Analysis of Power System Operational Risks from Gas System Dependence

Final Project Report

M-36

Power Systems Engineering Research Center
Empowering Minds to Engineer
the Future Electric Energy System

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Power Systems Engineering Research Center

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Executive Summary

Electricity generation increasingly relies on natural gas as older units are retired, because of the usually low fuel costs, considerably lower CO_2 emissions and the capability of gas-fired units to start up, shut down or change generation levels quickly. The fast response provides needed grid operational flexibility in systems with deep penetration of integrated renewable resources. The amount of electricity generated from natural gas has overtaken that generated from coal and is expected to continue its steady increase over the next three decades.

While there are sound reasons for increasing the proportion of electricity produced from natural gas, there are also hazards. Unlike other primary sources of energy used for electricity generation, gas also is used directly to meet other energy needs. Because gas used for other sectors has historically exceeded that used for electric power, the gas markets and delivery infrastructure have developed primarily to serve the needs of those other consumers. As a result, the timing of electricity and gas markets is not well coordinated, despite the changes made in response to FERC Order 809. In addition, electric power generators often procure gas under interruptible contracts. In contrast, industrial and commercial users, as well as the local distribution companies that provide gas to residential users, typically have firm transportation contracts for gas and thus receive higher priority for delivery when gas supplies are constrained. This combination of conditions creates economic risks for both gas generators and system operators. When the availability of contracted gas is limited, the gas generators may have to obtain fuel at high spot prices or switch to alternate fuels. The system operators may take various actions such as redispatching resources or importing power, which result in high wholesale electricity prices.

This project addressed two main issues related to the impacts on the power system of the uncertainty associated with natural gas supply and cost. The first issue is risk assessment and the second issue concerns the evaluation of alternative methods to mitigate the risk. A secondary issue of limited availability of public data on the gas system was addressed by providing a guide to such data that exist.

To assess the economic risk we approximate the probability distribution for the electric energy purchase costs to meet the forecast demand for electric energy over a time horizon of several hours to a day. First we cluster historical days based on weather and estimate the joint distributions of electric load and gas spot price in each cluster. We investigate the impact of uncertainty in the spot price of gas by conducting Monte Carlo simulations of hourly economic dispatch in two cases while systematically varying the amount of contracted gas available. In the first case, only load values are randomly sampled while the gas price is fixed at its mean value. In the second case, both input parameters are randomly sampled from their joint distribution. The simulation results confirm the experience of higher and more variable electric energy purchase costs when gas supply constraints combine with high spot prices. The risk is quantified in terms of metrics for the difference between the purchase cost distributions generated with and without gas price uncertainty.

We demonstrate how such risk quantification metrics can be used to evaluate alternative risk-mitigation strategies at the system level. In a numerical case study we find that an investment in

increased gas storage capacity reduces the risk more than an equal dollar investment in conversion to dual-fuel capability.

We also propose and analyze an alternative contractual arrangement under which a gas-fired generator could procure fuel in partnership with an industrial gas consumer. The basic concept of the proposed contract is for the gas-fired generator to sign a firm transportation contract and to resell any unused transportation to another gas customer whose gas demand may be more flexible. Such a contract can benefit both the gas generator and the industrial customer in the following ways. The gas-fired generator can benefit from the contract whenever its revenues under firm gas transportation exceed the additional costs of such service. As an example, the gas–fired generator may be dispatched under conditions of gas scarce transportation. Also, in certain situations, the generator may receive incentives to acquire firm transportation. The industrial customer can benefit from the contract if the surplus transportation purchased from the gas-fired generator is below the costs to handle intermittent supply situations that are due to non–firm transportation service. Typically, the resold transportation price is below the firm price paid by the gas generator and so is less than the interruptible transportation price that the industrial customer would otherwise face. Our analysis shows that the generator's load factor plays a key role in the determination of the firm contract costs. We conduct a wide range of simulations based on historical data to evaluate the profit outcomes of a large combined-cycle generator and a small combined-cycle turbine. Under the assumed conditions, the generators are able to acquire firm gas transportation and remain making a profit and in certain conditions the large generator obtains a much higher profit than under an interruptible contract.

Further investigation and additional testing would be required to produce specific recommendations for either system operators or gas-fired generators. For the system-wide study, our Monte Carlo simulations were conducted on a synthetic data set for the electric grid and gas system. System operators could combine actual data for their own systems with information on the pipeline network that serves their market participants and follow our procedure for risk quantification. Our proposed scheme for comparing alternative risk-mitigation strategies based on those risk quantification metrics should be tested more thoroughly under a variety of conditions, while considering possible combinations of investments. The dispatch model could be modified to represent some gas generators as having firm contracts for gas delivery while others rely on interruptible contracts, and the choice to enter into firm contracts could be evaluated as another risk-mitigation strategy. Future work on the proposed gas contract includes the construction of a more detailed representation of the cost elements related to pipeline operations and the modeling of gas nomination cycles in addition to the timely, day-ahead cycle. In addition, the incorporation of the proposed contract in a detailed, stochastic process-based production costing tool to evaluate the benefits that a gas-fired generator may obtain with and without the proposed contract could provide valuable insights on the effective deployment of the contract.

Project Publication:

[1] D. Hu and S. M. Ryan, "Quantifying the Effect of Natural Gas Price Uncertainty on Economic Dispatch Cost Uncertainty," in *IEEE Power and Energy Society General Meeting*, Chicago, July 2017.

Student Theses:

[1] Dan Hu. *Short Term Operation of Power Systems Considering the Natural Gas Network under Uncertainty*. Ph.D. Dissertation, Iowa State University, May 2019 (expected).

[2] Adriano Lima Abrantes. *Analysis and Proposal of Grid Operational Flexibility Metrics for Bulk Power Systems*. Ph.D. Dissertation, University of Illinois at Urbana-Champaign, May 2019 (expected).

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1. Introduction

1.1 Background

Electricity generation increasingly relies on natural gas as older units are retired, because of the usually low fuel costs, considerably lower CO_2 emissions and the capability of gas-fired units to start up, shut down or change generation levels quickly. The fast response provides needed *grid operational flexibility* (GOF)[1] in systems with deep penetration of integrated renewable resources. Natural gas currently accounts for 40% of the on-peak resource mix and this share is expected to increase to 43% by 2025 [1].

Regardless of the level of renewable penetration, the growing reliance on gas raises power system economic and *security*[2] concerns because gas generators often lack firm gas delivery contracts and, thus, have rather low priority for gas delivery. High demand for gas by higher-priority users may use up most or all of the pipeline capacity delivery to a region and result in sharply higher prices in the gas spot markets, as was the experience in the 2013-14 Polar Vortex [2] as well as earlier severe-weather events in Texas, New England, and Colorado [3]. Because gas-fired generators are often the marginal units in the dispatch, spikes in gas prices can cause high electricity prices. Under gas shortage conditions, some gas-fired generators may be unable to produce the quantities cleared by the markets and the planned dispatch may be subject to power shortages because gas is either too expensive or simply unavailable. The peakers normally dispatched to operate during contingency/disturbance conditions are primarily gas-fired units and become subject to gas delivery curtailments under such situations.

Similarly but to a lesser extent, severe winter weather in the Eastern U.S. in January, 2018, caused spikes in wholesale natural gas prices at the primary hubs for New England ($83/MMBtu at Algonquin), New York City ($140/MMBtu at Transco Z6), and the Mid-Atlantic region ($96/MMBtu at Tetco M-3). Accordingly, wholesale electricity prices reached peaks on January 5, 2018, of $262/MWh in PJM and $247/MWh in ISONE and NYISO, as well as $110/MWh in MISO. Later that month, annual high prices were set in ERCOT at $300/MWh and $99/MWh into Entergy in Louisiana [4]. The severe weather event, dubbed the "Bomb Cyclone," caused constraints on natural gas deliveries into New England, New York and the Mid-Atlantic. System operators in all three regions were able to avoid electricity shortages and limit the extent of electricity price spikes by switching some generation to oil-fired and dual-fuel generation [5].

In gas-dependent power systems with deep penetrations of integrated renewable resources, the compounded effects of the two distinct sources of uncertainty – in the renewable resource outputs and in the gas supplies and associated costs – multiply the security concerns. Fast-responding controllable resources, most of which are gas-fired units, provide the additional flexibility required for renewable generation. The uncertainty in the gas supply markedly reduces the GOF, which leads to system insecurity as the system cannot meet all the loads due to its inability to modify its

[1] GOF is the ability of a power grid to effectively respond to continual and uncertain changes that occur on a time scale from seconds to hours, be they in the supply-side resource outputs, the demand levels, or the transmission network ability to transfer power from injection nodes to withdrawal nodes.

[2] Power system security is the ability of the system to withstand disturbances without unduly impacting the service to the loads and any violation of operational limits.

power outputs in the required time or to deliver the power injections to the loads. To maintain the secure operations of the power system, system operators must commit additional non-gas-fired resources to meet the load. Because these units' contributions to GOF are below those of the fuel-deficient gas units, their commitment must occur well in advance of when they may be needed and any over-commitment may incur high no-load and/or minimum loaded capacity costs.

An Eastern Interconnection planning study assessed the gas infrastructure and the ability of gas to meet electric system demands under both base and contingency cases. Gas supply vulnerabilities were identified in three out of the seven market areas [6]. In a recent study, the North American Electric Reliability Corporation (NERC) also analyzed the potential impacts of large disruptions in the natural gas system on bulk power system reliability. They identified different impacts in various parts of the U.S. and identified several clusters of gas-fired generators with vulnerabilities to extreme outages [7]. Under FERC directives the industry has taken appropriate steps to better align the gas supply plans with the forecasted loads. Nevertheless, the impacts of the gas supply issue have complicated the power system unit commitment and dispatch scheduling functions. The Polar Vortex and Bomb Cyclone experiences indicate that the gas supply/cost uncertainty should be considered explicitly in such schedules. Vulnerability to delivery disruptions or high costs for the available gas also motivate consideration of longer-term strategies to mitigate the risks.

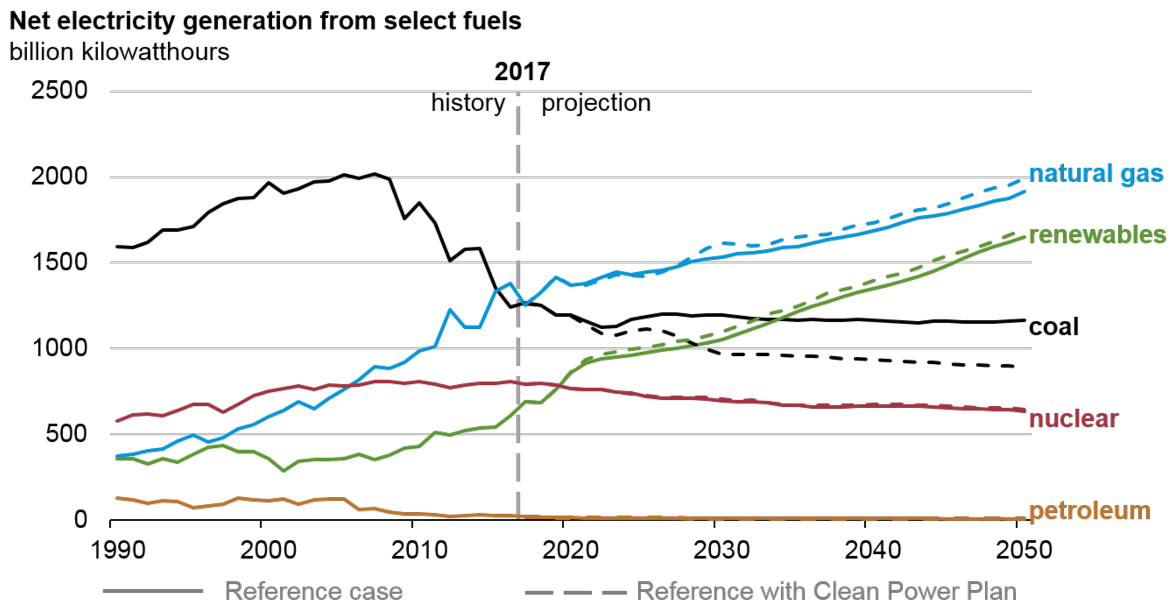


Figure 1-1: Historical and projected electricity generation by fuel [4]

1.2 Overview of the Problem

The power system's increasing reliance on natural gas is well-documented. According to the US Energy Information Agency [4], the amount of electricity generated from natural gas has overtaken that generated from coal and is expected to increase steadily over the next three decades (see Figure 1-1). In 2017, utility-scale generation from natural gas was 32% of the total and this percentage is expected to grow to 35% in 2019, while coal's share drops from 30% in 2017 to 27% in 2019 and nuclear's share falls from 20% to 19% in the same time frame [5]. This increase is due to a combination of retirement of coal-fired and nuclear generating units along with additions of renewable and natural gas generating capacity, as illustrated in Figure 1-2. The shift to electricity generation by natural gas is attributed to its relatively low cost; the flexibility of gas units to change

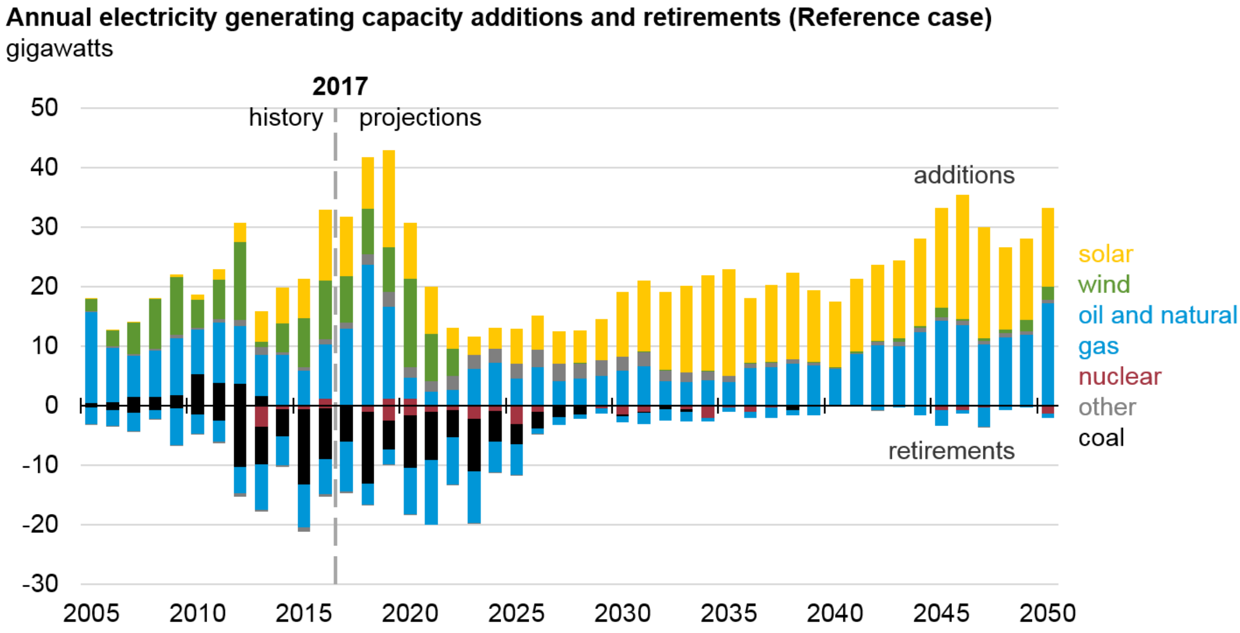


Figure 1-2: Historical and projected additions and retirements of electricity generation capacity by fuel type [4]

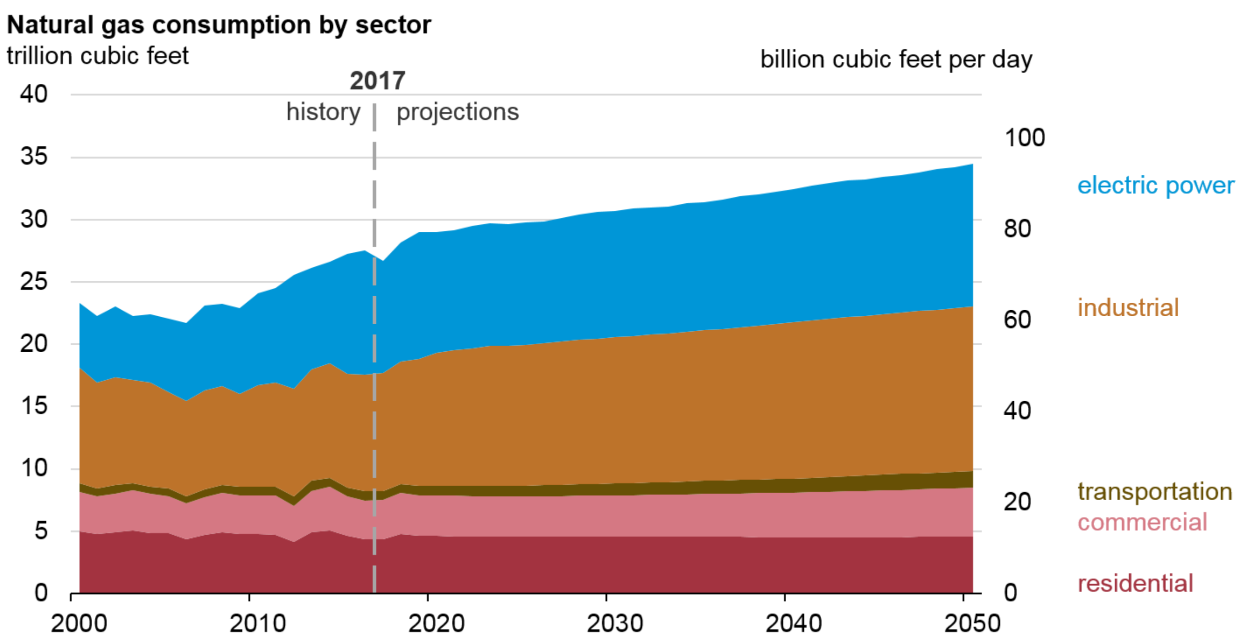


Figure 1-3: Natural gas consumption by sector [4]

production levels rapidly in response to fluctuations in the load and generation by variable sources such as wind and solar; and its relatively low emissions of pollutants compared to coal.

While there are sound reasons for increasing the proportion of electricity produced from natural gas, there are also hazards. Unlike other primary sources of energy used for electricity generation, gas is also used directly to meet other energy needs. The current consumption of gas for electric power generation is approximately equally divided into the amount used for electric power generation, that consumed by industrial users, and the total consumed by transportation, commercial and residential users combined. By the middle of the century, gas usage for electric power is projected to approximately equal the total for transportation, commercial and residential users while industrial use is projected to be higher (see Figure 1-3). Because gas used for other sectors has historically exceeded that used for electric power, the gas markets and delivery infrastructure have developed primarily to serve the needs of those other consumers. As a result, the timing of electricity and gas markets is not well coordinated, despite the changes made in response to FERC Order 809. According to the U.S. Energy Information Administration, 71% of gas purchases by U.S. power plants in 2016 were through firm contracts but this proportion was only 43% in the Northeast and 51% in the Midwest [8]. The remaining gas for power generation was procured through interruptible contracts (45% in New England) or a mix of interruptible and firm contracts. In contrast, industrial and commercial users, as well as the local distribution companies that provide gas to residential users, typically have firm transportation contracts for gas and thus may receive higher priority for delivery when gas supplies are constrained. This combination of conditions may result in a situation where a gas generator offers into the wholesale electricity market based on the contracted price, is dispatched in the day ahead market, has its contracted gas delivery interrupted and, thus, must procure gas on the spot market at a higher price than the one on which the offer was based.

