Could on-site fuel storage economically reduce power plant – gas grid dependence in New England?

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Abstract

In the Northeastern United States, natural gas supply constraints have led to periods when gas shortages have caused up to a quarter of all unscheduled power plant outages. Dual fuel oil/gas generators or local gas storage might mitigate gas supply shortages. We use 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 the historical fuel shortages at approximately 2 GW worth of gas-fired capacity could be mitigated using on-site fuel storage. For comparison, New England's average reserve margin was 1.7 - 2.8 GW over our sample period. Oil dual fuel plants would recoup their investment if compensated with a reliability adder of \$3-7/MWh during their normal operations, while \$7-16/MWh would incentivize using on-site, compressed natural gas storage. We estimate that the capital expenses associated with the fuel storage options would be less expensive than installing battery backup for resource adequacy at current battery prices.

Abbreviations

ABB – ASEA Brown Boveri

ATB – National Renewable Energy Laboratory Annual Technology Baseline

Bcf – billion cubic feet

BTU – British thermal unit

CNG – compressed natural gas

EDF – Environmental Defense Fund

EIA – (U.S.) Energy Information Administration

FSF – fuel shortage failure

GADS – Generating Availability Data System

GW - Gigawatt

ISO – independent system operator

kWh – kilowatt-hours

LCP – levelized cost premium

LNG – liquefied natural gas

MMscf – million standard cubic feet

MW – Megawatt

MWh – Megawatt-hours

NERC – North American Electric Reliability Corporation

NETL – National Energy Technology Laboratory

NPCC – Northeast Power Coordinating Council

scf – standard cubic feet

1. Introduction

Recently, a database of power plant failures provided by the North American Electric Reliability Corporation (NERC) was used to analyze why natural gas power plants failed due to unscheduled fuel shortages [1]. Only a few of those events could be explained by gas pipeline failures. In all areas of the contiguous US, most but not all failures 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 pipeline contracts. However, in some areas of the Northeastern United States pipeline constraints are likely to 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 is an area of concern [2]. In New England, half the total installed power plant capacity is fueled primarily by natural gas and nearly half of all electricity MWhs come from natural gas power plants [3, 4].

New England has no native natural gas production. In 2018, New England had approximately 4.1 billion cubic feet (Bcf) per day of natural gas pipeline import capacity, excluding liquefied natural gas (LNG) receipt terminals [5]. Data from the U.S. Energy Information Administration's (EIA) New England Dashboard show that in 2018 the peak daily residential/commercial natural gas consumption was approximately 3.5 Bcf during the winter season [6]. Most of that demand was for heating in the residential and commercial sectors. Thus, industrial and power generation pipeline customers had only ~0.6 Bcf to share during 2018's peak heating demand day. Using heat rate data from EIA-923 [4], we compute that 0.6 Bcf/day could support an average consumption of less than 8 GW of gas-fired power plant capacity in New England. That is less than half of the capacity of ISO-New England's gas-fired fleet [3]. LNG deliveries to New England have exceeded 0.25 Bcf/day on only a few occasions [6], and unless LNG injections into the New England pipeline system become stable at a significantly increased level, ISO-New England cannot count on LNG during the times when pipeline imports cannot meet demand.

This simple example may seem like an extreme case, but when heating demand spikes on key natural gas supply pipelines to New England, such as Algonquin Gas Transmission, the sum of daily gas deliveries to gas local distribution companies and power generation customers has caused the pipeline to reach its maximum delivery capacity on multiple occasions between 2012 and 2018 (Figure 1) [7].

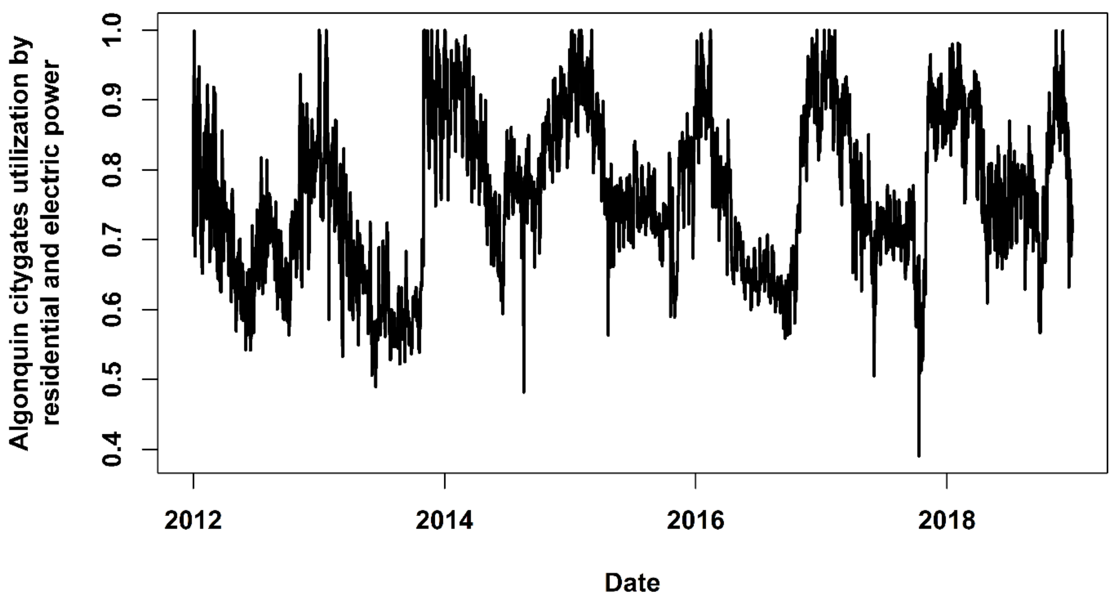

Fig. 1. The fraction of residential and electric power customers' daily use of the total gas deliveries (here termed "utilization" to follow naming conventions of the data source) along the Algonquin gas pipeline system within New England excluding deliveries within the J-system spur served by LNG import terminals. Data are from ABB Velocity Suite [7].

The effect of gas supply constraints like those shown in Figure 1 on power generators in the Northeast can be observed by comparing the average fraction of total unscheduled power plant outages due to gas fuel unavailability between 2012 and 2015 to those during days of high heating demand, such as during the 2014 downward shift of the north polar vortex (Figure 2).

