.790	0.857	7	-
NPCC (74)	0.838	0.833	36	-
RFC (192)	0.797	0.866*	82	55
SERC (227)	0.749	0.886**	44	30
SPP (77)	0.792	0.563**	16	5
TRE (101)	0.644	0.684	19	-
WECC (182)	0.714	0.667	27	-

We re-run the proportions test excluding plants that procured less than 90% of their fuel over the time period under the previously prescribed strategy. This reduces the numerator of our proportion estimates across all aggregations by imposing a stricter definition of "non-firm." Under this last robustness check, using the entire timeframe of data, the initial results remain unchanged with retained statistical significance at the α = 0.10 level in aggregated NERC and RFC. The results for SERC are no longer statistically significant at the α = 0.10 level.

3.4.4 Moving non-firm plants to firm pipeline contracts may be a successful mitigation strategy in parts of MISO, PJM and SPP

Because of the evidence of curtailment priority driving fuel shortage failures at power plants, we investigated whether firm capacity could have been obtained by power generators holding interruptible or spot market contracts at the times of their failures. We assigned each non-firm GADS failure event start date to the utilization (see equation 3.1) of the nearest natural gas hub at the time to construct cumulative distribution functions (CDFs) of the fraction of non-firm fuel shortage events as a function of utilization of the nearest gas trading hub (Figure 3.3).

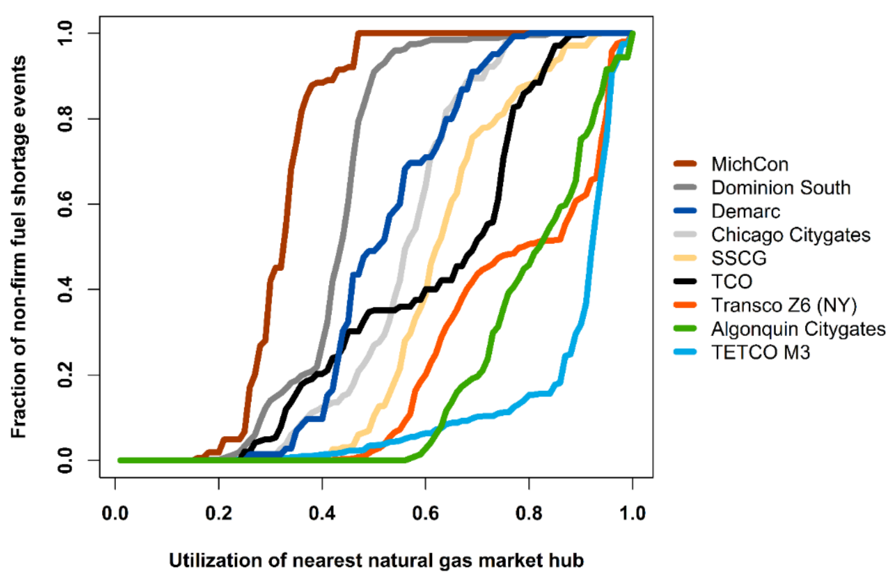

Figure 3.3. CDFs of the fraction of non-firm fuel shortage events at natural gas power plants as a function of the utilization of the nearest natural gas trading hub. We present the 9 hubs with 145 or more data points here. Curves that fall to the upper left indicate that physical pipeline capacity was available for use at the nearest hub at the time of failure events while curves falling in the lower right indicate that market hubs were constrained during failure events.

We find that most fuel shortage reports at power plants with non-firm fuel procurement strategies nearest the Chicago Citygates, Demarc, Dominion South and MichCon hubs were reported when the volume of gas flowed through those hubs was less than 60% of their demonstrated peaks. The 2,350 events at the plants nearest these hubs represented 60% of all MWh lost to fuel shortages between 2012 and 2017. The footprint composed of the counties closer to those hubs than any other hub in our dataset is in Figure 3.4.

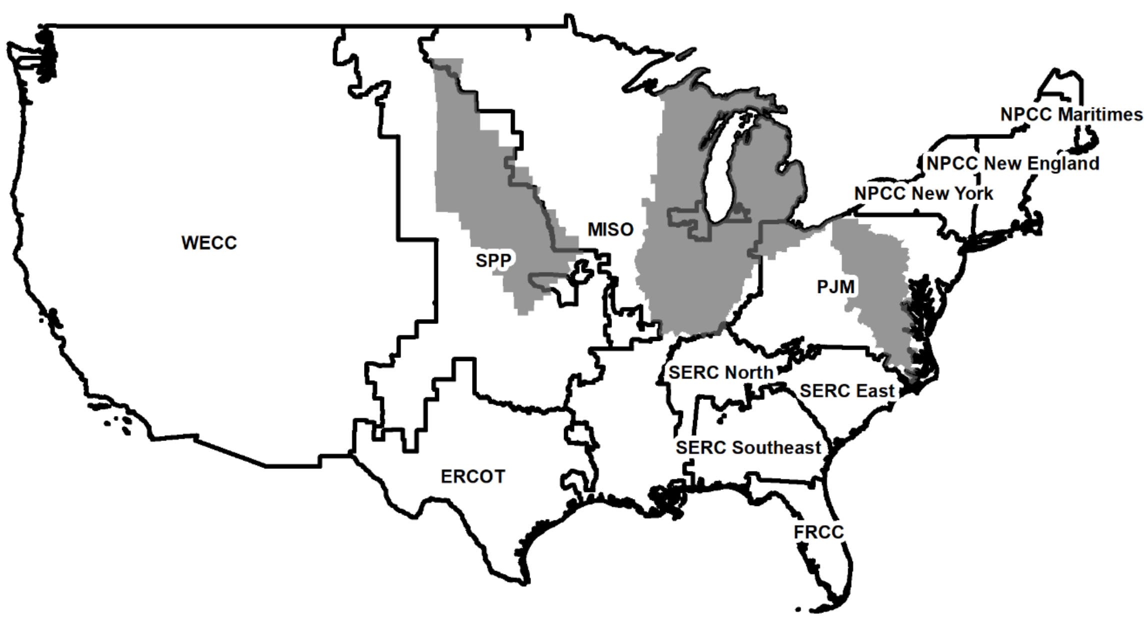

Figure 3.4. Map of U.S. counties closest to hubs where most non-firm fuel shortage power plant failures occurred when the hub was less than 60% utilized.

There are three main reasons why the volume of natural gas flowed through a hub could be low: (1) low demand for natural gas, (2) gas supply disruptions preventing flow in the regional pipeline network, or (3) curtailment of load by pipelines downstream of the hub. We rule out the first reason because greater than 85% of fuel shortage events near these hubs occurred between October and May—the traditional heating season in Chicago (Weatherspark, 2016). [6] While it is possible that gas supply disruptions contributed to this low utilization during fuel shortage events, it is unlikely that supply disruptions were large enough to reduce the utilization to this extent. This is because natural gas trading hubs represent areas where multiple pipelines come together. To observe a hub utilization of less than 60% due mostly to supply issues, a large disruption to the gas supply on all the pipelines connecting to the hub would have to occur, including those pipelines that import gas from different regions of North America.

Because a large portion of these events occurred during the heating season and because downstream pipeline issues were exceedingly rare, we conclude that there were two plausible contributing factors to these low utilizations at the gas hubs: (1) non-firm customers were over-curtailed and/or (2) firm pipeline capacity went unused. Our results show that there was unused capacity on the regional pipeline network to flow gas. They do not, however, show that firm capacity was available to be purchased. For this to be the case, shippers holding

[6] The traditional heating season includes the months during which the historical average temperature was less than 65°F. Heating degree days are calculated using this threshold temperature.

firm capacity would need to efficiently release their unused capacity to the secondary market in a timely manner, or more ideally, would need to right-size their contracted capacity amount so power plants could secure long-term firm contracts. Operationalizing this re-allocation of firm capacity to power plants to prevent fuel shortage failures would require close coordination between actors in all the major natural gas grid segments.

With this in mind, large areas of the PJM, MISO and SPP assessment areas may have been able to support the migration of power plant gas supply from non-firm arrangements to long-term firm contracts because there was room to flow more gas through the regional trading hubs at the times of non-firm fuel shortage events.

3.4.5 Power plants could have out-prioritized commercial and industrial pipeline customers at the times of almost all the fuel shortage events in parts of MISO, PJM and SPP

Just because there was space available at the nearest hub, does not necessarily mean that if power plants were able to obtain firm capacity, they could have mitigated these failures unless they could have out-prioritized less important customers on the natural gas network. On the gas grid, some customer classes, such as residential, hold the highest priority for gas flow because of cold-weather heating demands. Commercial and Industrial (C&I) class customers, however, often have non-essential natural gas loads that could be shed in the event of a high-stress event on the gas network. We now estimate the fraction of gas that would have had to be diverted from C&I customers to have avoided power plant outages due to fuel shortages.

With the EIA's state-level data that identifies monthly natural gas deliveries by customer class, we computed the fraction of natural gas deliveries to C&I customers during the months when correlated fuel shortage failures occurred at non-firm power plants (Figure 3.5). Only 3 events out of the 2,350 in those areas occurred during months when the statewide fraction of gas consumed by C&I customers was less than 25%. The distribution also exhibits a long right tail suggesting that, if enough gas had been delivered to the C&I classes at the time, power plants could have out-prioritized C&I customers if they had procured their fuel through firm contracts in those areas.

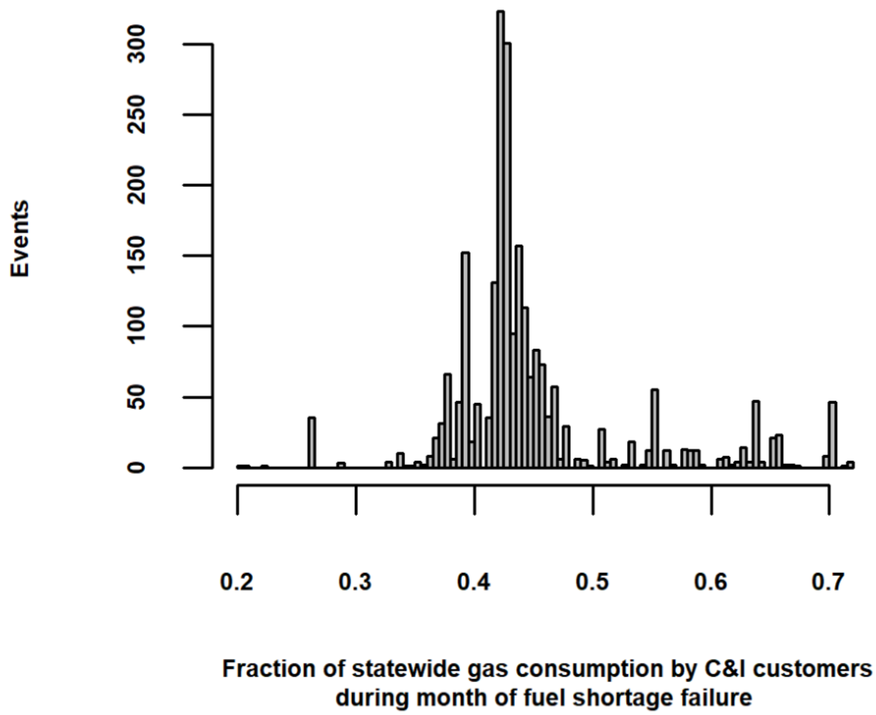

Figure 3.5. Histogram of the fraction of statewide gas consumption by C&I customers on the pipeline network during the month of the fuel shortage power plant failures at non-firm plants in the areas indicated by Figure 3.4.

Combining capacity factor data available in the EIA-923 database with gas consumption data for the 2018-19 heating season, we estimate that between 0.1% and 9%[7] of the total statewide volume of gas delivered to C&I customers would have been sufficient to supply the natural gas requirement of all MWh lost to fuel shortage failures at gas plants in the areas highlighted in Figure 3.4.

3.5 Conclusions and Policy Implications

Failures at large natural gas power plants due to fuel shortages from the

[7] Depending on the state.

natural gas pipeline network are an issue that energy system planners need to address in efforts to reduce correlated power plant failures. Correlated fuel shortage failures in the Eastern Interconnection took down multiple plants every winter period of our study, peaking at over 15 GW in 2014. These correlated failures caused a peak of greater than 15% of the installed natural gas power plant capacity to go offline in the RFC NERC region.

Even with the limited data availability of pipeline failures, we have shown that physical disruptions of the pipeline network severe enough to impede gas flow to customers did not sufficiently explain most of the correlated natural gas plant fuel shortages.

Over-representation of power plants that procured their fuel supplies through the spot market or interruptible contracts highlight that curtailment priority on pipeline networks was the likely reason for most correlated failures. But, as shown in Figure 3.1, in ERCOT and the Western Interconnection, firm contracts were not a cure-all solution. In these areas, and other areas where the pipeline network has historically been highly constrained (New England), other mitigation strategies should be explored.

We highlight areas of PJM, MISO and SPP where a combination of firm contracts at power plants and proper allocation of the capacity on the pipeline network during heating months could result in power plants out-prioritizing commercial and industrial pipeline customers. Only a small fraction (0.1-9%) of the total natural gas deliveries to C&I customers during the months of fuel shortage events in these areas could have helped prevent 60% of the total MWh lost to fuel shortages over the six-year timeframe.

It is important to note, however, that these data only suggest that the capacity could have been reallocated from C&I customers within the state. The operational ability to do this is unclear for several reasons. First, these results show only that pipeline space was available. This does not necessarily mean that firm contracts were available for purchase on pipelines at the times of fuel shortage events nor that firm contracts are available now. If firm pipeline capacity went unused during these events, policy measures to ensure that this capacity is reallocated to critical power plants in the future should be explored to help prevent reliability events on the electricity grid due to gas shortages at power plants. Second, the C&I gas load that could potentially be out prioritized by power plants with firm pipeline contracts might be located long distances away from where power plants need natural gas to be delivered. More granular data are needed to pinpoint where within each state the C&I gas demand was. Third, with the evolving power generation mix, additions of gas capacity and increasing gas capacity factors warrant periodic monitoring of electric-gas dependence as presented here; this will become even more important with the continuing retirements of oil, nuclear, and coal facilities. But, the fact that the volume of gas needed by power plants to fuel the lost MWh was only a small fraction of the total volume delivered to C&I customers is enough to support the policy that selective firming of power plants in those regions could be a valid mitigation option in areas where firm contracts are available.

A large-scale migration of power plants to firm contracts would affect electricity prices in those regions. Data from the EIA-923 database suggest that long-term firm pipeline contracts were more expensive than interruptible or spot market pipeline contracts over the study period (U.S. Energy Information Administration, 2019b). Higher fuel costs could be reflected in electricity generator bids in the bulk power market. In RTOs such as PJM and ISO-New England, measures that use payment mechanisms to incent power plant operators to produce electricity during stress periods have been implemented. These payments could be used to offset the added cost of procuring firm pipeline capacity.

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3.7 Appendix B: Supporting material

3.7.1 Map of natural gas trading hubs used in analysis

Figure 3.6 is a map of the 28 natural gas market hubs included in this study. The colors of the markers correspond to the plot legend of Figure 3.3. While we completed the analysis for all 28 hubs, in this paper we only present results for hubs with 145 or more data points for the CDF plots. The number of fuel shortage events at power plants closest to each hub is labeled on the map.