Recent events have exposed vulnerabilities in the ability of the power system to meet demand for electricity at low prices due to the increased gas dependence. In the eastern U.S. and Texas, threats of electricity shortage and high electricity prices have occurred during severe cold weather incidents. In California, a leak in the Aliso Canyon natural gas storage facility that lasted for nearly six months from October, 2015, affected gas markets significantly and prompted CAISO to both implement market changes and develop operational tools to adjust to constrained natural gas supply [9].

From the system operator point of view, the problem is that increased reliance on a primary energy source that is mainly delivered to generators “just in time,” largely under contracts that allow interruptions in scheduled deliveries, results in the risk of not being able to meet the demand for electricity. To avoid loss of load, the operators prevail upon the dispatched generators to procure gas on the spot market or dispatch other, higher-cost, generators instead. Generators with dual-fuel capability can switch to the alternate fuel. The end result is that the cost for system operators to procure electricity to meet demand may increase dramatically when the availability of gas is restricted.

The high correlation between price spikes in the natural gas spot markets and high LMPs in the wholesale electricity markets during recent events are symptomatic of this problem. As one example, ISO-NE documented the strong link between regional prices of natural gas and electricity, with dramatic spikes during conditions of constrained pipeline capacity in the winter (see Figure 1-4). A recent analysis projected that in nearly every fuel-mix scenario studied for winter 2024/2025, energy shortfalls would occur to an extent that would require frequent use of emergency actions including load shedding [8].

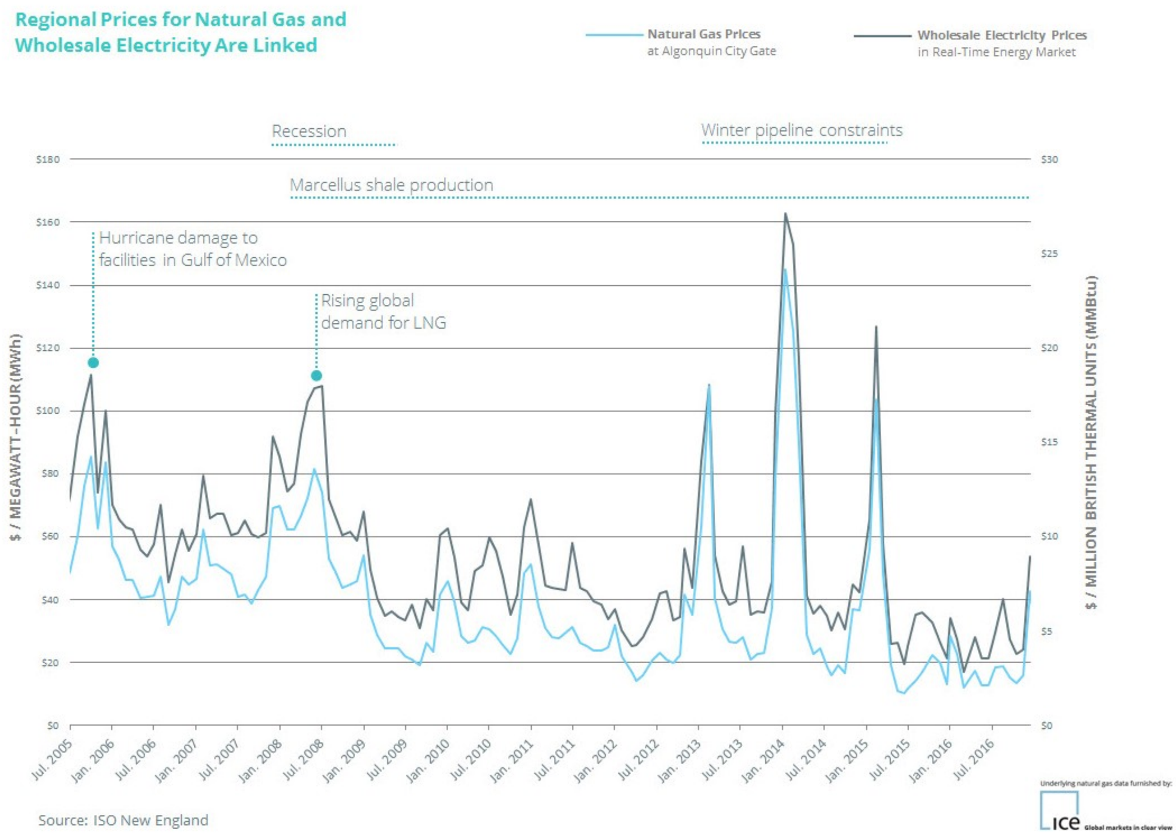


Figure 1-4: Correlation between natural gas prices and wholesale electricity prices in ISO-New England [71]

1.2.1 Main Issues

This project addressed two main issues related to the impacts on the power system of the uncertainty associated with natural gas supply and cost. The first issue is risk assessment and the second issue concerns the evaluation of alternative methods to mitigate the risk.

As a result of studies [6], [7], under FERC directives the industry has taken appropriate steps to better align the gas supply plans with the forecasted loads. However, the traditional reliability metrics such as loss of load probability (LOLP) and expected unserved energy (EUE) do not capture the economic risks that result from high spot market prices for gas accompanying constraints in the supply. Indeed, spikes in wholesale electricity prices result from the system operators' strenuous efforts to avoid loss of load. Our approach to assessing the economic risk is to approximate the probability distribution for the electric energy purchase costs to meet the forecast demand for electric energy over a time horizon of several hours to a day. This approximation serves to quantify the risks in terms of expectation, variance, and quantiles or superquantiles[3] of the purchase cost distribution. Approximating this cost distribution involves estimating the distributions of uncertain parameters, such as electric load and gas spot prices, and sampling from them to generate inputs to a Monte Carlo simulation of the economic dispatch optimization problem.

The second issue we address is how to evaluate and choose from among alternative investments that could mitigate the risks. Such investments potentially include building infrastructure such as natural gas storage facilities, liquefied natural gas (LNG) import terminals, or pipeline expansions; commitment to financial agreements such as the purchase of long-term firm transportation contracts; or generator retrofits such as conversion to dual fuel capability. Evaluating the worth of such investments requires careful analysis and simulation to estimate the potential cost savings or increases in generator profits that would result as the system is operated over a long time horizon with variations in load, fuel supply and fuel prices. Specifically, we compare risk-mitigation strategies of dual fuel conversion and increased gas storage according to the amount of risk reduction each provides given the same level of investment in Section 3. In Section 4 we evaluate a proposed alternative contractual arrangement for gas procurement and resale in Chapter 4.

1.2.2 Secondary Issues

A major issue that complicates research in this area is the lack of easily accessible, publicly available data on the gas system. Due to the development of the industry with emphasis on bilateral contracts between consumers and suppliers as well as restrictions on publishing pipeline data due to physical security concerns, it is relatively difficult to obtain information on pipeline topology and capacities. Compared with wholesale electricity market price data, which is freely available from each ISO, gas market price data at useful levels of temporal and spatial detail is available only to fee-paying customers of a few private data providers. Information concerning pipeline constraints is published online by pipeline operators but not easily collected and aggregated over time and space.

Another complicating issue is the lack of coordination and communication between the electricity system and the gas system. Although some efforts have been made recently to reduce this gap, its presence contributes to the risks we attempt to assess in this project. For example, the value of market modifications that reduce the mismatches between gas nomination and unit commitment timing might be quantified to gain an improved understanding of the risks imposed by such mismatches. While changes in the structure or processes of either or both markets might improve efficiency and reduce risk, such proposals were considered outside the scope of this project. Instead, we attempt to capture the salient effects of the market mismatches in our simulation models.

[3] One commonly used example of a superquantile is Conditional Value at Risk, defined as the conditional expected value given that the random variable exceeds the quantile known as Value at Risk.

1.3 Report Organization

In an effort to address the secondary issue of data availability, Section 2 contains a guide to publicly available data on the gas system that may be useful to power system researchers.

Section 3 describes our proposed methods to assess the economic risk that emanates from unit commitment and dispatch schedules in the presence of gas supply and price uncertainty. To address economic impacts under security constraints, an economic dispatch model is formulated to simulate the grid operations. This optimization problem is a fundamental building block of the stochastic simulation approach to represent real-time grid operations with spot fuel prices as well as gas storage and fuel-switching capability explicitly represented. The primary inputs for the existing dispatch optimization are the set of committed units, their economics – primarily fuel prices – and the forecast *net load*, i.e., the portion of system load that must be supplied by the controllable resources. Probabilistic models are estimated to represent fuel prices and loads, correlated by their common dependence on weather. A constraint on gas availability represents physical constraints imposed by the natural gas supply delivery system as well the demands of local distribution companies and large industrial gas customers with firm transportation contracts.

Variations of the model represent the impacts of adding gas storage or dual fuel capability in selected locations. To extract specific findings in numerical cases, we conduct Monte Carlo simulation using the outputs of the data-driven probabilistic models as inputs in the dispatch model. The case studies characterize probabilistically the payments for electric energy purchases to securely satisfy demand in a gas-dependent system for various sensitivity cases of gas availability from the pipeline. Performance metrics are used to compare the distributions of the purchase payments with and without gas price uncertainty. Extensive *what-if* studies are performed to quantify the sensitivity of these metrics in response to gas availability from the pipeline, and to evaluate investments in dual-fuel capability or in gas storage facilities.

Section 4 presents the design, analysis and simulation of a proposed contractual arrangement for natural gas procurement that would reduce the risk borne by a power generator in partnership with a large industrial consumer. The basic concept of the proposed contract is for the gas-fired generator to sign a firm transportation contract and to resell any unused transportation to another gas customer whose gas demand may be more flexible. The cost advantage to the generator is shown to depend on the load factor. In a deterministic simulation based on recent market data, the proposed contract increases the profit earned by a large combined-cycle generator but is less advantageous for a small combined-cycle gas turbine.

Section 5 concludes the report with suggestions for future research.

2. Public Natural Gas Data for Use in Electricity System Dispatch Studies

This section describes some data sources for the natural gas system that can be used in studies of electricity system dispatch. The data sources as well as the detailed content of gas supply, price and demand are explained and the corresponding links to those data sets are provided to help researchers to locate the data quickly and conveniently.

2.1 Data Sources

Considerable background information on the natural gas system can be obtained from the U. S. Department of Energy [10], [11]. The major data sources can be divided into several categories including federal government organizations, the natural gas transmission, storage, and distribution (TS&D) companies and some other data-providing firms.

The U.S. federal organizations include the U.S. Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC). They mostly provide monthly, annual U.S. and state data for gas supply, price and demand, which are useful for long term analysis and planning studies.

The TS&D companies manage gas infrastructure including natural gas storage, liquefied natural gas (LNG) terminals, processing capacity, high-pressure transmission pipelines, and local gas distribution networks [10]. Different regions have different TS&D companies to perform these functions; for example, Northern Natural Gas Company in the Midwest, Pacific Gas and Electric Company (PG&E) in California, and Transcontinental Gas Pipe Line Company (Transco) in the East. From the viewpoint of the natural gas contracts and aiming at maintaining the reliability of the natural gas system, these companies provide daily and hourly reports on the pipeline and storage facility working capacity, tariffs, and cutoff notices. These reports give some information about the pipeline availability and contingencies. However, the data are not easy or straightforward to use in electricity dispatch models because the network topology is not clear and it is hard to identify a typical day.

The data-providing firms collect and sell detailed data concerning the natural gas system. The prominent natural gas data providers include Natural Gas Intelligence (NGI) [12], Intercontinental Exchange (ICE) [13], S&P Global Platts [14], Point Logic Energy and Thomson Reuters [15]. These firms collect data from the market according to the natural gas nomination and bidding trades as well as their collaborators and summarize the future in terms of one week ahead as well as day ahead natural gas prices for different locations. Compared with FERC and EIA, the natural gas prices they provide are more granular and thus more useful for use in short term models. However, research budgets may not allow for paying the fees they charge.

2.2 Content, Temporal Granularity and Spatial Granularity

This section characterizes and summarizes the detailed data available for natural gas supply, demand and price from temporal and spatial viewpoints using all the data sources described in Section 2.1.

2.2.1 Gas Supply

Sources of natural gas include wellheads, imports by pipeline and LNG as well as underground storage. From the viewpoint of the electricity economic dispatch problem, the natural gas comes to generators from pipelines, storage facilities and LNG.

Natural Gas Pipelines:
Pipelines are used to transport gas from the wellhead and some other gas upstream hubs to the end customers. More detailed introduction about the pipelines can be found at the EIA's website [16]. Here we focus on discussing various data sources on pipelines. The EIA describes the capacity of interstate pipelines between states, international borders and from the Gulf of Mexico offshore along with detailed information on the size and location of pipeline projects announced or under construction [17]. This information can be used for long term analysis and also provides a general concept of pipelines for the short term analysis. However, the natural gas pipelines are not guaranteed to operate with full capacity. Instead, their working capacities highly depend on the pipeline operation, the amount of gas supplied from wellhead or upstream, and the gas demand. One way to assess the exact gas supply from the pipelines is to check with the corresponding gas transmission company. For example, the Northern Natural Gas Company posts daily reports of the timely, evening, Non-Grid A.M., intraday and Final A.M. cycle reports which describe the indicated direction, operation capacity, design capacity, total scheduled quantity, operationally available quantity, and quantity not available with reasons for each location [18]. The operationally available quantity posted is an estimate of the capacity that is scheduled at or through the point in the indicated direction of flow. Because of the dynamic operation of pipelines, the capacities estimated are still subject to change without notice and thus not guaranteed to be accurate. Accordingly, those customers who are willing to pay a higher price for guaranteed gas delivery are motivated to purchase firm contracts, while the other customers have interruptible contracts. The gas transmission company also posts information about gas quality, tariff notices, imbalances, regulatory issues, and transactional reporting including firm or interruptible transportation and storage quantities. All this information from the transmission company can be summarized and employed as natural gas pipeline data.

Natural Gas Storage Facilities:
Natural gas storage plays an important role in maintaining the reliability of supply to meet demand. There are three principal types of storage: depleted natural gas or oil fields, aquifers, and salt caverns. The EIA provides extensive weekly, monthly, annual state, regional and national data for each type of underground storage capacity and activity, such as weekly regional and national natural gas working underground storage, monthly state underground volume, monthly and annual base and working gas volume as well as net withdrawals for each storage type, monthly and annual storage capacity and working gas capacity for each state [19]. The EIA also lists the monthly and annual storage field level base gas volume, working gas and total field capacity along with maximum daily delivery [20]. Similar to the natural gas pipelines, all the data provided by the EIA are relevant to the long term analysis. Detailed information on daily or hourly natural gas storage capacity and activity must be obtained from the gas transmission company reports or corresponding data.

Liquefied Natural Gas Facilities:
LNG is natural gas (mostly methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure. Little publicly available data exists for LNG compared with pipelines and storage facilities. The EIA reports the state annual net LNG additions to and withdrawals from storage [21] while FERC reports monthly and annual LNG reports which mostly contain information on the export and import long term contracts [22].

2.2.2 Gas Consumption

Natural gas consumers can be classified as residential, commercial, industrial, vehicle fuel and electric power. The EIA summarizes the monthly and annual U.S. and state natural gas consumption by each type of consumer [23], which indicates that the annual gas consumption by electric power has increased dramatically from 7.57 million Mcf in 2011 to 9.25 million Mcf in 2017, while that of all the other consumers has remained quite stable. Due to security concerns, publicly available data on weekly or daily electric power and non-electric-power consumption are scarce. One possible way to obtain them may be to contract with the local natural gas distribution center companies for their private records.

2.2.3 Market Prices: Types and Locations

Natural gas is traded in forward markets, next-day markets and spot markets. Geographically, these markets are located at different hubs. The most widely-referenced hub is the Henry Hub in Louisiana, because it has the highest quantity traded and relatively stable prices. Figure 2-1, which compares the natural gas next-day prices between Henry Hub and the Algonquin City gate (located at New England area) over a recent period, illustrates the relative stability of the Henry Hub gas price. In this subsection, we will discuss the different natural gas markets and locations as well as the corresponding data sources.

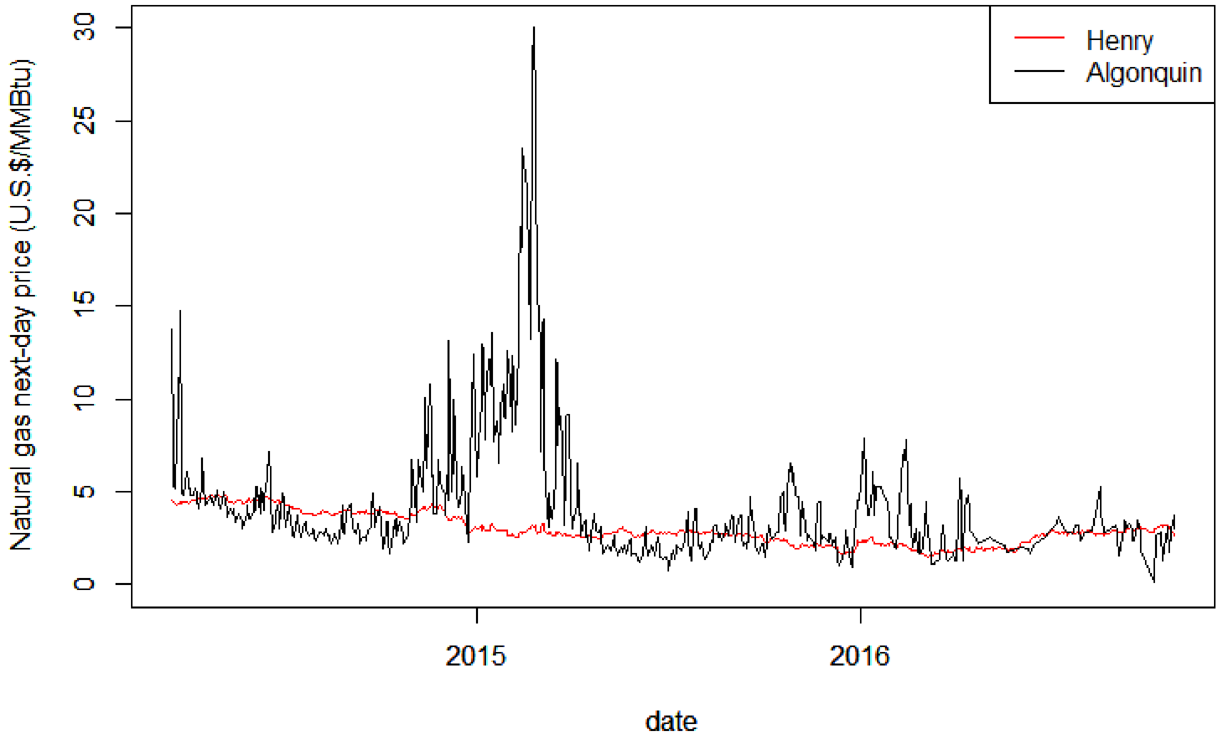


Figure 2-1: Daily natural gas next-day price comparison between Henry Hub and Algonquin Citygate from 3/17/2014 to 10/25/2016

Market Types:
The natural gas markets consist of the forward market, the next-day market and the spot market. In the forward market, where usually the New York Mercantile Exchange (NYMEX) future price is taken as a reference, a future contract specifies the trade price, trade quantity and the delivery date which could be one month or one week after the trade date. The next-day market specifies the price for a one-time open market transaction for delivery of a specific quantity of product whose delivery date is the day following the trade date. The spot market is a market where the natural gas consumers are able to acquire gas within a very short time period. The Federal Energy Regulatory Commission (FERC) has recently adjusted the regulations of electric and natural gas nomination cycles to better coordinate operations. Figure 2-2 illustrates the operation of electric and natural gas markets at PJM. The gas transmission company accepts and processes five types of nominations: Timely, Evening, Intraday 1 (ID1), Intraday 2 (ID2), and Intraday 3 (ID3). The flows of timely and evening nomination are effective on the early morning of the day following the trade date, while those of the intraday nominations are effective within one hour of the time when the nomination is confirmed by the transmission company. The next-day market comprises both the timely and evening nominations and the next-day price is a weighted average of the accepted nomination within those two nomination cycles. The spot market includes the three Intraday nomination cycles. Other regions have a similar operation structure, but the nomination market timing displays a few differences. For example, Pacific Gas and Electric Company's California Gas Transmission page [24] lists the detailed nomination and effective time information.

