What causes natural gas fuel shortages at U.S. power plants?

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Highlights

- Fuel shortages caused large, correlated failures at gas-fired power plants
- Fuel shortages affected plants with both firm and non-firm pipeline arrangements
- Pipeline failures explain ≤5% of MWh and ≤18% of peak MW lost to fuel shortages
- Out-prioritization of power plants by other pipeline customers drove these failures
- Switching to firm contracts may be an effective mitigation strategy in some areas

Keywords

Correlated failures
fuel assurance
fuel security
Generating Availability Data System
pipeline failures
pipeline curtailment

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.

Abbreviations

C&I – commercial and industrial
GW – gigawatt
MW – megawatt
MWh – megawatt-hour
NERC – North American Electric Reliability Corporation
RTO – Regional Transmission Organization
GADS – Generating Availability Data System
DOT – U.S. Department of Transportation
PHMSA – Pipeline and Hazardous Materials Safety Administration
LNG – Liquefied Natural Gas
ERCOT – Electric Reliability Council of Texas
MISO – Midcontinent Independent System Operator
NPCC – Northeast Power Coordinating Council
PJM – PJM Interconnection LLC
SERC – SERC Reliability Corporation
SPP – Southwest Power Pool
WECC – Western Electricity Coordinating Council

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 steadfast operation of these gas units depends on the reliability 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 a 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 a 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.

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.

2.1. Natural gas power plant failure data

2.1.1. 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 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].

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 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."

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[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.

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 receipts 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).

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.

2.3.1. 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.

[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.

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.

2.3.2. 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.

2.4. Natural gas scheduling data

2.4.1. 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.

2.4.2. ABB Velocity Suite Daily Hub Report

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 A-1 of the online supplemental information.

2.4.3. U.S. EIA 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. Methods

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 occurs 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 section 2 of the online supplemental information. We were able to provide a match for all the power plants in the GADS sample.

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 A-2 of the online supplemental information.

3.3. Matching of GADS events to pipeline failure reports

We time-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.

3.4. 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.

3.4.1. 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:

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

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.

4. Results and Discussion

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

[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.