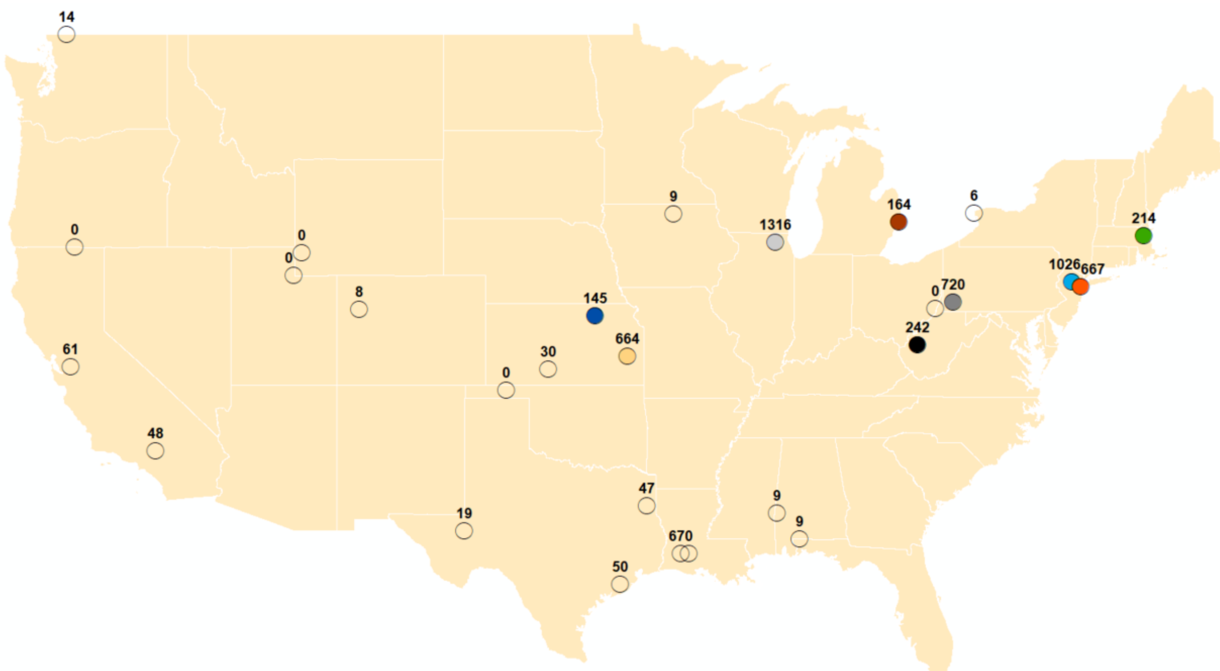
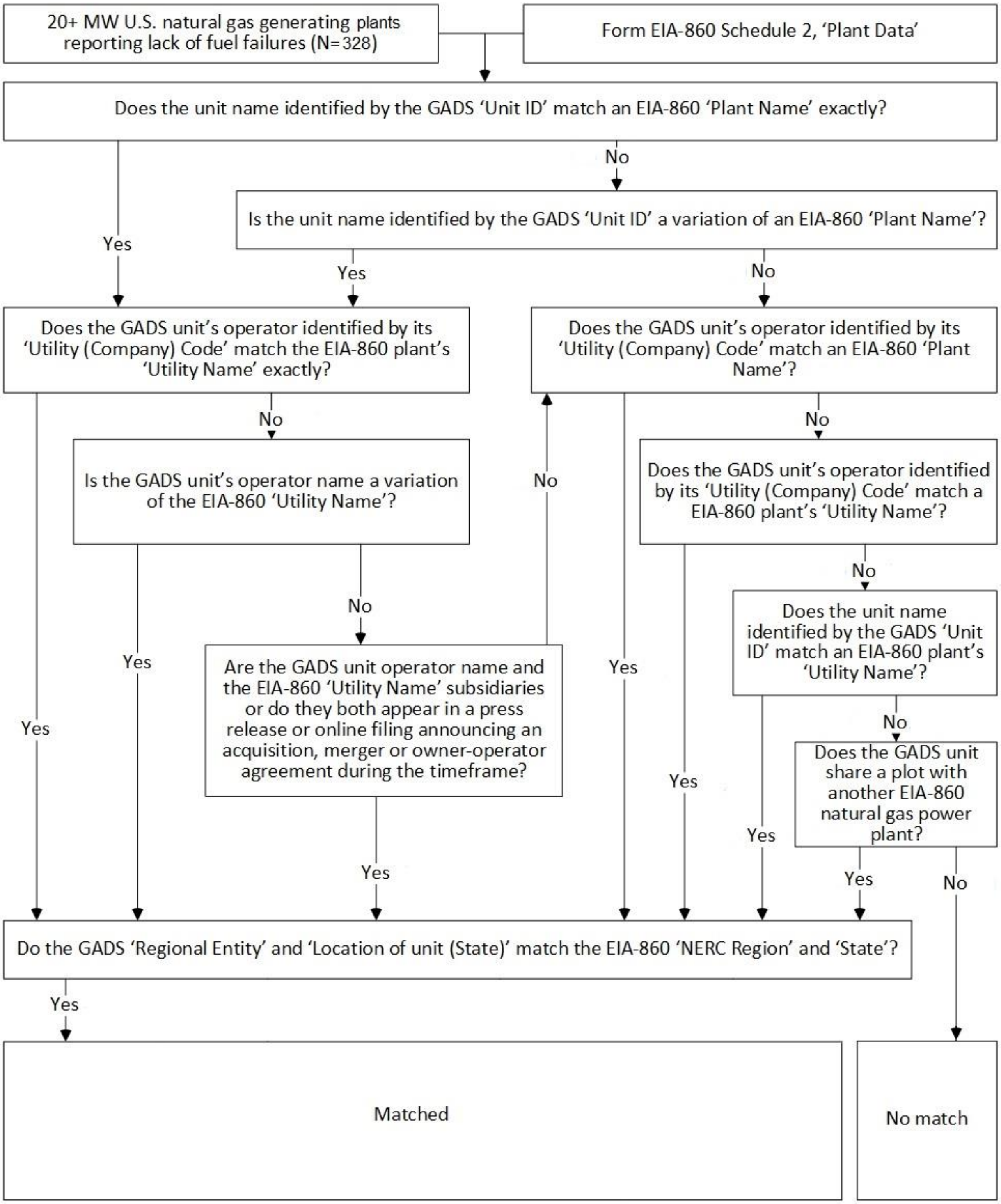


Figure B.1. Map of the 28 natural gas market hubs used in this analysis. All were available in the ABB Velocity Suite daily hub report except the Algonquin City Gates Hub near Boston.

3.7.2 Process schematic for matching NERC to EIA Data



3.7.3 Maps of NERC regions and assessment areas

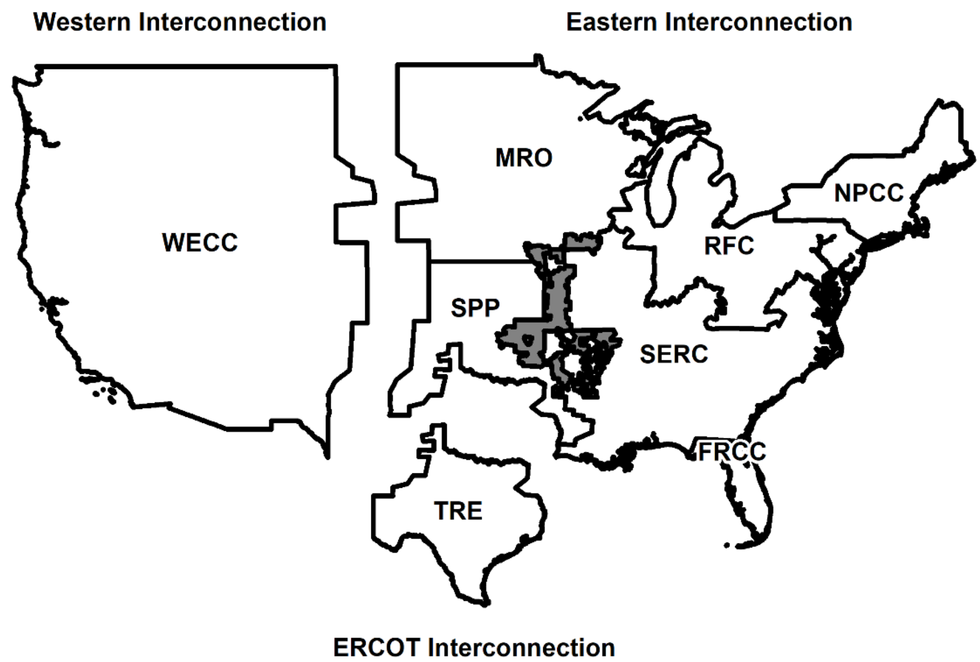


Figure B.2. Map of the 8 NERC Regions and 3 electricity interconnections used for spatial aggregation in this analysis. Grey areas indicate parts of the country where NERC regional jurisdictions overlap.

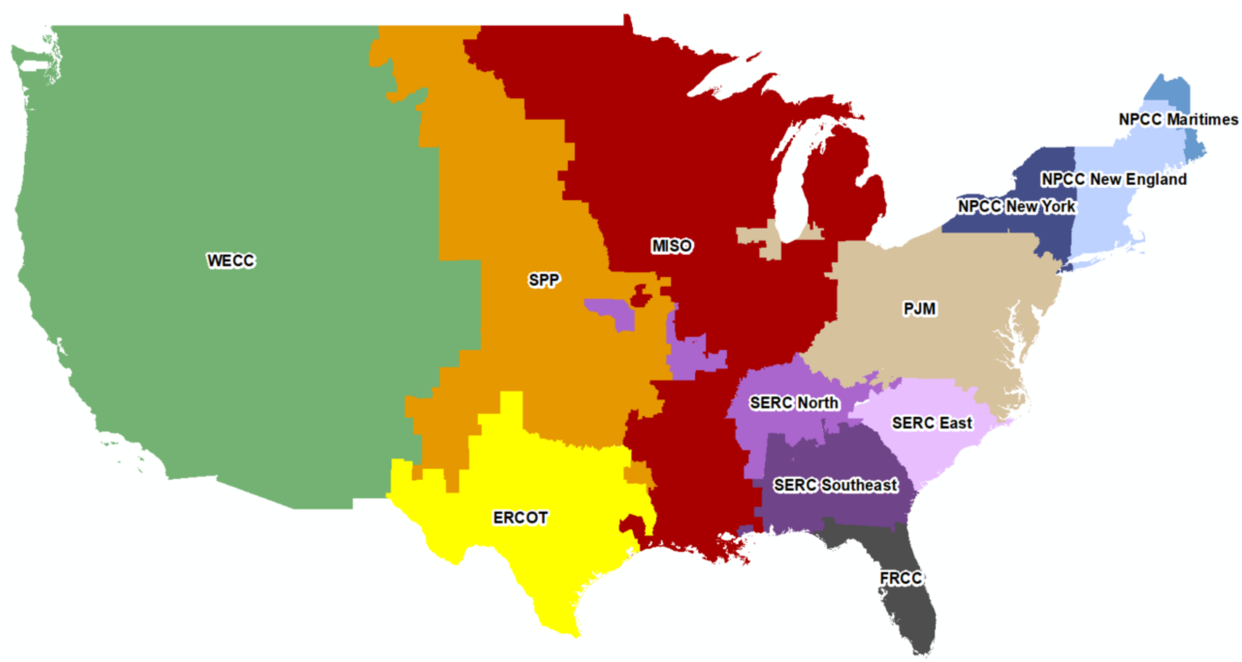


Figure B.3. Map of the 12 NERC Assessment Areas referenced in discussions and results of this analysis.

4. How does on-site fuel storage compare to other options for fuel security measures at gas-fired power plants?

Abstract

In the Northeastern United States, natural gas supply constraints have led to periods when gas shortages have accounted for up to a quarter of all unscheduled power plant outages. Gas supply shortages might be mitigated by dual fuel oil/gas generators or local gas storage. We use a case study with historical power plant operational and availability data to develop a supply curve of the costs required for generators to mitigate fuel shortage failures in New England. Based on 2012-2018 data, we find that approximately 2.6 – 7 GW of gas-fired capacity's fuel shortage failures could be mitigated using oil dual fuel (or 1.7GW – 3.1 GW using CNG storage) if those plants were compensated with a reliability adder of $1/MWh during their normal operations. We estimate that the capital expenses associated with the fuel storage options would be less expensive than installing battery backup for resource adequacy and are comparable to the customer incentive costs spent by utilities in New England for demand response between 2013 and 2017.

4.1 Introduction

In the previous chapter, we used a database of power plant failures provided by the North American Electric Reliability Corporation (NERC) to analyze why natural gas power plants failed due to unscheduled fuel shortages (Freeman et al., 2019). We found that only a few of these events could be explained by gas pipeline failures. Most were caused by non-firm gas fuel purchase arrangements. In the upper Midwest, sufficient natural gas supplies were available so that generator outages might have been avoided with firm supply contracts. However, we also identified areas of the Northeastern United States where pipeline constraints likely hinder the opportunity for power generators to reserve firm pipeline space in order to assure adequate natural gas fuel supplies.

For ISO-New England, the issue of fuel assurance for the gas-fired power plant fleet has recently become an area of concern (ISO New England, 2018). In New England, half of the total installed power plant capacity is fueled primarily by natural gas and nearly half of all electricity MWhs comes from natural gas power plants (U.S. Energy Information Administration, 2019c).

In 2018, New England had approximately 4.1 billion cubic feet (BCF) per day of natural gas pipeline import capacity (U.S. Energy Information Administration, 2019f). Data from the U.S. Energy Information Administration's (EIA) New England Energy Dashboard show that the peak of daily residential/commercial natural gas consumption in 2018 was approximately 3.5 BCF during the winter season (U.S. Energy Information Administration, 2019e). If we assume that most of that demand was for heating in the residential and commercial sectors, that means that industrial and power generation pipeline customers had only a little more than 0.7 BCF to share during last year's peak residential demand day. According to average heat rate data from EIA-923 (U.S. Energy Information Administration, 2019d), 0.7 BCF/d could support an average consumption of about 8 GW of gas-fired power plant capacity in New England. That is less than half of the capacity of ISO-NE's gas-fired fleet. Only by adding in the 0.85 BCF of LNG imports into New England during the peak day – about 0.45 BCF more than New England imported during its peak day of imports during the previous winter – could New England support full operation of the whole gas fleet. This is assuming that no industrial customers use any gas.

This simple example may seem an extreme case, but when heating demand spikes on key natural gas supply pipelines to New England, such as Algonquin, the share of the pipeline's total daily gas deliveries to gas local distribution companies and power generation customers has reached 100% on multiple occasions between 2012 and 2018 (ABB Velocity Suite, 2019).