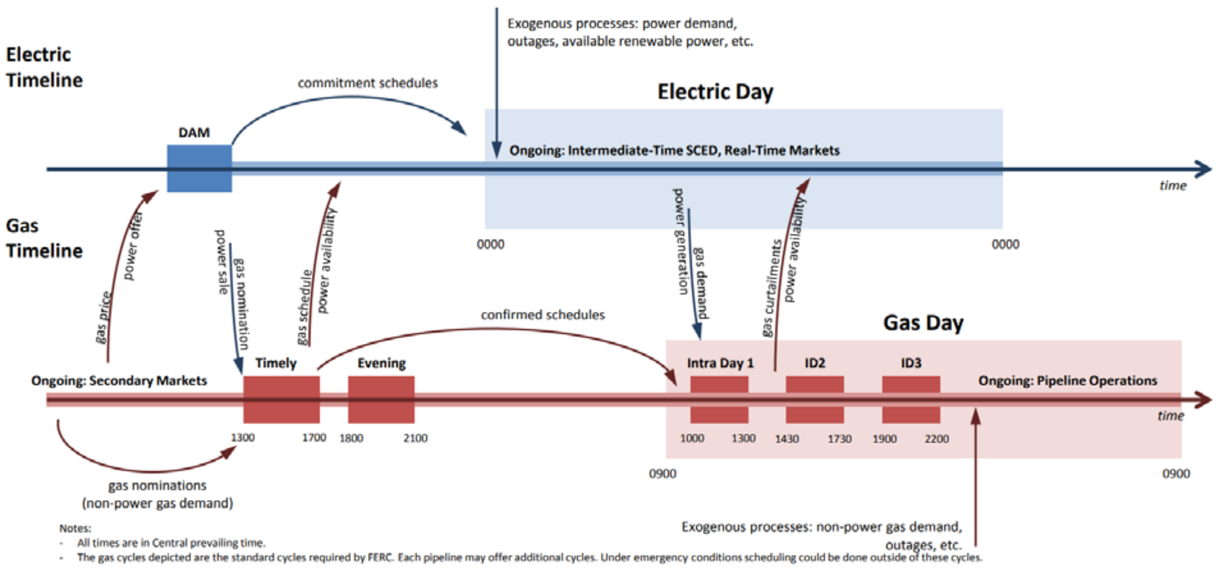


Figure 2-2: Electric and gas operation timeline [25]

Locations:

There are more than two dozen electricity product trading hubs and more than 120 natural gas product hubs in North America. Figure 2-3 shows the eight major electricity hub locations and their corresponding natural gas hubs. Figure 2-4 illustrates the selected hubs and wholesale daily spot price names.

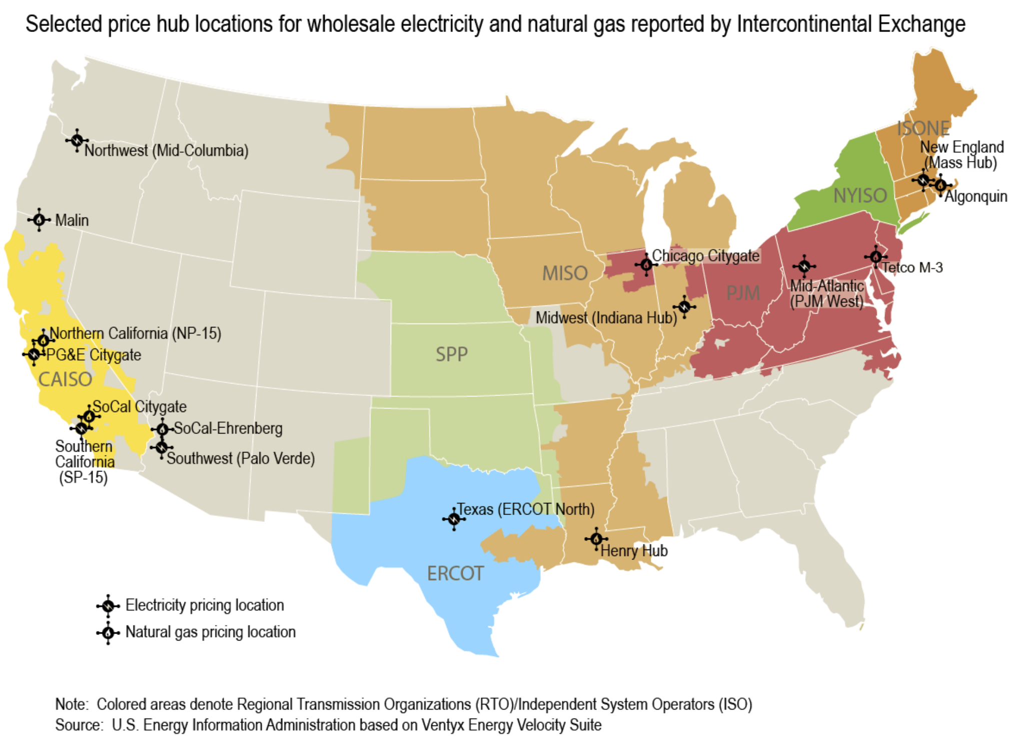


Figure 2-3: Selected price hub locations for wholesale electricity and natural gas reported by Intercontinental Exchange. (Source: EIA)

Region	Electricity Hub Name	ICE Electricity Product Name	Natural Gas Hub Name	ICE Natural Gas Product Name
New England	Mass Hub	Nepool MH DA LMP Peak (from 2001)	Algonquin	Algonquin Citygates
PJM	PJM West	PJM WH Real Time Peak (from 2001)	TETCO-M3	TETCO-M3
Midwest	Indiana Hub	Indiana Hub RT Peak (from 2006)	Chicago Citygates	Chicago Citygates
Texas	ERCOT North	ERCOT North 345KV Peak (from 2014)	Henry Hub	Henry
Northwest	Mid-C	Mid C Peak (from 2001)	Malin	Malin
Northern California	NP-15	NP15 EZ Gen DA LMP Peak (from 2009)	PG&E - Citygate	PG&E - Citygate
Southwest	Palo Verde	Palo Verde Peak (from 2001)	Socal-Ehrenberg	Socal-Ehrenberg
Southern California	SP-15	SP15 EZ Gen DA LMP Peak (from 2008) SP-15 Peak (2001 to 2009)	Socal-Citygate	Socal-Citygate

Figure 2-4: Selected hubs and wholesale daily spot price names (Source: EIA)

The EIA website has a section devoted to natural gas including overview, data, analysis and projection reports [26]. Specifically, on this website, EIA provides data about monthly and annual U.S. and state prices for wellhead, imports, exports, city gate and end-use sectors; monthly average price of natural gas delivered to residential consumers and commercial consumers by state; daily, weekly, monthly and annual New York Mercantile Exchange futures contracts for natural gas based on delivery at the Henry Hub in Louisiana; and natural gas liquid composite price for natural gas liquids at Mont Belvieu, Texas.

Besides weekly, bidweek and forward natural gas price for region hubs including Henry Hub, Natural Gas Intelligence (NGI) gives more information about the daily natural gas price at various detailed natural gas hubs in multiple regions, such as the Algonquin Citygate for the Northeast region [27]. What do the NGI natural gas indexes represent? According to the manual [28], *"the bidweek indexes represent the price of gas that will flow every day during the forthcoming calendar month ('base load' transactions), while the Daily prices measure gas flows up to and including the next trading day ('day-ahead'). The data upon which we derive our indexes are a combination of negotiated fixed priced transactions and physical basis trades (bidweek only) that are the product of arms-length transactions between non-affiliated counter parties.*" The two main sources of these data are companies who are principals to the trade and the ICE, which provides data services to inform users on the details of contracts over various time frames as well as trade data. A paid subscription is required to access those data [13].

2.3 Test Systems

The previous subsections discuss sources for daily, weekly, monthly and annual natural gas data for various locations. Beyond that, we still require some information about the network topology of natural gas system including the pipelines, compressors, storage facilities, non-electric consumers and its connection to the electric power system. Here we list four frequently-used coupled power system and natural gas test systems from the literature.

2.3.1 Six-Bus Power System with Seven-Node Gas System

A small-scale natural gas system connected to a power system is the six-bus power system with seven-node gas system as shown in Figure 2-5. The detailed network topology and physical parameters of the gas system can be obtained from [29].

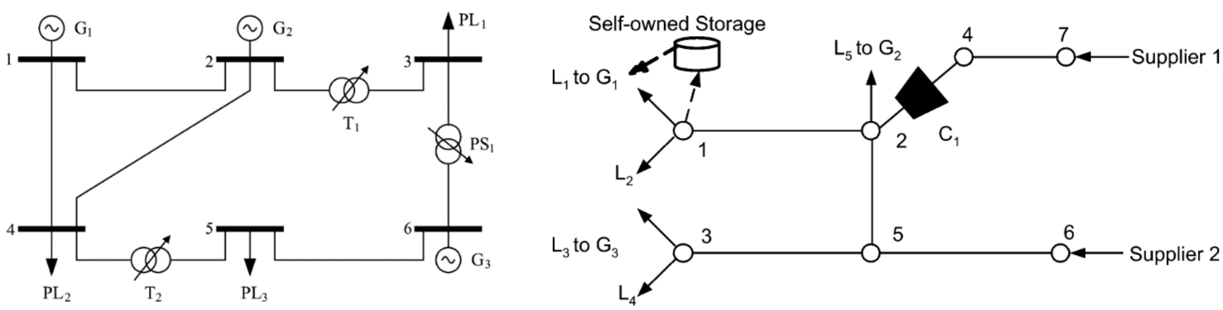


Figure 2-5: Six-bus power system with seven-node gas system [29] Left: Six-bus power system; Right: Seven-node gas system

2.3.2 Belgian 20-Node Gas System

Data for the Belgian natural gas system was first published in 2000 [30] and in recent years has been coupled with multiple IEEE electric power test systems due to the lack of publicly available U.S. natural gas network data. Researchers have coupled Belgian 20-node gas system with IEEE 14-bus power system [31] as shown in Figure 2-6, the IEEE 24-bus power system [32] as illustrated in Figure 2-7 and the IEEE 118-bus power system [33], [34].

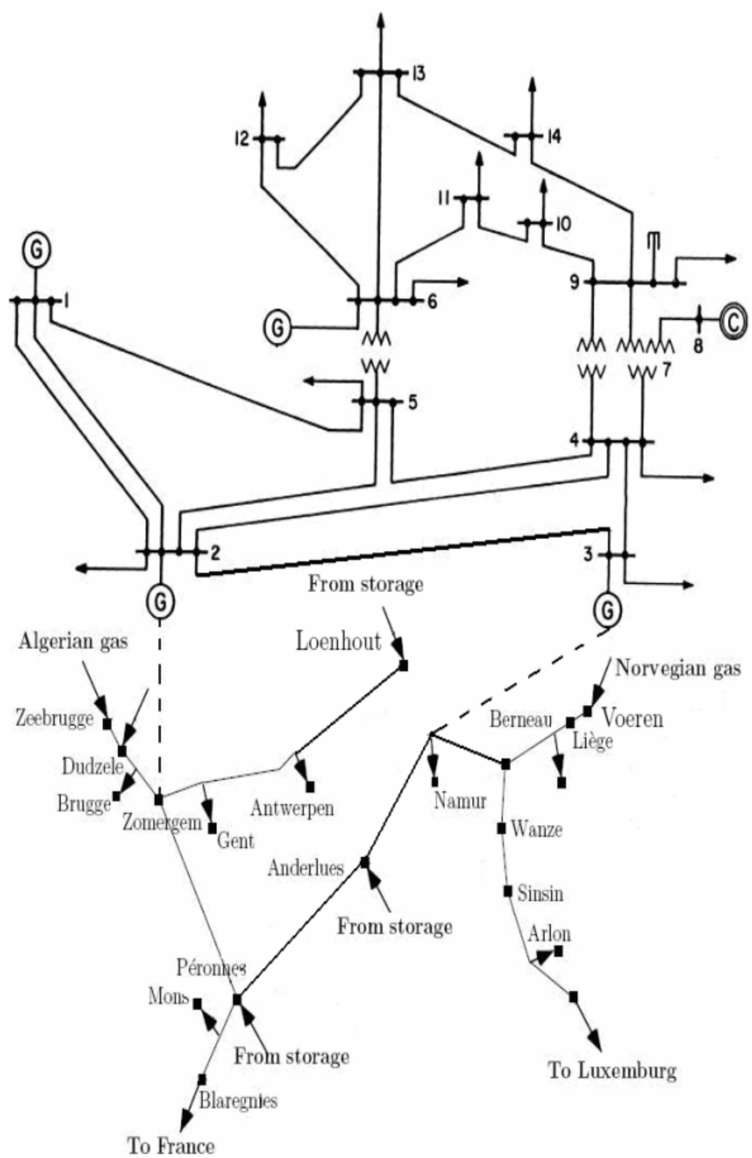


Figure 2-6: IEEE 14-bus power system with Belgian 20-node gas system [31]

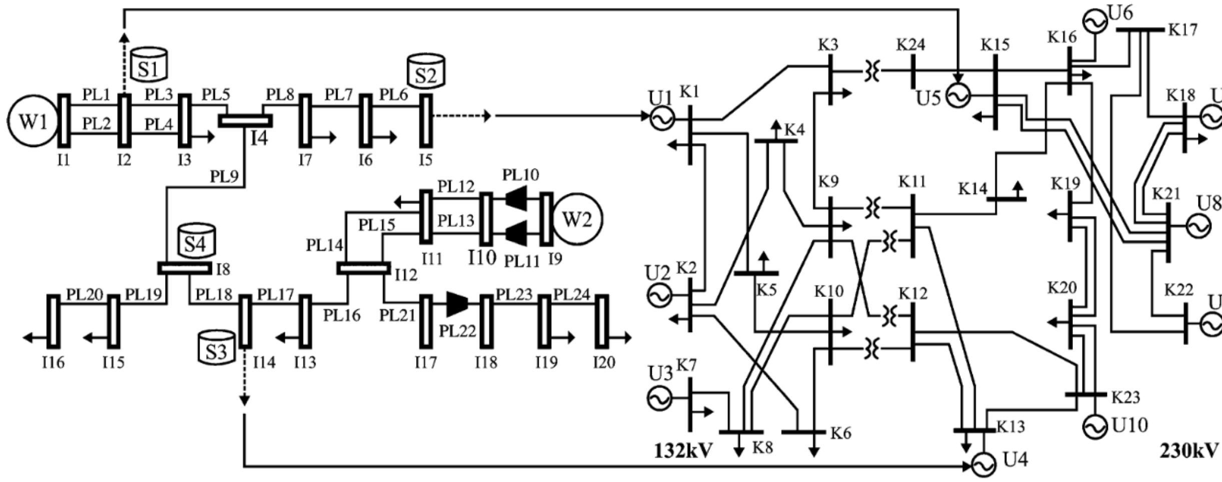


Figure 2-7: IEEE 24-bus power system with Belgian 20-node gas system

2.3.3 IEEE RTS96 Single Area 24 Node Power System with the 24 Pipe Natural Gas System

Figure 2-8 illustrates the topology of the IEEE RTS 96 one area 24 node power system with the 24 pipe natural gas system dataset [35].

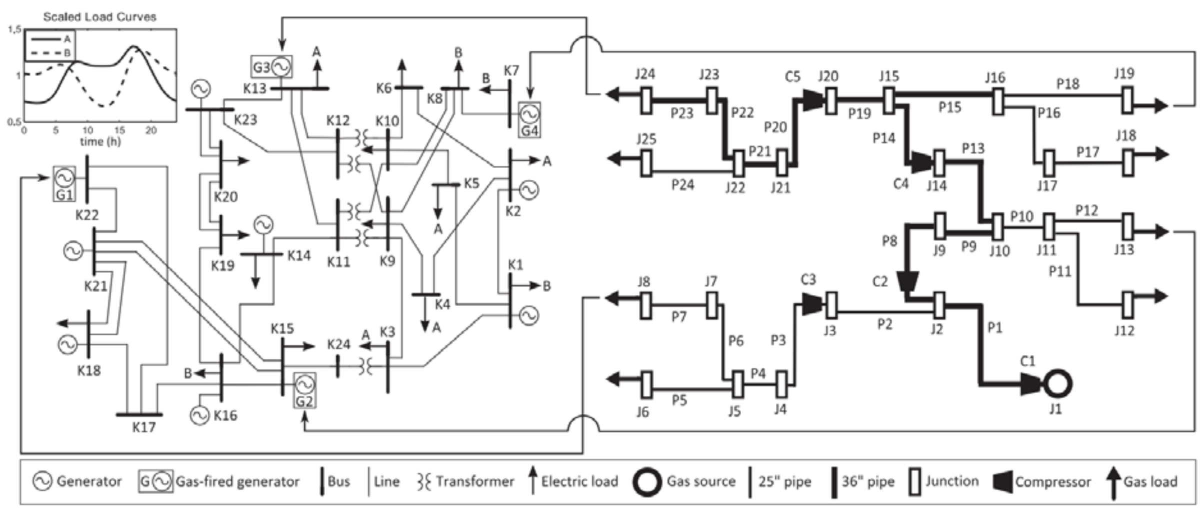


Figure 2-8. IEEE RTS96 single area 24 node power system (left) coupled with the 24-pipe natural gas system (right) [35]

2.3.4 IEEE 118-Bus System with 14-Node Natural Gas System

Currently the largest integrated test system appearing in the literature is the IEEE 118-bus system with a 14-node natural gas system [36]. The corresponding data can be accessed through [33].

3. Quantifying the Effect of Uncertain Natural Gas Spot Prices on Economic Dispatch Cost Considering Correlated Uncertainties

3.1 Introduction

The daily economic dispatch (ED) problem finds production quantities for the committed thermal units for each hour that minimize the total cost including production cost and penalties for energy imbalances while satisfying the electric load, transmission and other operational constraints. Due to the retirements of coal-fired and nuclear generators, the development of highly efficient gas-fired generators, the increase of natural gas supply with a relatively stable gas price since 2009, and potential emission regulations, natural gas and renewable energy sources have taken a rapidly increasing share of electricity production. Natural gas experiences a more competitive market than other fossil fuels because of its fast procurement and low price. In competitive electricity markets, gas generators often procure gas in low-cost interruptible contracts and therefore receive lower priority for delivery than customers with firm contracts. High demand of natural gas by the high-priority customers, which consist of residential, industrial and commercial entities, may cause gas generators to pay high spot prices to avoid outages, as was the experience in the eastern US during early January, 2018; the 2013-14 Polar Vortices [37]; and earlier severe-weather events in Texas, New England, and Colorado [3]. Increased reliance on natural gas not only decreases operational cost and environmental pollution but also increases the fuel risk in the power system. Short-term dispatch decisions by the power system operator determine the cost of serving realized electric demand under increasingly constrained gas supply and uncertain spot prices. For the longer term, understanding the risk imposed by dependence on interruptible contracts and exposure to the volatile spot market can help generators and system operators to evaluate potential investments to mitigate the risks.

Our goal in this report is to present approaches for quantifying the risks imposed by limited natural gas availability and price uncertainty in terms of the probability distribution of daily dispatch cost based on the joint distribution of load and gas spot prices. We generate discrete scenarios for natural gas price jointly with electric load. The impact of uncertainty in natural gas availability is assessed through sensitivity analysis. An electricity system operator can use the quantification methods to evaluate alternative risk-mitigation strategies according to the tradeoff between investment cost and risk reduction.