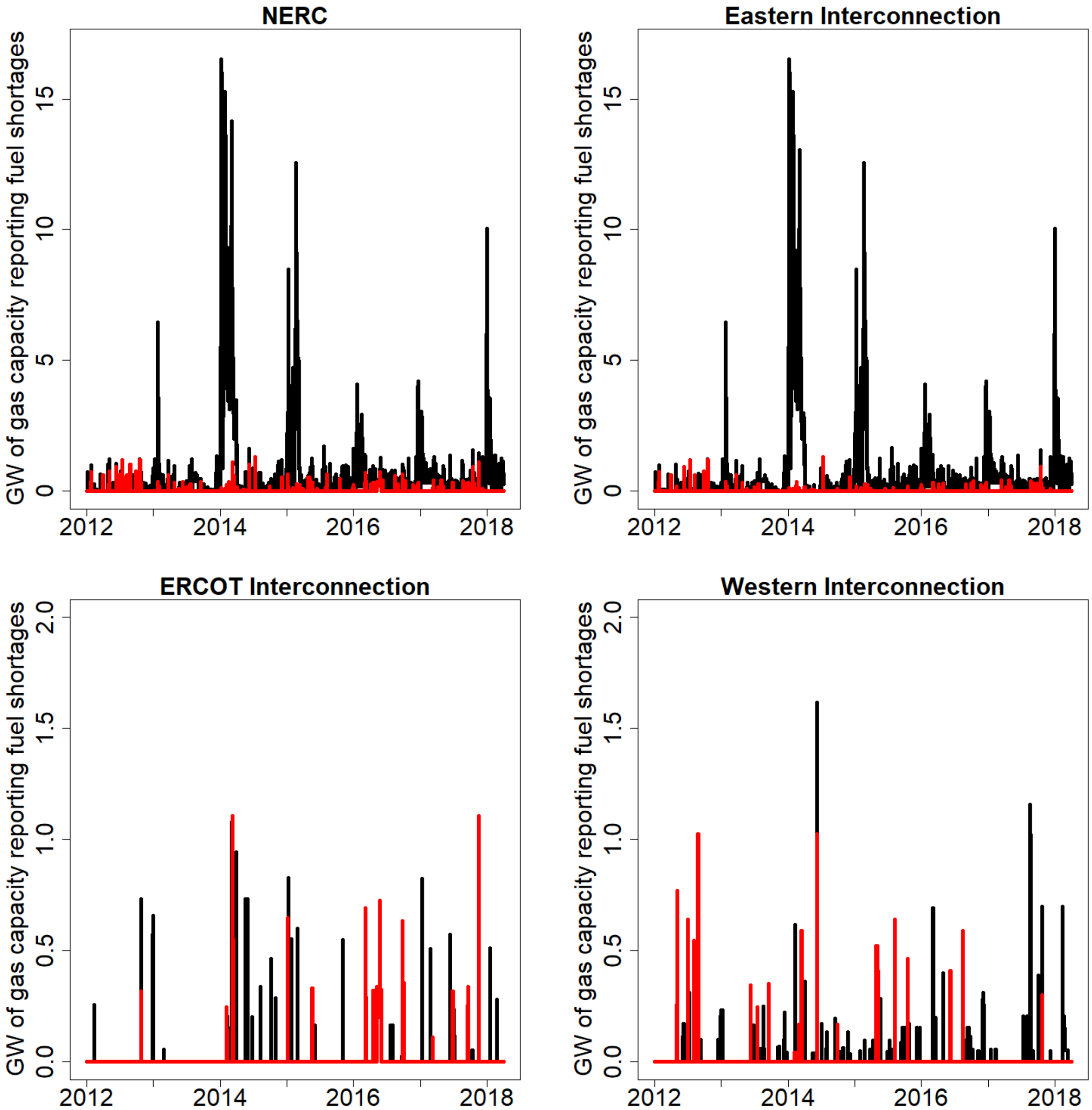

Fig. 1*. Time series plots of gas plant fuel shortage and conservation interruption failure magnitude aggregated by electricity interconnection, grouped by generator contract type. Plots are the sum of all unscheduled lack of fuel outages, de-ratings (partial outages) and startup failures at gas units. 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.*

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 2).