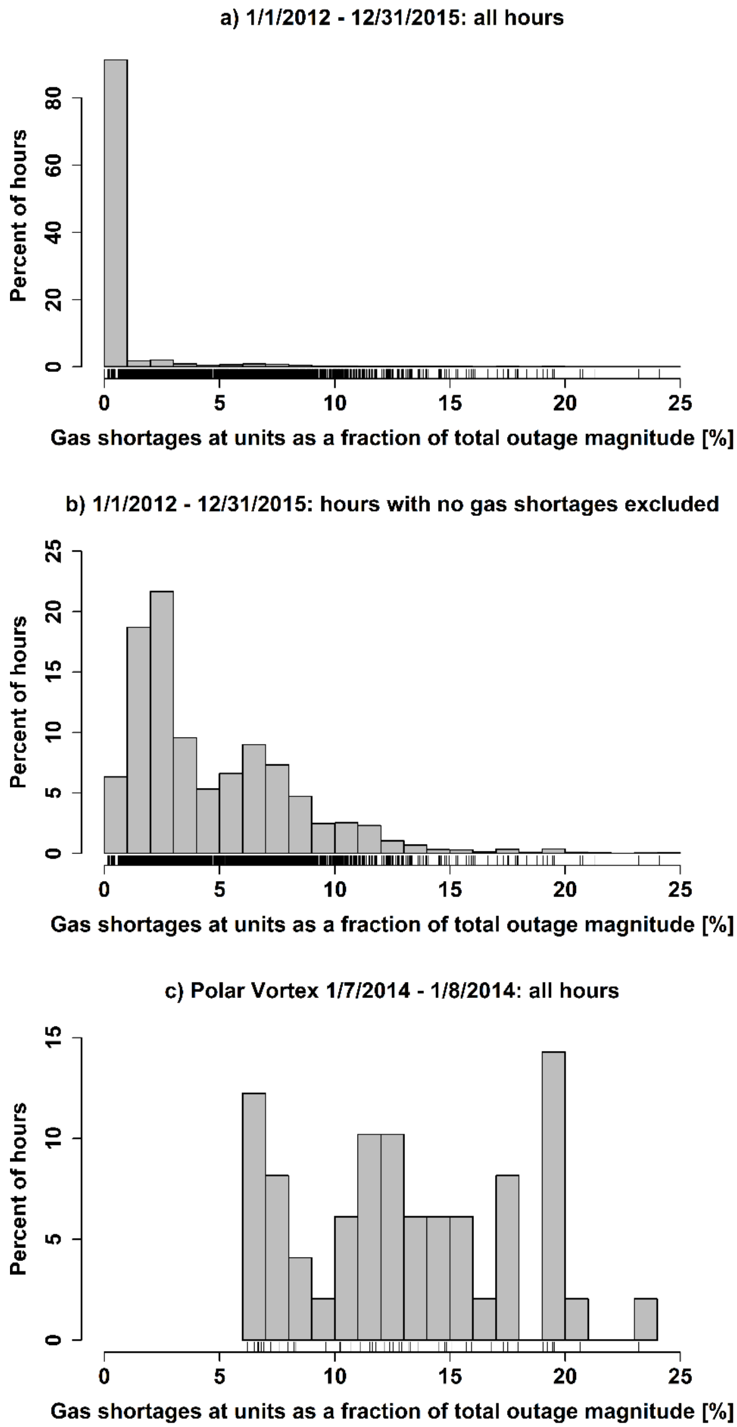

Fig. 2. Histograms of the fraction of total hourly unscheduled outages at power plants in the NPCC NERC region that were solely gas shortage causes. Histograms are given over two time periods for comparison: Over the entire initial study period of the NERC Generating Availability Data System conducted by Murphy et al. [8] (a) with and (b) without hours with no gas shortages reported included and c) all hours during the peak of the 2014 polar vortex. 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.

Between 2012 and 2015, during periods of high coincident electricity and natural gas demand, such as the 2014 polar vortex (Fig. 2c), unscheduled fuel shortages accounted for between 5% and 25% of all unscheduled outages during every hour.

If sufficient gas supply is not available through pipelines or LNG imports, there are three methods that might be used to avoid fuel shortage failures: 1) power plants might use dual fuel capability to burn petroleum products; 2) plants might store enough natural gas on-site to mitigate the longest observed gas outage; and/or 3) batteries might be used to substitute for generators.

Currently, only slightly more than a third of New England's natural gas generating capacity has dual fuel capability (Table 1).

Table 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 [3].

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 [2]. 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 [9, 10]. A finding of those studies was that building above-ground storage of one day's supply of natural gas at generator sites was a prohibitively expensive mitigation option for fuel shortage situations [10]. This was because storage tank costs ranged 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. They focused on the New England region. To increase reliability of the interdependent gas and electricity grids, they found that the economically optimal placement of distributed natural gas storage in New England may be at generator sites [11].

Here, we build on the work described above. For the first time publicly, we analyze a database of historical power plant failures, to ask the question: What would the cost of on-site fuel storage at gas-fired power plants be to mitigate historically observed natural gas fuel shortages? We answer this question by computing the overnight capital, fuel carrying and land costs (when applicable) required for gas generators in New England to assure their fuel supplies using fuel storage systems sized according to their most extreme fuel shortage failure during our study period. We present these costs as adders to the levelized cost of energy at the units in our sample. Our estimates are different from previous studies because they are based on actual failure event durations and magnitudes at generators rather than an arbitrary fuel supply duration. 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. We construct supply curves of fuel shortage mitigation based on these cost estimates. We conduct this analysis under the assumption that firm gas pipeline contracts are unavailable due to pipeline constraints.

Our key findings are that: 1) approximately 2 GW of gas-fired capacity in New England that experienced one or more fuel shortages per year on average between 2012 and 2018 could mitigate those failures for a levelized energy cost premium of $3-7/MWh using gas/oil dual fuel capability or $7-16/MWh 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 at current battery storage prices.

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 and discusses the key quantitative results, and section 5 concludes with policy implications.

2. Materials

In our analysis and for the first time publicly, we pair a historical database of failure information for large generators in the US with power plant operational information over the same period and cost estimates from literature and vendor sources. In the following sections, we provide descriptions of the three aforementioned categories of data used to build supply curves of fuel shortage mitigation at gas-fired generators in New England.

2.1. Historical “lack of fuel” failure reports by gas-fired generators

Using data from the North American Electric Reliability Corporation’s Generating Availability Data System (GADS) [12], we analyze failure events at natural gas power generators in the New England region with lack of fuel causes. We define a ‘failure event’ as any period when a generating unit reports an unscheduled outage, partial outage (de-ratings) or startup failure to the GADS database. Murphy et al. [8] acknowledged that de-rating events at each unit can overlap. For results reported in terms of the number of 'failures,' we count these overlapping de-ratings as separate 'failures.' When a second (or further) de-rating commences at a unit that already has a de-rating event underway, the maximum amount of power that a unit can provide to the grid is not its net maximum capacity. In this way, any departure from the maximum amount of power that a unit can provide to the grid during a time period is considered a 'failure.'

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 [13]. 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. [8] 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.

2.2. Power plant operational data

Using a systematic data matching process as in Freeman et al., [1] we matched the power plant failure reports to power plant operational data from the U.S. Energy Information Administration (EIA) Forms 860 [3] and 923 [4] to identify which fuel assurance measures every unit in our sample had in place during the 2012-2018 operation years. We also calculate generator heat rates using EIA-923 Monthly Generation and Fuel Consumption Time Series file fields: '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 to generate time series of the petroleum fuel stock levels at all the power plants in our sample.

2.3. Cost information for fuel storage equipment

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 use is $0.98 – $3.05 / gallon capacity [14]. The raw tank cost quotes used to construct this range are included in Table A.1. 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 [15]. 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 while taking up a minimal land footprint. Smith and Gonzales estimate that CNG storage with capacities between 16,250 standard cubic feet (scf) and 55,000 scf costs 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.

Although some CNG fueling station tank configurations may not be ideal for storage applications at large power plants, we use the fueling station costs as a conservative estimate of tank costs. For instance, if we were to employ torpedo-style tanks as used in some of the CNG fueling stations in the Smith and Gonzales study [15], approximately 95 three-tank cascade fixtures made up of 12,000 scf tanks would need to be deployed to fuel the median fuel shortage event in our sample. But it is possible that a spherical or cylindrical tank of slightly larger scale than used at a fueling station could be suitable.

It is also possible that larger tanks for power generation applications could be less expensive per unit volume stored. An enlarged spherical tank design is mentioned in Myles et al. [10]. They gathered a $1.4M vendor quote for their 1.3 MMscf capacity tank. It would take only three of these larger tanks to fuel the median fuel shortage event in our power plant failure sample. But their estimate does not include costs for installation and erection. Smith and Gonzales' costs include "[basic] engineering, equipment, and installation at a site with the[ir] specified assumptions" [15].

2.4. Cost information for land

We use assessed property values from tax entries for land parcels adjacent to power plants when adding an additional land cost to generator's mitigation costs at sites that need to purchase more land for fuel storage equipment. These data were gathered from municipality, county and state information portal websites in New England. A summary of property values used as a result of our plant-by-plant land analysis is in section 1 of the online supplemental information.

3. Methods

3.1. Plant-specific mitigation cost estimation

The data show that fuel shortages cause some units to fail more frequently and/or be out of service longer than other units. 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. For comparison, we present cost estimates observed using simulation approaches in sections 2 of the online supplemental information. We use the costs we calculate to construct mitigation supply curves for the New England gas-fired generation fleet.

In constructing the mitigation supply curves, we account for some units in New England having fuel shortage mitigation measures already 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 and EIA-923 enables us to calculate the cost of paying for only what the unit has not already installed. For the 54 units in our GADS sample of plants that failed because of fuel shortages, a summary of measures that each had installed at the times of their first reported fuel shortage failures is in Table S.1.

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 and dispatched.

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 [4]. If the peak of oil stocks over the period prior to the plant's first fuel shortage event exceeded the oil 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.

3.2. Estimating capital costs for storage equipment

We calculate the capital cost of mitigation (denoted $CAPEX_x$) using the equation:

$$CAPEX_x = \left(\frac{Cap_{max,x}\Delta t_{max,x}HR_x}{HV_x}\right)c_{tank} + c_{equipment} \qquad (1)$$

Where, $Cap_{max,x}$ is the magnitude in MW and $\Delta t_{max,x}$ is the duration in hours of unit *x*'s worst fuel shortage event reported to GADS over the study period, HR_x is generator *x*'s heat rate in BTU/MWh and *HV* is the average heat content of the fuel in BTUs per volumetric unit (standard cubic foot for natural gas or gallon for oil). The product of the terms in the parentheses is the estimate of the fuel consumption of the generating unit if it had been available and dispatched 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. The dual fuel conversion cost estimate that we use was developed by NETL and is $54,000/MW for field-installed equipment [9].