Previous research has investigated various aspects of the effect of gas system uncertainties on the power system. For evaluating bidding strategies and efficiencies of an integrated natural gas generating unit and power-to-gas conversion facility, the financial risk introduced by the uncertain price gap between electricity and natural gas was assessed according to the conditional value at risk (CVaR) [38]. The effect of gas supply uncertainty and gas price variability on unit commitment has been investigated through stochastic programming with few assumed discrete scenarios [39]. However, both [38] and [39] consider only a single natural gas price parameter. In fact, the current gas-fired generators acquire gas from both contracts and the spot market with different prices. While the contracted natural gas price is fixed, that from spot market has high uncertainty. In addition, the scenarios in the literature are frequently generated without any validation using actual data. Some papers discuss methodologies to assess the forecast uncertainty associated with gas prices; for example, based on weekly data [40]. At the same time, substantial research has been aimed at generating point or probabilistic forecasts of the electric load [41]. The gas spot price is highly correlated with electric load, especially in severe cold weather. But few studies have investigated their joint distribution. To our knowledge, no previous work has addressed the dispatch cost risk resulting from these uncertainties or their influence on the selection of a risk-mitigation strategy.

In this section, from the viewpoint of an independent system operator (ISO), based on the work in [42], we propose a dispatch model incorporating the gas availability from both contracts and the spot market. A joint distribution of daily electric load and gas spot price is estimated for use as input to a Monte Carlo simulation. The objective of this research is to quantify the effect of uncertainties in the availability of contracted natural gas as well as its price in the spot market on the economic dispatch cost. We compare the dispatch cost distributions obtained with and without uncertainty in the spot price for various levels of available contracted gas with the same electric load distribution. The contributions of this paper are summarized as follows:

- Formulate an economic dispatch model considering gas availability and price from spot market and contracts.
- Generate the joint distribution functions of a temporal and weather conditional daily electric load and natural gas spot price as a transformed multivariate normal distribution.
- To quantify the effect of uncertain natural gas spot price on the dispatch cost, apply the Wasserstein distance metric and a CVaR metric to characterize the difference between the cost distribution functions generated from the two simulations where one simulation uses a point estimate for gas spot price and the other one uses the spot price distribution.
- Employ the uncertainty quantification to inform choices among alternative risk-mitigation strategies; namely, dual fuel capability conversion and the addition of gas storage facilities

In the remainder of this section, the economic dispatch model is formulated in Section 3.2. In Section 3.3 we describe how to estimate the joint distribution functions for the daily electric load and daily gas spot price for different weather conditions and seasons. Section 3.4 describes the detailed steps of quantifying the effect of uncertain natural gas spot price on dispatch cost. Section 3.5 revises the dispatch cost model of Section 3.2 according to these risk-mitigation strategies. Case studies and numerical results are shown in Section 3.6 and finally Section 3.7 concludes.

3.2 Economic Dispatch (ED) Model with Natural Gas Availability Constraints

Below we formulate a linear programming (LP) model of the daily economic dispatch problem considering gas price and availability from both contracts and the spot market. First, we introduce the following notation:

Sets:

$\boldsymbol{J}$	Gas nodes, indexed by j
$\boldsymbol{J}'(j)$	Gas nodes connected to j by passive pipelines from j, indexed by j'

$\boldsymbol{J}''(j)$	Gas nodes connected to j by passive pipelines to j , indexed by j''
$\boldsymbol{\Lambda}(j)$	Gas wells in node j, indexed by λ; $\boldsymbol{\Lambda} = \bigcup_{j\in J} \boldsymbol{\Lambda}(j)$ is the set of all gas wells
$\boldsymbol{\Psi}(\boldsymbol{j})$	Storage facilities in node j, indexed by ψ; $\boldsymbol{\Psi} = \bigcup_{j\in J} \boldsymbol{\Psi}(j)$ iis the set of all storage facilities
$\boldsymbol{\Psi}'(\boldsymbol{j})$	Added storage facilities in node j , indexed by ψ; $\boldsymbol{\Psi}' = \bigcup_{j\in J} \boldsymbol{\Psi}'(j)$ iis the set of all added storage facilities
$\boldsymbol{I}$	Electricity nodes, indexed by i
$\boldsymbol{I}'(i)$	Electricity nodes connected to i by a transmission line from i, indexed by i'
$\boldsymbol{I}''(i)$	Electricity nodes connected to i by a transmission line to i, indexed by i''
$\boldsymbol{G}(i,j)$	Gas-fired generators at power node i and gas node j, indexed by g; $\boldsymbol{G} = \bigcup_{i\in I, j\in J} \boldsymbol{G}(i,j)$ is the set of all gas-fired generators converted to dual fuel units
$\boldsymbol{G}'(i,j)$	Gas-fired generators converted to dual fuel units at power node i and gas node j, indexed by g'; $\boldsymbol{G}'(i,j) \subset \boldsymbol{G}(i,j)$; $\boldsymbol{G}' = \bigcup_{i\in I, j\in J} \boldsymbol{G}'(i,j)$ is the set of all gas-fired generators converted to dual fuel units
$\boldsymbol{N}(i)$	Conventional non-gas-fired generators at node i, indexed by n; $\boldsymbol{N} = \bigcup_{i\in I} \boldsymbol{N}(i)$ is the set of all non-gas-fired generators
$\boldsymbol{K}$	Set of all gas-fired and non-gas-fired generators, indexed by k; $\boldsymbol{K} = \boldsymbol{G} \cup \boldsymbol{N}$
$\boldsymbol{T}$	Hours from 1 to $\lvert\boldsymbol{T}\rvert$, indexed by t

Fixed parameters:

$u_{g,t}, u_{n,t}, u_{k,t}$	Unit commitment indicator: equals 1 if unit is online in hour t and 0 otherwise
$v_{g,t}^{u}, v_{n,t}^{u}, v_{k,t}^{u}$	Unit start-up indicator: equals 1 if the unit is started up in hour t and 0 otherwise
$v_{g,t}^{d}, v_{n,t}^{d}, v_{k,t}^{d}$	Unit shut-down indicator: equals 1 if the unit is shut down in hour t and 0 otherwise
λ_g^C	Gas price from contract [$/kcf]
λ_λ^Λ	Gas price of the storage outflow [$/kcf]
$\overline{L}_\psi, \underline{L}_\psi$	Maximum and minimum storage level [kcf]
$\Delta\overline{L}_\psi$	Increased storage capacity [kcf]
$\overline{q}_\psi$	Max net flow (outflow minus inflow) [kcf]
ϕ_g	Efficiency of gas generator [kcf/MWh]
$\phi_{g'}^{oil}$	Cost of using oil as dual fuel [$/MWh]
C_n^{prod}	Power production cost [$/MWh]
$\Gamma_\beta^-, \Gamma_\beta^+$	Unserved/excess electric penalty [$/MWh]
$\Gamma_\alpha^-, \Gamma_\alpha^+$	Unserved/excess gas penalty [$/kcf]
$\overline{P}_g, \underline{P}_g, \overline{P}_n, \underline{P}_n \overline{P}_k, \underline{P}_k$	Max/min electricity generation [MWh]
$\overline{F}_{i,i'}$	Max line flow from i to i' [MWh]
$x_{i,i'}$	Transmission line impedance from i to i' [pu]
$\overline{G}_{j,t}$	Available gas from gas contract for the power system [kcf]

Uncertain parameters:

$D_{i,t}$	Electric load [MWh]
Λ^M	Gas price in the spot market [$/kcf]

Nonnegative decision variables:

$\alpha_{j,t}^-, \alpha_{j,t}^+$	Unserved/excess gas [kcf]
$l_{\psi,t}$	Storage level [kcf]
$p_{g,t}, p_{n,t}, p_{k,t}$	Electricity production [MWh]
$\beta_{i,t}^-, \beta_{i,t}^+$	Unserved/excess electricity [MWh]
$q_{\psi,t}^{out}, q_{\psi,t}^{in}$	Out/in-flow of storage facility [kcf/h]
$m_{j,t}$	Gas from spot market for the power system [kcf]
$\eta_{g,t}^C$	Consumed gas from pipeline contract [kcf]
$\eta_{g,t}^M$	Consumed gas from spot market [kcf]

Decision variables:

$\theta_{i,t}$	Phase angle [rad]
$f_{i,i',t}$	Line flow from i to i' [MWh]

The economic dispatch model including constraints on contracted gas availability and prices from both contract and the spot market is as follows:

$$\min \sum_{t\in T} \Big\{ \sum_{g\in G} \lambda_g^C \eta_{g,t}^C + \sum_{j\in J} \Lambda^M m_{j,t} + \sum_{n\in N} C_n^{prod} p_{n,t} + \sum_{\psi\in\Psi} \lambda_{\psi,t}^{\psi} q_{\psi,t}^{out} + \sum_{i\in I}\left(\Gamma_\beta^+ \beta_{i,t}^+ + \Gamma_\beta^- \beta_{i,t}^-\right) + \sum_{j\in J}\left(\Gamma_\alpha^+ \alpha_{j,t}^+ + \Gamma_\alpha^- \alpha_{j,t}^-\right) \Big\} \tag{3.1}$$

s.t.

$$\sum_{j\in J}\sum_{g\in G} p_{g,t} + \sum_{n\in N(i)} p_{n,t} + \sum_{i''\in I''(i)} f_{i'',i,t} + \beta_{i,t}^- = D_{i,t} + \sum_{i'\in I'(i)} f_{i,i',t} + \beta_{i,t}^+, \quad \forall i,t \tag{3.2}$$

$$p_{k,t} \ge \underline{p}_k\left(u_{k,t} - v_{k,t}^u\right), \ \forall k \in K, t \tag{3.3}$$

$$p_{k,t} \le \overline{p}_k\left(u_{k,t} - v_{k,t}^u\right) + \underline{p}_k\left(v_{k,t}^d + v_{k,t}^u\right), \ \forall k \in K, t \tag{3.4}$$

$$f_{i,i',t} = \frac{\theta_{i,t} - \theta_{i',t}}{x_{i,i'}}, \ \forall i' \in I'(i), i, t \tag{3.5}$$

$$-\overline{F}_{i,i'} \le f_{i,i',t} \le \overline{F}_{i,i'}, \ \forall i' \in I'(i), i, t \tag{3.6}$$

$$\phi_g p_{g,t} = \eta_{g,t}^C + \eta_{g,t}^M + \eta_{g,t}^{out}, \quad \forall g, t \tag{3.7}$$

$$\sum_{i\in I}\sum_{g\in G(i,j)} \eta_{g,t}^C \le \rho \overline{G}_{j,t}, \quad \forall j, t \tag{3.8}$$

$$\sum_{i\in I}\sum_{g\in G(i,j)} \phi_g p_{g,t} + \alpha_{j,t}^+ \le \rho \overline{G}_{j,t} + m_{j,t} + \sum_{\psi\in\Psi(j)}\left(q_{\psi,t}^{out} - q_{\psi,t}^{in}\right) + \alpha_{j,t}^-, \ \forall j, t \tag{3.9}$$

$$\underline{L}_\psi \le l_{\psi,t} \overline{L}_\psi, \ \forall \psi, t \tag{3.10}$$

$$-\overline{q}_\psi \le q_{\psi,t}^{out} - q_{\psi,t}^{in} \le \overline{q}_\psi, \ \forall \psi, t \tag{3.11}$$

$$l_{\psi,t} = l_{\psi,t-1} - q_{\psi,t}^{out} + q_{\psi,t}^{in},\ \forall\, \psi, t \tag{3.12}$$

The objective (3.1) is to minimize the total daily dispatch cost including the fuel cost from contracts and the spot market for gas-fired generators, production cost of the non-gas generators, the net cost of gas flows from storage and the penalties on non-served or excess electricity and gas demands. Constraints (3.2) enforce the power balance at each electricity node for each hour. Constraints (3.3) − (3.4) limit the maximum and minimum production by each generator based on its commitment status in each hour. Constraints (3.5) − (3.6) compute and limit the flows through transmission lines according to a linear DC approximation. Constraints (3.7) compute the gas consumption, which can be divided into gas from contracts, spot market and storage facilities. Constraints (3.8) dictate that the total gas quantity consumed by the gas-fired generators is less than or equal to the current available gas quantity from the contracts. In order to assess the effect of uncertainty in the gas availability on the dispatch cost, a parameter of contracted gas availability factor, ρ , and a parameter of nominal available gas quantity from gas contract for the power system, $\overline{G_{j,t}}$, are defined, respectively. Thus, $\rho\overline{G_{j,t}}$ represents various levels of contracted gas availability. Any $\rho < 1$ indicates that less gas than desired is available, and thus the committed gas-fired generators cannot obtain enough gas from contracts and must acquire gas from spot market. Meanwhile, some non-gas-fired generators might have to be dispatched at higher levels. Any $\rho > 1$ indicates a surplus, in which case the gas-fired generators have more flexibility of getting gas from spot market if the spot price is low or from the pipeline if the spot price is high. Constraints (3.9) express the gas balance for each hour at each gas node where a linear function is applied to describe the input-output curve [43]. Constraints (3.10) − (3.11) define the upper and lower limits on the storage levels and flow rates of each gas storage facility. Constraints (3.12) connect storage levels of consecutive hours.

3.3 Uncertainty Identification

The electric load and natural gas spot price are the two major uncertain quantities in the economic dispatch model formulated in Section 3.2. Given a specific realization of electric load and spot price, we can obtain the corresponding dispatch cost. Thus, it is crucial to estimate the joint distribution of daily electric load and natural gas spot price. Historical electric load and natural gas spot price data along with the corresponding weather information can be obtained from system operator and local natural gas hub records. Our goal in this section is to use the available data to generate discrete realizations that can be used individually as input to the ED model formulated in Section 3.2. The simulated dispatch cost distribution can be constructed from the outputs of each simulation run.

To improve the accuracy of estimating the correlation and generating scenarios, similar weather days in the same season are clustered using the K-means method. The details of K-means method and definition of distortion which helps to decide the number of clusters can be found in [44]. For each cluster, a joint distribution of electric load and gas price is generated, where the theoretical multivariate distribution is adopted to represent features of data adequately and reduce unrealistic assumptions. Among parametric approaches to continuous multivariate observations, normality takes an overwhelming role due to its mathematical tractability and its simplicity when dealing with fundamental statistical analysis [45]. The Box-Cox transformation is the most common approach to transforming observations in order to achieve multivariate normality [46] and results in normality in many cases. A nonnegative observation y can be transformed to $y^{(\tau)}$ through Eq. (3.13) where τ is a scalar or a vector with the same dimension as the observation. Based on the assumptions of $y^{(\tau)}$ satisfying multivariate normal distribution, the maximum-likelihood estimate of τ can be obtained according to the detailed steps described in [46].

$$y^{(\tau)} = \begin{cases} \dfrac{y^{\tau} - 1}{\tau} & (\tau \neq 0) \\ \log(y) & (\tau = 0) \end{cases} \tag{3.13}$$

The multivariate normality test is required for the transformed data. There are many analytical methods to test multivariate normality including Mardia's, Henze-Zirkler's and Royston's normality tests as well as graphical approaches of chi-square quantile-quantile (Q-Q) plots [47].

The best number of clusters is chosen considering distortion [44] and the goodness of transformed multivariate normality fit within each cluster. Some discrete scenarios can be generated from the estimated joint distributions within each cluster, where each equally likely scenario specifies the electric load and gas spot price. Much research has been done on scenario generation and reduction as well as continuous distribution discretization. Because this is not the focus of this research, we randomly sample observations from the fitted multivariate normal distributions for each segment. A histogram of the randomly sampled observations is constructed using R software. The center of each bin of the histogram is adopted as one scenario and the relative frequency for that bin is taken as the scenario probability. More accurate and tractable scenario generation and reduction methods can be found in [44], [48].

3.4 Quantifying the Effect of Uncertain Natural Gas Spot Price on ED Cost

Given the model presented in Section 3.2 and the discrete scenarios generated by the methods in Section 3.3, this section presents methodologies to quantify the effect of natural gas spot price uncertainty on the economic dispatch cost uncertainty. We review and apply the Wasserstein distance measure and the CVaR measure in Sections 3.4.1 and 3.4.2, respectively. The detailed quantification steps are illustrated in Section 3.4.3 .

3.4.1 Review of Wasserstein Distance (WD)

The Wasserstein distance was proposed to measure the distance between probability distributions [49]. If $\boldsymbol{H}$ and $\boldsymbol{R}$ are discrete probability distributions having finitely many scenarios ξ_s (with probabilities h_s), $s = 1, \ldots, S$, and $\tilde{\xi}_{s'}$ (with probabilities $r_{s'}$), $s' = 1, \ldots, S'$, respectively, we obtain the Wasserstein distance as Eq. (3.14) where $d(\xi_s, \tilde{\xi}_{s'})$ is the distance between scenario ξ_s in $\boldsymbol{H}$ and $\tilde{\xi}_{s'}$ in $\boldsymbol{R}$ according to some norm.

$$\mathrm{WD} = \inf\left\{\sum_s^S \sum_s^S d(\xi_s, \tilde{\xi}_{s'}) y_{s,s'}:\ y_{s,s'} \geq 0, \sum_{s'=1}^{S'} y_{s,s'} = h_s,\ \sum_s^S y_{s,s'} = r_{s'}\right\} \tag{3.14}$$

3.4.2 Review of Conditional Value at Risk (CVaR)

The CVaR was described in [50] as a coherent risk measure. For a cost probability density function $f_X(x)$ and a confidence level $\gamma \in (0,1)$, which usually is set to be 0.95 or 0.99, define value at risk (VaR) and CVaR as follows:

Definition 1 (VaR) The value-at-risk measures is defined as:

$$\mathrm{VaR}_\gamma(\mathrm{X}) = inf\{x\colon \Pr[X \le x] \ge \gamma\}. \tag{3.15}$$

Definition 2 (CVaR) The conditional value-at-risk measure is defined as:

$$\mathrm{CVaR}_\gamma(X) = \frac{1}{1-\gamma}\int_{\mathrm{VaR}_\gamma}^{\infty} f_X(x)dx. \tag{3.16}$$

Definition 3 (CVaR for discrete probability distributions) The conditional value-at-risk measure for discrete probability distribution $f_X(x) = \Pr(X = x) = \Pr(\{\omega \in \Omega : X(\omega) = x\})$ is defined as:

$$\mathrm{CVaR}_\gamma(X) = \frac{1}{1-\gamma}\mathbb{E}\left[\mathrm{VaR}_\gamma + \left[X - \mathrm{VaR}_\gamma\right]^+\right] = \frac{1}{1-\gamma}\sum_{\omega\in\Omega}\left\{\Pr(\omega)\left(\mathrm{VaR}_\gamma + \left[X(\omega) - \mathrm{VaR}_\gamma\right]^+\right)\right\}. \tag{3.17}$$

The CVaR of a discrete probability distribution can be obtained by Algorithm 1.

Algorithm 1: CVaR Algorithm for Discrete Probability Distribution	
	Input: Discrete probability distribution $f_X(x) = \Pr(X = x) = \Pr(\{\omega \in \Omega : X(\omega) = x\})$ and confidence level γ
	Output: The CVaR of distribution $f_X(x)$: CVaR_γ
1	**Sort:** Sort X, such that $x^1 \le x^2 \le x^3 \le \cdots \le x^n$, where $x^i = X(\omega^i), \forall i = 1, \ldots, n$ indicates the i^{th} smallest random variable realization.
2	$i = 1$
3	**While** $\sum_{\omega=\omega^1}^{\omega^i} \Pr(\omega) \le \gamma$ **do** $i = i + 1$
4	$i^* = i, \mathrm{VaR}_\gamma = X(\omega^{i^*})$
5	$\mathrm{CVaR}_\gamma = \dfrac{1}{\sum_{i=i^*}^{n} \Pr(\omega^i)} \sum_{i=i^*}^{n} \left[X(\omega^i) \Pr(\omega^i)\right]$
6	**Return** CVaR_γ

3.4.3 Quantifying Steps

We use the WD and CVaR metrics to compare the cost distributions resulting from the economic dispatch with price estimate (ED-PE) simulation, where the load uncertainty is considered but the price uncertainty is not, and the economic dispatch with price distribution (ED-PD) simulation, where both uncertainties are included, as illustrated in Figure 3-1. The method can be applied to each segment of each season and is summarized as follows:

Step 1. Obtain input parameter values, including unit commitment/start-up/shut-down indicators $(u_{k,t}, v_{k,t}^{u}, v_{k,t}^{d})$ and available gas from contracts $(\overline{G}_{j,t})$ by solving the day-ahead unit commitment (UC) problem. The detailed formulation of the UC model can be found in [51]. The UC model includes a reserve requirement and natural gas network constraints of pipelines as well as storage facilities using the 24-hour electric load point estimation and contracted gas only. Set the optimal UC decisions and hourly schedule of the gas network as the input parameters of the ED model.