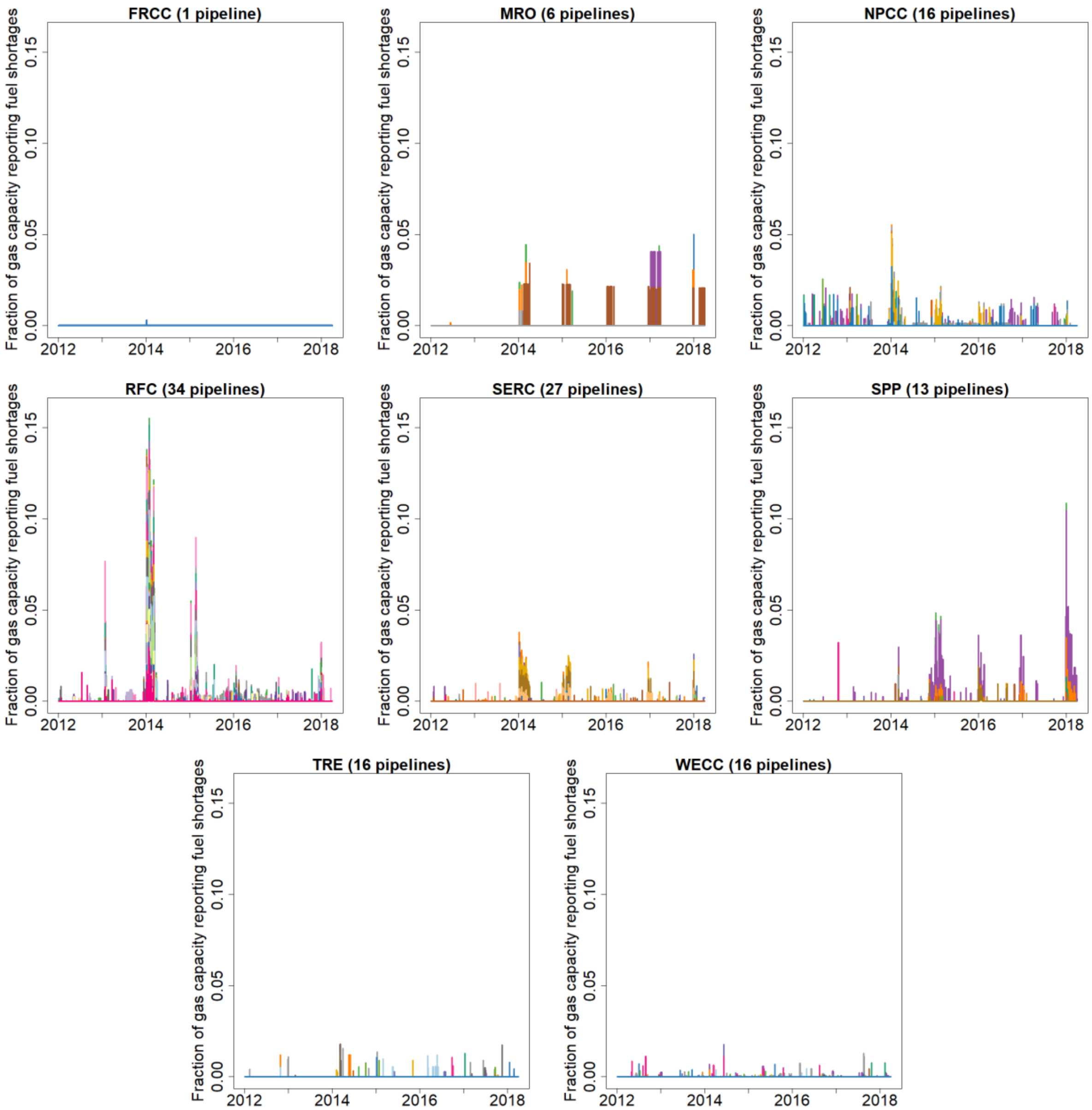

Fig. 2. *Time series plots of gas plant fuel shortage and conservation interruption failure magnitude as a fraction of nameplate capacity aggregated by NERC region, indicating the pipeline fueling the plant. Each color represents an individual pipeline system. Note: some pipelines span multiple NERC regions and therefore appear in multiple plots.*

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.

4.2.1. 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 = 0.014). When we disaggregated the timeframe to individual years, a statistically significant over-representation of non-firm plants was observed for years 2013 ($p < 0.05$), 2014 ($p < 0.01$) and 2015 ($p < 0.05$).

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 ($p < 0.1$) and SERC ($p < 0.05$).

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 1.