3.3. Estimating fuel carrying costs

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

$$FUEL_x = \frac{\left(\frac{\sum_i \left(Cap_{i,x}\Delta t_{i,x}\right)HR_x}{HV_x}\right)c_{Fuel}}{T} \qquad (2)$$

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 derived from historical data during times of modest fuel prices to capture a pattern of fuel purchases for storage while prices are low, and *T* is the study period length, 6.25 years.

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, but the fraction of the total MWh lost to fuel shortages was spread evenly throughout winter, spring and fall (Table S.2.). 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 [16]. 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 [6].

Long-term storage of compressed natural gas may create the potential for leakage from storage tanks. Recent studies of leakage from natural gas infrastructure systems are summarized in Brandt et al. [17].

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. [17] as a proxy for the systems we analyze here. The bottom-up studies look mainly at 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 like those of the storage tanks we specify. We note that this approach is likely a conservative estimate of leakage because our storage solutions would not continuously move gas through piping systems throughout the year as many natural gas processing plants do.

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

$$C_{replenishment} = \left(\frac{9}{12}\right) LR \rho_{NG} c_{Fuel} \quad (3)$$

Where, *LR* is the annual emissions magnitude of methane from gas processing facilities in Brandt et al. [17] and ρ_{NG} is the density of natural gas. Substituting equation 3 into equation 2, the average annual fuel costs for CNG storage options are:

$$FUEL_{x,CNG} = \frac{\left(\frac{\sum_i \left(Cap_{i,x} \Delta t_{i,x}\right) HR_x}{HV_x} + \left(\frac{9}{12}\right) LR \rho_{NG}\right) c_{Fuel}}{T} \quad (4)$$

3.4. Estimating land requirements and costs

Although our capital cost estimation approach is tank morphology agnostic, we make a few assumptions about the land requirement for fuel storage tanks to estimate the cost of additional land purchases to house storage tanks, when needed. For this purpose, we calculate the land requirement for fuel storage options using the actual dimensions of various oil storage tanks from our vendor source [14] and a 30,000 gallon, cylindrical CNG storage tank unit with a diameter of 10 feet and a 15-foot length that stores gas at 5,000 psi as in Myles et al. [10] We further add a 20-foot safety buffer between all tanks and on the ends of each row of tanks to comply with the National Fire Protection Association’s code for compressed natural gas storage [18]. For generating units that require more than one fuel tank, we base our footprint calculations on multiples of the 25,000-gallon capacity oil storage tank or multiples of the 30,000-gallon CNG storage tank.

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 [19] 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 section 1 of the online supplemental information).

In completing this plant-by-plant process, we found that only one plant required additional land. All other plants in our study reside on lots with room to fit many more tanks than are required by our estimates. For the one plant 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 [20]. 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.

3.5. Amortizing costs across generated electricity (MWh)

We use a slightly modified version of the approach in the National Renewable Energy Laboratory's Annual Technology Baseline [21] 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:

$$LCP_x = \frac{\left((CAPEX_x + LAND_x) \times FCR\right) + FUEL_x}{DF_x \times CF_x \times 8760} \qquad (5)$$

$CAPEX_x$ is calculated using equation 1. $LAND_x$ is the cost of land required for additional fuel storage equipment for unit x. *FCR* is the fixed charge rate, here calculated to be 0.12 using the Annual Technology Baseline's (ATB) method [21] and the parameters in Table A.2. We conduct a sensitivity analysis to examine how our financial parameters would affect the cost estimates using a more general simulation approach in section 2 of the online supplemental information. $FUEL_x$ is calculated using equation 2 for oil dual fuel or 4 for CNG storage options. To avoid double counting of fuel costs, we bring the fuel cost into the numerator of Equation 5 to reflect that this is a carrying cost premium for fuel in storage at the power plant site. All costs in the numerator are normalized by the unit's nameplate capacity to conform to the format of calculations in the ATB. An alternative formulation could include total costs in the numerator and a factor of the unit's nameplate capacity in the denominator. *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. To estimate what the historical capacity factors of the units in our sample might have been with mitigation measures in place, we add the MWhs lost to fuel shortages over the study period to the historical generation data for each unit under the assumption that the unit could have generated during those hours had they had on-site storage in place.

We use the cost estimates computed with equations 1-5 to construct supply curves for capacity mitigation of fuel shortage failures. We compare the range of fuel storage mitigation options' cost estimates using the actual failure data at New England plants to the cost of battery storage as an alternative option.

3.6. Costs not quantified in our estimates

We note that both fuel storage mitigation strategies would require operations and maintenance expenses as well as permitting and siting costs. 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, permitting and siting costs here.

For dual fuel back up, some maintenance cost considerations might include fuel polishing and filtration if the plant stores 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.

3.7. Summary of baseline and scenario assumptions for cost estimates

We present low, medium and high cost estimates based on historical data and vendor quote ranges. The parameters used to construct low, medium, and high cost estimate scenarios are in Table 2.

Table 2. 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	[15]
CNG compressor cost	$C_{equipment}$	\$1000	50	70	90	[15]
Volumetric oil tank cost	c_{tank}	\$/gal	0.97	1.90	3.05	[14]
Delivered natural gas cost	c_{NG}	\$/Mcf	4	6	12	[4] 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	[4] New England units
CNG storage leakage rate	*LR*	g/yr	10^3	10^5	10^7	[17]

4. Results and Discussion

4.1. Regional gas shortages in New England could create electricity generation capacity scarcity

When we analyzed the 54 New England gas-fired units with NERC Generating Availability Data System (GADS) reports of outages or partial outages due to unscheduled fuel shortages between 2012 and 2018, we found that the capacity-weighted average annual frequency was 0.7 fuel shortage failures per year (4.37 failures/6.25 yrs.; Fig. 3a). Eight generating units in the sample, representing 2.4 GW of gas-fired capacity, reported more than one fuel shortage failure per year on average. For comparison, ISO-New England's average reserve margin ranged between 1.7 and 2.8 GW over our sample period. If the eight generating units with more than one fuel shortage failure per year on average were offline simultaneously during an extended fuel shortage, a capacity scarcity condition could be created in New England. We observe that there were 22 unique instances over our six-year study period when two or more of those eight units were simultaneously affected by fuel shortages. Five of those eight generating units, accounting for 1.5 GW of gas-fired capacity, were served by the same pipeline and, on three separate occasions between September and December of 2016, four of the five units fueled by the pipeline in common simultaneously reported fuel shortages, each time affecting about 0.5 GW of capacity.

If dual fuel or CNG storage were used to mitigate outages for the 8 units with one or more fuel shortage failures per year on average, much of the long right tails of the mean and maximum fuel shortage duration distributions would disappear (Figs. 3b and 3c). We see from this that within our New England sample, the units that fail more frequently tend to fail for longer periods in general over our study period.