Step 2. **(ED-PE simulation)** Solve the ED model for each scenario from the electric load probability distribution $P_{i,t}(D)$ and the **point estimate of the gas spot price**. Construct the corresponding discrete dispatch cost probability distribution $\boldsymbol{H}$ having finitely many scenarios ξ_s (with probabilities h_s), $s = 1, \dots, S$, where ξ_s denotes optimal cost of scenario s for the ED-PE simulation.

Step 3. **(ED-PD simulation)** Solve the ED model for each scenario of the joint probability distribution of the electric load and the gas spot price. Construct the corresponding discrete dispatch cost probability distribution $\boldsymbol{R}$ having finitely many scenarios $\tilde{\xi}_{s'}$ (with probabilities $r_{s'}$), $s = 1, \dots, S'$, where $\tilde{\xi}_{s'}$ denotes optimal cost of scenario s' for the ED-PD simulation.

Step 4. Compare the two dispatch cost probability distributions, $\boldsymbol{H}$ and $\boldsymbol{R}$. Calculate the Wasserstein distance (WD) as the optimal cost of model (3.14) [52], where $d(\xi_s, \tilde{\xi}_{s'})$ and $y_{s,s'}$ are the distance and flow between the costs of scenario s and s', respectively. Calculate CVaR_γ of $\boldsymbol{H}$ and $\boldsymbol{R}$ using Algorithm 1. Then the CVaR difference between the ED-PD simulation and the ED-PE simulation can be assessed as $\Delta\mathrm{CVaR}\gamma = \mathrm{CVaR}_\gamma(\boldsymbol{R}) - \mathrm{CVaR}_\gamma(\boldsymbol{H})$.

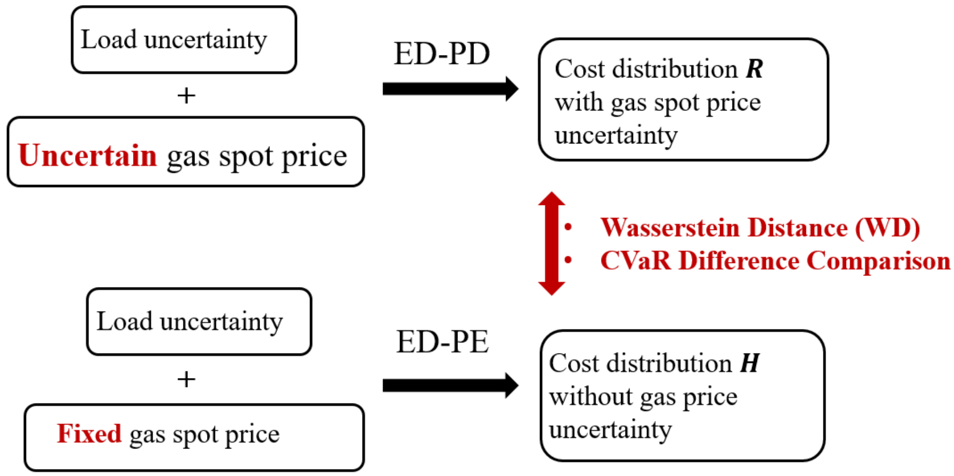


Figure 3-1: Illustration of uncertainty assessment

3.5 Applying WD and CVaR Metrics to Assess Risk-Mitigation Strategy Selection

The previous sections discuss how to assess the WD and CVaR metrics to quantify the effect of gas spot price uncertainty and the risk of dispatch cost for the daily short-term operation. To reduce this risk, the ISO can coordinate or suggest some risk-mitigation strategies, such as converting a natural gas fueled unit into a dual fuel unit and building new gas storage facilities, to generator owners. Both of these strategies not only potentially are able to reduce risk but also will result in conversion and installment costs. In this section we present revisions to the daily short-term dispatch model once adopting risk-mitigation strategies. Using these revised models, modified values of the WD and CVaR metrics can be assessed through methods in Section 3.4.3.

3.5.1 Strategy 1: Dual Fuel Conversion

Adding dual fuel, such as fuel oil, capability is one useful strategy to mitigate the effect of natural gas price volatility. Conversion of natural gas fueled generators to be able to operate on a dual fuel requires building dual fuel storage tanks, which results in a one-time conversion cost. For the operation of dual fuel generator, it takes some time, ranging from 4 to 72 hours, to switch between fuels. Here we assume that within one day, a converted generator can only use one kind of fuel. The effect of having dual fuel capability on the economic dispatch model is that Eq. (3.18) defines an additional variable of daily production cost of a converted generator as the minimum cost between using natural gas and using dual fuel.

$$\zeta_g = inf\left\{\sum_{t\in T}\left(\lambda_g^C\eta_{g,t}^C + \Lambda^M\eta_{g,t}^M + \lambda_\psi^\Psi\eta_{g,t}^{out}\right), \sum_{t\in T}\phi_g^{oil}p_{g,t}\right\}, \forall g \in G'(i,j), \psi \in \Psi(j) \qquad (3.18)$$

The gas balance constraint (3.9) becomes (3.19). The first expression in the left hand side of (3.9) is divided into two parts in (3.19) where the first part is the gas consumption by the non-converted gas generators and the second part indicates the gas consumption by the converted gas generators. Here for each converted generator, we use $b_g\left(\eta_{g,t}^C + \eta_{g,t}^M + \eta_{g,t}^{out}\right) = b_g\phi_g p_{g,t}$ to indicate the gas consumption, where b_g is a binary variable indicating whether natural gas results in a smaller cost, compared with the alternative fuel. While producing a fixed amount of power, $b_g = 1$ if the gas fuel cost is lower and $b_g = 0$ otherwise, as illustrated in Eq. (3.20) − (3.21).

$$\sum_{i\in I}\sum_{g\in G(i,j)\backslash G'(i,j)}\phi_g p_{g,t} + \sum_{i\in I}\sum_{g\in G'(i,j)} b_g\phi_g p_{g,t} + \alpha_{j,t}^{+} \leq \rho\overline{G}_{j,t} + m_{j,t} + \sum_{\psi\in\Psi(j)}\left(q_{\psi,t}^{out} - q_{\psi,t}^{in}\right) + \alpha_{j,t}^{-}, \forall j,t \tag{3.19}$$

where

$$b_g = 1, if \quad \sum_{t\in T}\left(\lambda_g^C\eta_{g,t}^C + \Lambda^M\eta_{g,t}^M + \lambda_\psi^\Psi\eta_{g,t}^{out}\right) \leq \sum_{t\in T}\phi_g^{oil}p_{g,t}, \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.20}$$

$$b_g = 0, if \quad \sum_{t\in T}\left(\lambda_g^C\eta_{g,t}^C + \Lambda^M\eta_{g,t}^M + \lambda_\psi^\Psi\eta_{g,t}^{out}\right) > \sum_{t\in T}\phi_g^{oil}p_{g,t}, \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.21}$$

Constraints (3.18) − (3.21) are nonlinear and hard to solve directly. Thus, we transform them into mixed integer linear constraints via the disjunctive method. Constraints (3.18) and (3.20) − (3.21) can be linearized as (3.22) − (3.26), where b_g can be assessed and M is a big number. Constraints (3.27) are added because now we must determine the exact amount of gas the converted generator consumes from the storage facility, which influences the objective function. Constraints (3.19) are linearized as Eq. (3.28)− (3.32) where another big number M is used and a new variable, $z_{g,t} \equiv b_g\left(\eta_{g,t}^C + \eta_{g,t}^M + \eta_{g,t}^{out}\right) = b_g\phi_g p_{g,t}$, is introduced.

$$\zeta_g \leq \sum_{t\in T}\left(\lambda_g^C\eta_{g,t}^C + \Lambda^M\eta_{g,t}^M + \lambda_\psi^\Psi\eta_{g,t}^{out}\right), \qquad \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.22}$$

$$\zeta_g \leq \sum_{t\in T}\phi_g^{oil}p_{g,t}, \ \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.23}$$

$$\zeta_g \geq \sum_{t\in T}\left(\lambda_g^C\eta_{g,t}^C + \Lambda^M\eta_{g,t}^M + \lambda_\psi^\Psi\eta_{g,t}^{out}\right) - M(1-b_g), \ \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.24}$$

$$\zeta_g \geq \sum_{t\in T}\phi_g^{oil}p_{g,t} - Mb_g, \ \forall g\in G'(i,j), \psi\in\Psi(j) \tag{3.25}$$

$$b_g \ is \ binary, \ \forall g\in G'(i,j) \tag{3.26}$$

$$\sum_{i\in I}\sum_{g\in G(i,j)}\eta_{gt}^{out} = \sum_{\psi\in\Psi(j)} q_{\psi,t}^{out}, \ \forall t \tag{3.27}$$

$$\sum_{i\in I}\sum_{g\in G(i,j)\setminus G'(i,j)}\phi_g p_{g,t}+\sum_{i\in I}\sum_{g\in G'(i,j)}z_{g,t}+\alpha_{j,t}^{+}\le\rho\overline{G}_{j,t}+m_{j,t}+\sum_{\psi\in\Psi(j)}\left(q_{\psi,t}^{out}-q_{\psi,t}^{in}\right)+\alpha_{j,t}^{-},\ \forall j,t \tag{3.28}$$

$$z_{g,t}\le Mb_g,\ \forall g\in G'(i,j) \tag{3.29}$$

$$z_{g,t}\le\phi_g p_{g,t},\ \forall g\in G'(i,j),t \tag{3.30}$$

$$z_{g,t}\ge\phi_g p_{g,t}-M\left(1-b_g\right),\ \forall g\in G'(i,j),t \tag{3.31}$$

$$z_{g,t}\ge 0,\ \forall g\in G'(i,j),t \tag{3.32}$$

We define another variable, $\tilde{z}_g\equiv b_g\sum_{t\in T}\lambda_{\psi}^{\Psi}\eta_{g,t}^{out},\forall g\in G'(i,j),\psi\in\Psi(j)$, to indicate the gas storage outflow cost of the converted dual fuel generator, which is linearized as Eqs. (3.33) − (3.36). In this way, all the nonlinear constraints are transformed into mixed integer linear constraints.

$$\tilde{z}_g\le Mb_g,\forall g\in G'(i,j) \tag{3.33}$$

$$\tilde{z}_g\le\sum_{t\in T}\lambda_{\psi}^{\Psi}\eta_{g,t}^{out},\forall g\in G'(i,j),\psi\in\Psi(j) \tag{3.34}$$

$$\tilde{z}_g\ge\sum_{t\in T}\lambda_{\psi}^{\Psi}\eta_{g,t}^{out}-M(1-b_g),\forall g\in G'(i,j),\psi\in\Psi(j) \tag{3.35}$$

$$\tilde{z}_g\ge 0,\forall g\in G'(i,j) \tag{3.36}$$

Finally, the revised ED model with dual fuel conversion strategy is formulated as follows. The objective function is revised based on (3.1). The difference is that the fuel cost is computed separately for the converted generators and non-converted generators. Since all the storage outflow cost is considered in the fourth expression, we must take care with the definition of the first expression. According to the previous discussion, given $b_g=0$, the dual fuel is used, and the first expression indicates the fuel cost of using dual fuel. If $b_g=1$, then natural gas is used, and the first expression indicates the total production cost minus the storage outflow cost for the converted generators since all the storage outflow costs are calculated through the fourth expression. The revised model is:

$$min \sum_{g\in G'}\left(\zeta_g - \tilde{z}_g\right) + \sum_{t\in T}\left\{\sum_{g\in G\setminus G'}\left(\lambda_g^C \eta_{g,t}^C + \Lambda^M \eta_{g,t}^M\right) + \sum_{n\in N} C_n^{prod} p_{n,t} + \sum_{\psi\in\Psi}\left(\lambda_\psi^\Psi q_{\psi,t}^{out}\right) + \sum_{i\in I}\left(\Gamma_\beta^+ \beta_{i,t}^+ + \Gamma_\beta^- \beta_{i,t}^-\right) + \sum_{j\in J}\left(\Gamma_\alpha^+ \alpha_{j,t}^+ + \Gamma_\alpha^- \alpha_{j,t}^-\right)\right\} \tag{3.37}$$

s.t. (3.2) − (3.8), (3.10) − (3.12),(3.22) − (3.36).

3.5.2 Strategy 2: Adding Gas Storage Facilities

Adding gas storage facilities is another strategy to mitigate risk. Here we define $\Psi'(j)$ as the set of added gas storage facilities at gas node j, and the revised ED model is as follows. The only difference between this model and the ED model from Section 3.2 is that all the expressions involving $\Psi(j)$ and Ψ are replaced with $\Psi(j) \cup \Psi'(j)$ and $\Psi \cup \Psi'$, respectively, to reflect the presence of the additional gas storage facilities.

$$min \sum_{t\in T}\left\{\sum_{g\in G} \lambda_g^C \eta_{g,t}^C + \sum_{j\in J} \Lambda^M m_{j,t} + \sum_{n\in N} C_n^{prod} p_{n,t} + \sum_{\psi\in \Psi\cup\Psi'} \lambda_{\psi,t}^{\psi} q_{\psi,t}^{out} + \sum_{i\in I}\left(\Gamma_\beta^+ \beta_{i,t}^+ + \Gamma_\beta^- \beta_{i,t}^-\right) + \sum_{j\in J}\left(\Gamma_\alpha^+ \alpha_{j,t}^+ + \Gamma_\alpha^- \alpha_{j,t}^-\right)\right\} \tag{3.38}$$

s.t.

(3.2) − (3.8)

$$\sum_{i\in I} \sum_{g\in G(i,j)} \phi_g p_{g,t} + \alpha_{j,t}^+ \le \rho \overline{G}_{j,t} + m_{j,t} + \sum_{\psi\in\Psi(j)\cup\Psi'(j)}\left(q_{\psi,t}^{out} - q_{\psi,t}^{in}\right) + \alpha_{j,t}^-, \ \forall j,t \tag{3.39}$$

$$\underline{L}_\psi \le l_{\psi,t} \overline{L}_\psi, \ \forall \psi \in \Psi \cup \Psi', t \tag{3.40}$$

$$-\overline{q}_\psi \le q_{\psi,t}^{out} - q_{\psi,t}^{in} \le \overline{q}_\psi, \ \forall \psi \in \Psi \cup \Psi', t \tag{3.41}$$

$$l_{\psi,t} = l_{\psi,t-1} - q_{\psi,t}^{out} + q_{\psi,t}^{in}, \ \forall \psi \in \Psi \cup \Psi', t \tag{3.42}$$

3.5.3 Risk-Mitigation Strategy Comparison

The daily cost distributions of each strategy can be obtained using the discrete scenarios generated in Section 3.3 and quantification method in Section 3.4 along with the revised ED models in Sections 3.5.1 and 3.5.2. A comparison between the quantification measures in the form of the WD and CVaR metrics and the corresponding conversion or installation costs informs the choice of the better strategy. This method can be extended to other risk-mitigation strategies including building new units and pipelines.

Now we have two strategies of dual fuel conversion and adding storage facilities. We assume the dual fuel conversion cost is C^D (\$/MW). Suppose one option is to convert a specific natural gas generator with a capacity of $\overline{P}_g$ into a dual fuel generator. If the installation cost of a new storage facility is C^S ($/kcf) at the same location, then the investment cost of dual fuel conversion could alternatively be used build a storage facility with a maximum capacity of $\bar{L}_{\psi'} = \overline{P}_g\, C^D/C^S$. With the same investment, the strategy that results in greater reduction of risk as quantified by the WD metric or CVaR difference between the ED-PD result and the ED-PE result is preferred. Since the risk-mitigation strategies have different results for each segment and each contracted gas availability factor, we assign each segment risk a weight a_c and each contracted gas availability factor case a weight b_ρ where c and ρ indicates segment number and contracted gas availability factor, respectively, and $\boldsymbol{C}$ indicates the set of segments. Use $\mathrm{R}^1, \mathrm{R}^2$ to indicate the risk measures for strategy 1 and 2, respectively. Strategy 1 is preferred if $\mathrm{R}^1 < \mathrm{R}^2$ and strategy 2 is preferred otherwise, where $\mathrm{R} \in \{\mathrm{WD}, \Delta\mathrm{CVaR}_\gamma\}$ as defined in Eqs. (3.43) − (3.44). Let $\mathrm{R}^1_{c,\rho}, \mathrm{R}^2_{c,\rho}$ indicate the risk measures for strategies 1 and 2 for segment c and contracted gas availability factor ρ, respectively. Then the composite risk measures are constructed as:

$$R^1 = \sum_\rho \sum_{c\in C} b_\rho a_c \mathrm{R}^1_{c,\rho}\ , \tag{3.43}$$

and

$$R^2 = \sum_\rho \sum_{c\in C} b_\rho a_c \mathrm{R}^2_{c,\rho}\ . \tag{3.44}$$

3.6 Case Study

We apply our models in a case study of a modified IEEE 24-bus system with a modified Belgian 20-node natural gas system [53]. The cost function is revised according to [54]. The non-served energy penalty cost is set to be $3500/MWh, as recommended by MISO [55]. The excess energy penalty cost is set to be $350/MWh, while the non-served gas and excess gas penalties are set to be $3500/kcf and $350/kcf, respectively. The gas price from contracts is set to be $2.0/kcf and we assume for simplicity that 1 kcf of natural gas can generate 1 MBtu of energy. The electric load is set to be the total electric load for the state of Connecticut. The electric load is allocated to buses according to the same proportions as in the IEEE 24-bus system load data. The non-electric natural gas demand is set to equal that of the Belgian 20-node natural gas system. The Algonquin Citygate natural gas price for the ISO-NE is taken as the gas price for the Belgian 20-node natural gas system. The optimal unit commitment decisions and natural gas network schedules of the day-ahead short-term scheduling model of a combined natural gas and power system with reserves of 3% are fixed to be the initial values of the unit commitment parameters $u_{k,t}, v^u_{k,t}, v^d_{k,t}$ and gas availability from gas contract $\overline{G}_{j,t}$. The linear programs are solved with GAMS/CPLEX 23.4.3 on a Linux workstation (24 CPU, 94GB RAM).

3.6.1 Uncertainty Identification

As explained in Section 3.3, we generate discrete scenarios for correlated electric load and natural gas price for each weather information segment. This section 3.6.1describes the sources of historical data for the uncertain parameters and shows the best clustering result. For each segment of each season, the joint distribution of electric load and natural gas spot price is generated, where multivariate normal distribution are seen to be valid after data transformation. Lastly, we present the generated discrete scenarios for correlated electric load and gas price.

Data Sources

Hourly electric load data can be accessed from ISO-NE for each year [56]. ISO-NE also provided us with the weather information data including temperature, dew point and wind speed from 2012-12-31 to 2016-11-07 for each hour of each day [57]. We use the Algonquin Citygate natural gas spot price as the referenced natural gas spot price index for the ISO-NE area, available from 2014-03-17 and 2017-01-03 [58]. Because the natural gas spot price is recorded daily, we sum the hourly electric load data to find corresponding daily electric loads. Similar process has been done for the daily average weather information. According to the regression result of [59] and because each season has its own typical electric load pattern, the electric load data are divided into three seasons, spring/fall (April 1 − May 14 and September 15 − November 30), summer (May 15 − September 14) and winter (December 1 − March 31). Altogether we had available data of daily weather information (temperature, dew point and wind speed), daily electric load and daily natural gas spot price for ISO-NE from 2014-03-17 to 2016-11-07. We display results only for winter and the state of Connecticut (CT) because in winter natural gas price intends to have high uncertainty, while Connecticut is the single largest demand zone in ISO-NE. This study can be replicated for each season and zone within the ISO-NE region.