Table 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 α = 0.1 level, '**' indicates significance at the α = 0.05 level, and '***' indicates significance at the α = 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 α = 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.

4.3. Moving non-firm plants to firm pipeline contracts could 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 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 5).

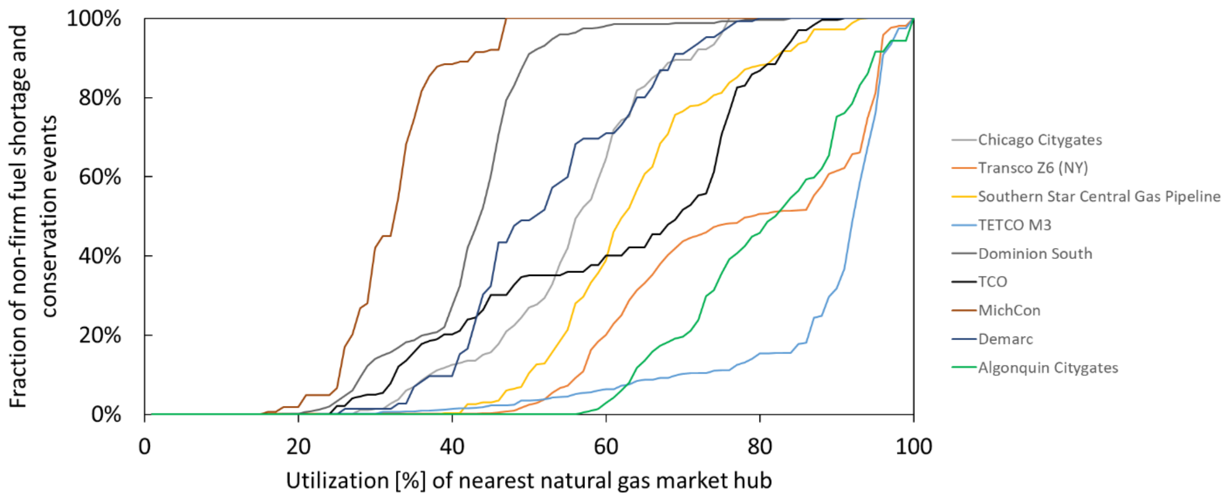

Fig. 3. *CDFs of the fraction of non-firm fuel shortage events at natural gas power plants as a function of the utilization of the nearest natural gas trading hub. We present the 9 hubs with 145 or more data points here. Curves that fall to the upper left indicate that physical pipeline capacity was 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 6.