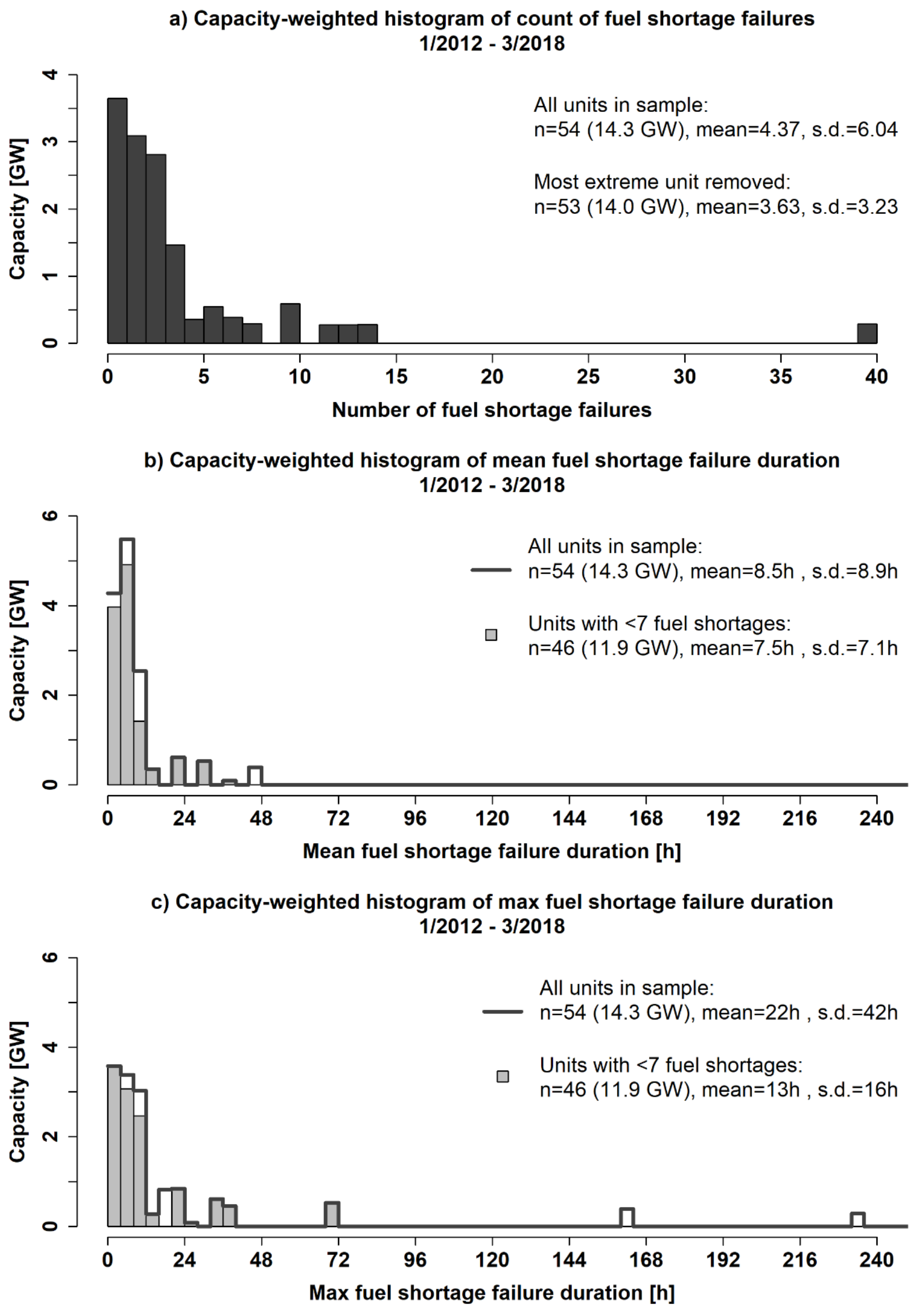

Fig. 3. Capacity-weighted histograms of the number of fuel shortage failures (a), the mean fuel shortage failure duration (b) and the maximum fuel shortage failure duration (c) for all gas-fired units in New England reporting fuel shortage failures to GADS between 1/1/2012 and 3/31/2018.

4.2. Supply curves for natural gas generator fuel shortage mitigation

Using observed fuel shortage failure data from NERC GADS between 2012 and 2018, we build supply curves for mitigating fuel shortage events using gas/oil dual fuel capabilities or CNG storage (Fig. 4 and 5). We find that 2.6 – 8.0 GW of gas-fired capacity could mitigate fuel shortages at historical frequencies for $1/MWh or less using gas/oil dual fuel capabilities (black lines in Fig. 4). We estimate that 1.7 – 3.1 GW could use on-site CNG storage to mitigate their gas shortages for $1/MWh (black lines in Fig. 5). The colored lines in Figures 4 and 5 show similar supply curves for only those generators that experienced at least one fuel shortage failure (FSF in the figures) each year on average during the study period, or more than six FSFs total.

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. We note that the 'capacity loss mitigated' dimensions of the curves in Figures 4 and 5 are not additive – they display the levelized-cost adder required at each unit in the sample to secure on-site fuel storage mitigation for their past fuel shortages using either technology option.

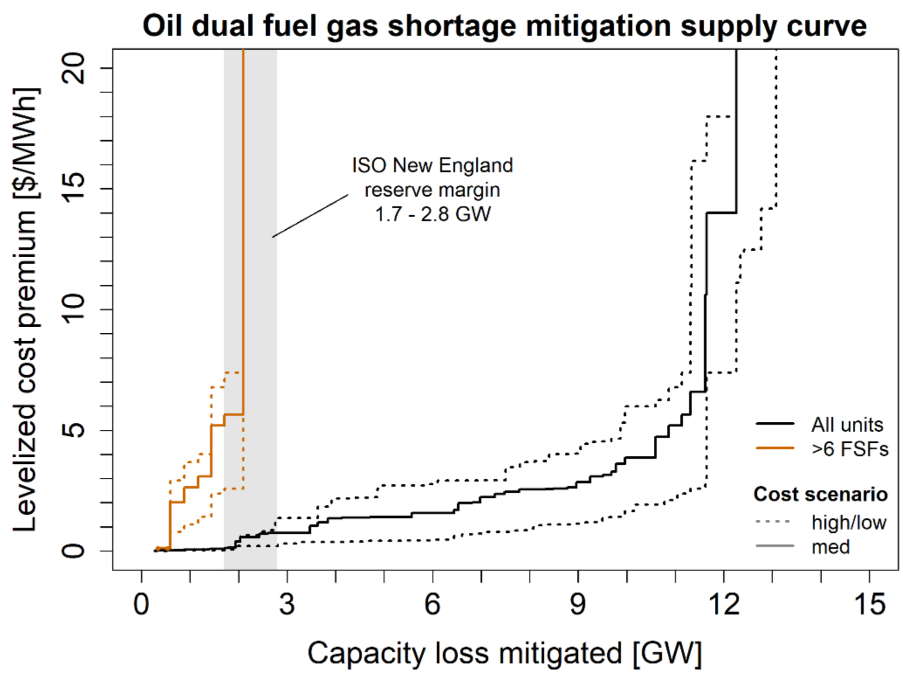

Fig. 4. Supply curves for the oil dual fuel mitigation option for fuel shortage failures (FSFs) at gas-fired generators in New England using actual failure and operational data. Low, medium and high scenario results are calculated using inputs from Table 2. Units may be rearranged between low, medium and high scenarios.

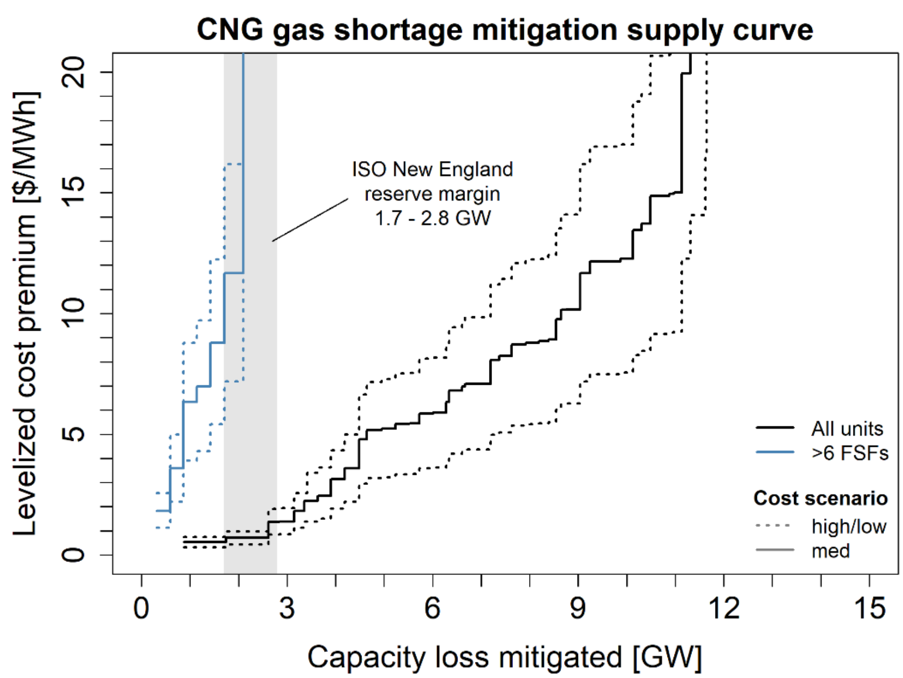

Fig. 5. Supply curve for the CNG storage mitigation option for fuel shortage failures (FSFs) at gas-fired generators in New England using actual failure and operational data. Low, medium and high scenario results are calculated using inputs from Table 2. Units may be rearranged between low, medium and high scenarios.

ISO-New England's reserve margin was 1.7-2.8 GW over the study period, which is approximately equal to the collective capacity of all generators that had more than six fuel shortage events during the study period. Figures 4 and 5 demonstrate that more than this amount of capacity could mitigate historical fuel shortages for $1/MWh or less using either dual fuel capability or CNG storage. However, it is important to note that the black supply curves in Figures 4 and 5 include all units in the New England sample, even those with less than one fuel shortage per year on average. The fuel-shortage mitigation supply curve for units with more than six FSFs during the study period (depicted by colored lines in Figures 4 and 5) appears steeper because of the higher frequency and longer duration of fuel shortage events at those units (as shown in Figure 3). The sizing (and cost) of fuel storage systems for the units that failed one or more times per year historically is generally larger in our sample than those that failed less frequently. For those units, the levelized reliability adder could rises to $3-7/MWh using gas/oil dual fuel or $7-16/MWh using on-site CNG. Even if mitigation measures were focused only on units that have experienced fuel shortage events more frequently, Figures 4 and 5 show that enough high-FSF capacity could mitigate fuel shortages at a cost of $10/MWh to cover the entirety of ISO New England's capacity reserve margin. Similarly, if we remove the units for which at least one of our estimates for the levelized cost premium was less than $1/MWh from the sample, we recover the right tails of both the mean and maximum fuel shortage event duration distributions (Figure 6).