Clustering According to Weather

We cluster the weather information using the K-means method. As illustrated in Figure 3-2, for each additional cluster beyond three, the distortion decreases by less than one. There are no clear ways of choosing the best number of clusters. For this case, three is chosen as the best because it results in good transformed multivariate normality goodness of fit as illustrated in

Table 3-1 whereas using four clusters does not. Figure 3-3 compares the original and the clustered weather data for winter, where the three segments labeled 0, 1 and 2 represent the coldest, merely cold and moderate winter days, respectively.

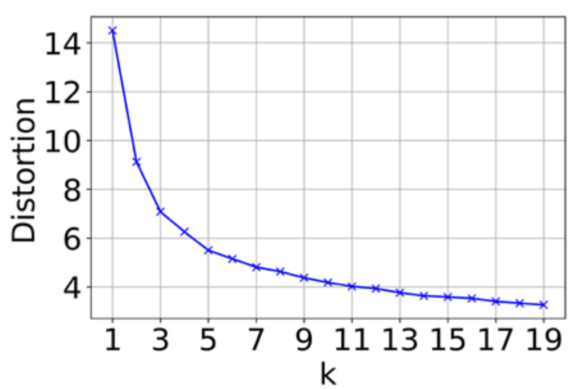


Figure 3-2: Clustering optimization distortion of the K-means method

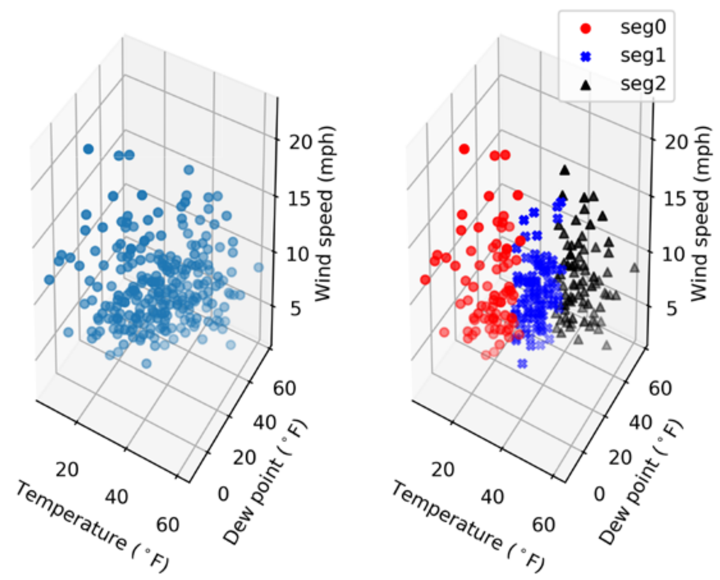


Figure 3-3: Winter weather data for CT (a) original; (b) clustered

Joint Distribution of Electric Load and Gas Price

Figure 3-4 displays scatterplots of the natural gas price and electric load for each segment of the winter season. The coldest days tend to combine high natural gas price and high electric load, while the moderate days in the winter have relatively low values for both quantities.

Table 3-1 illustrates the results of multivariate normality tests for the transformed data of each segment of winter. Segments 0 and 1 pass all the multivariate normality tests while Segment 2 passes more than half of the tests. Figure 3-5 to Figure 3-7 show the test results using Q-Q plots, from which we make two observations. The first is that the histograms of the marginal distributions are approximately bell-shaped and the corresponding univariate Q-Q plots fall close to straight lines, both indicating normality of the marginal distributions. The second observation, from panels (c), is that the multivariate Q-Q plots are nearly linear for most data points except several points at the top right. The Adjusted Mahalanobis distance metric indicates that none of these points are outliers. In addition, a similar process has been followed using the multivariate gamma distribution and the statistical results suggest that the multivariate normal distribution performs better. Thus, we selected the multivariate normal distribution to represent the joint uncertainty of daily electric load and natural gas price. For the future research, some other theoretical or empirical multivariate distributions can also be tested. After obtaining the maximum-likelihood estimate of τ, $y^{(\tau)}$ can be back-transformed to the original scale of observations. The corresponding results as well as the relevant statistical values are listed in Table 3-2. The coldest segment has the highest expected load and gas price, while the moderate days have the lowest expected load and gas price. Also, each cluster has different correlation between the transformed load and price.

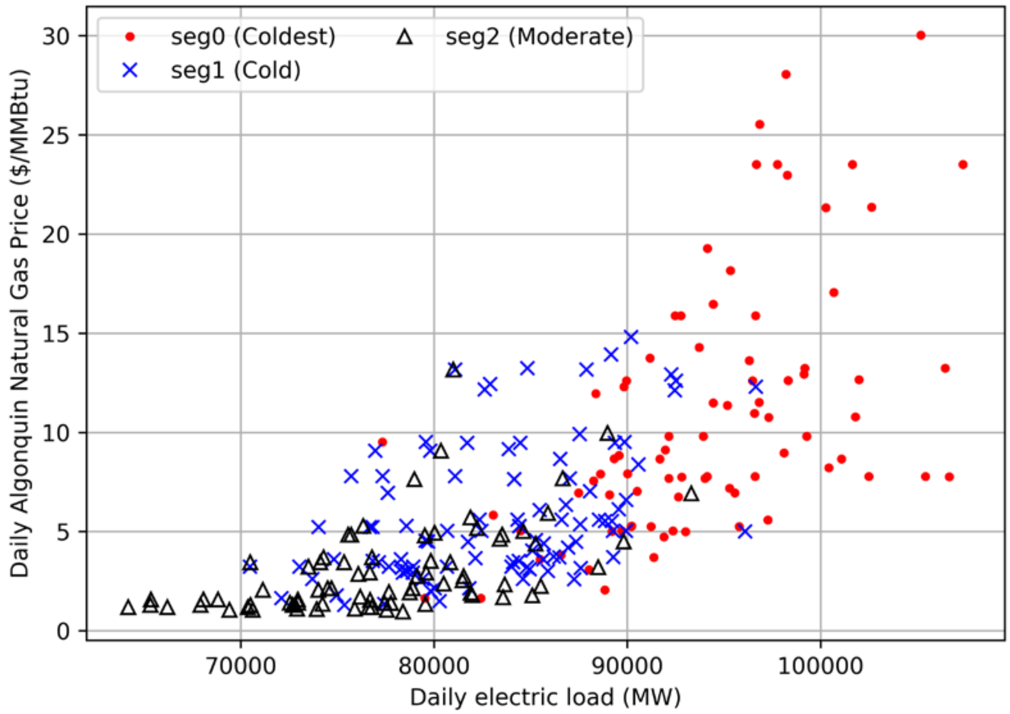


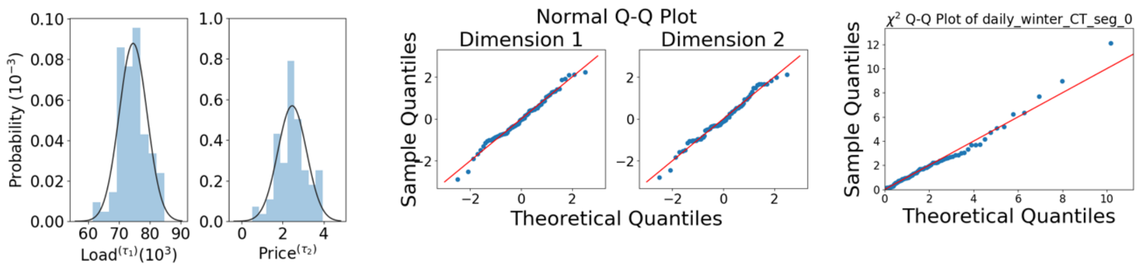
Figure 3-4: Winter daily Algonquin price vs. load in CT

Table 3-1: Multivariate normal distribution test results for each segment of the winter season in CT

		Seg0			Seg1			Seg2	
Test	Test Statistic	p-value	Result	Test Statistic	p-value	Result	Test Statistic	p-value	Result
Univariate Normality									
Shapiro-Wilk									
Load$^{(\tau_1)}$	0.990	0.735	YES	0.989	0.635	YES	0.995	0.988	YES
Price$^{(\tau_2)}$	0.982	0.290	YES	0.976	0.079	YES	0.956	0.009	NO
Multivariate Normality									
Mardia									
Skewness	1.117	0.892	YES	1.474	0.831	YES	0.244	0.993	YES
Kurtosis	0.466	0.641	YES	-1.756	0.079	YES	-2.101	0.036	NO
Henze-zirkler	0.381	0.825	YES	0.932	0.059	YES	0.778	0.129	YES
Royston	1.228	0.544	YES	3.331	0.191	YES	6.811	0.033	NO
E-statistic	0.547	0.744	YES	0.875	0.111	YES	0.769	0.211	YES

Table 3-2: Box-Cox transformation maximum-likelihood estimate and MVN fit results for each segment of winter in CT

	τ		Means					
Cluster	Load	Price	Transformed Load (MWh)	Transformed Price ($/MMBtu)	Load (MWh)	Price ($/MMBtu)	Covariance Matrix	Corre-lation
0 (Coldest)	1.019	0.096	115408	2.501	94253	9.415	$\begin{bmatrix} 5.364 \times 10^{7} & 2.956 \times 10^{3} \\ 2.956 \times 10^{3} & 5.187 \times 10^{-1} \end{bmatrix}$	0.560
1 (Cold)	0.682	0.048	3486	1.700	89501	5.128	$\begin{bmatrix} 2.588 \times 10^{4} & 5.017 \times 10^{1} \\ 5.017 \times 10^{1} & 4.055 \times 10^{-1} \end{bmatrix}$	0.490
2 (Moderate)	0.797	-0.464	9845	0.667	77388	2.212	$\begin{bmatrix} 3.732 \times 10^{5} & 1.490 \times 10^{2} \\ 1.490 \times 10^{2} & 1.658 \times 10^{-1} \end{bmatrix}$	0.599

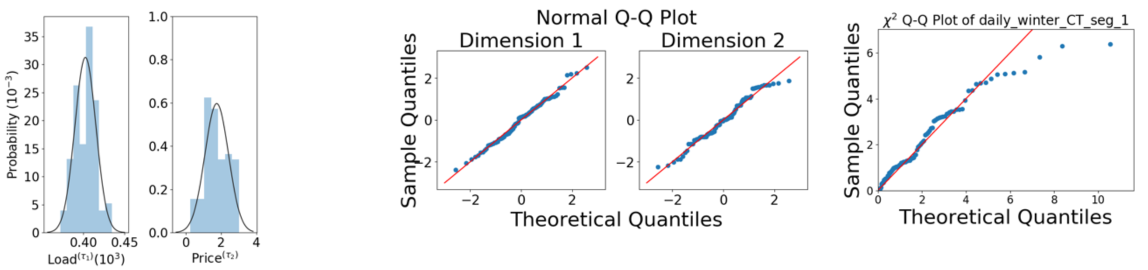


(a) Univariate Histogram

(b) Univariate Q-Q Plots

(c) Multivariate Q-Q Plots

Figure 3-5: Multivariate normal distribution validation for winter Segment 0

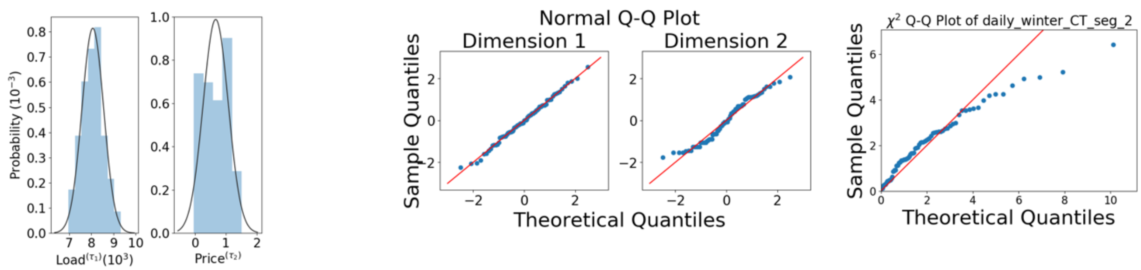


(a) Univariate Histogram

(b) Univariate Q-Q Plots

(c) Multivariate Q-Q Plots

Figure 3-6: Multivariate normal distribution validation for winter Segment 1



(a) Univariate Histogram (b) Univariate Q-Q Plots (c) Multivariate Q-Q Plots

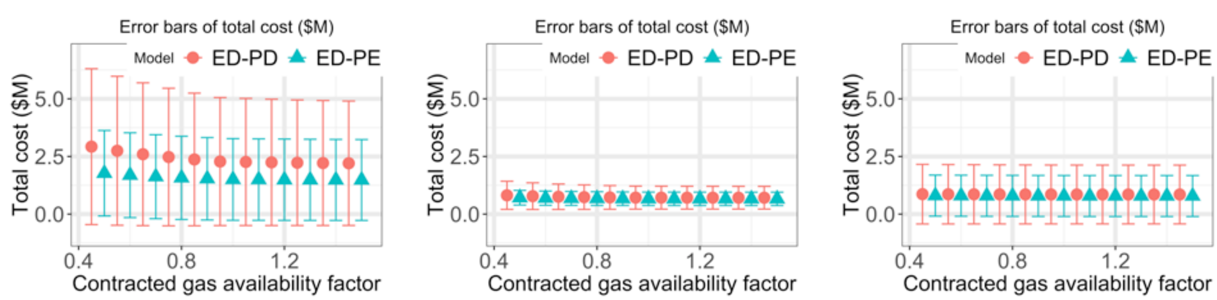
Figure 3-7: Multivariate normal distribution validation for winter Segment

Discrete Scenario Generation

We randomly sample 100,000 observations from the fitted multivariate normal distributions for each segment. These scenarios are reduced into 900 discrete scenarios as described in Section 3.3. More accurate and tractable scenario generation and reduction methods can be found in [48].

3.6.2 Effect of Natural Gas Price Uncertainty in Base Case

The case studies are done for each segment of winter because past electricity price spikes have been experienced in cold weather events. To demonstrate the influence of the contracted gas availability on the simulation results, we use $\rho\overline{G}_{j,t}$ to represent various levels of contracted gas availability by increasing ρ from 0.5 to 1.5 by increments of 0.1. Figure 3-8 summarizes the center and spread (mean +/-standard error) of costs from the ED-PE simulation and the ED-PD simulation for each winter segment. For each segment, both the mean and the standard deviation of the total cost from ED-PD simulation are greater than those from the ED-PE simulation, which is exactly the result of gas price uncertainty. Specifically, the cost of winter segment 0 (coldest days) has the maximum standard deviation and mean. As the contracted gas availability factor increases, the mean total cost from each simulation first decreases and then becomes stable, illustrating that low contracted gas availability has larger effect. This is mainly because given low contracted gas availability, the committed natural gas generator is not able to acquire enough gas from contracts and must acquire gas from the spot market with a possibly high price.



(a) Segment 0 (b) Segment 1 (c) Segment 2

Figure 3-8: Mean +/- standard deviation of the total cost for each segment of winter

However, the error bars cannot quantify the difference between the ED-PE simulation and the ED-PD simulation. In Figure 3-9, bars colored black illustrate the WD measure comparison for various contracted gas availability ρ of each segment. When ρ is less than 1.0, as ρ increases from 0.5 to 1.0, the WD of each segment decreases dramatically. When ρ is greater or equal to 1.0, the WD remains stable. When the actual available gas quantity is less than the nominal value, the dispatch cost experiences high uncertainty due to uncertain gas price. The CVaR difference between the ED-PD simulation and the ED-PE simulation, indicating the risks coming from gas price uncertainty, shows a pattern of change similar to WD (see Figure 3-10). Segment 0 (coldest days) has the largest WD and CVaR difference, compared with segments 1 and 2, indicating the gas price uncertainty has the most impact on dispatch cost distribution and risks in the coldest days.

3.6.3 Comparison of Risk-Mitigation Strategies

We compare two risk-mitigation strategies of dual fuel conversion and adding gas storage facilities. The idea here is to compare the WD and CVaR difference metrics while applying different risk-mitigation strategies given a fixed investment cost. The strategy that reduces the WD or CVaR difference more dominates the other one. Here we use one simple example to demonstrate the comparison process.

The general dual fuel conversion cost is approximately \$7,500-\$16,000/MW [60]. We assume the dual fuel conversion cost is \$10,000/MW and totals \$3.15 million in our test system. The production cost of using dual fuel is \$26.91/MWh. The Inner City Fund expects that it takes \$30 million to construct a storage facility with a capacity of 1.1 Bcf in New England [61]. In addition, we set the cost of filling the storage facility as \$2.5/kcf. Then the cost of constructing and filling a new storage facility is $\frac{\$30\times10^6}{1.1\times10^6 kcf}+\frac{\$2.5}{kcf}=\$29.77/kcf$. Thus the \$3.15 million could alternatively be used to construct and fill one storage facility with capacity $\frac{\$3.15\times10^6}{29.77\$/kcf}=105{,}811\ kcf$. The hourly maximum outflow is 2,500 kcf [61]. This new storage facility is added at gas node 2 (as strategy 1), where alternatively the connected gas fuel generator is converted to dual fuel in strategy 2. The storage outflow cost is set to be identical with storage facility 1 which is located at gas node 2 as well.

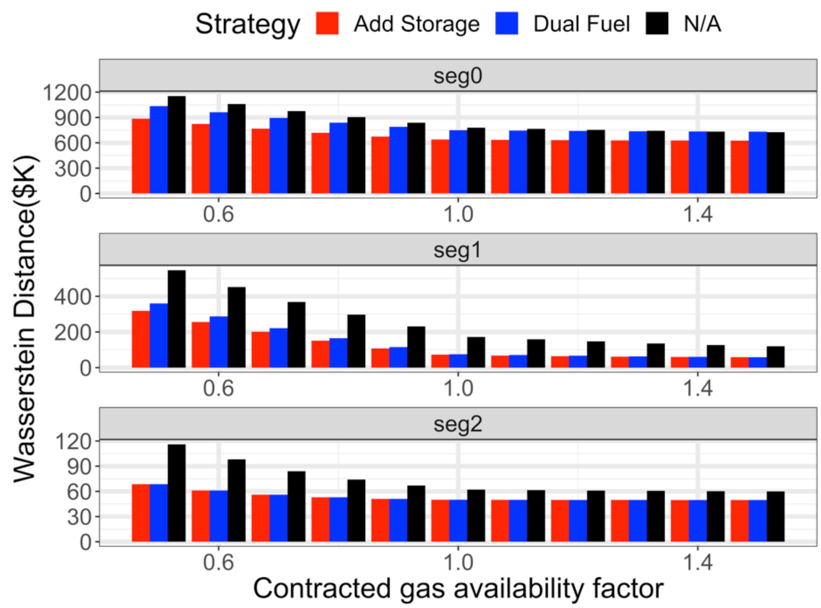


Figure 3-9: Wasserstein distance comparison between applying expansion strategies of adding storage, dual fuel conversion and N/A (no strategy applied) for each segment of winter season

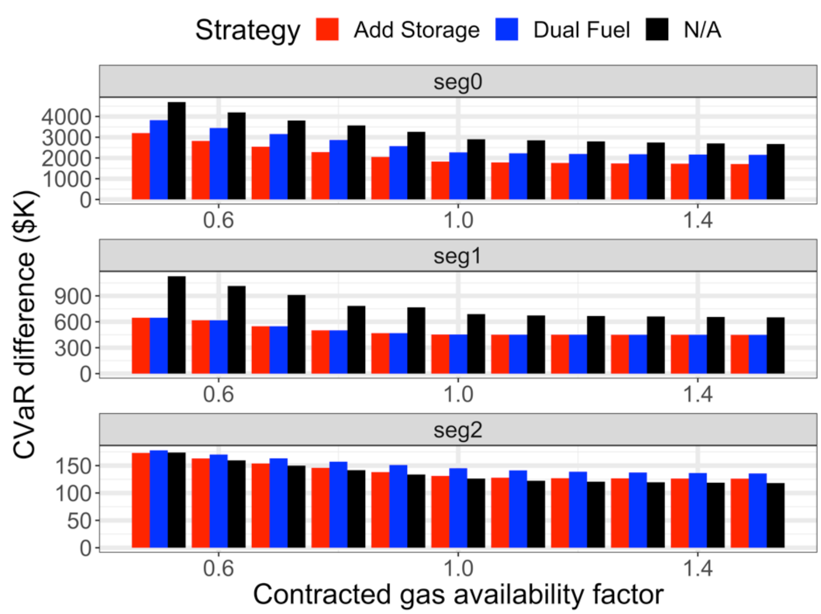


Figure 3-10: Conditional value at risk difference due to gas price uncertainty comparison between applying strategies of adding storage, dual fuel conversion and N/A (no strategy applied) for each segment of winter season

Figure 3-9 compares the WD measures applying various strategies for each segment, indicating the difference between the cost distributions of the ED-PD simulation and the ED-PE simulation. Compared with no strategies, either adding storage facilities or dual fuel capability always results in a smaller WD metric, indicating that the effect of gas price uncertainty on the dispatch cost decreases. Moreover, adding storage facility always results in a smaller WD metric than dual fuel conversion while the investment cost is fixed. This indicates that using WD in the risk measure defined in Section 3.5.3, we find $\mathrm{WD}^1 < \mathrm{WD}^2$, where strategy 1 is adding storage and strategy 2 is dual fuel conversion. From the WD metric aspect, which indicates the effect of natural gas price uncertainty on the dispatch cost uncertainty, adding a storage facility dominates the dual fuel conversion strategy.