The effect of gas supply constraints on power generators in the Northeast (Figure 4.1) can be observed by comparing the average fraction of total

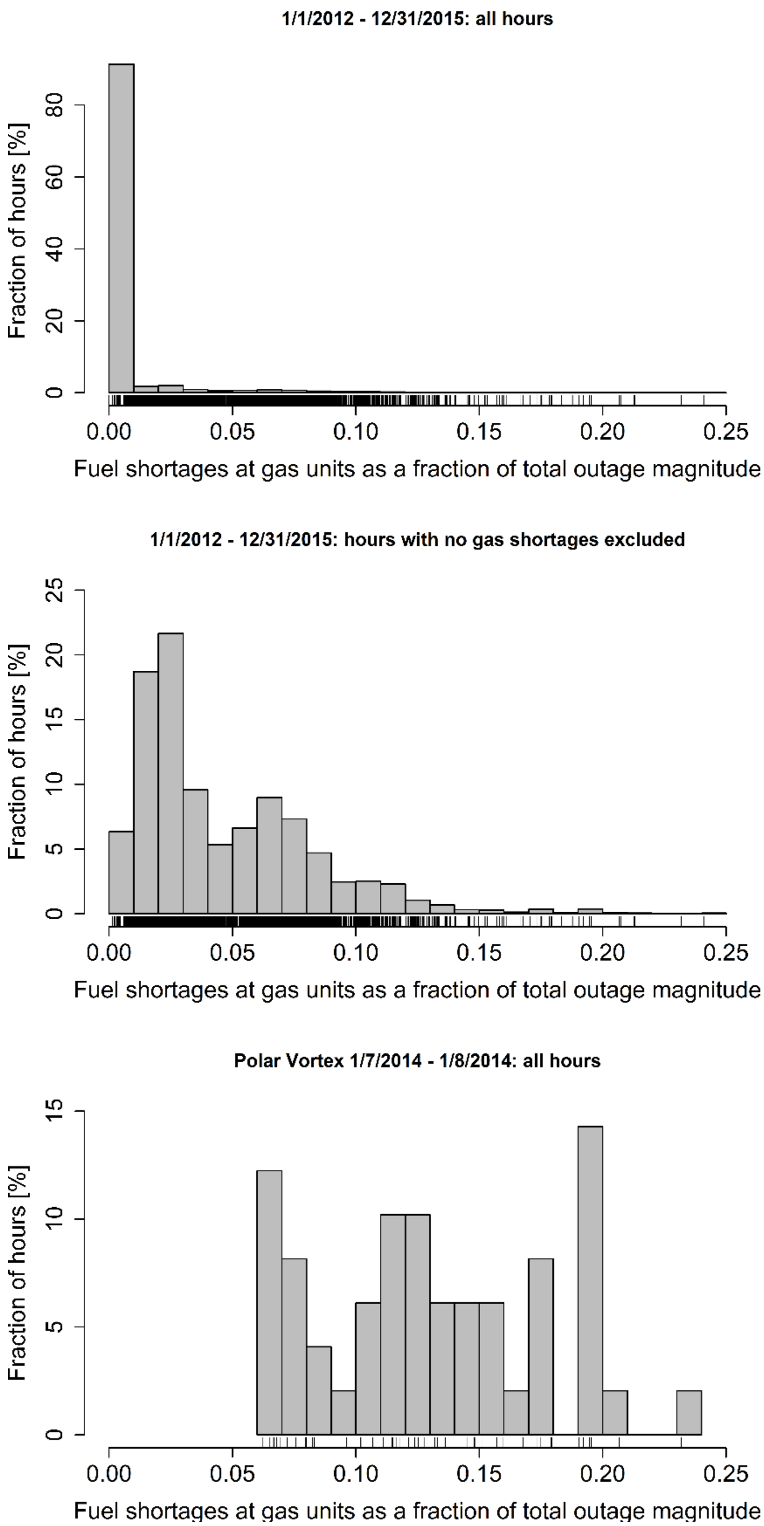


Figure 4.1. Histograms of the fraction of total hourly unscheduled outages at power plants in the NPCC NERC region that were solely gas shortage causes. Histograms are given over two time periods for comparison: a.) Over the entire initial study period of the NERC Generating Availability Data System conducted by Murphy et al. (2018) (top and middle) and b.) During the peak of the 2014 Polar Vortex (bottom). Note that 31,814 hours (90.7% of all hours) with no gas shortages are excluded in the middle plot. Horizontal axis tick marks represent hourly observation values in the sample.

unscheduled power plant outages due to gas fuel unavailability between 2012 and 2015 to those during days of high heating demand as during the 2014 downward shift of the North polar vortex. On January 7-8, 2014, gas shortages accounted for up to a quarter of all unscheduled Northeastern power plant outages during some hours.

Barring the ability for power generators to secure firm pipeline space to avoid fuel shortage failures, power plants might use dual fuel capability as a valid mitigation option. Currently, only slightly more than a third of New England's natural gas capacity has backup fuel capability (Table 4.1).

Table 4.1. Summary of the generation fleet in New England with special attention to the gas-fired portion of the generation portfolio. Gas-fired units are further broken down by the dual fuel measures they have installed as of the 2018 operation year. Data are derived from Form EIA-860 (U.S. Energy Information Administration, 2019c).

Generator type	Number of generating units	Nameplate Capacity [GW]
All 20+ MW Generators	245	32.7
Gas-fired 20+ MW Generators	118	17.5
Gas-fired units with:		
No oil dual fuel capability	64	11.5
Gas-oil fuel switch capability	54	6.0

In the past, ISO-New England has acknowledged the importance of on-site petroleum fuel storage as a measure to prevent fuel shortages (see most recently ISO New England, 2018). But, until the last few years, natural gas storage at generator sites has received little serious consideration as a fuel security option. In 2016 and 2017, the U.S. Department of Energy's National Energy Technology

Laboratory (NETL) was tasked with identifying the necessary equipment, fuel requirements, costs and land footprint required to ensure one-day backup fuel supplies for gas-fired power plants in the event of a fuel disruption (Brewer, et al., 2016 and Myles, et al., 2017). Myles et al. found above-ground storage of gas at generator sites to be a prohibitively expensive mitigation option for fuel shortage situations with storage tank costs ranging from the tens to hundreds of millions of dollars depending on the size of the power plant. In 2019, a research group at The Pennsylvania State University developed a joint electricity-natural gas expansion model. They used this model to identify where it makes sense on the system level to strategically build distributed natural gas storage capability in the New England region to increase reliability of an interdependent gas and electricity grid network. They found that the economically optimal placement of distributed natural gas storage in New England may be at generator sites (Blumsack and Wu, 2019).

Here, we build on the work described above. Aided by a database of historical power plant failures, we compute the overnight capital, fuel carrying and land costs (when applicable) required for gas generators in New England to assure their fuel supplies. Our estimates are based on actual failure event durations and magnitudes at generators rather than an arbitrary fuel supply duration as in Myles et al. (2017). We examine distributed compressed natural gas (CNG) storage at generator sites and dual fuel capabilities with oil storage; we then compare these costs to those of installing batteries with enough capacity to cover historically observed fuel outages, and to the participant incentive costs of demand response programs in New England. We construct supply curves of fuel shortage mitigation based on these cost estimates. We also compute the revenue that generators could have captured had they been available during fuel shortage events and the payback periods associated with these potential revenue streams. We conduct this analysis under the assumption that firm gas pipeline contracts are unavailable due to pipeline constraints.

Our key findings are that: 1) a levelized energy cost premium of $1/MWh could help approximately 2.6 – 7 GW of gas-fired capacity in New England mitigate the fuel shortage failures they experienced between 2012 and 2018 with gas/oil dual fuel capability or approximately 1.7 – 3.1 GW with on-site CNG storage, and 2) the capital expense associated with the fuel storage options would be less expensive than installing battery backup for resource adequacy and would be comparable to incentive costs for demand response programs.

The remainder of this paper is organized as follows: section 2 describes the historical data used in this analysis, section 3 explains the methods employed, section 4 highlights the key quantitative results, and section 5 concludes with policy implications.

4.2 Data

In this section we discuss the historical power plant failure data, generator operational characteristics, cost and pricing information that we use to compute the expenditures required to mitigate fuel shortage failures at natural gas power plants and the revenues foregone by generators because of fuel shortage failures.

4.2.1 North American Electric Reliability Corporation Generating Availability Data System

As in Freeman et al. (2019), we use the NERC Generating Availability Data System (GADS). We include unscheduled outages, partial outages (de-ratings) and startup failure events at natural gas generators in the New England region with lack of fuel causes. In 2012, dispatchable generators with nameplate capacities of 50 megawatts (MW) or greater were required to report to the GADS database. In 2013, the threshold was lowered to 20 MW for the remainder of our study period (North American Electric Reliability Corporation, 2019b). To ensure that only unscheduled, non-economic failure events were included, and that data were recorded accurately, the sample was pre-processed as in Murphy et al. (2018). Our sample includes 308 fuel shortage failure reports by 54 natural gas generating units located at 29 unique plant locations between 1/1/2012 and 3/31/2018.

4.2.2 U.S. Energy Information Administration Power Plant Operations Reports

Using the data matching process described in Freeman et al. (2019), we matched the power plant failure reports to power plant operational data from the U.S. Energy Information Administration (EIA). These data are collected annually through EIA Forms 860 and 923 for grid-connected generators of 1 MW or larger nameplate capacity (U.S. Energy Information Administration, 2019c and 2019d).

We use the generator characteristics in the EIA-860 database to identify which fuel assurance measures every unit in our sample had in place during the 2012-2018 operation years. To calculate generator heat rates, the specific fields we use from the EIA-923 Monthly Generation and Fuel Consumption Time Series file are: 'reported fuel type code', 'quantity consumed in physical units for electricity generation', and 'electricity net generation (MWh).' The fields we use for fuel costs are from the EIA-923 Fuel Receipts and Cost Time Series file and include 'fuel group' and 'fuel cost.' We also use the EIA-923 Monthly Ending Petroleum Liquids Fuel Stocks Time Series file (U.S. Energy Information Administration, 2019d) to generate time series of the petroleum fuel stock levels at all the power plants in our sample.

4.2.3 Vendor quotes for fuel storage tank costs

For natural gas storage options, we use cost estimates provided in a 2014 Department of Energy report gathered from case studies of compressed natural gas vehicle fueling stations (Smith and Gonzales, 2014). Fast-fill CNG fueling stations employ the type of high-pressure natural gas storage that would be required to provide on-site gas storage for a power plant with minimal footprint. Smith and Gonzales estimate that CNG storage with capacities between 16,250 standard cubic feet (scf) and 55,000 scf cost between $70,000 and $130,000. We use these end points to estimate a cost for CNG storage of between $2 and $4.50 per scf of natural gas stored at high pressure. Their estimates are based on actual station costs and discussions with equipment vendors.

For petroleum-based mitigation options we derive a scalable cost factor for fuel storage tanks of varying sizes from a table of tank costs publicly available from tank vendors. The range we compute is $0.98 – $3.05 / gallon (Eagle Tanks, 2019). The tank costs used to construct this range are included in Appendix C.

4.2.4 Land costs for larger storage facilities

We use assessed property values from tax entries for land parcels adjacent to power plants when assessing an additional land cost on generator sites that need to purchase more land for fuel storage equipment. These data are gathered from municipality, county and state information portal websites in New England. A summary of property values used as a result of the plant-by-plant land analysis is in Appendix C.

4.2.5 Real time generator locational marginal prices

To estimate foregone energy revenues for generators reporting fuel shortage failures we used real-time, hourly locational marginal prices for the nodes of the generators in our sample. These data were retrieved from ABB Velocity Suite (2019).

4.3 Method

The data show that some units fail more frequently and/or are out of service longer than other units due to fuel shortages (Figure 4.2). Because of the influence of individual generator circumstances on the durations and frequencies of fuel shortages, we take a plant-specific approach using actual failure event durations from generating units in New England. We explore the difference in cost estimates observed using the simulation approaches described in Appendices D and E. We use the costs we calculate to construct mitigation supply curves for the New England gas-fired generation fleet.

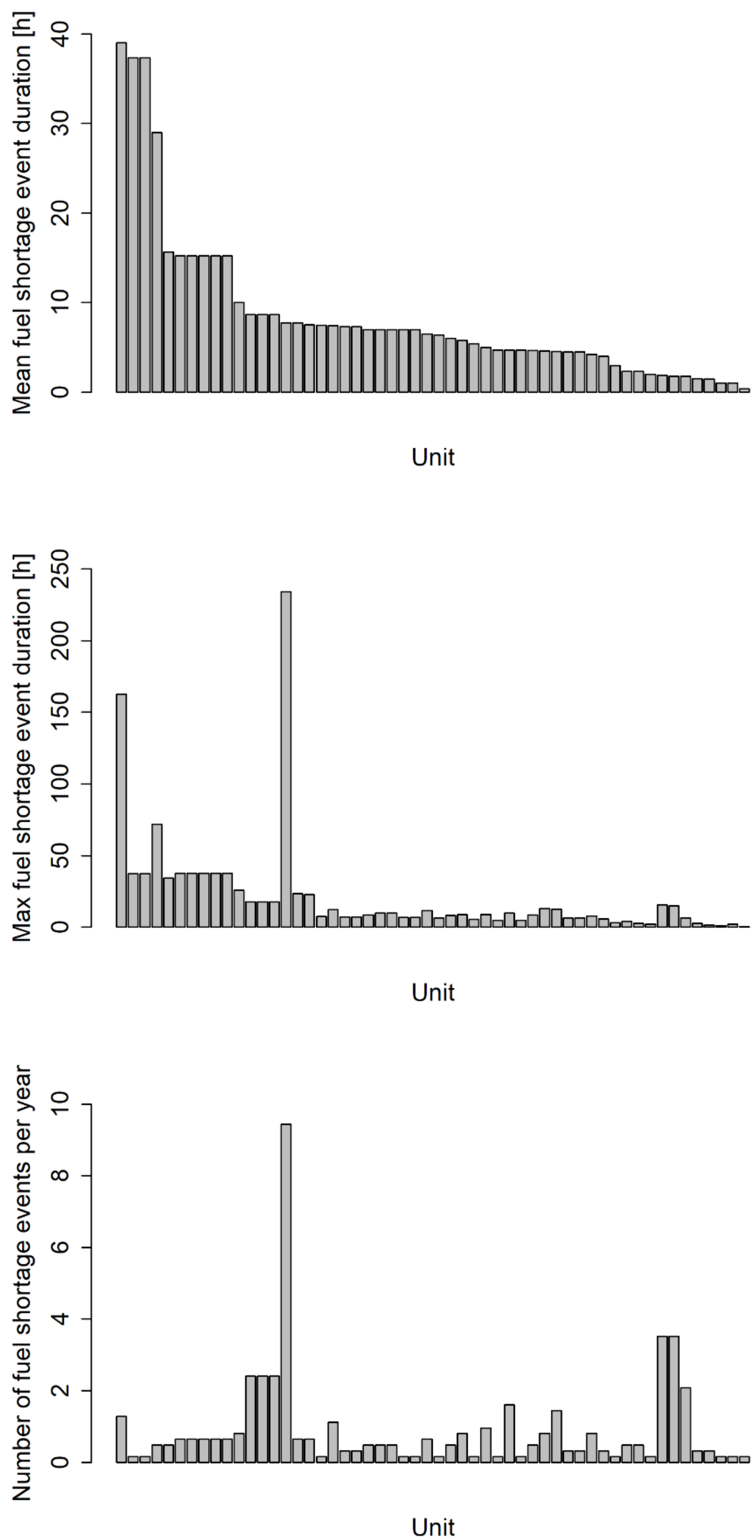


Figure 4.2. Mean fuel shortage event durations (top), maximum fuel shortage event durations (middle), and the number of fuel shortage failure events per year (bottom) by gas-fired unit in New England that reported fuel shortage failures to the GADS database 1/2012-3/2018. Each bar represents one of the 54 units with fuel shortages in the GADS sample and bars are not re-ordered in the middle and bottom plot.

4.3.1 Plant-specific mitigation cost estimation

Some units in New England had mitigation measures installed on-site at the times of their first fuel shortage failures in the GADS dataset. The matching of the GADS data to the generator characteristic data from EIA-860 enables us to calculate the cost of paying for only what the unit has not already installed. 54 units in our GADS sample of plants failed because of fuel shortage in 2012-2018; a summary of measures that each had installed at the time of their first reported fuel shortage failure is in Table 4.2.