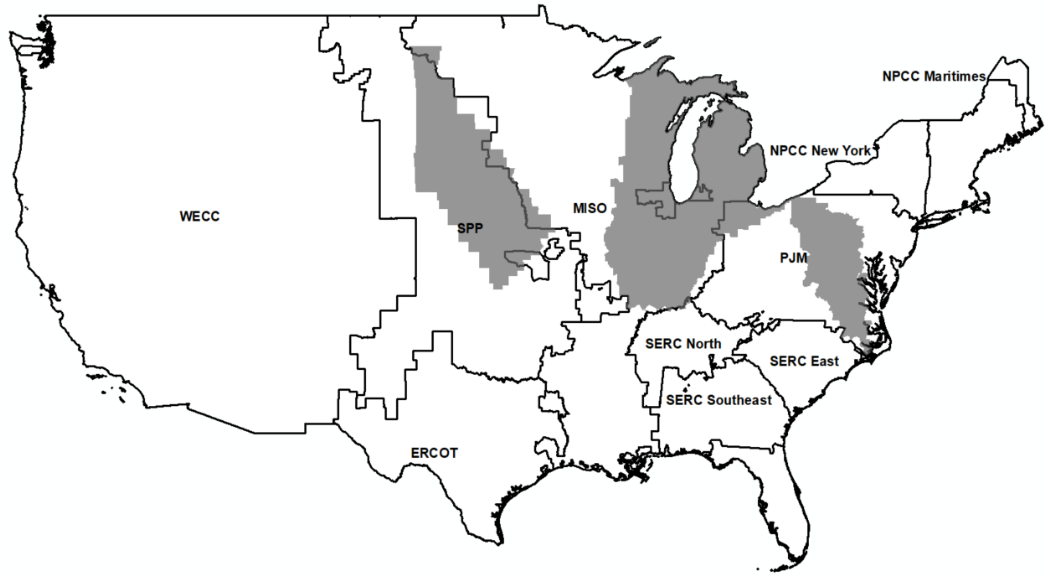

Fig. 4. *U.S. counties closest to hubs where most non-firm fuel shortage power plant failures occurred when the hub was less than 60% utilized.*

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 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

[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.

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.

4.3.1. Power plants could have out-prioritized commercial and industrial pipeline customers at the times of almost all the fuel shortage events in parts of PJM, MISO 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 7). 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 was 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.

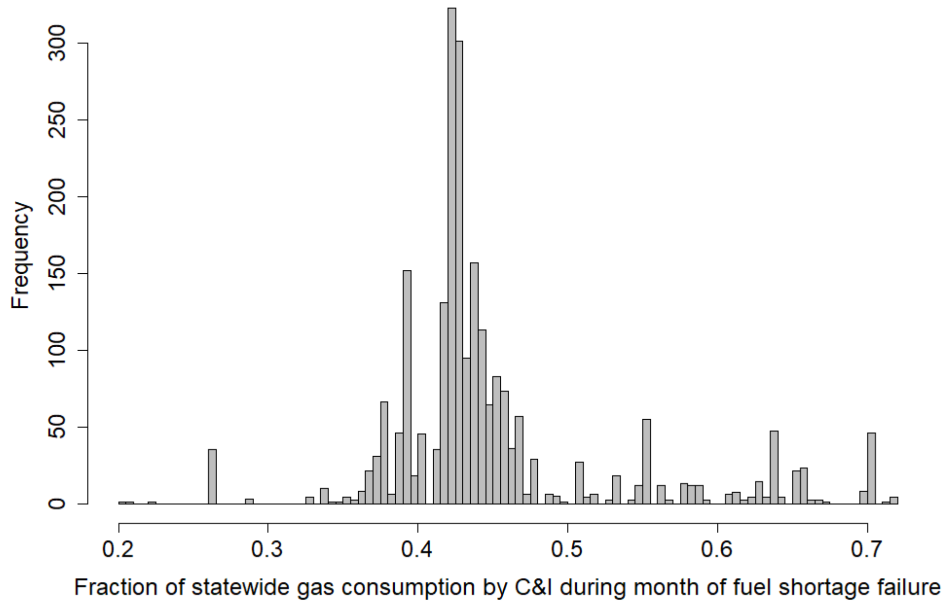

Fig. 5 histogram of the fraction of statewide gas consumption by C&I customers on the pipeline network during the month of the fuel shortage power plant failures at non-firm plants in the areas indicated by Figure 6.