Figure 3-10 compares the CVaR difference between the ED-PD and ED-PE simulation which indicates the CVaR risk coming from the gas price uncertainty. For segments 0 and 1, adding either a storage facility or dual fuel capability results in a smaller CVaR difference than no strategy, while for segment 2 both these two strategies result in a larger CVaR difference. This anomaly occurs mainly because we incorporate the risk-mitigation strategies in the unit commitment decision and the inputs of the dispatch problem differ between strategies. Thus, in the moderate days (segment 2), the risk-mitigation strategies do not guarantee reducing the risks coming from natural gas price uncertainty. The risk-mitigation strategies have the most effect for the coldest days, as we can see in Figure 3-10 that the CVaR difference for segment 0 is the largest compared with segments 1 and 2. The effect of the risk-mitigation strategies on the CVaR difference decreases as the contracted gas availability factor increases. In other words, as expected, given less available natural gas from pipelines, the effects of risk-mitigation strategies are more obvious. Specifically, taking the risk measure defined in Section 3.5.3, the ISO can choose the corresponding values for parameters b_ρ and a_c according to its preference. Here we arbitrarily choose $b_\rho = 1/11$ for each ρ and $a_c = 1/3$ for each c; i.e., we equally weight each value of the gas availability factor and each segment of days, which leads to the conclusion that $\Delta\mathrm{CVaR}_\gamma^0 = \$1.4\mathrm{M}$, $\Delta\mathrm{CVaR}_\gamma^1 = \$0.9\mathrm{M}$ and $\Delta\mathrm{CVaR}_\gamma^2 = \$1.1\mathrm{M}$. Here, the superscripts 0, 1, 2 represent respectively that no strategy, strategy 1, or strategy 2 is applied. In conclusion, given a fixed investment cost, the storage facility strategy performs best at reducing the risk coming from natural gas price uncertainty. Other combinations of values for b_ρ and a_c can be substituted according to the estimated likelihood and severity of gas constraints, and the decision-maker's assessment of the relative importance of different segments, respectively.

3.7 Conclusions

In this section, we proposed a daily economic dispatch model with natural gas from spot market and contracts while considering the natural gas availability constraints and gas fuel cost. Data are clustered based on weather information and, within each cluster, a multivariate normal joint distribution of daily electric load and gas spot market price is estimated by transforming the data, using maximum likelihood estimation to identify a parameter for the transformation. To quantify the effect of uncertain gas spot price on dispatch cost, two cost probability distributions are obtained by simulation. The first one fixes the gas spot price at its point estimate, while the second one incorporates the estimated gas spot price probability distributions. The results for different days clustered according to weather information in winter show that the effect of gas spot price uncertainty is weakened as the contracted gas availability increases. Based on the investment cost and risk reduction comparison, this quantification method can be applied to help choose the most effective risk-mitigation strategy for a given investment cost. Our case study suggests that adding a gas storage facility is preferred over dual fuel conversion.

4. Analysis and Simulation of a Proposed Natural Gas Transportation Contract

Natural gas customers, such as commercial and industrial customers and electricity generators, may obtain their gas from a local distribution company (LDC) or directly from an interstate pipeline. LDCs supply residential customers' loads to heat buildings and water, to cook and to dry clothes. In 2016, the residential sector accounted for 16 % of the total U.S. natural gas consumption [26]. Aggregations of residential customers result in relatively predictable demands so as to allow LDCs to purchase firm gas supplies and associated firm transportation. Industrial customers have means to schedule production and predict natural gas demand as well. Most gas-fired generators, on the other hand, have considerable uncertainty of their future gas demands in today's competitive electricity markets, whose outcomes determine whether or not they get dispatched. Consequently, many gas-fired generators to increase their competitiveness choose to purchase as available gas supplies and transportation service and operate as interruptible gas customers. As such, they may have inadequate gas supplies whenever gas becomes scarce and prices increase or when transportation is limited. Natural gas transportation constraints arise from pipeline capacity limits and consequently result in cases, in which natural gas customers experience service interruptions. In order to manage the service priority of the customers, interstate pipelines provide two distinct priority services at different prices. Natural gas transportation service is classified as either "firm" or "interruptible". Firm transportation service is acquired ahead of the service period for the specified amount of natural gas to be delivered from a given source point to the delivery location. Such a service is provided on a "take–or–pay" basis, i.e., the customer must pay for the contracted transportation, whether or not it is fully or partially used. On the other hand, interruptible transportation service is paid on the actual delivered amount of natural gas, which may be, in certain cases, below the demanded amount. The lower service priority compared to firm transportation contracts is provided to ensure that any violation of the pipeline capacity limits is avoided. As such, pipeline operations in cases of congestion, i.e., the pipelines operate at their capacity limits, lead to the interruption of gas delivery to the interruptible transportation customers to help maintain safe and reliable pipeline operations.

The impacts of interruptible generator gas service are particularly acute in regions without natural gas production, such as New England, where much of the natural gas is supplied from gas-producing areas located west of its geographic footprint. Gas is, typically, delivered through the Algonquin interstate pipeline. This Algonquin pipeline topology resembles a tree, as shown in Figure 4-1. We note that the delivery of natural gas to the "leaves" located in Massachusetts is restricted in the eastern part of the pipeline by the various capacity constraints on the flows emanating from the West in addition. The ISO–New England (ISO–NE) refers to the current natural gas transportation infrastructure as inadequate and considers fuel–security uncertainty as a major concern for the geographic footprint of its grid. This inadequacy, combined with the low natural gas prices from shale production and the marked dependence on natural gas for electricity generation, creates major fuel-security risks that the ISO–NE must address [62]. The experience in recent winters shows that a major part of pipeline capacity has been dedicated to supply the firm needs of the regional gas utilities, leaving gas-fired generators without adequate gas supplies. Under extreme weather events, the situation is exacerbated, as such events cause increased natural gas demand for heating and may result in outages due to frozen coal piles and frozen equipment, as was the case in the Polar Vortex of 2013–2014 [63].

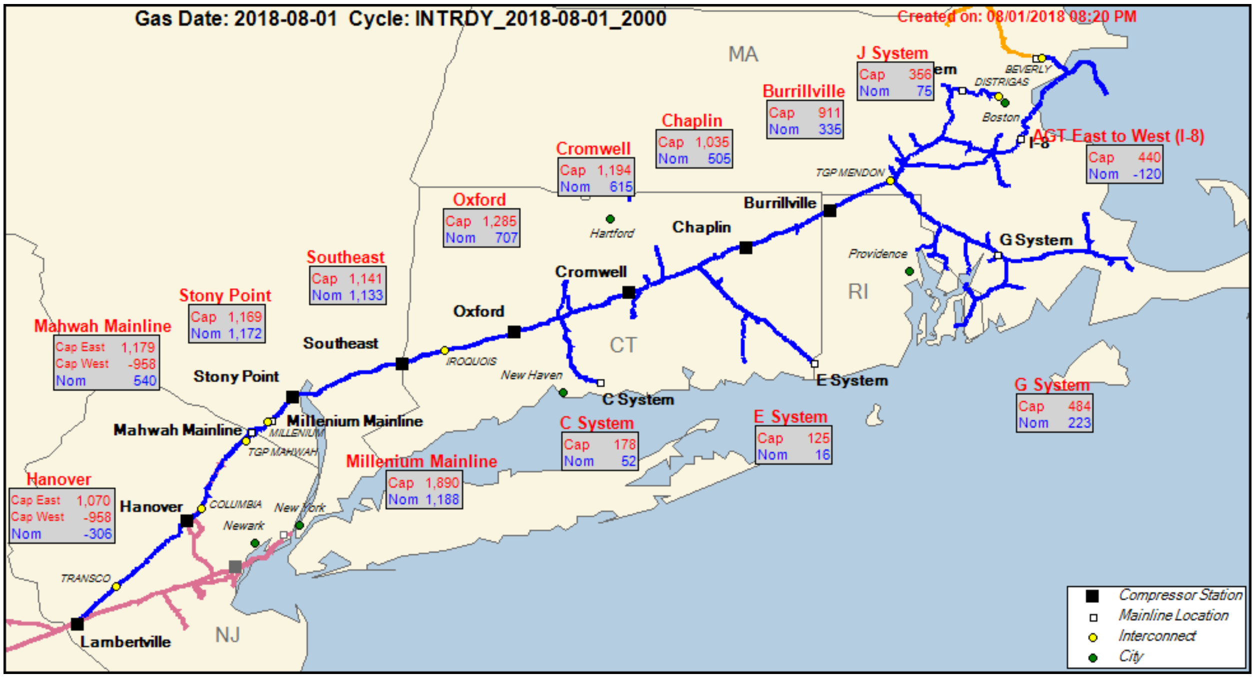


Figure 4-1: Algonquin Interstate Pipeline trajectory with the available transportation capacities for an intraday cycle indicated for August 8, 2018; all units are MMBtu/day [64].

Events such as the Polar Vortex provide the motivation for the proposed new transportation contract in order to give generator natural gas customers more effective mechanisms to address the gas supply cost and delivery uncertainty. In the next section, we describe the salient characteristics of the proposed contract, whose deployment leads to the more cost–effective acquisition of firm gas transportation by gas–fired generators. We provide representative results of simulation studies in the section that follows. We end this chapter with concluding remarks on the deployment of the proposed contract by gas generation customers.

4.1 The Proposed Natural Gas Transportation Contract

The basic concept of the proposed contract is for the gas–fired generator to sign a firm transportation contract and to resell any unused transportation to another gas customer whose gas demand may be more flexible. Such a scheme takes advantage of the cost components of natural gas transportation contracts. Such contracts are under the jurisdiction of FERC, which sets their rates. The two cost components are fixed and variable costs, whose values determine the gas transportation contract rates [65]. Fixed costs are used to specify the so–called reservation rate and variable costs are used to derive usage rates. The rates for an interruptible gas transportation contract are given by the sum of the reservation and the usage rates. For firm transportation contracts, the customer pays the reservation rate on the contracted amount, regardless of the actual usage. Consequently, the per–unit costs of firm gas transportation are higher when the actual demand falls below the contracted amount. The ratio between the actual transportation demand and the contracted transportation amount is called the load factor and is, typically, expressed in per cent.

As gas–fired generators have no certainty of their natural gas demand, the purchase of firm gas transportation by gas generation units is not common because of the required payment for transportation that may not be used. We propose to mitigate this risk by the construction of a contract, under which the gas–fired generator may resell the unused transportation to another gas customer that may have a more flexible gas demand. For example, the other gas customer may be an industrial gas user with access to alternative fuels or ability to shift demand in time without major repercussions. Figure 4-2 illustrates the pipeline deployment for the proposed contract.

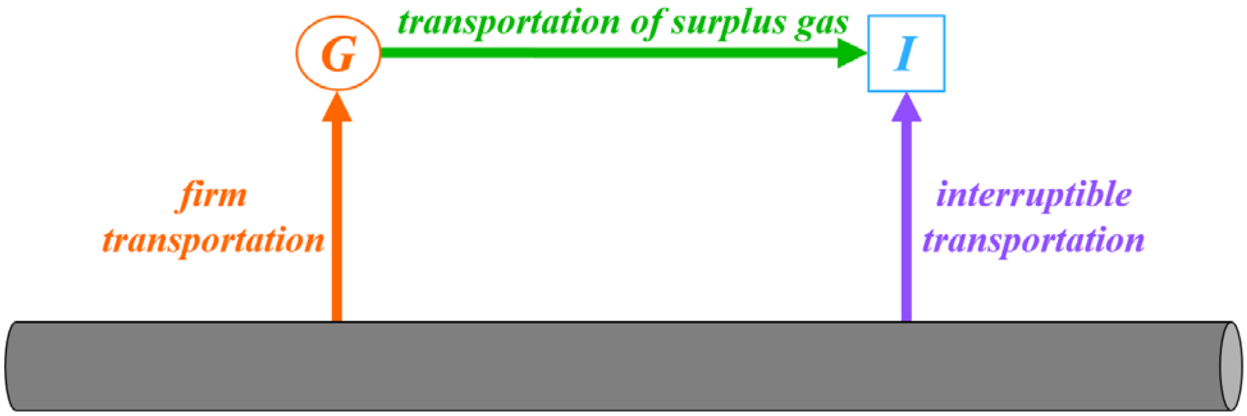


Figure 4-2: The pipeline deployment by the gas-fired generator ***G*** and the industrial customer ***I*** for firm and interruptible transportation without the contract, respectively, is modified to benefit both parties under the contract.

Such a contract can benefit both the gas generator and the industrial customer in the following ways. The gas–fired generator can benefit from the contract whenever its revenues under firm gas transportation exceed the additional costs of such service. As an example, the gas–fired generator may be dispatched under conditions of gas scarce transportation. Also, in certain situations, the generator may receive incentives to acquire firm transportation. The industrial customer can benefit from the contract if the surplus transportation purchased from the gas-fired generator is below the costs to handle intermittent supply situations that are due to non–firm transportation service. Typically, the resold transportation price is below the firm price paid by the gas generator and so is less than the interruptible transportation price that the industrial customer would otherwise face.

Under the proposed arrangement, as the gas–fired generator becomes able to resell the unneeded gas transportation, its load factor increases and so can share the benefits with the industrial customer by reselling for a lower price than the interruptible rate. From the point of view of the industrial customer, the resold transportation is indistinguishable from the interruptible transportation that would be the alternative. Furthermore, when the gas–fired generator has no surplus to sell, the industrial customer may still attempt to purchase transportation via the interruptible contract alternative.

We provide next a more concrete mathematical explanation of the situation discussed under the proposed contract. We consider first the case that the gas–fired generator acquires interruptible transportation, the total purchase costs of gas commodity and transportation are given by

$$C_i = \left(R_r + R_u + \rho_g\right) D_a \;, \tag{4.1}$$

where, C_i is the interruptible gas costs in \$, R_r is reservation rate in \$/MMBtu, R_u is the usage rate in \$/MMBtu, ρ_g is gas price in \$/MMBtu and D_a is amount of gas demand in MMBtu. The effective gas price under interruptible transportation is given by

$$\rho_i = \frac{C_i}{D_a} = \left(R_r + R_u + \rho_g\right) . \tag{4.2}$$

The profit under interruptible transportation is given by

$$\pi_i = \left(\sum_{d \epsilon \mathcal{D}} \sum_{h \epsilon \mathcal{H}_{i,d}} \left(\hat{\rho}_{e,h,d} \cdot P\right)\right) - C_i \;, \tag{4.3}$$

where, $\hat{\rho}_{e,h,d}$ is the electricity hourly Locational Marginal Price (LMP) at hour h of day d in \$/MWh, P is the unit's rated capacity in MW, $\mathcal{D}$ is the set of analyzed days and $\mathcal{H}_{i,d}$ is the set of hours of day d in which interruptible transportation is available and the unit's offer price is below the hourly LMP. In this discussion, the LMP is determined by the market clearing for the 24 hourly day–ahead markets. When the daily available gas transportation is not enough to supply the generator during all the hours that it would be dispatched based on its offer, the set $\mathcal{H}_{i,d}$ is restricted to the most profitable hours of that day, i.e., the hours with the highest LMP values.

Next, we consider the case that the gas-fired generator acquires firm transportation. The gas purchase costs in \$ are given by

$$C_f = R_r D_c + (R_u + \rho_g) D_a \,. \tag{4.4}$$

Here, C_f states the firm gas costs in \$ and D_c is the contracted demand. The effective gas price under firm transportation, then, becomes

$$\rho_f = \frac{C_i}{D_a} = R_r \frac{D_c}{D_a} + \left(R_u + \rho_g\right) . \tag{4.5}$$

The effective gas price under firm transportation is a function of the ratio between the contracted and the actual demands so that the effective price matches the interruptible price only if the actual demand equals the contracted demand. Now, if we consider that the gas–fired generator may resell the unused gas – along with its transportation – to the industrial customer for a combined price ρ_s in \$/MMBtu, we compute

$$C_w = R_r D_c + \left(R_u + \rho_g\right) D_a - \rho_s (D_c - D_a) \,. \tag{4.6}$$

We use C_w in \$ to denote the firm gas costs with the resale. Note that for $D_c = D_a$, C_w matches C_i and for $D_a \leq D_c$, C_w is lower than C_f as long as ρ_s is positive.

We observe that the load factor plays a key role in the determination of the firm contract costs. Indeed, as Figure 4-3 indicates, the lower the load factor, the higher are the per–unit costs of firm gas transportation. The resale to the industrial gas customer mitigates the higher costs in light of the new revenue stream. Consequently, the expression for C_w results in a lower effective gas price, given by C_w/D_a, for the gas generator as long as the resale price ρ_s is positive.

The generator's profits under the firm contract are

$$\pi_f = \left(\sum_{d \epsilon \mathcal{D}} \sum_{h \epsilon \mathcal{H}_d} \left(\hat{\rho}_{e,h,d} \cdot P\right)\right) - C_w \,, \tag{4.7}$$

where $\mathcal{H}_d$ is the set of hours of day d in which the unit's offer price is below the hourly LMP.

In the next section, we present representative results of the simulation studies we performed on the proposed contract to gain an improved understanding of its performance and to gain some insights into its ability to manage the uncertainty in gas supply and gas costs for gas generators.