Table 4.2. A summary of the fuel security measures that New England natural gas generating units had in place at the time of their first fuel shortage failure. Data derived from NERC GADS and EIA-860 data 2012-2018.

Units	Capacity [MW]	Gas/oil dual fuel	Has oil storage sufficient to fuel its worst fuel shortage (2012-18)	Has enough land on its currently owned property for oil storage requirements	Has enough land on its currently owned property for CNG storage requirements
34	10,177			X	X
6	986	X		X	X
1	85	X	X	X	
13	3,038	X	X	X	X

For cost estimates, we assume that generators size their fuel storage systems to mitigate the worst fuel shortage event that they experience over the six-year study period. We do this by using the magnitudes and durations of the fuel shortage events reported to GADS for each unit and the unit's heat rate from EIA-923 to calculate the amount of fuel that the unit would have consumed if its unavailable capacity had instead been available.

To check if dual fuel units already had enough back up fuel storage capacity on-site, we generated monthly time series of oil stocks at each plant between 2007 and 2018 using the EIA-923 data. If the peak of oil stocks over the period prior to the plant's first fuel shortage event exceeded the fuel requirement of the worst fuel shortage failure experienced by the plant between 2012 and 2018, we assume that the current storage is adequate. If not, we assume that the plant must install incremental oil storage capacity.

4.3.2 Estimating capital costs for storage equipment

We calculate the capital cost of mitigation using the equation:

$$CAPEX_x = \left(\frac{Cap_{max,x}\Delta t_{max,x}HR_x}{HV_x}\right)c_{tank} + c_{equipment} \qquad (4.1)$$

Where, $Cap_{max,x}$ is the magnitude and $\Delta t_{max,x}$ is the duration of unit x's worst fuel shortage event, HR_x is generator x's heat rate and HV is the heating value of the fuel as reported to EIA-923 during the study period. The product of these first four terms is the estimate of the fuel consumption of the generating unit if it had been available during its worst fuel shortage event. The fuel consumption is multiplied by the scalable storage tank cost, c_{tank}. $c_{equipment}$ is the cost of equipment required to enable the fuel storage mitigation options. For CNG, this includes compression equipment for filling the on-site storage tanks. For oil-based dual fuel options, this includes a cost to convert power generation equipment to dual fuel capable. This cost estimate was developed by NETL (Brewer, et al., 2016) and is $54,000/MW for field-installed equipment.

4.3.3 Estimating fuel costs

The average annual additional fuel cost incurred by units to fuel the generation lost to fuel shortages is calculated as:

$$FUEL_x = \frac{\left(\frac{\sum_i \left(Cap_{i,x} \Delta t_{i,x}\right) HR_x}{HV_x}\right) c_{Fuel}}{T} \qquad (4.2)$$

Where, $\sum_i \left(Cap_{i,x} \Delta t_{i,x}\right)$ is the sum of all of unit x's MWh lost to fuel shortage events over the study period, c_{Fuel} is the delivered cost of either natural gas or oil to power generators in New England, and T is the study period length, 6.25 years.

4.3.3.1 Leakage and replenishment of distributed CNG storage facilities

According to the GADS data for plants in New England, the majority of 2012-2018 fuel shortage events occurred during the winter and spring seasons[1], but the fraction of the total MWh lost to fuel shortages was spread evenly throughout winter, spring and fall (Table 4.3). We note that the Massachusetts state law for residential minimum heating requirements set the heating season in New England between mid-September and mid-June (Commonwealth of

[1] We adopt NERC's definition of seasons in this analysis. December – February is winter, March – May is spring, June – September is summer and October – November is fall (North American Electric Reliability Corporation, 2018)

Massachusetts, 2019). These data indicate that, for reliability purposes, generators should fill CNG storage tanks during the warm summer months of July and August for use during potential fuel shortages in fall, winter and spring. It also makes sense to fill tanks during the summer months because wholesale prices for natural gas are typically lower in New England during those months (U.S. Energy Information Administration, 2019e) .

Table 4.3. Fraction of fuel shortage events and MWh lost to fuel shortages by NERC-defined seasons.

Season	Count of fuel shortage events	Fraction of total fuel shortage events	Fraction of total MWh lost to fuel shortage events
Winter	111	36%	27%
Spring	92	30%	31%
Summer	61	20%	11%
Fall	44	14%	32%

Long-term storage of compressed natural gas may create the potential for leakage from storage tanks. Recent studies are summarized in Brandt et al. (2014).

Although no studies have been conducted that look specifically at the high-pressure storage that we specify for the tanks at the power plant sites in our sample, we can use bottom-up leakage estimates compiled in Brandt et al. as a proxy for the systems we analyze here. The bottom-up studies look at mainly gas processing facilities, production sites and compressor stations. We use the leakage rate ranges from the studies at gas processing facilities as our proxy because natural gas processing plants use large storage tanks to move gas through the steps of pre-processing and these tanks may have leakage characteristics similar to those of the storage tanks we specify.

We assess an average annual fuel replenishment cost for storing natural gas for 9 months of the year of:

$$C_{replenishment} = 0.75 LR \rho_{NG} c_{Fuel} \quad (4.3)$$

Where, LR is the annual emissions magnitude of methane from gas processing facilities in Brandt et al. (2014) and ρ_{NG} is the density of natural gas. Substituting equation 4.3 into equation 4.2, the average annual fuel costs for CNG storage options are:

$$FUEL_{x,CNG} = \frac{\left(\frac{\sum_i \left(Cap_{i,x} \Delta t_{i,x}\right) HR_x}{HV_x} + 0.75 LR \rho_{NG}\right) c_{Fuel}}{T} \quad (4.4)$$

4.3.4 Estimating land requirements and costs

We calculate the land requirement for fuel storage options using the actual dimensions of oil storage tanks from our vendor source (Eagle Tanks, 2019) and a CNG storage tank unit that would take up a square area with 36-foot sides including 5-ft safety buffers on all sides, based on the spherical storage tank option in Myles at al. (2017). For storage options that require more than one tank, we base our footprint calculations on multiples of the footprint of the 25,000-gallon capacity oil storage tank or multiples of the 36-foot CNG storage tank unit.

The assessment of land costs is conducted on a plant-by-plant basis by geo-locating every plant in our sample and consulting the corresponding municipality's property map. Aerial imagery from Google Maps (2019) is used to estimate the area of the plant's lot that is not already occupied by building or equipment. If the undeveloped land on the power plant's lot is smaller than the amount of space needed for additional fuel storage tanks, we use the respective municipality's property tax assessment files to estimate costs for land adjacent to the plant using neighboring lots' assessed values (summarized in Appendix C).

In completing this plant-by-plant process, we found that only one unit required additional land. All other units in our study reside on lots with room to fit many more tanks than are required by our estimates. For the one unit that requires land purchases, four lots surround the plant. Two of the lots surrounding the plant are currently undeveloped and are much less expensive than the other developed lots. The undeveloped lots are valued between $12,000 and $65,000/acre (Commonwealth of Massachusetts, 2019). Both lots are industrial zoned. The only difference is that the $65,000/acre lot has approximately 900 feet of railroad frontage and a gravel access road that appears to have been a railroad siding in the past.

4.3.5 Amortizing costs across generated MWh

We use a slightly modified version of the approach in the National Renewable Energy Laboratory's Annual Technology Baseline (National Renewable Energy Laboratory, 2019a) to compute the levelized cost of fuel shortage mitigation options. We elect this approach so our cost estimates can be viewed as a premium to be added to the levelized cost of energy generated at the natural gas units in our sample. The levelized cost premium (LCP_x) is calculated as:

$$LCP_x = \frac{\left((CAPEX_x + LAND_x) \times FCR\right) + FUEL_x}{DF_x \times CF_x \times 8760} \qquad (4.5)$$

$LAND_x$ is the cost of land required for additional fuel storage equipment for unit x. *FCR* is the fixed charge rate as calculated by the Annual Technology Baseline's (National Renewable Energy Laboratory, 2019a) method using the parameters in Table 4.4. *DF* is a de-rating factor applicable to units operating in oil-fired mode based on historical efficiencies of units in gas-fired and oil-fired modes according to EIA-923. *CF* is the capacity factor of the unit calculated using historical data from EIA-923. We conduct a sensitivity analysis to examine how our financial parameters would affect the cost estimates using a more general simulation approach in Appendix D.

Table 4.4. Financial parameters used to calculate the fixed charge rate for the baseline scenario.

Parameter	**Value**
Federal Tax Bracket	21%
State Tax Bracket	6%
Equity financing rate (r_e)	12%
Percentage of total project debt financed (D/V)	50%
Pre-tax debt financing rate (r_d)	5.5%
Economic Plant Life (n)	20
Fraction of Investment that can be Depreciated (b)	100%
Depreciation Period (M)	20

To avoid double counting of fuel costs, we bring the fuel cost into the numerator of Equation 4.3 to reflect that this is a carrying cost premium for fuel in storage at the power plant site.

We use these cost estimates to construct a supply curve for capacity mitigation of fuel shortage failures. We compare the range of fuel storage mitigation options' capital cost estimates using the actual failure data at New England plants to the cost of battery storage resources and demand response program incentives as alternative options.

4.3.6 Costs not quantified in our estimates

We note that both mitigation strategies will require operations and maintenance expenses. Because we calculate first-order estimates of mitigation costs without a case-by-case engineering design of fuel storage systems, we do not quantify operations and maintenance costs here.

The dual fuel back up options will require fuel polishing and filtration if the plant will be storing petroleum for long periods. Depending on the quality of the oil used for backup fuel, this process might occur sub-annually while oil is stored on-site. Natural gas storage options will require continuous leak detection and monitoring to ensure optimal performance and reduce replenishment costs.

4.3.7 Summary of baseline and scenario assumptions for cost estimates

The parameters used to construct low, medium, and high cost estimate scenarios are in Table 4.5.

Table 4.5. Parameters used to create low, medium and high estimate cost scenarios. The range of derating factors is provided here for reference. In calculations, plant-specific derating factors within this range is used.

Variable	Symbol	Unit	Low	Base	High	Source
CNG storage tank cost	c_{tank}	\$/scf	2	3.25	4.50	Smith and Gonzales, 2014
CNG compressor cost	$C_{equipment}$	\$1000	50	70	90	Smith and Gonzales, 2014
Volumetric oil tank cost	c_{tank}	\$/gal	0.97	1.90	3.05	Vendor – Eagle Tanks, 2019
Delivered natural gas cost	c_{NG}	\$/Mcf	4	6	12	Annual average from (U.S. Energy Information Administration, 2019b) for New England plants
Delivered Petroleum liquid cost	c_{DFO}	\$/Bbl	60	110	130	
Efficiency derating factor (η_{DFO}/η_{gas})	DF		0.85	0.80	0.75	EIA-923 for units in New England
CNG storage leakage rate	LR	g/yr	10^3	10^5	10^7	Brandt et al., 2014

4.3.8 Calculating the payback time of mitigation options

We compute simple payback periods for mitigation options at the plants in our New England sample. To do this, we first compute the average annual lost energy revenue during fuel shortage events. Enabled by the data mapping between the GADS reports and the EIA generator characteristics, we use real-time locational marginal prices (LMPs) from ABB Velocity Suite at the price nodes of each generator in our sample to compute forgone energy revenues.

ISO–New England implemented a pay for performance (PFP) mechanism in their forward capacity market in 2018. In PFP, during any five-minute interval when the grid is deficient in capacity reserves, units that provide more than the availability factor they bid into the ISO's forward capacity market are awarded a performance bonus. There is a penalty on under-performing units that provide less than their availability bid into the capacity auction, during any five-minute interval of capacity scarcity (Gillespie, 2018). We next estimate what average annual payments and avoided capacity penalties from PFP would have been if they had been in place during our study period.

If the unit is fully available when a capacity scarcity period is declared, the unit captures an annual PFP revenue (R_{PFP}) of:

$$R_{PFP} = (1 - BR \times AF) \times Cap_{Nameplate} \times PFP \times h_s \qquad (4.6)$$

Where, BR is the balancing ratio calculated by summing the system load and reserve requirement during the scarcity period and dividing by the total capacity supply obligation of generators on the system, AF is the availability factor by which the unit's owner deflates its capacity during the capacity auction, $Cap_{Nameplate}$ is the unit's nameplate capacity, PFP is the level of the performance incentive, and h_S is the number of hours per year that capacity scarcity events are in effect. The unit also avoids a penalty ($Penalty_{PFP}$) that it would otherwise incur if it were unavailable of:

$$Penalty_{PFP} = BR \times AF \times Cap_{Nameplate} \times PFP \times h_s \qquad (4.7)$$

In our baseline scenario, we calculate simple payback periods for mitigation options based on the sum of average annual forgone energy revenues, PFP revenues and avoided PFP penalties under a scenario in which we assume that a similar number of capacity scarcity hours would have been called each year in our sample period as in the first year of PFP implementation (2.4 hours) (ISO New England, 2019). For PFP payments, our baseline calculations use the 2018 level of the incentive, \$2,000/MWh (ISO Newswire, 2018), a high-load situation balancing ratio of 0.9 and an availability factor of gas-fired units of 100% based on NREL's Annual Technology Baseline best-case scenario (National Renewable Energy Laboratory, 2019b).

4.4 Results and Discussion

4.4.1 Plants with capacity of 2-4 times ISO-New England's reserve requirement could mitigate fuel shortage failures for $1/MWh or less

Using actual fuel shortage failure data from GADS between 2012 and 2018, we find that 2.6 – 7 GW of gas-fired capacity could mitigate their experienced fuel shortages for $1/MWh or less using gas/oil dual fuel capabilities (Figure 4.3). We estimate that 1.7 – 3.1 GW could use on-site CNG storage to mitigate their gas shortages for $1/MWh (Figure 4.4). 2.6 GW is 170% of ISO New England's 1.5 GW reserve requirement. All the plants that could mitigate failures for $1/MWh or less using CNG could also do so using gas/oil dual fuel, but CNG is not strictly dominated economically by oil at all those units.

About two-thirds of the entire New England gas-fired fleet, 10.6 – 11.6 GW, could mitigate their fuel shortages for $6.6/MWh or less with gas/oil dual fuel. For the same cost, 5.0 – 8.7 GW, or around 40% of the gas-fired fleet, could do so with on-site CNG. Results for all units are given in Table 4.6.

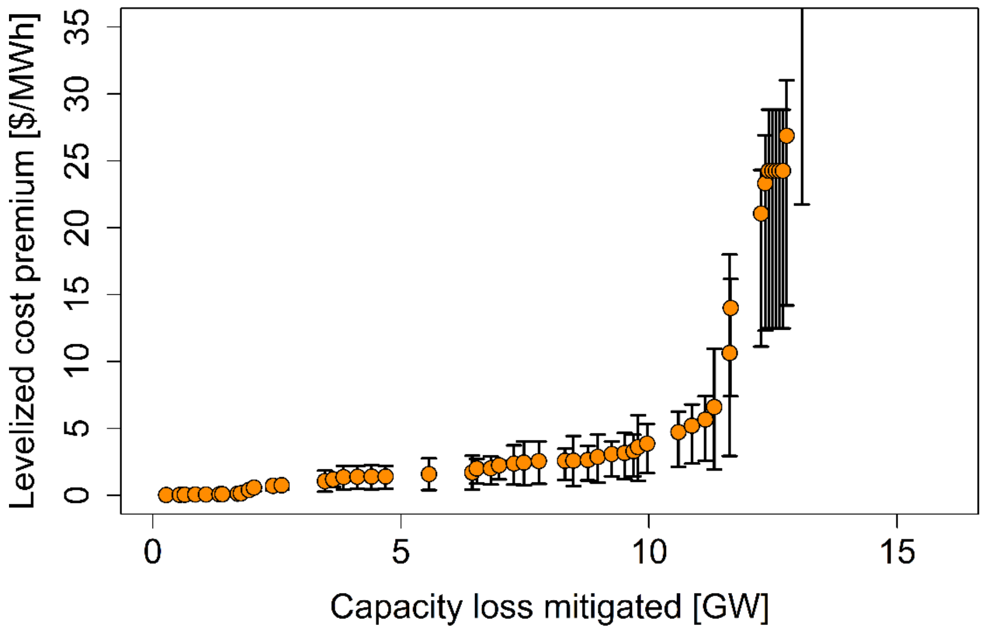


Figure 4.3. Supply curve for the oil dual fuel mitigation option for fuel shortage failures at gas-fired generators in New England using actual failure and operational data. Uncertainty bars represent ranges created by the scenario parameters in Table 4.5.