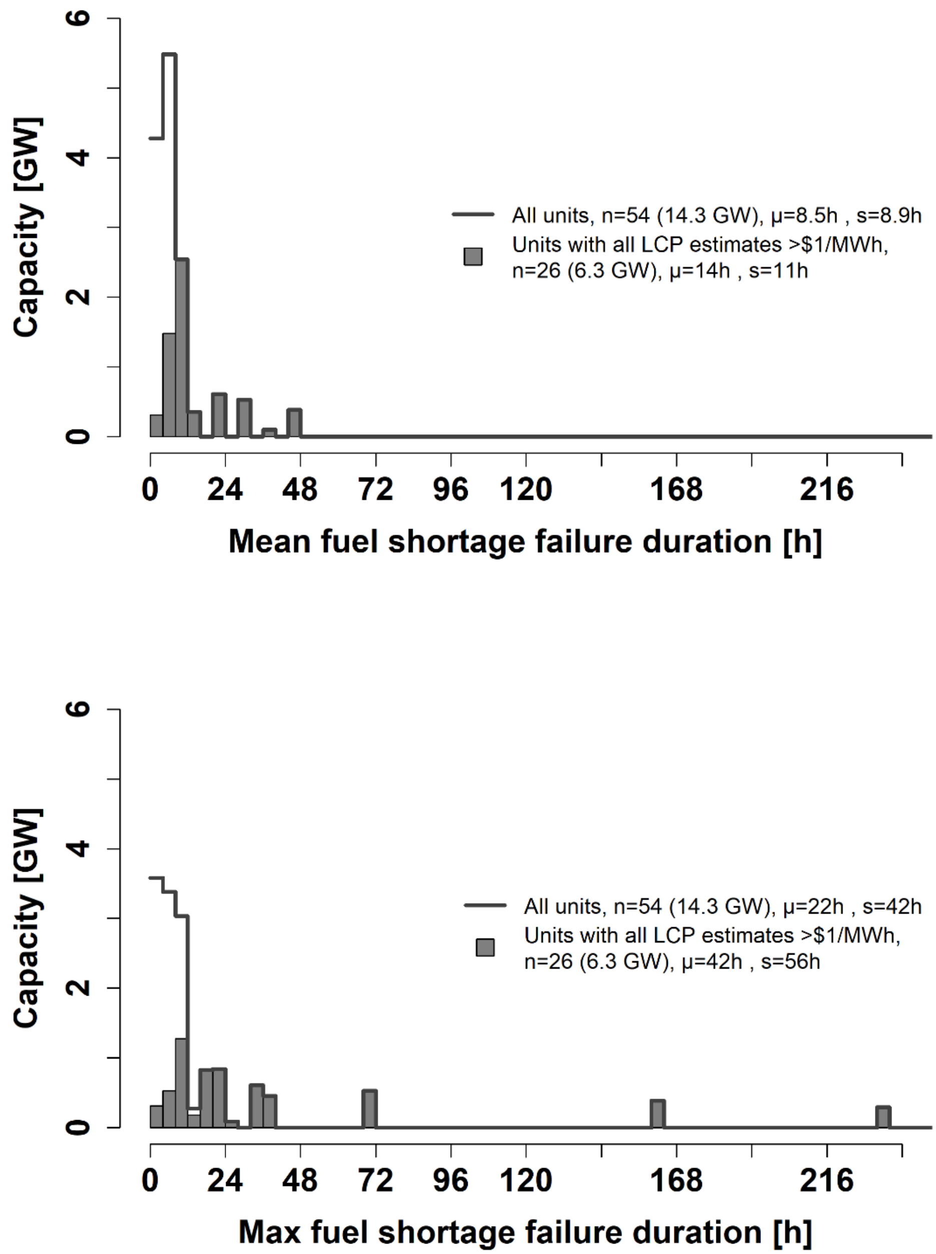

Fig. 6. Capacity-weighted histograms of the mean fuel shortage failure duration (top) and the maximum fuel shortage failure duration (bottom) for all gas-fired units in New England reporting fuel shortage failures between 1/1/2012 and 3/31/2018 (black line) and units with levelized cost premium (LCP) estimates of greater than $1/MWh (grey bars).

4.3. Battery storage, at present technology costs is more expensive than fuel storage for mitigating fuel shortage failures

When we compare the range of levelized costs for the fuel storage mitigation options and projections for the levelized costs for wholesale battery storage options of sizes and durations large enough to mitigate the fuel shortages in our sample, we find that both fuel storage mitigation strategies dominate the battery alternatives based on the New England sample. According to a study conducted by the Rocky Mountain Institute [22], advanced Li-Ion, zinc-based, flow or high temperature batteries are the most promising emerging battery technologies that could be used in an application to mitigate MW-scale fuel shortage failures of durations longer than 4 hours. Their study estimates the costs of advanced batteries such as these to be $200/kWh+ currently, falling to around $100/kWh of storage in the 2030 time frame. In contrast, if we use our cost estimates to compute a similar metric, the highest estimate of all of our costs between both fuel storage options is $50/kWh of useful energy stored (factoring in heat rate conversion when combusting the gas out of storage).

Fuel storage assets do not provide the same level of flexibility of applications to the power grid 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 it may be feasible to do so is during the summer months when natural gas prices are generally low [6]. Sufficiently large-capacity gas storage may be able to provide some level of gas supply balancing for the local gas grid and perhaps receive compensation for this practice.

Another alternative 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 provide 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. Further research would be required to quantify the level and duration of demand response during the cold weather periods of natural gas fuel shortages.

5. Conclusions and policy implications

Using historical failure data from the North American Electric Reliability Corporation, we find that approximately 2.4 GW of New England's gas-fired capacity failed one or more times per year due to fuel shortages. Up to 0.5 GW of these units have failed simultaneously on three separate occasions. 2 GW of the natural gas units with the highest historical frequency of fuel supply failures could mitigate the shortages they experienced between 2012 and 2018 for approximately $3-7/MWh in additional levelized cost with on-site oil fuel storage or $7-16/MWh with CNG. This shortage mitigation cost falls to around $1/MWh for gas-fired generators that have historically experienced less-frequent or shorter-duration fuel shortages. The 2 GW of generators that could be made more reliable in this manner represents two thirds of the expected five-year capacity margin in ISO-New England from NERC's December 2018 Long-Term Reliability Assessment [23].

If the relevant generators take private steps to ensure their fuel supply by building on-site storage, we could expect to see these premiums passed on to the bids of those generators unless some other incentive is in place: such as Pay for Performance or a reliability adder. In order to avoid distorting the dispatch order and revenue, these reliability adders might be settled out-of-market. Researchers at the Environmental Defense Fund (EDF) estimated that the extended cold weather event in early January 2014 cost New England electricity ratepayers roughly $1.8 billion [24]. New England generated ~100,000,000 MWh of electricity in 2018; roughly half of that came from gas-fired units [4]. Compensation in the form of a reliability adder of $150M - $800M to all gas generators, regardless of whether they experienced fuel shortages or not, to avoid fuel shortages would be only 8-44% of the added cost from the 2014 polar vortex event. EDF's estimate of the added cost in January 2014 could be reduced by more than 50% and the fuel storage mitigation options presented here would still exhibit a positive benefit-cost.

Future research could assess what the size of fuel storage mitigation measures at gas-fired generators should be based on a tolerable level of risk. Our cost estimates are for potentially over-sized systems based on the most extreme historical events at each unit. As such, they may be over-estimates of the cost premium that could form the basis for a reliability adder.

Furthermore, our analysis focuses solely on mitigation cost with some qualitative discussion of value streams. When we compare the levelized cost of useful stored energy between the fuel storage alternatives and emerging, long-duration battery storage, we find that the fuel storage options are currently significantly less expensive than battery storage to supply power during fuel shortages. However, battery storage options can provide additional value to the owner and the grid in the form of ancillary services but only during situations when those grid issues are not caused by the fuel shortage failures they are being installed to help avoid. And, CNG storage might be used to help balance regional gas supply and demand during times when generators do not need gas from storage.