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 6.

5. Conclusions and Policy Implications

Failures at large natural gas power plants due to fuel shortages from the 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 1, in ERCOT and the Western Interconnection, firm contracts were not a cure-all solution. In these areas,

[7] Depending on the state.

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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Appendix Supplementary data

A.1. Map of natural gas trading hubs used in analysis

Figure A-1 below 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 5. 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.

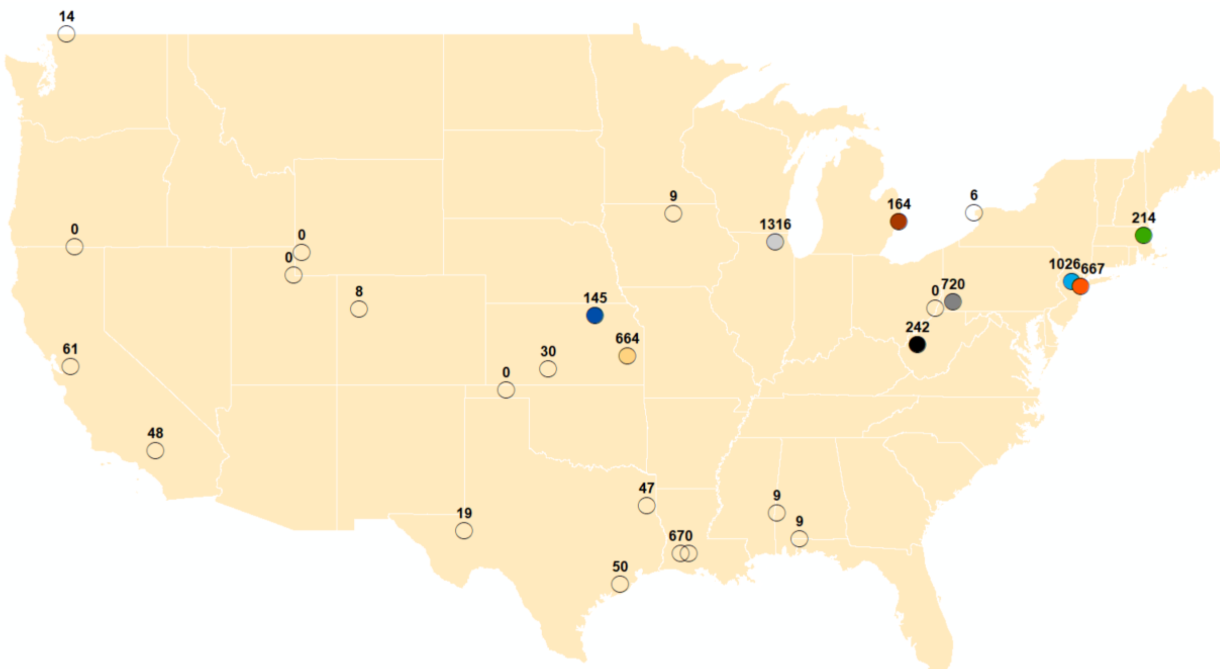
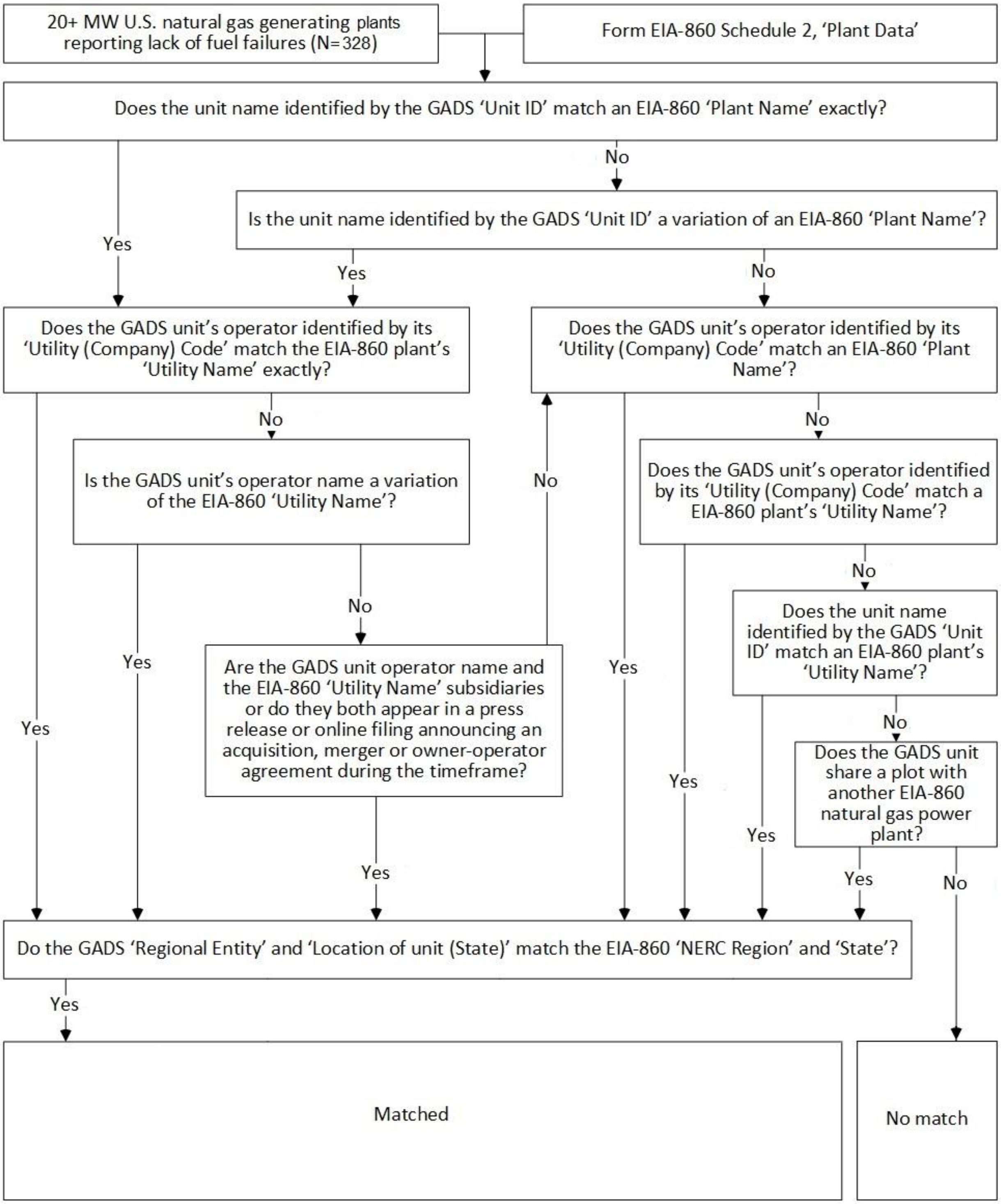