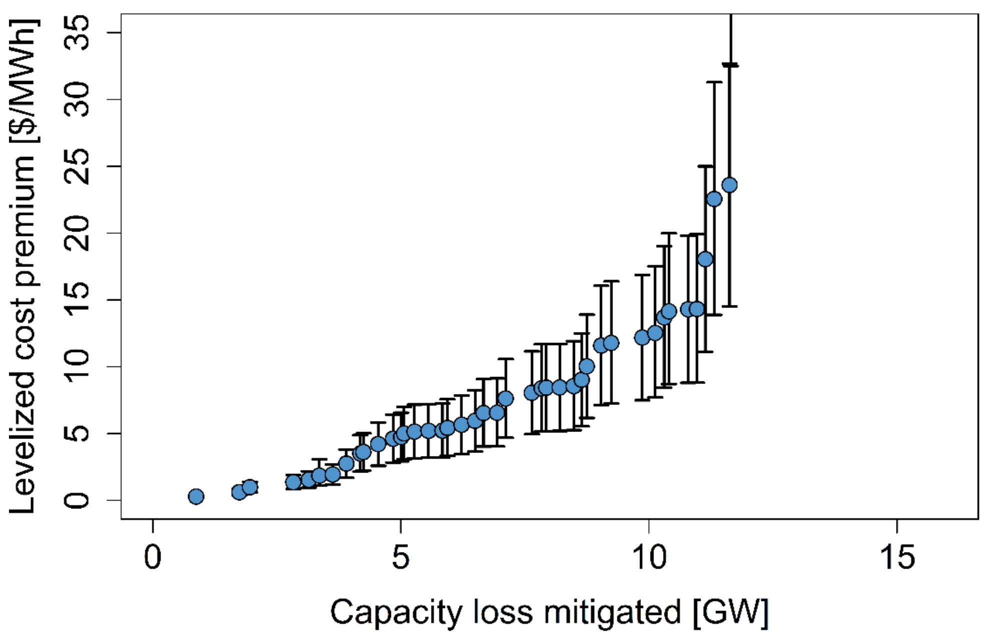


Figure 4.4. Supply curve for the CNG storage mitigation option for fuel shortage failures at gas-fired generators in New England using actual failure and operational data. Uncertainty bars represent ranges created by the scenario parameters in Table 4.5.

Table 4.6. Levelized cost premium estimates and uncertainty ranges for the units in the GADS sample. Units numbers correspond to the order that units appear in Fig 4.3. Colored columns indicate units <~$1/MWh cost.

	Oil Dual Fuel levelized cost premium [$/MWh]			CNG levelized cost premium [$/MWh]		
Unit	Low	Med	High	Low	Med	High
1	0.01	0.01	0.02	1.20	1.94	2.71
2	0.01	0.03	0.03	1.70	2.76	3.82
3	0.02	0.04	0.04	3.35	5.43	7.57
4	0.03	0.05	0.06	1.15	1.86	3.08
5	0.03	0.05	0.06	0.61	0.99	1.40
6	0.03	0.06	0.07	5.20	8.46	11.72
7	0.04	0.08	0.09	3.10	5.02	6.98
8	0.06	0.12	0.13	0.96	1.55	2.18
9	0.07	0.14	0.16	2.24	3.62	5.02
10	0.20	0.38	0.44	2.92	4.74	6.57
11	0.30	0.57	0.66	6.17	10.03	13.89
12	0.37	0.70	0.81	8.80	14.29	19.81
13	0.39	0.74	0.86	4.69	7.63	10.58
14	0.26	1.05	1.83	0.38	0.62	0.87
15	0.63	1.18	1.37	5.56	9.03	12.50
16	0.42	1.35	2.18	3.17	5.15	7.17
17	0.47	1.38	2.17	3.21	5.21	7.22
18	0.44	1.39	2.23	3.49	5.66	7.85
19	0.47	1.41	2.20	3.22	5.23	7.24
20	0.39	1.58	2.76	0.18	0.29	0.40
21	0.44	1.70	2.94	0.83	1.35	1.89
22	0.87	1.99	2.72	5.20	8.44	11.71
23	0.79	2.01	2.91	5.26	8.55	11.93
24	1.18	2.23	2.58	11.11	18.05	25.00
25	0.79	2.36	3.72	2.60	4.22	5.84
26	0.73	2.44	4.03	5.16	8.39	11.68
27	0.85	2.55	4.01	2.84	4.61	6.43
28	1.13	2.57	3.47	4.95	8.05	11.15
29	0.69	2.59	4.43	4.03	6.54	9.07
30	1.10	2.64	3.68	7.13	11.58	16.06
31	0.94	2.86	4.54	7.25	11.78	16.38
32	1.41	3.08	4.02	2.16	3.52	4.88
33	1.20	3.16	4.66	7.72	12.53	17.51
34	1.41	3.29	4.53	8.81	14.32	19.91
35	1.06	3.60	5.98	8.71	14.14	19.99
36	1.65	3.86	5.32	8.43	13.69	19.03
37	2.11	4.72	6.26	7.49	12.18	16.87
38	2.37	5.19	6.78	3.66	5.95	8.25
39	2.58	5.65	7.39	4.04	6.56	9.13
40	1.93	6.59	10.95	13.88	22.55	31.29
41	2.93	10.63	18.00	14.53	23.60	32.69
42	7.39	14.00	16.16	32.50	52.79	73.43
43	11.12	21.06	24.31	41.79	67.91	94.05
44	12.31	23.32	26.92	58.16	94.50	130.95
45	12.48	24.26	28.82	38.87	63.16	87.46
46	12.48	24.26	28.82	38.91	63.23	87.59
47	12.48	24.26	28.83	39.54	64.23	89.53
48	12.48	24.26	28.83	38.89	63.19	87.51
49	12.48	24.26	28.83	38.87	63.16	87.46
50	14.18	26.87	31.02	62.71	101.90	141.22
51	21.74	45.99	58.82	116.06	188.52	264.76
52	39.02	75.98	90.23	70.80	115.05	159.40
53	144.13	272.80	314.89	79.76	129.60	179.48
54	367.59	696.74	805.38	212.81	345.82	478.84

4.4.2 More than 8 GW of gas-fired capacity could experience paybacks of 10 years or less from fuel storage measures

Using historical LMPs and current incentives for capacity performance present in ISO New England, we find that 15 of the 29 plants in our sample could see a private payback of fuel security measures of 10 years or less if they had been available to capture energy revenues lost during their fuel shortages and PFP had been in place during the study period. Those plants represent a little over 8 GW of capacity – less than half of the gas-fired capacity in New England. The oil dual fuel options dominate the CNG option in terms of private payback at all but one plant in our sample (Figure 4.5).

We conduct sensitivity analysis on the average annual duration of capacity scarcity events and the level of the payment incentive and present the results in Appendix F. We note that if the payment incentive were to increase to the 2024, full-implementation level of $5,455/MWh (ISO Newswire, 2018) holding the 2.4 hours of scarcity per year constant based on the number of scarcity periods in 2018, 21 of the 29 plants in our sample could see simple paybacks of oil dual fuel measures of less than 10 years – a little over 11 GW of capacity (Figure F.2).

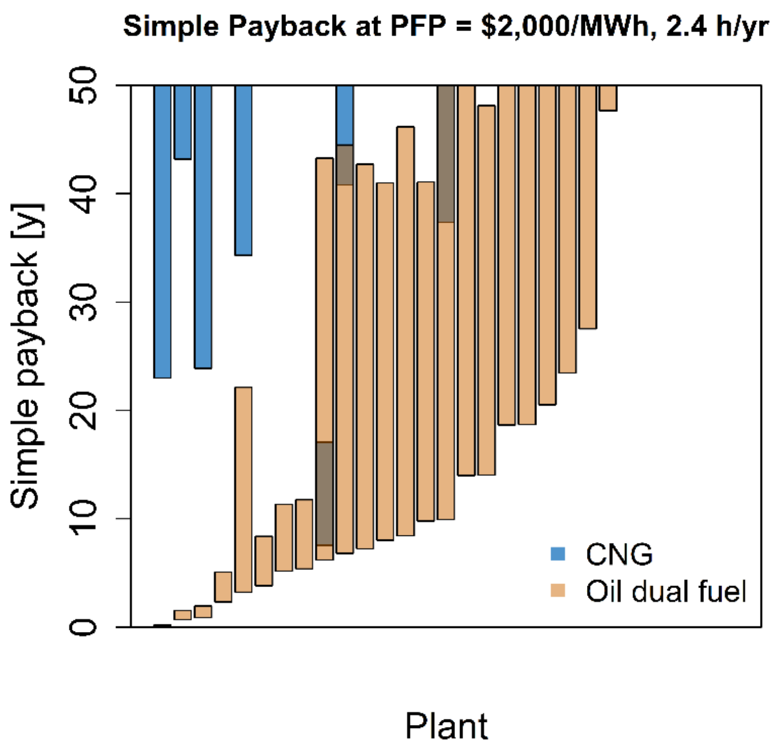


Figure 4.5. Simple payback periods for fuel shortage mitigation options at the 29 plants in the New England GADS sample. Results here assume 2.4 hours of PFP scarcity per year based on 2018 and a $2,000/MWh PFP incentive/penalty amount. Bar ranges represent the difference between the low and high scenario estimates created by the inputs in Table 4.5.

4.4.3 The range of capital costs for fuel storage options in the New England sample compares favorably to battery storage and demand response alternatives

When we compare the range of estimated capital costs for fuel storage mitigation options by megawatt of capacity mitigated and Lazard's capital cost estimates for wholesale battery storage options (Lazard, 2018), we find that oil dual fuel mitigation strategies dominate the battery alternatives based on the New England sample. Capital costs of mitigation for units that needed to install additional equipment to use oil dual fuel ranged from a minimum of $8/kW with the low-cost scenario inputs to a maximum of $165/kW using the high-cost scenario inputs. Lazard estimates that batteries on the MW-scale required to store enough energy to mitigate large fuel shortage failures[2] cost $1,100 - $2,300/kW. CNG options, however, may not be competitive with battery storage alternatives because of the capital costs associated with storage tanks for longer or larger capacity outages. In the New England sample, units' maximum fuel shortage event durations ranged from less than an hour to over 200 hours. This creates a capital cost range for CNG storage options that spans three orders of magnitude between $7 - $7,700/kW.

Fuel storage assets do not provide the same level of flexibility of applications that a battery storage system would. Asset owners choosing to install batteries to address fuel security issues at gas-fired plants could also capture additional revenue streams from ancillary services markets. These additional revenue streams create uncertainty in what the charge-discharge behavior of the battery installation would be. The gas storage options we explore here would not likely be able to sell back their fuel at a profit because our data show that the only time

[2] Lazard's levelized cost of storage analysis presents six storage "use cases" based on industry surveys to size the illustrative systems it presents in their financial analysis. We consider the in-front-of-the-meter wholesale-level use case. Capital cost estimates are based on a 100 MW, 400 MWh system. For comparison, of the fuel shortage events in the New England sample, the median number of MWh lost was 434 MWh.

it may be feasible to do so is during the summer months when natural gas prices are general low (U.S. Energy Information Administration, 2019e).

Another alternative from a system perspective is using demand response resources to provide load reduction at times of gas scarcity in the New England region. With the introduction of Fully Integrated Price Responsive Demand in ISO-New England's capacity market, it is possible that demand resources on the power system could complete the necessary load reduction required when a large gas-fired plant falls offline due to fuel shortages. This action, however, is different than economic demand response, but remains as a potentially less expensive alternative to fuel storage at gas power plants.

The ranges we compute for the capital cost estimates for both CNG and oil storage options overlap with the range of costs of customer incentives for demand response programs in New England during the study period. Although fuel storage options do not dominate demand response programs economically (Figure 4.6), much more capacity could be mitigated using fuel storage compared to current levels of demand response enrollment. According to early release data from 2018 EIA Form 861 (U.S. Energy Information Administration, 2019a), 24,000 customers in ISO New England were enrolled in Demand Response programs with a total potential peak reduction of 158 MW. These 158 MW of potential peak savings were spread across 8 different utilities in Massachusetts, Vermont and New Hampshire.

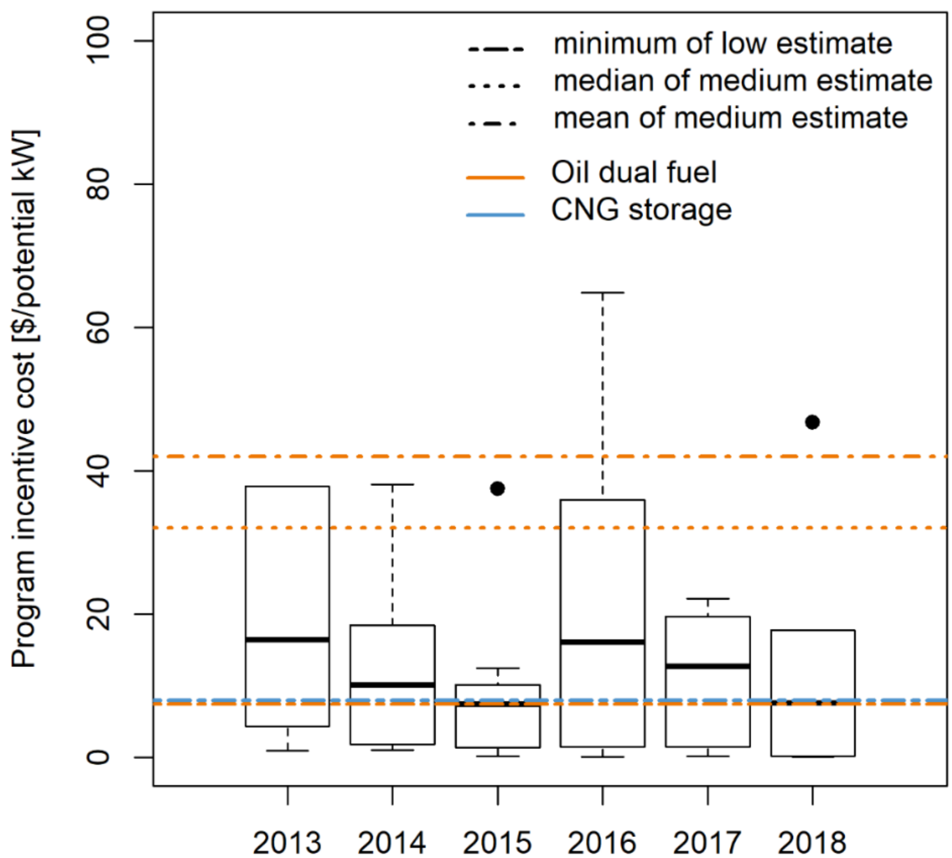


Figure 4.6. Comparison of the program incentive costs for Demand Response participation in the New England states and the capital cost of fuel storage mitigation options per kilowatt. Boxplots show the distribution of incentive costs of all active programs in New England by year. Lines show the minimum, median and mean of capital costs of oil dual fuel and CNG storage options estimated using actual failure and operational data for New England generators between 2012 and 2018.