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Appendix A. inputs and parameters used in cost estimates

The following tables summarize the values used either directly or indirectly in cost computations in the main text. Table A.1 presents a summary of the tank costs gathered from source [14] that were used to create linear oil storage tank cost parameters used in calculations in the main text and supplemental information. Table A.2 presents the financial parameters used to calculate the fixed charge rate that is used as an input to equation 5. The sensitivity of cost estimates to changes in the parameters in Table A.2 is examined in the online supplemental information.

Table A.1. Summary of tank costs gathered from online vendor pricing lists used to construct the range of scalable oil storage tank costs [14].

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

Table A.2. 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

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1. Supplemental Tables

Table S.1. 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 [12] and EIA-860 [3] 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

Table S.2. Fraction of fuel shortage events and MWh lost to fuel shortages by NERC-defined seasons. 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 [13].

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%

Table S.3. 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 state data [20].

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	-	-

Table S.4. Levelized cost premium estimates for the units in the GADS sample. Units numbers correspond to the order that units appear in the black solid line, gas/oil dual fuel medium estimate in Figure 4.

	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

2. Supplemental Methods

2.1. A general simulation approach to calculating the cost of mitigation for fuel shortage failures

We construct a general simulation approach informed by the North American Electric Reliability Corporation (NERC) Generating Availability Data System (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 the 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 2 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.

2.1.1. 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 S.1 and Table S.5.

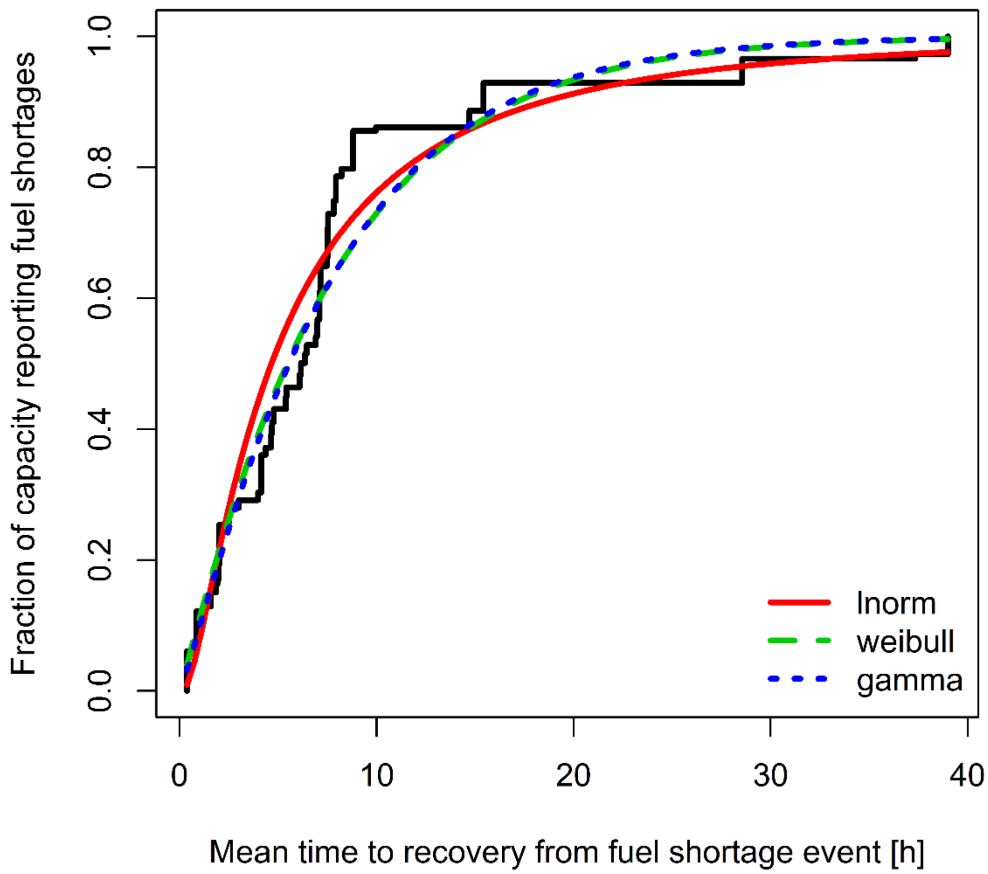

Fig. S.1. Cumulative Density Function of mean time to recovery from fuel shortage events of New England units reporting to GADS 1/2012 – 3/2018. Log-normal, Gamma and Weibull fit lines are included.

Table S.5. 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})

2.1.2. 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 S.2 and S.3 and Tables S.6 – S.9. We display results that follow with outliers removed.

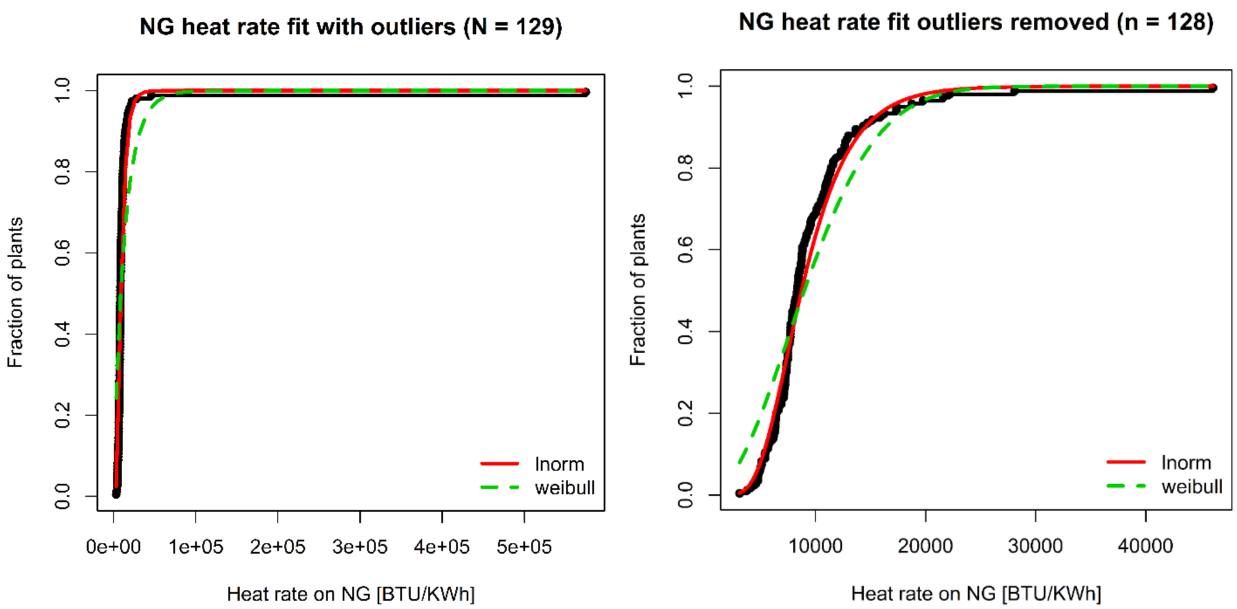

Fig. S.2. Cumulative Density Functions of heat rates of New England power plants fueled by natural gas with suspected outliers (left) and without suspected outliers (right). Log-normal and Weibull fit lines are included.

Table S.6. 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 S.7. 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)

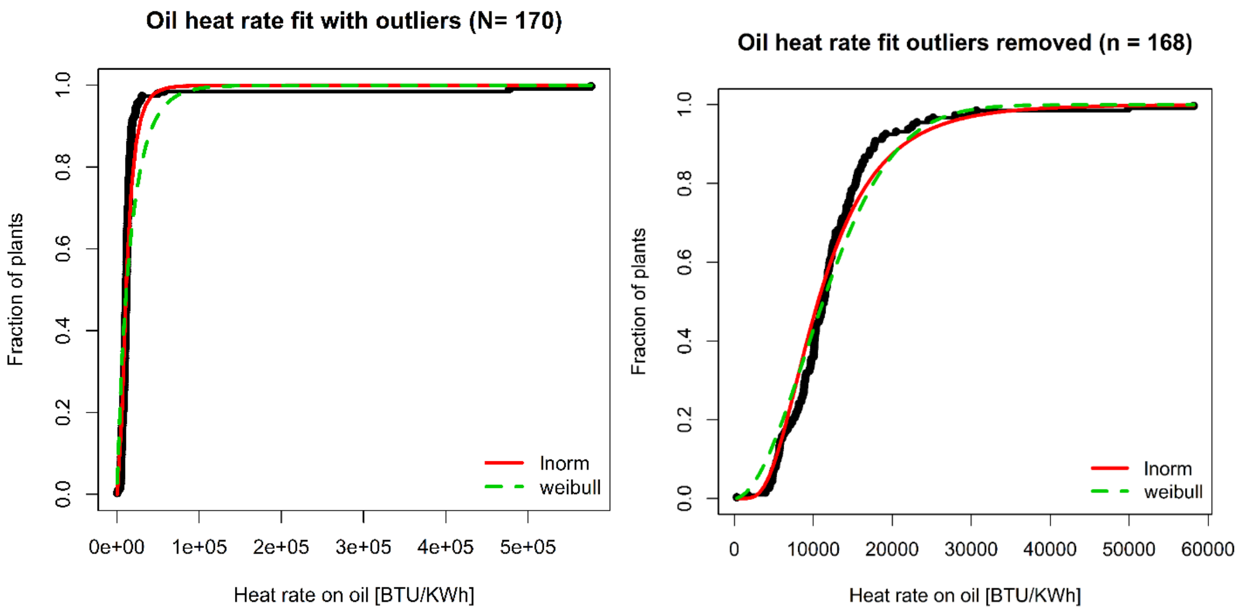

Fig. S.3. Cumulative Density Functions of heat rates of New England power plants fueled by oil with suspected outliers (left) and without suspected outliers (right). Log-normal and Weibull fit lines are included.