Fig. A-1. *Map of the 28 natural gas market hubs used in this analysis. All were available in the ABB Velocity Suite daily hub report except the Algonquin City Gates Hub near Boston.*

A.2. Process Schematic for Matching NERC to EIA Data



A.3. Maps of NERC interconnections, regions and assessment areas

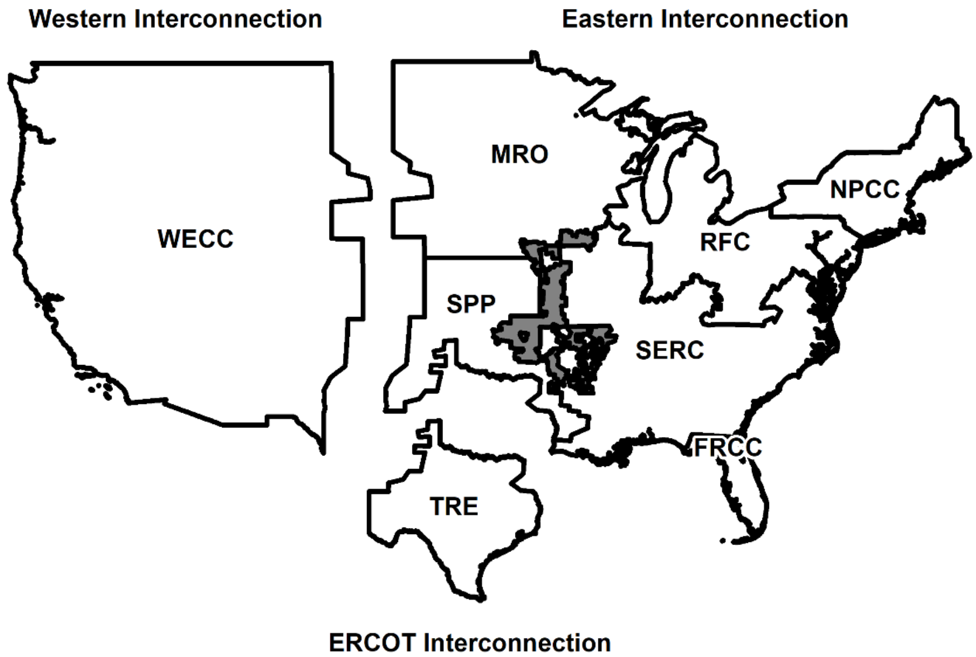


Fig. A-2. *Map of the 8 NERC Regions and 3 electricity interconnections used for spatial aggregation in this analysis. Grey areas indicate parts of the country where NERC regional jurisdictions overlap.*

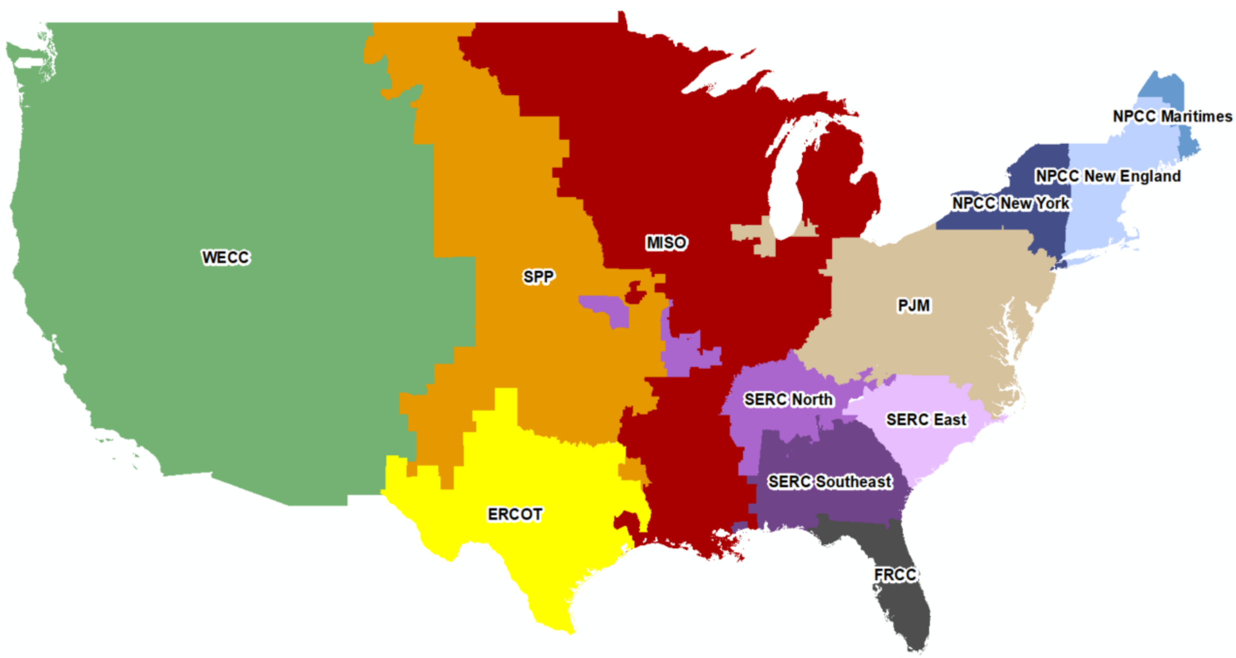


Fig. A-3. *Map of the 12 NERC Assessment Areas referenced in discussions and results of this analysis.*

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