4.5 Conclusions and policy implications

Using the historical failure data from the North American Electric Reliability Corporation, we find that approximately 2.6 – 7 GW of New England's gas-fired capacity could mitigate the fuel shortage failures they experienced between 2012 and 2018 for approximately $1/MWh in additional levelized cost. This amount of capacity compares favorably to the 3 GW of expected five-year capacity margin in ISO-New England from NERC's December 2018 Long-Term Reliability Assessment (North American Electric Reliability Corporation, 2018).

Private paybacks of less than 10 years may be realized at plants totaling 8 GW of capacity at current pay for performance incentive levels in ISO New England. When performance incentive levels increase from the current $2,000/MWh to the 2024, full-implementation level of $5,455/MWh we find that an additional 3 GW of capacity could be incentivized through the elevated performance payments.

We conclude that the pay for performance (PFP) mechanism in ISO-New England may provide a good incentive for gas-fired generation owners to install back-up fuel storage and dual fuel capabilities based on our analysis. At current levels, paybacks are ~10 years for many plants and become shorter at higher incentive levels. Furthermore, if gas constraints in the New England region worsen, we could expect an increase in the number of capacity scarcity hours per year in addition to the increase in the PFP incentive level in future years. This would reduce private payback time for fuel storage measures at plants (Appendix F). Between when the Federal Energy Regulatory Commission approved the PFP mechanism in 2014 and PFP's effective data on June 1, 2018, 2,500 MW of dual fuel capacity was added to the generation mix in ISO New England (ISO Newswire, 2018).

On a capital cost per MW of mitigation basis, fuel storage options at gas-fired plants are less expensive than battery storage as a resource adequacy measure. However, battery storage options can provide additional value to the owner and the grid in the form ancillary services.

While sometimes less expensive than fuel storage mitigation options, Demand Response (DR) programs have not been adopted at levels in New England that are sufficient to mitigate gas shortages at power plants. Of the 8 utility DR programs active during the 2018 year, only 158 MW of potential peak reductions were enrolled. During peak demand periods, only 108 MW of DR enrollment was called across all of ISO New England in 2018 for an average across utilities of about 6 hours throughout the year (U.S. Energy Information Administration, 2019a). Comparing these numbers to ISO New England's average non-zero hourly coincident fuel shortage generator outage magnitude – 278 MW – and average annual number of hours with fuel shortage outages – 255 hours – between 2012-2017 (North American Electric Reliability Corporation, 2019a) we see that DR programs for mitigation of fuel shortages require much more enrollment to be an adequate alternative to fuel storage as a mitigation option for gas shortages at generators in New England.

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4.7 Appendix C: Supporting material

4.7.1 Vendor data used for oil storage tank cost estimates

Table C.1. Summary of tank costs gathered from online vendor pricing lists used to construct the range of scalable oil storage tank costs (Eagle Tanks, 2019).

Capacity [gal]	Diameter [ft]	Height [ft]	Cost [$]	Cost/Capacity
240	3.2	4.0	732	3.05
300	3.2	5.0	820	2.73
340	3.8	4.0	857	2.52
420	3.8	5.0	1078	2.57
520	3.8	6.0	1336	2.57
675	3.8	8.0	1507	2.23
750	3.8	9.0	1940	2.59
1000	5.3	6.0	2098	2.10
1500	5.3	9.0	2890	1.93
2000	6.3	9.5	4527	2.26
4000	6.3	18.0	7185	1.80
6000	8.0	17.0	8927	1.49
8000	9.5	17.0	11222	1.40
10000	9.5	20.0	12257	1.23
12000	9.5	24.0	15469	1.29
14000	11.5	19.0	16216	1.16
15000	10.9	23.0	17671	1.18
20000	11.5	27.0	21163	1.06
25000	12.0	31.0	24442	0.98

4.7.2 Summary of plant-by-plant land analysis

Table C.2. Summary of the results of the plant-by-plant land analysis. Property values for the adjacent lots for the one plant that does not have enough room for the CNG storage requirement are derived from Commonwealth of Massachusetts, 2018.

Plant	**Lot Size** [acre]	**Building Footprint** [acre]	**Footprint of CNG Storage** [acre]	**Land left after CNG** [acre]	**Value of Adjacent Property 1** [$/acre]	**Value of Adjacent Property 2** [$/acre]
1	2.6	1.5	1.2	-0.1	12,900	64,950
2	2.3	0.7	0.4	1.1	-	-
3	7.4	3	2.9	1.4	-	-
4	36.5	4.03	30.7	1.8	-	-
5	8.8	5.03	1.6	2.2	-	-
6	6.2	3.27	0.5	2.3	-	-
7	7.8	4.42	0.3	3.1	-	-
8	25	10.12	9.4	5.4	-	-
9	13.3	4.39	0.2	8.7	-	-
10	27	7	9.4	10.6	-	-
11	17.5	3.5	1.0	13.0	-	-
12	36.3	18.13	2.3	15.8	-	-
13	29.5	4.27	8.3	16.9	-	-
14	28.3	6	3.2	19.1	-	-
15	32.3	9.5	3.3	19.5	-	-
16	27.7	6.1	1.9	19.7	-	-
17	27.5	4	2.1	21.3	-	-
18	32	8.43	1.7	21.8	-	-
19	66.4	42	0.5	23.9	-	-
20	39.4	10.6	0.9	27.9	-	-
21	61.9	23.32	3.9	34.7	-	-
22	44.9	7.45	0.7	36.8	-	-
23	56.7	16	2.7	38.0	-	-
24	49.7	8.6	2.2	38.9	-	-
25	70.8	3.88	27.4	39.6	-	-
26	71.3	13.1	1.1	57.0	-	-
27	123.1	37.4	1.1	84.6	-	-
28	147	17	0.6	129.4	-	-
29	310	28	0.1	281.9	-	-

4.8 Appendix D: A general simulation approach to calculating the cost of mitigation for fuel shortage failures

We construct a general simulation approach informed by the NERC GADS sample of fuel shortage failures at natural gas generators in New England by fitting distributions to unit's mean times to recovery from fuel shortage events and heat rates. We use these parameterized values in equations 1 and 2 in the main text rather than actual event durations and heat rates. We retain the low, medium and high cost scenario inputs from Table 4.5 in the main text. In this approach, we neglect land costs because in the plant-by-plant land analysis we found that the vast majority of plants in the GADS sample already had more than enough land to install additional fuel storage facilities.

4.8.1 Fitting distributions to mean times to recovery from fuel shortage events.

For each of the 54 generating units in the GADS sample we compute the mean time to recovery from fuel shortage events as the average of the unit's fuel shortage event durations over the six-year timeframe. We weight each unit by its rated capacity to produce capacity-weighted histograms of mean times to recovery from fuel shortages. We compute the parameters of fitted distributions for use in simulations and for reference by practitioners. Graphical representations and fit parameters are provided in Figure D.1 and Table D.1.

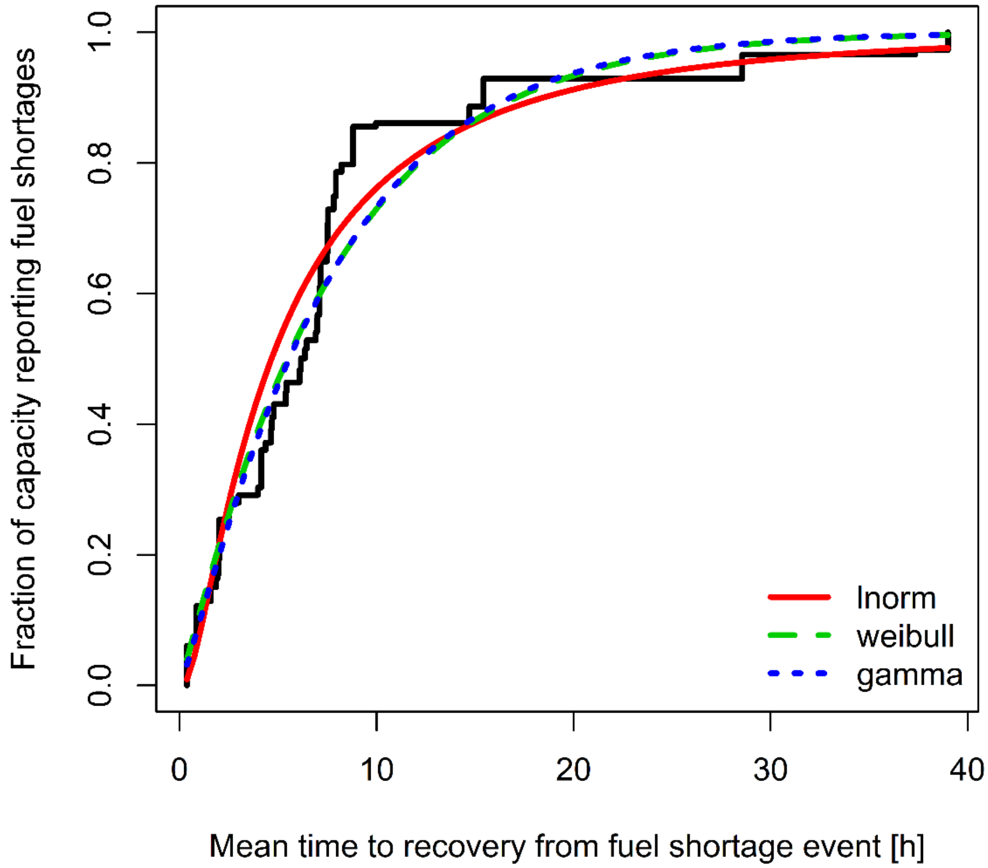


Figure D.1. Cumulative Density Function of mean time to recovery from fuel shortage events of New England units reporting to GADS 1/2012 – 3/2018. Log-normal, Gamma and Weibull fit lines are included.

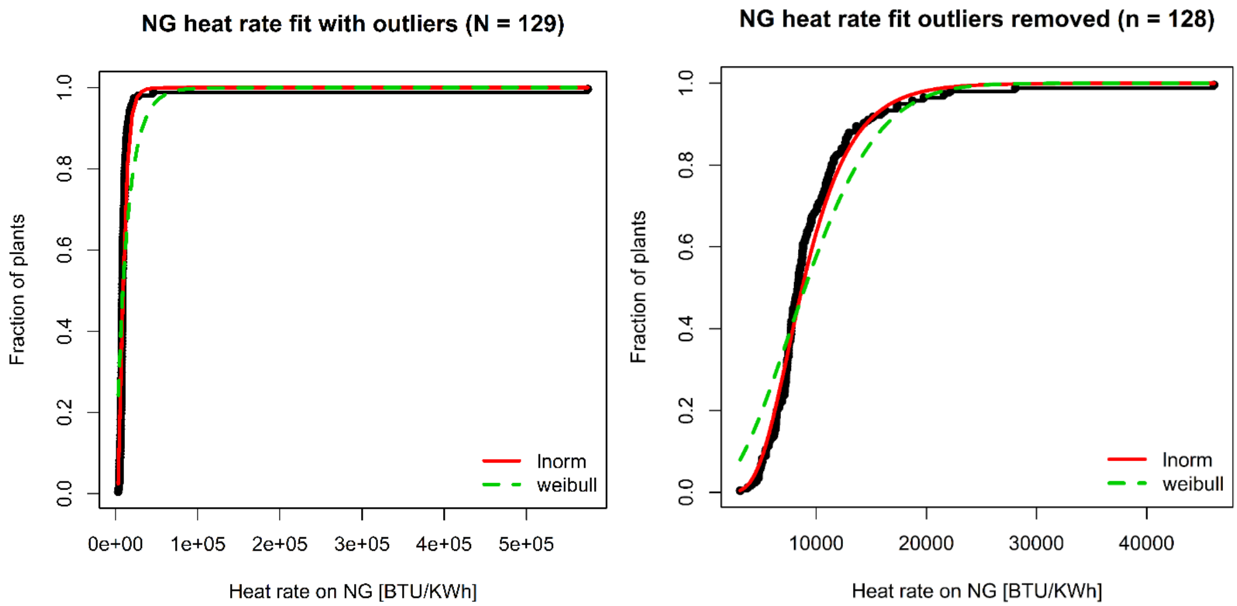
Table D.1. Parameters for fitted distributions of mean time to recovery from fuel shortage events of New England units reporting to GADS 1/2012 – 3/2018. Asterix indicates fit used to produce results.

Fitted distribution	**Parameter 1**	**Parameter 2**
Gamma	Shape = 0.815 (6.72 x 10^{-3})	Scale = 13.7 (8.09 x 10^{-4})
Log-normal*	Mean-log = 1.69 (7.87 x 10^{-3})	SD-log = 1.17 (5.56 x 10^{-3})
Weibull	Shape = 0.823 (3.87 x 10^{-3})	Scale = 9.79 (8.52 x 10^{-2})

4.8.2 Fitting distributions to unit heat rates

For simulation runs, we also fit distributions to the generating units' heat rates running in both gas-fired and oil-fired modes. We do this by filtering the overall EIA-923 unit set by plants within New England and with EIA Fuel codes 'DFO', 'JF', 'KER', 'NG', 'RFO', and 'WO'. EIA-923 includes 129 power plants in New England that generated electricity using natural gas between 2012 and 2018 and 170 that generated electricity using oil between 2012 and 2018. We note that some of these plants are dual fuel plants and appear in both samples. Furthermore, the EIA-923 data for heat rates are given at the plant level. As such, we assign the computed heat rate to all units in the GADS sample at each EIA plant.

While plotting the distributions of heat rates at power plants we note a few instances of potential outliers possibly because of reporting errors. The heat rates at these plants were orders of magnitude larger than their counterparts. We present distribution fit CDFs and parameters for the distribution of power plants heats rates with the outliers included and with the outliers removed in Figures D.2 and D.3 and Tables D.2 – D.5. We display results that follow with outliers removed.