Table S.8. 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 S.9. 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.

2.1.3. 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 S.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 2 in the main text) resulting in a premium of approximately $25/MWh to mitigate almost all fuel shortage failures.

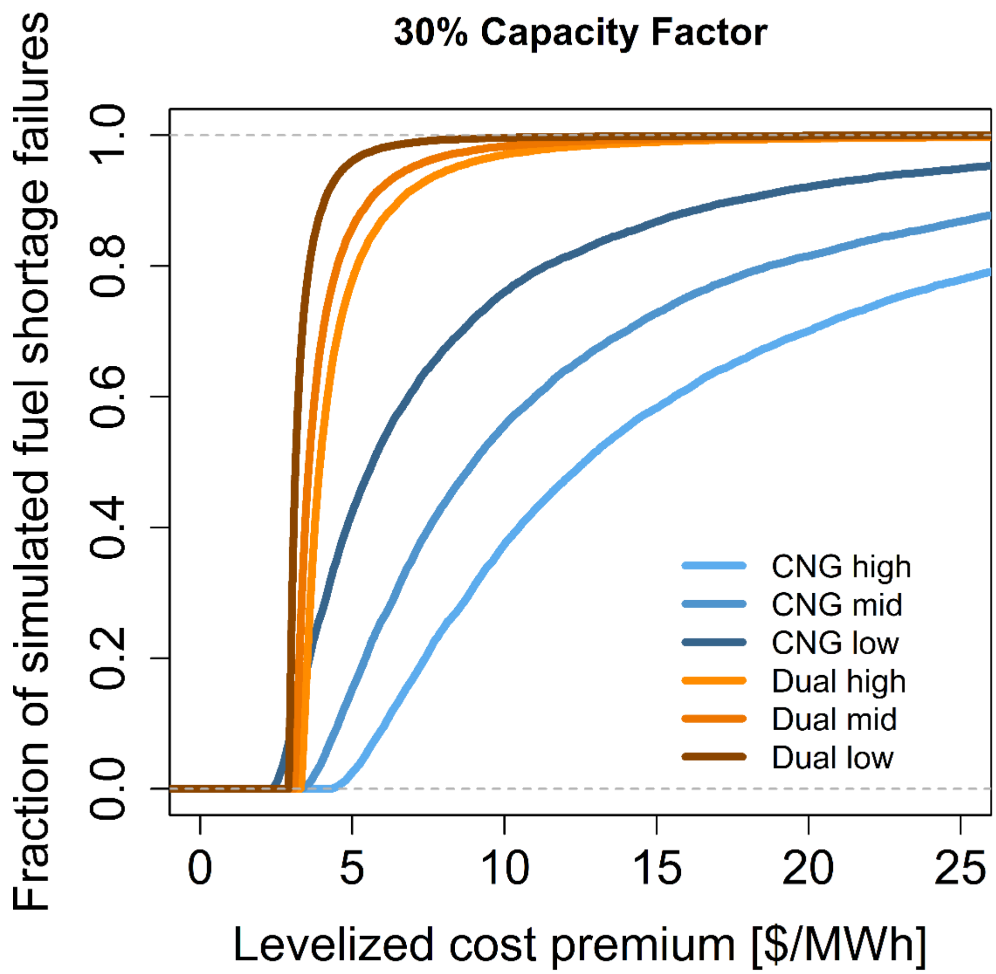

Fig. S.4. Cumulative density functions of 10,000 simulation trial computations of the levelized cost premium of oil dual fuel and CNG storage mitigation options. Color shades represent different input scenarios; darker colors represent lower input values from Table 2 in the main text.

2.1.4. Sensitivity of simulation results to unit capacity factor

The simulation results 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 (inversely) with the unit's capacity factor.

Figure S.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.

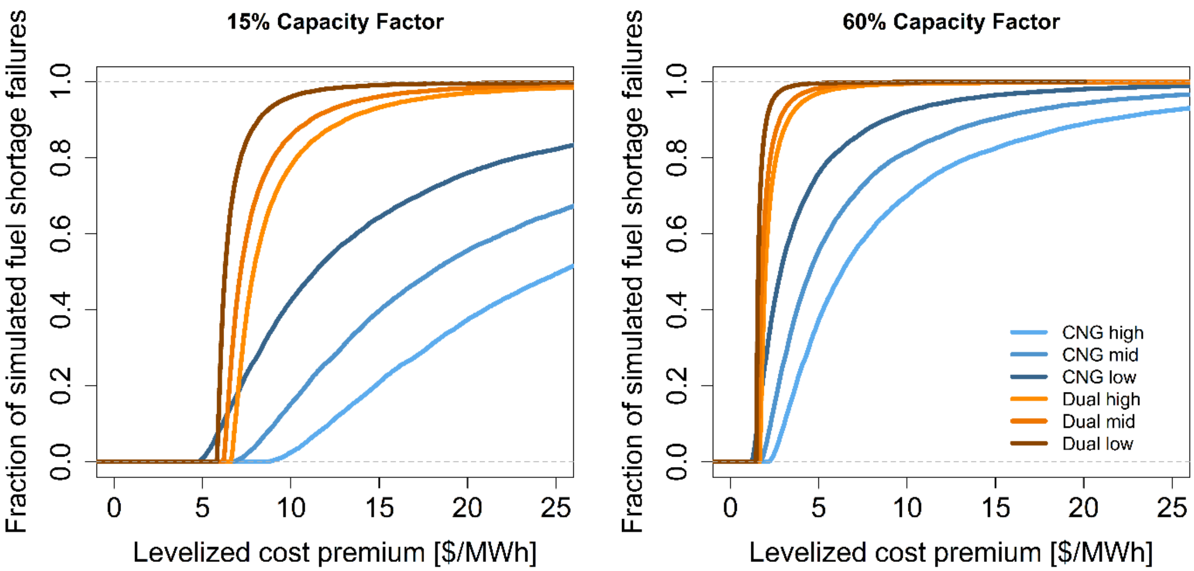

Fig. S.5. Cumulative density functions of 10,000 simulation trial computations of the levelized cost premium of oil dual fuel and CNG storage mitigation options at 15% (left) and 60% (right) capacity factors. Color shades represent different input scenarios; darker colors represent lower input values from Table 2 in the main text.

2.1.5. 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 A.2. The result is shown for levelized cost premiums of the medium scenario inputs (Table 2 from the main text) oil dual fuel option in Figure S.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.