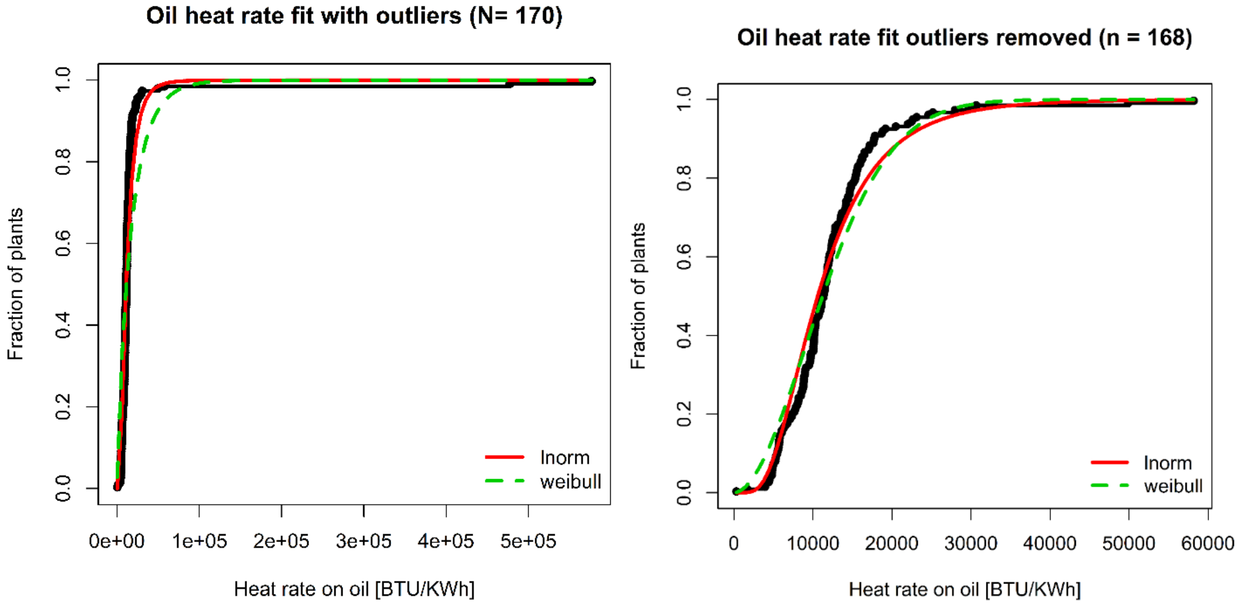
Figures D.2. Cumulative Density Functions of heat rates of New England power plants fueled by natural gas with suspected outliers (left) and without suspected outliers (right). Log-normal and Weibull fit lines are included.

Table D.2. Parameters for fitted distributions of heat rates of power plants in gas-fired mode without noted outliers removed. Data from EIA-923 2012-2018 for plants in New England.

Fitted distribution	Parameter 1	Parameter 2
Log-normal	Mean-log = 9.11 (4.75 x 10^{-2})	SD-log = 0.539 (3.36 x 10^{-2})
Weibull	Shape = 0.904 (4.20 x 10^{-2})	Scale=1.28 x 10^{4} (1.28 x 10^{3})

Table D.3. Parameters for fitted distributions of heat rates of power plants in gas-fired mode with noted outliers removed. Data from EIA-923 2012-2018 for plants in New England. Asterix indicates the fit used to construct results.

Fitted distribution	Parameter 1	Parameter 2
Log-normal*	Mean-log = 9.07 (3.50 x 10^{-2})	SD-log = 0.396 (2.48 x 10^{-2})
Weibull	Shape = 2.00 (0.111)	Scale=1.08 x 10^{4} (509)



Figures D.3. Cumulative Density Functions of heat rates of New England power plants fueled by oil with suspected outliers (left) and without suspected outliers (right). Log-normal and Weibull fit lines are included.

Table D.4. Parameters for fitted distributions of heat rates of power plants in oil-fired mode without noted outliers removed. Data from EIA-923 2012-2018 for plants in New England.

Fitted distribution	**Parameter 1**	**Parameter 2**
Log-normal	Mean-log = 9.31 (5.31×10^{-2})	SD-log = 0.693 (3.76×10^{-2})
Weibull	Shape = 0.892 (3.83×10^{-2})	Scale=1.70×10^{4} (1.56×10^{3})

Table D.5. Parameters for fitted distributions of heat rates of power plants in oil-fired mode with noted outliers removed. Data from EIA-923 2012-2018 for plants in New England. Asterix indicates the fit used to construct results.

Fitted distribution	**Parameter 1**	**Parameter 2**
Log-normal*	Mean-log = 9.26 (4.27×10^{-2})	SD-log = 0.553 (3.02×10^{-2})
Weibull	Shape = 1.87 (9.61×10^{-2})	Scale=1.36×10^{4} (599)

It is important to note that the simulation results that follow assume one failure per year at a simulated power plant. According to the data from the GADS reports, at units in New England, the counts of these events vary widely between just 1 event to nearly 60 events over the 6.25-year study period. The average frequency of events in the sample is slightly less than 1 event per year (North American Electric Reliability Corporation, 2019a).

4.8.3 Simulation results suggest that almost all fuel shortage events could be mitigated for about $5-10/MWh using on-site fuel storage

Based on the results of 10,000 trials with parameterized values for generating units' mean time to recovery from fuel shortage failures and heat rate, all simulated fuel shortage failures at power plants in New England could be mitigated for an additional $5-10/MWh using oil dual fuel options. Figure D.4 presents a cumulative density function of the levelized cost premium calculated during the 10,000 simulation runs at a 30% capacity factor unit. CNG storage options at generator sites are generally much more expensive with the low-cost scenario inputs (see Table 4.5 in the main text) resulting in a premium of approximately $25/MWh to mitigate almost all fuel shortage failures.

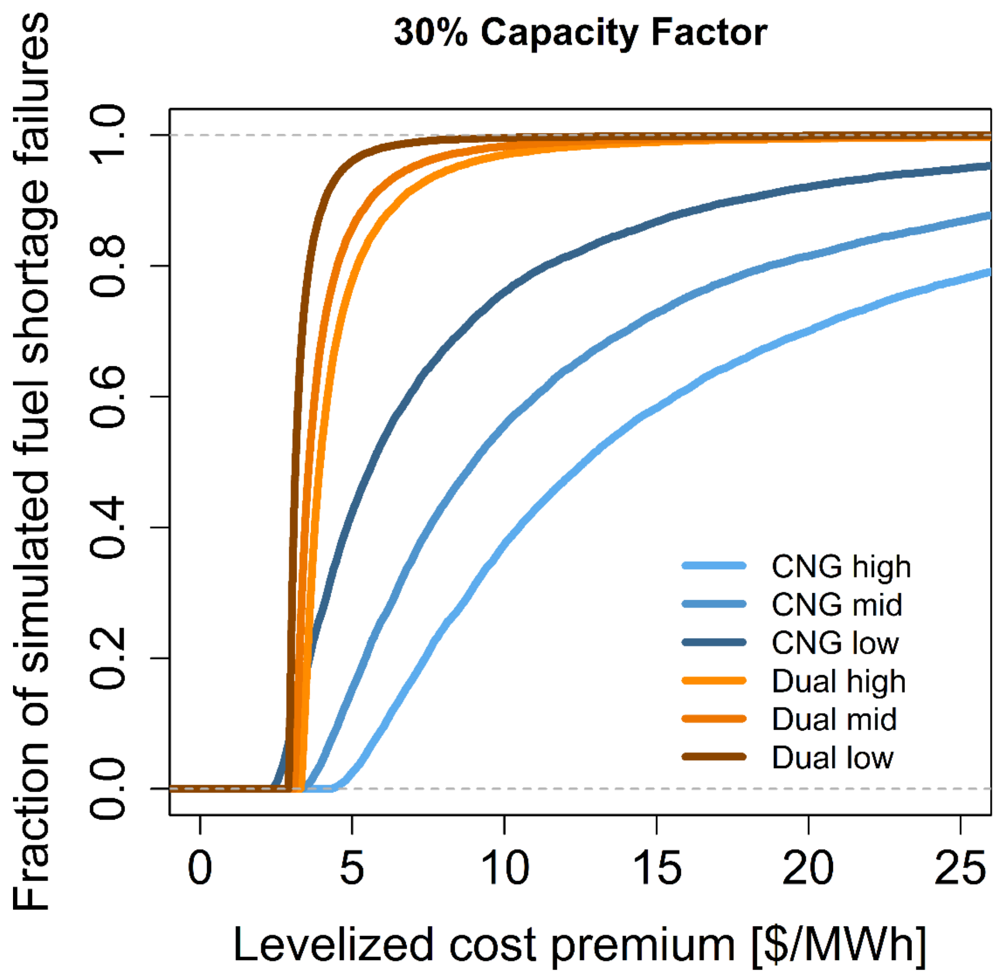


Figure D.4. Cumulative density functions of 10,000 simulation trial computations of the levelized cost premium of oil dual fuel and CNG storage mitigation options. Color shades represent different input scenarios; darker colors represent lower input values from Table 4.5 in the main text.

4.8.4 Sensitivity of simulation results to unit capacity factor

But the results in 4.7.3. are very sensitive to the capacity factor at which the fuel secure plant will operate. $5-10/MWh assumes a 30% capacity factor (approximately the operational average of the plants in the New England GADS sample over the study period), the cost premium scales proportionally to the unit's capacity factor.

Figure D.5 shows the effect of varying the capacity factor of the simulated power generator by a factor of 2. We see that the oil dual fuel price premium scales from an upper limit of $10/MWh to either $20/MWh or $5/MWh for oil dual fuel units when the capacity factor is dropped to 15% or increased to 60% respectively.

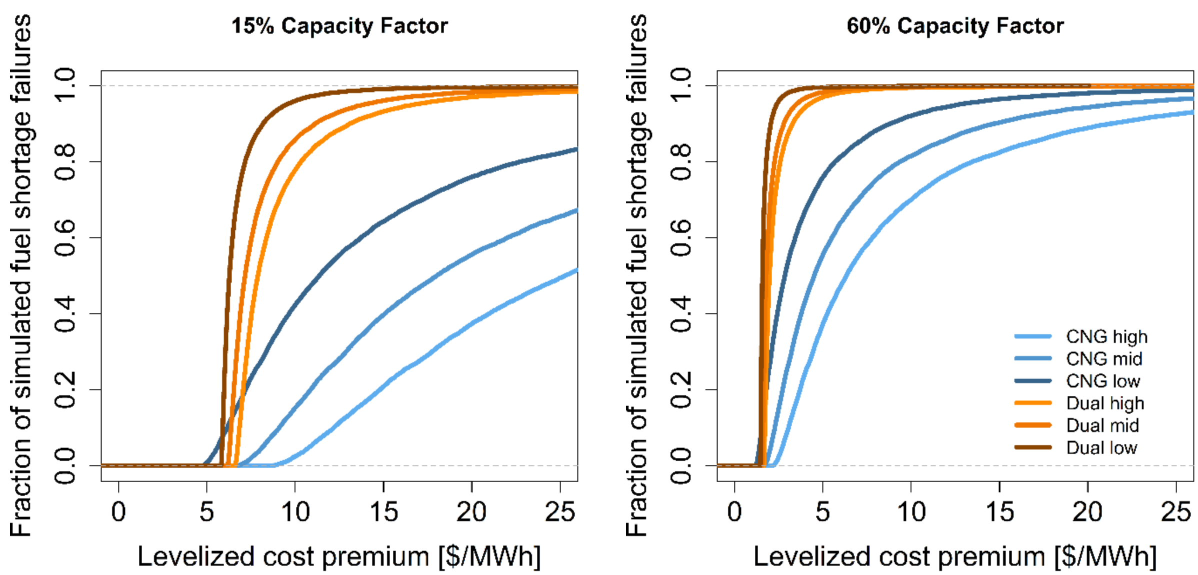


Figure D.5. Cumulative density functions of 10,000 simulation trial computations of the levelized cost premium of oil dual fuel and CNG storage mitigation options at 15% (left) and 60% (right) capacity factors. Color shades represent different input scenarios; darker colors represent lower input values from Table 4.5 in the main text.

4.8.5 Sensitivity of simulation results to financial inputs

We conducted two-way sensitivity analysis of the financial inputs used to calculate the fixed charge rate by varying the federal tax bracket, state tax bracket, equity financing rate, debt financing rate, and debt-to-equity ratio between 75% and 125% of the baseline values listed in Table 4.4 in the main text. The result is shown for levelized cost premiums of the medium scenario inputs (Table 4.5 from the main text) oil dual fuel option in Figure D.6. Results simulate a unit with the average capacity factor from the New England GADS sample (30%). We find that the results are most sensitive to changes in the equity financing rate and debt-to-equity ratio holding all else constant. Cost premiums could vary by up to $0.75/MWh for units that have small-to-average magnitude fuel shortage failures as the equity financing rate rises or falls.

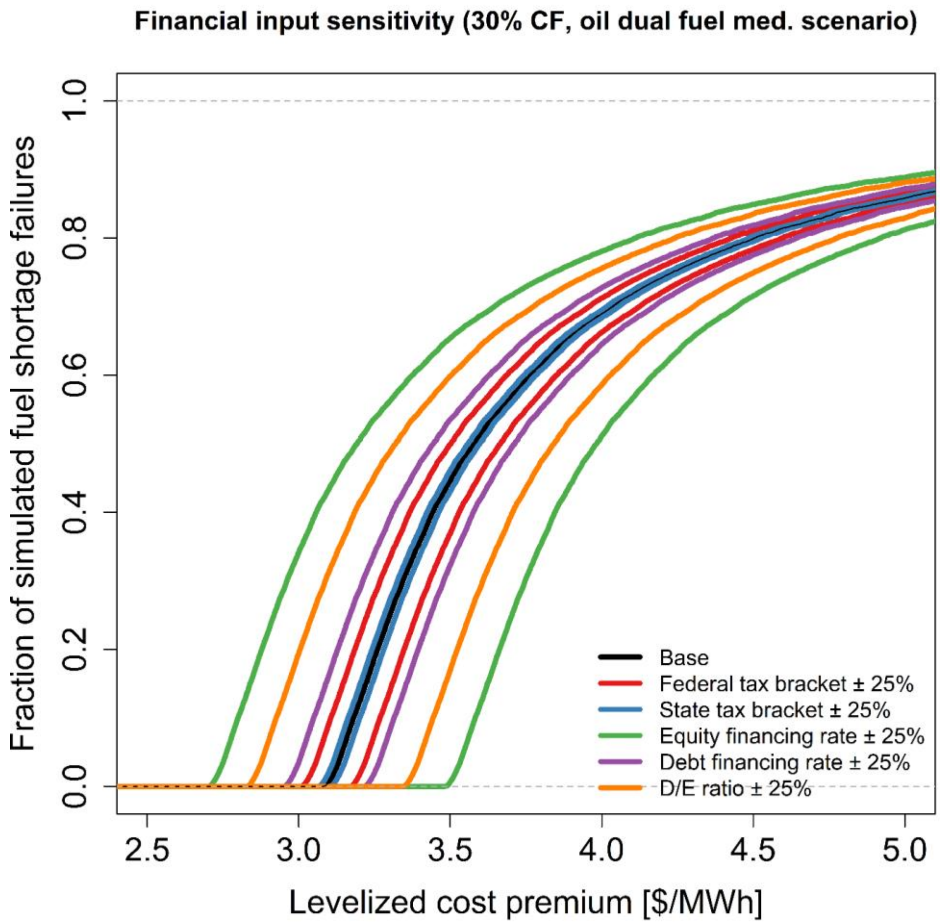


Figure D.6. Results of a sensitivity analysis on the 10,000 simulation draws of mitigating fuel shortage failures at a simulated unit. We vary financial inputs ± 25% and present results for a 30% capacity factor unit employing the oil dual fuel mitigation option. Costs are from the medium non-financial inputs scenario from Table 4.5 in the main text.

4.9 Appendix E: A Monte Carlo approach to calculating cost premiums for mitigation options

Rather than extrapolating one simulated fuel shortage failure per year across the 20-year cost estimation timeframe, we explored a Monte Carlo simulation of the average sum of annual fuel shortage event durations at all generators in New England. For the years 2012 to 2018, we used the generator sheet of the EIA-860 dataset to identify all 20+ MW gas-fired generating units in the New England region (the GADS reporting threshold). We next summed the number of hours each generating unit reported fuel shortage failures to the GADS database over the study period. We divided this sum by the number of years that our study period covers (6.25) to calculate the average annual duration of fuel shortages for every generating unit in New England. A capacity-weighted histogram of average annual fuel shortage event durations is presented in Figure E.1. We note that, of the 104 generating units with complete data in both the EIA-860 and 923 databases[3,4], 26 had average annual fuel shortage event durations of 0 hours. These 26 units represented about 20% of the 16,000 MW of capacity in the combined EIA sample.

[3] We note the loss of 14 units from the initial 118 units in the EIA-860 database because they were not present in the EIA-923 database. We therefore did not have enough information to compute generator heat rates and capacity factors for these units.

[4] We also note a difference between reporting of a "unit" between the GADS and EIA databases here. Within the GADS database, operators can report combined-cycles as either units (the combustion turbine and steam turbine separately) or blocks (the combustion turbine and steam turbine paired) (North American Electric Reliability Corporation, 2019b). In the EIA database, combined-cycle elements are all reported as individual units (U.S. Energy Information Administration, 2019c, d). When a mismatch appears between our samples, we assign all the units in the EIA sample associated with a block reported to GADS to the block's average annual event duration.

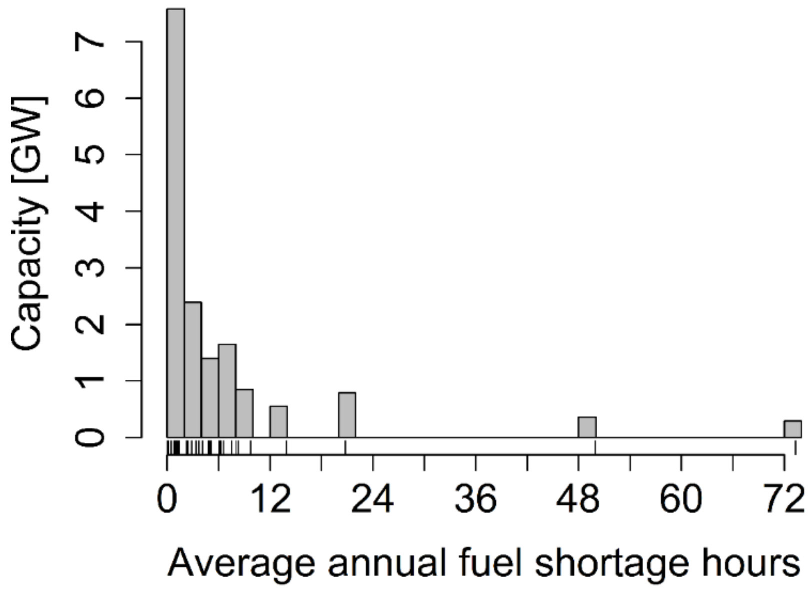


Figure E.1. Capacity-weighted histogram of average annual fuel shortage event durations at the 104 natural gas generating units in New England from the EIA sample.

We conduct a Monte Carlo simulation to effectively eliminate the influence of individual unit's fuel supply characteristics on the cost premium by treating the average annual fuel shortage event duration as an exogenous random variable. We compare the results from the simulation to the results using actual failure data in the main text.

Holding the operational heat rates and capacity factors of the units in the EIA sample constant based on historical data from the EIA-923 database, we draw 1,000 random samples with replacement from the vector of average annual fuel shortage durations at all generating units in New England. We complete this random sampling for all 104 generating units in New England to construct

Monte Carlo distributions of average annual fuel shortage durations. We then estimate a distribution of mitigation costs assuming that units do not already have any mitigation measures in place and that outages affect each unit's entire capacity. In this approach, we neglect land costs because in the plant-by-plant land analysis we found that the vast majority of plants in the GADS sample already had more than enough land to install additional fuel storage facilities.

We modify equations 4.1 and 4.2 from the main text using the Monte Carlo draws for the average annual fuel shortage event duration to construct Monte Carlo supply curves of mitigation options. We present 90% confidence intervals for simulated distributions assuming a Gaussian distribution.

4.9.1 The Monte Carlo results suggest premiums less than $10/MWh could mitigate average annual fuel shortage failures at all New England gas-fired generators

As seen in Figures E.2 and E.3, the 90% confidence intervals of the 1,000 Monte Carlo draws used to calculate the levelized cost premium indicate that the whole New England gas-fired fleet could mitigate gas shortages for an additional $1.35-$1.60/MWh using oil dual fuel. CNG options could add $2-$8/MWh to mitigate fuel shortage failures.

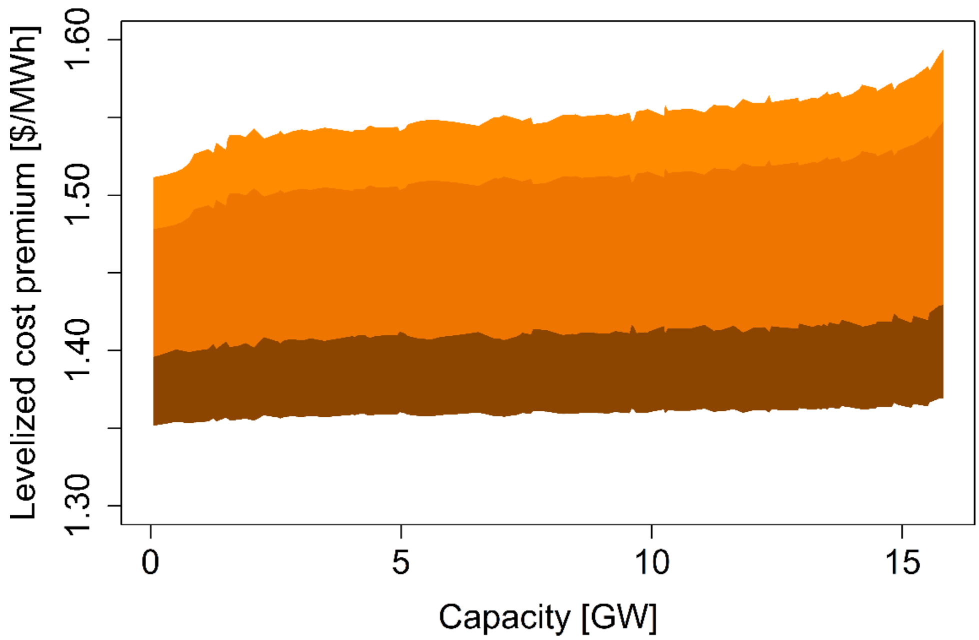


Figure E.2. Supply curve for the oil dual fuel mitigation option for fuel shortage failures at gas-fired generators in New England. Color bands represent 90% confidence intervals generated by 1,000 Monte Carlo simulations of annual fuel shortage event durations at 104 generating units in New England with replacement. Color shades represent different input scenarios; darker colors represent lower input values from Table 4.5.

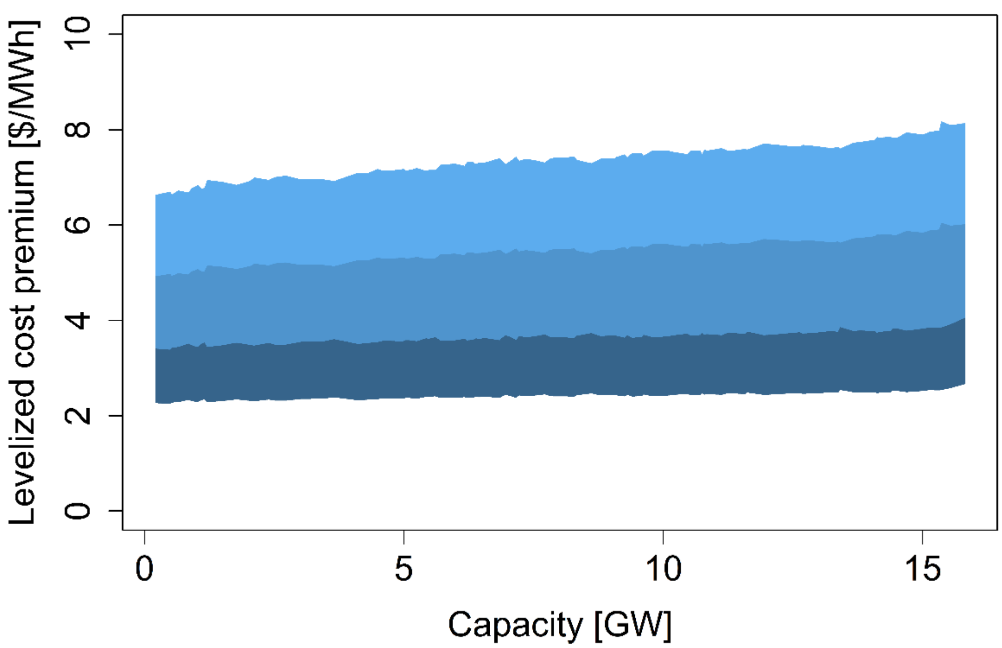


Figure E.3. Supply curve for the CNG storage mitigation option for fuel shortage failures at gas-fired generators in New England. Color bands represent 90% confidence intervals generated by 1,000 Monte Carlo simulations of annual fuel shortage event durations at 104 generating units in New England with replacement. Color shades represent different input scenarios; darker colors represent lower input values from Table 4.5.

If we compare these results to the main text results using the actual failure data from the GADS sample at New England power plants, we find that using the average annual event durations over-estimates how much capacity can be mitigated inexpensively. With actual failure durations, we observed that only about one third of the gas-fired capacity in New England could mitigate their actual fuel shortage failures using oil dual fuel for a premium of $1.60/MWh – the Monte Carlo simulation's upper bound of the 90% confidence interval to mitigate the whole gas-fired fleet.

4.10 Appendix F: Sensitivity analysis of pay-for-performance length and payment level

To examine the pay for performance mechanism as a policy intervention that may be successful in motivating backup fuel storage to prevent fuel shortages at natural gas power plants in New England, we vary the average annual length of scarcity periods and the level of the PFP incentive.

We note that as we double and then triple the number of hours of capacity scarcity from the first year of implementation in 2018 (2.4 hours up to 4.8 then 7.2), we see an increase in the number of plants in the New England sample with simple payback periods of oil dual fuel measures of less than 10 years. If scarcity hours were to increase from 2.4 to 7.2 hours per year, we could see an increase from 15 to 22 of the 29 plants with paybacks less than 10 years (Figure F.1).

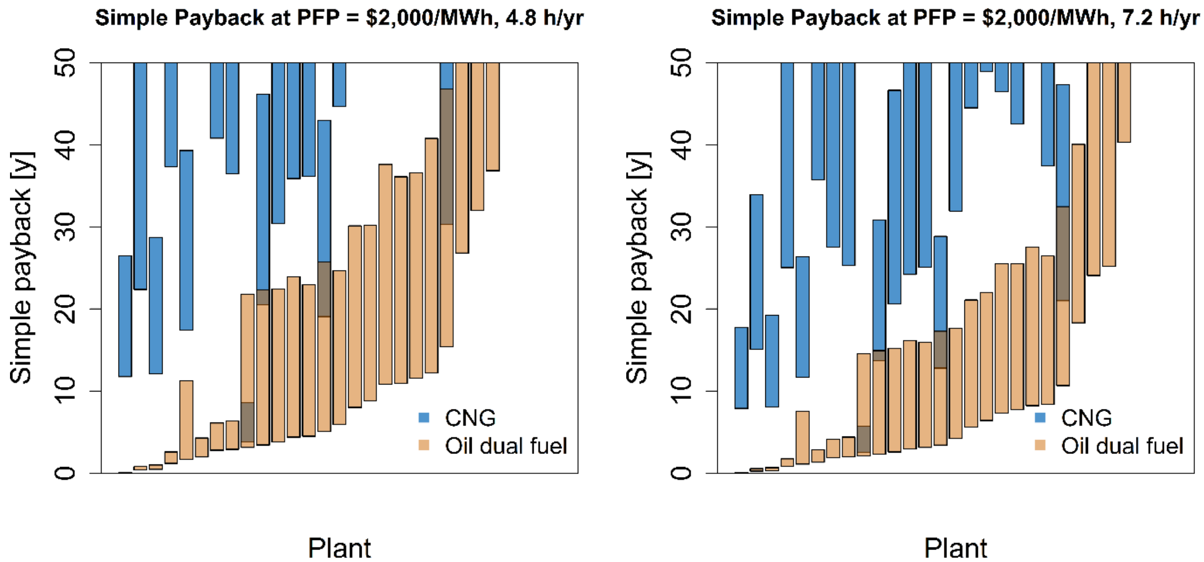


Figure F.1. Simple payback periods for fuel shortage mitigation options at the 29 plants in the New England GADS sample. Results here assume 2x the 2018 scarcity length– 4.8 hours of PFP scarcity per year (left), and 3x the 2018 level – 7.2 hours of PFP scarcity per year (right). Incentive/penalty levels are held constant at the 2018 level of $2,000/MWh. Bar ranges represent the difference between the low and high scenario estimates created by the inputs in Table 4.5 of the main text.

Similarly, we see an increase from 15 to 22 plants with paybacks of less than 10 years when we increase the PFP incentive amount from the introductory level of $2,000/MWh to the $5,455/MWh incentive level when the program is fully implemented in 2024. (Figure F.2).

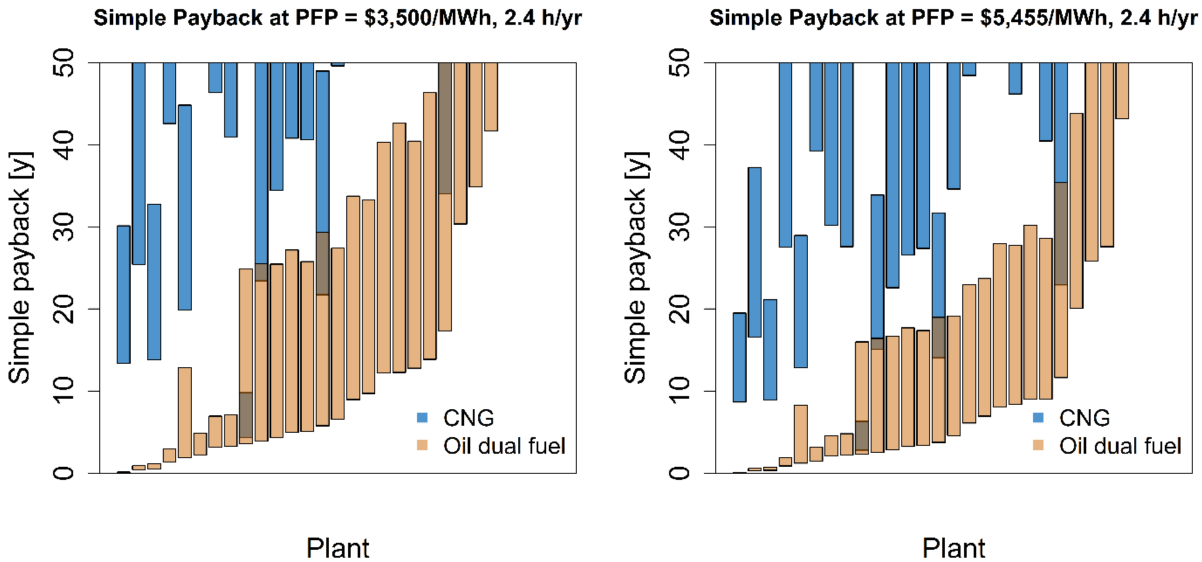


Figure F.2. Simple payback periods for fuel shortage mitigation options at the 29 plants in the New England GADS sample. The 2018 duration of scarcity events – 2.4 hours – is held constant here. Incentive/penalty levels are varied between the level to be implemented in 2021 - $3,500/MWh (left), and the full implementation level to be introduced in 2024 - $5,455/MWh (right). Bar ranges represent the difference between the low and high scenario estimates created by the inputs in Table 4.5 of the main text.