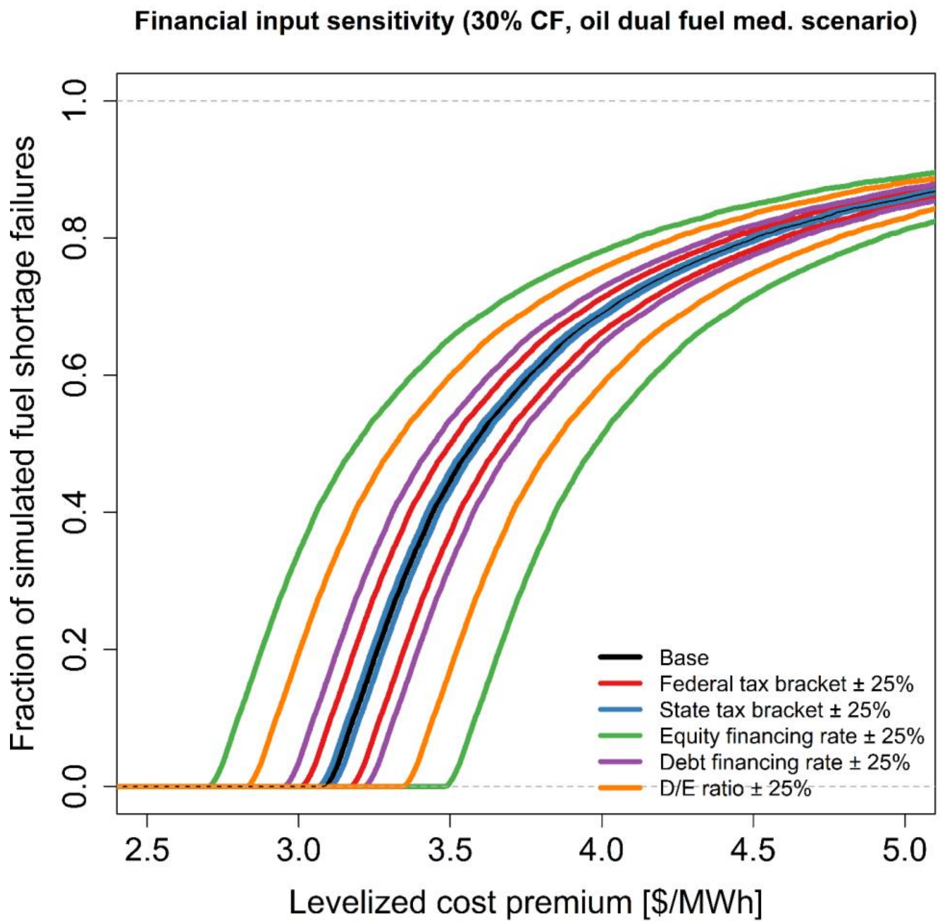

Fig. S.6. Results of a sensitivity analysis on the 10,000 simulation draws of mitigating fuel shortage failures at a simulated unit. We vary financial inputs ± 25% and present results for a 30% capacity factor unit employing the oil dual fuel mitigation option. Costs are from the medium non-financial inputs scenario from Table 2 in the main text.

2.2. 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 S.7.

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.

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) [13]. In the EIA database, combined-cycle elements are all reported as individual units [3, 4]. 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.

Of the 104 generating units with complete data in both the EIA-860 and 923 databases, 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.

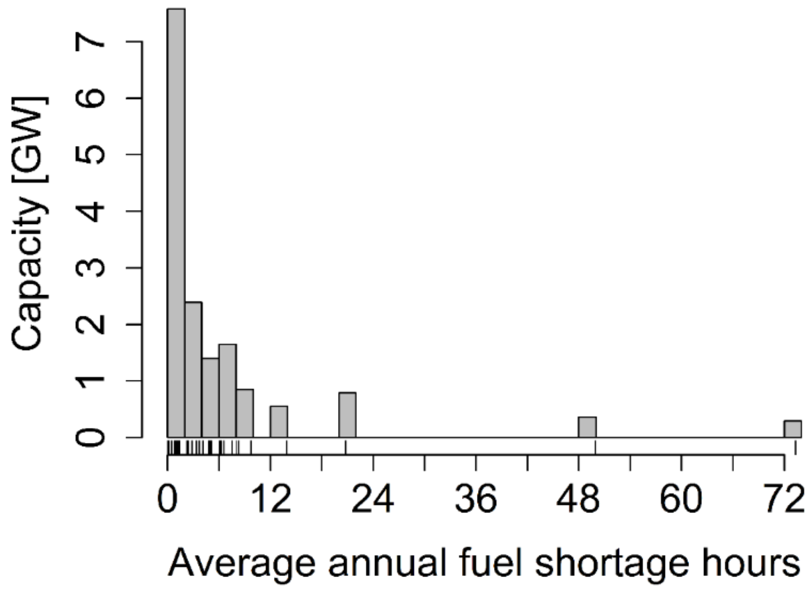

Fig. S.7. Capacity-weighted histogram of average annual fuel shortage event durations at the 104 natural gas generating units in New England from the EIA sample [3, 4].

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 1 and 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.

2.2.1. 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 S.8 and S.9, 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.

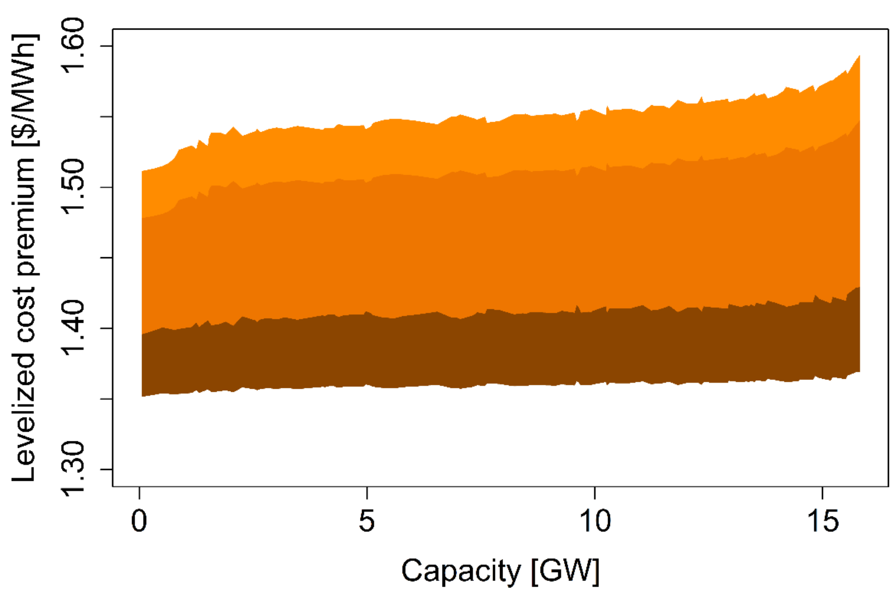

Fig. S.8. Supply curve for the oil dual fuel mitigation option for fuel shortage failures at gas-fired generators in New England. Color bands represent 90% confidence intervals generated by 1,000 Monte Carlo simulations of annual fuel shortage event durations at 104 generating units in New England with replacement. Color shades represent different input scenarios; darker colors represent lower input values from Table 2 in the main text.

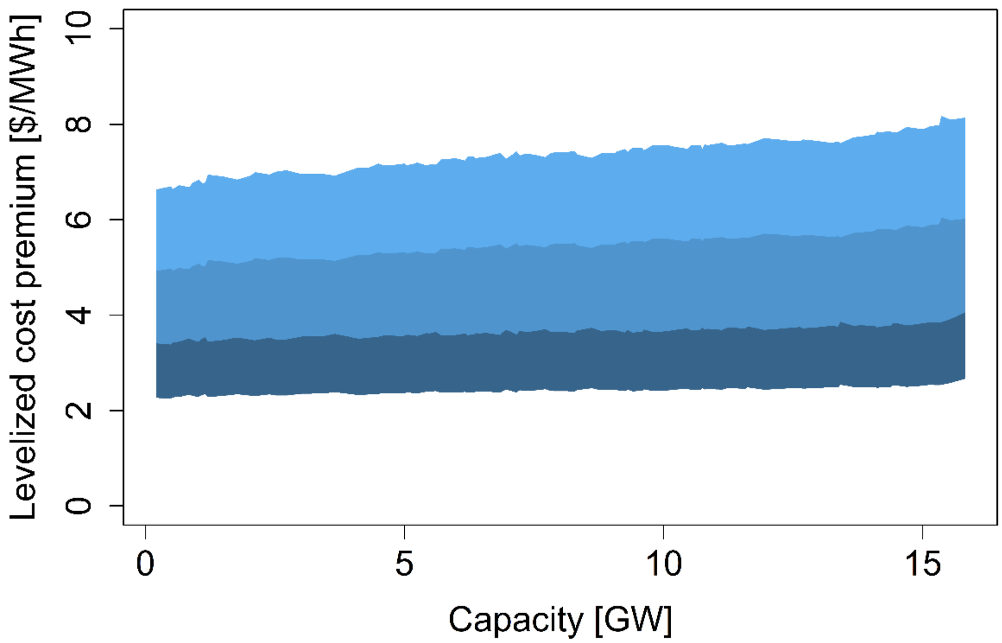

Fig. S.9. Supply curve for the CNG storage mitigation option for fuel shortage failures at gas-fired generators in New England. Color bands represent 90% confidence intervals generated by 1,000 Monte Carlo simulations of annual fuel shortage event durations at 104 generating units in New England with replacement. Color shades represent different input scenarios; darker colors represent lower input values from Table 2 in the main text.

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.