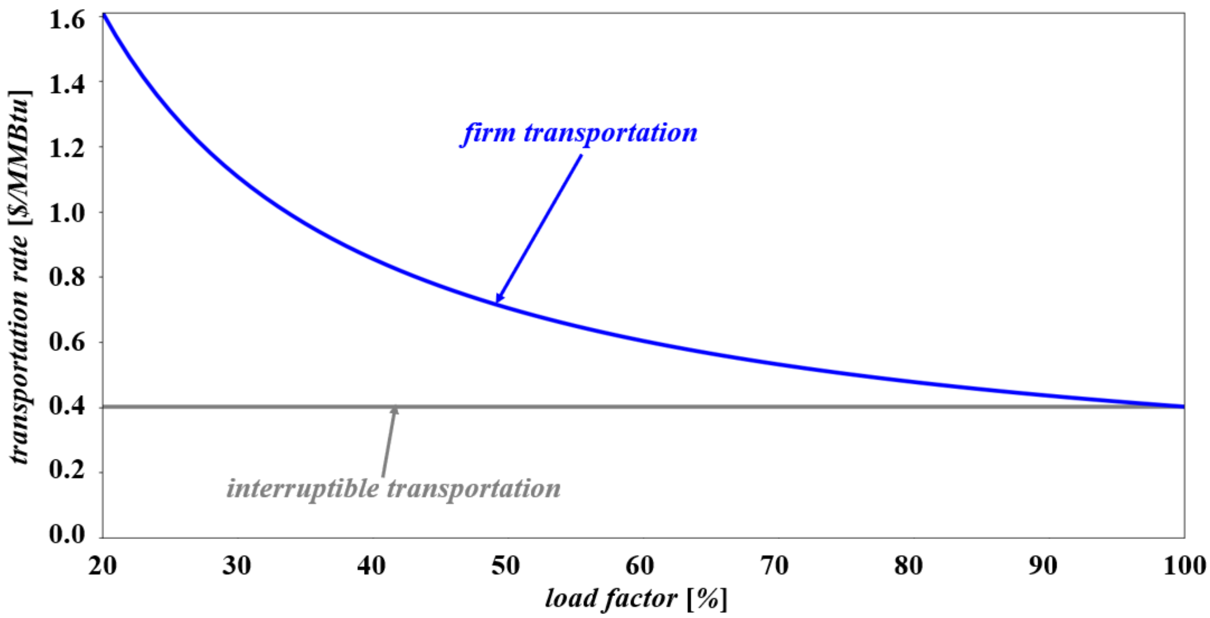


Figure 4-3: The plot of the per unit natural gas transportation rates as a function of the load factor based on the reservation rate set at 0.302 $/MMBtu and the usage rate at 0.099 $/MMBtu. The reservation and usage rate values extracted from [65].

4.2 Representative Numerical Results for the Proposed Gas Transportation Contract

We performed a wide range of simulations for the deployment of the proposed contract under a broad set of conditions. For the discussion here, we focus on two distinct gas generators – a small 50–MW combined–cycle gas turbine and a larger, 645–MW combined–cycle gas unit. The parameter values for these generators come the EIA database [66] and an industry periodical [67]. For the gas data, we make use of the tariff rate values from a portion of the Algonquin Interstate Pipeline [68] and operationally available gas transportation capacity in timely nomination cycles for the Algonquin system [64] —historical data available starting in August 2015. The natural gas prices are as published by EIA [69]. We use the ISO–NE data of the locational marginal prices or LMPs [70].

All the studies are carried out for the period from November 1, 2017 to January 31, 2018. The ISO–NE hourly day-ahead market LMPs are the actual values and are not forecasts, as would be the case in the deployment of the contract in practice. We assume that the gas-fired generator submits offers based on its computed marginal costs from the incurred gas supply and transportation expenses. We construct the base case for the simulation under the condition that the generator is dispatched at its rated capacity for each hour with adequate gas supply delivered under interruptible transportation as long as the delivered gas price results in an offer at or below the hourly day–ahead LMP. When the generator has fuel to run for only a restricted period of a day, the dispatch is limited to those hours with the highest LMP values for that day. We compute the daily generator electricity revenues and resulting profits for each hour from the dispatch results and the supplied gas costs.

We then repeat the simulation for the situation with the deployment of the proposed contract by the generator for an amount of firm gas to allow continuous operations over the study period. In these cases, we assume the generator has acquired the minimum amount of firm gas transportation so as to not encounter fuel shortage situations. In case the generator is not dispatched as a result of the offers submitted into the hourly day–ahead markets, the resulting surplus gas is resold to the industrial customer. The offers prepared by the generator use the same procedure as in the interruptible transportation base case simulation. We carry out sensitivity studies under the proposed contract for different discounted resale prices, each expressed as a fraction of the interruptible price.

We carry out the set of studies for both the small and the larger generators and provide representative results. We first present the small combined–cycle gas turbine results and follow with those for the large combined–cycle gas generator.

The small, 50–MW combined–cycle gas turbine has a heat rate of 7,652 Btu/kWh. For the base case study results, we use the Algonquin system data in [68] to represent the impacts of the pipeline capacity limits. We tabulate the key metrics of the base case in Table 4-2. Figure 4-4 displays the amount of natural gas that is available to ensure that the pipeline capacity limits are not violated. Figure 4-5 illustrates the hourly LMPs that are key to determine the daily generator offers jointly with the daily natural gas prices. The plots in Figure 4-6 display the daily costs and revenues of the generator operating under the proposed contract with a resale price at 70 % of the interruptible price. Figure 4-7 displays the corresponding daily cash flows and cumulative profits for that case. The study results for the other resale price values are given in Figure 4-8 through Figure 4-11.

Figure 4-8 displays the daily costs and revenues of the generator operating under the proposed contract with a resale price at 80 % of the interruptible price. Figure 4-9 displays the corresponding daily financial results and cumulative profits. The plots in Figure 4-10 and in Figure 4-11 display the daily costs and revenues and the corresponding daily financial results, respectively, for the generator operating under the proposed contract with a resale price at 90 % of the interruptible price. We summarize the cumulative financial results over the study period for these cases in Table 4-1.

Table 4-2: Base case results for the small combined–cycle gas turbine

total revenues [$]	gas costs [$]	gas consumption [MMBtu]	total profits [$]
1,120,422	926,560	71,929	193,861

Table 4-3: Cumulative financial results for different resale price values for the small combined–cycle gas turbine

resale price factor as % of the interruptible rate	total revenues [$]	electricity revenues [$]	gas resale revenues [$]	gas costs [$]	gas consumption [MMBtu]	total profits [$]
70	10,254,404	2,838,219	7,416,185	10,169,370	72,424	85,035
80	10,378,600	2,838,219	7,540,381	10,169,370	72,424	209,231
90	10,502,795	2,838,219	7,664,576	10,169,370	72,424	333,427

Our results indicate that, for this generator in this study period, even though a resale price of 90 % of the interruptible rate results in profits, those profits are below the base case ones. The illustrative results presented measure quantitatively the financial performance of the gas generator in situations when the generator is not dispatched and resells the unused gas to the industrial customer at a lower price. For larger discount prices, the profit performance becomes weaker for the study period considered. We note that in actual deployment, the forecasts of the LMPs will include errors in their values and so in actual applications with such forecasted values of the hourly day-ahead market LMPS the financial performance measures depend on the forecast errors. However, the size of the generator is of critical importance because the financial performance under the contract is markedly different when we consider the larger generator studies, which we next examine.

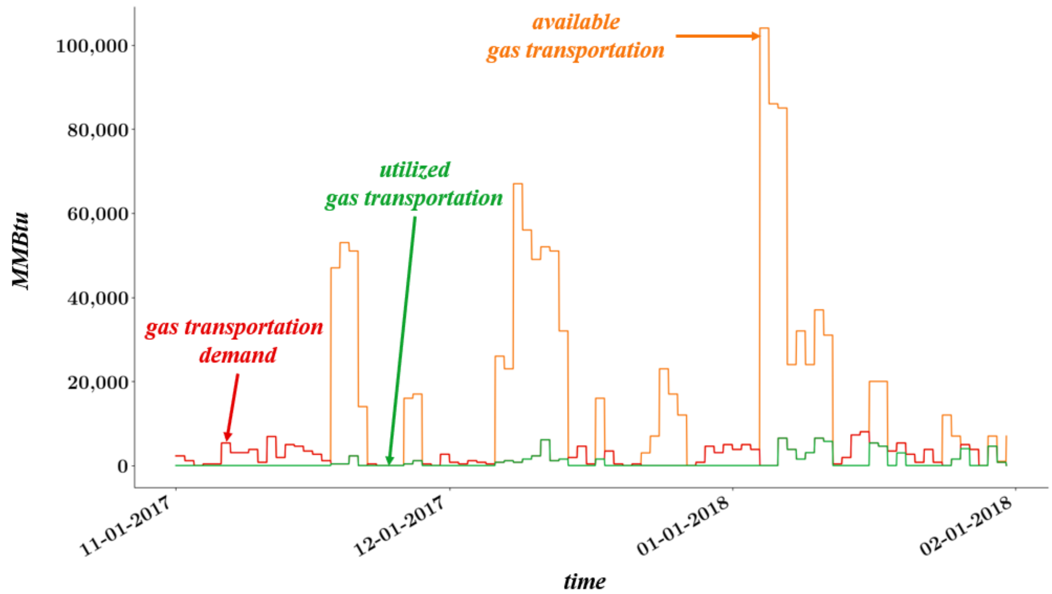


Figure 4-4: Daily amounts of available gas for the small combined–cycle gas turbine with the explicit consideration of pipeline capacity limits; utilized gas transportation refers to the actual transportation utilized by the generator operating with an interruptible contract; gas transportation demand is the result of the gas required to meet the day–ahead dispatch submitted in the generator's offers and sets the transportation the generator obtains under its firm transportation contract.

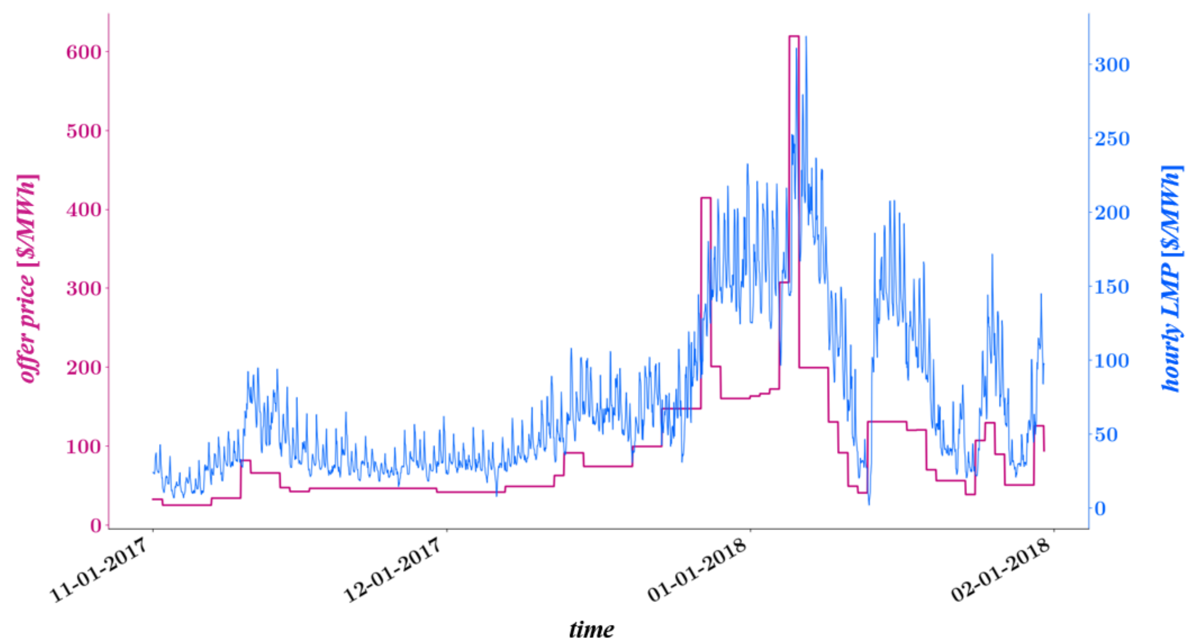


Figure 4-5: Daily day–ahead market generator offers for the small combined–cycle gas turbine based on the daily natural gas prices and the hourly LMPs over the study period.

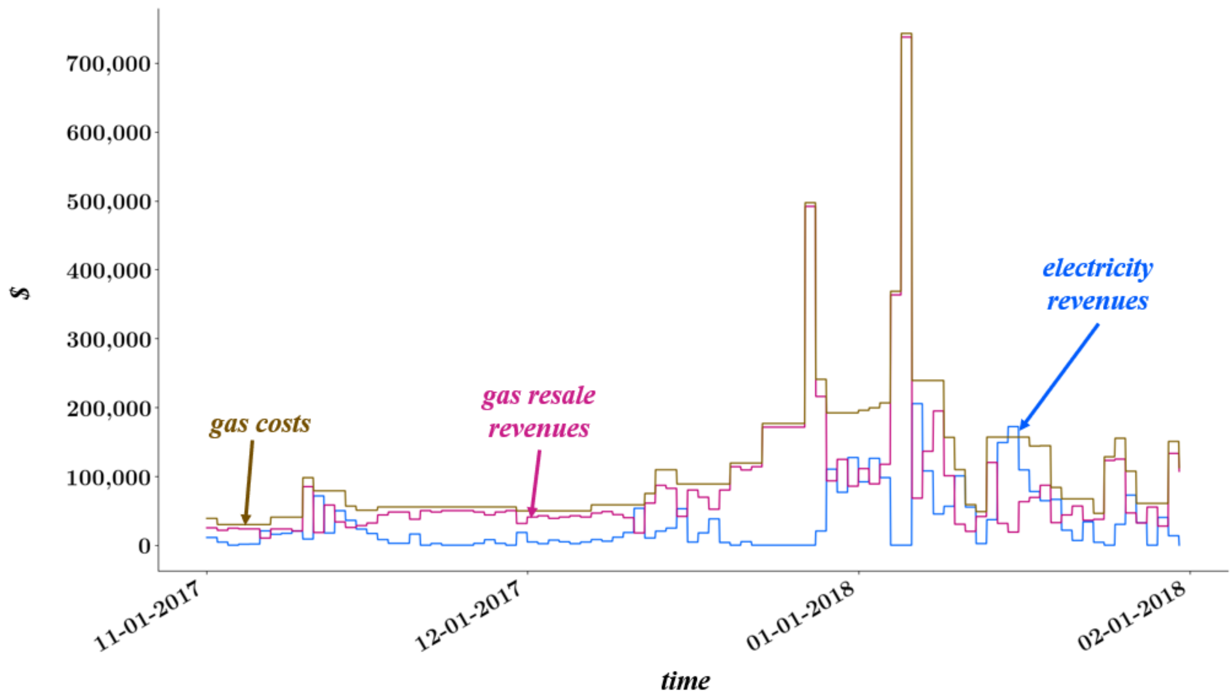


Figure 4-6: Daily costs and revenues under a resale price of 70 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

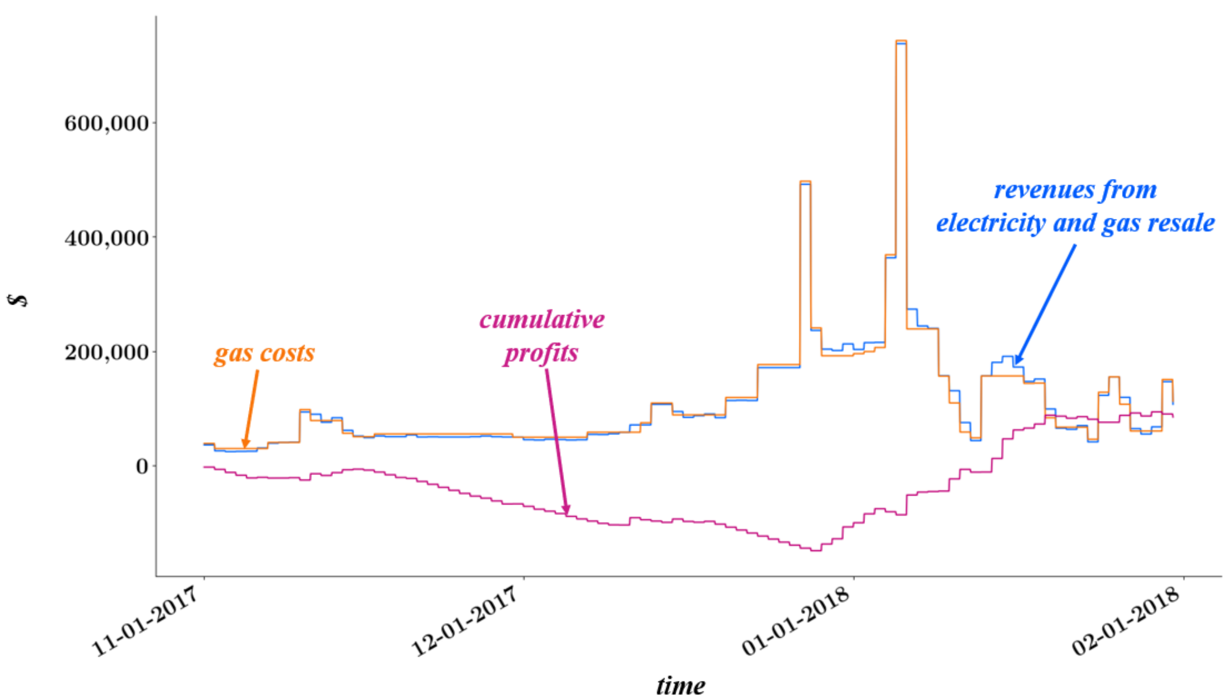


Figure 4-7: Daily financial results and cumulative profits under a resale price of 70 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

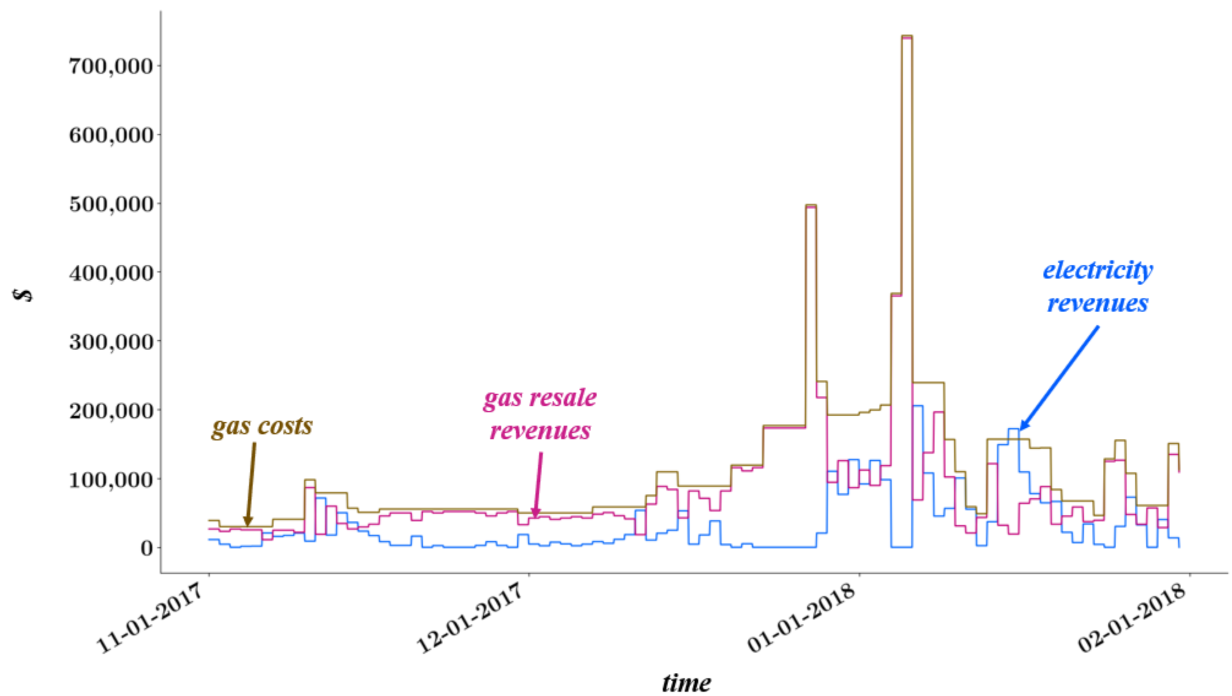


Figure 4-8: Daily costs and revenues under a resale price of 80 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

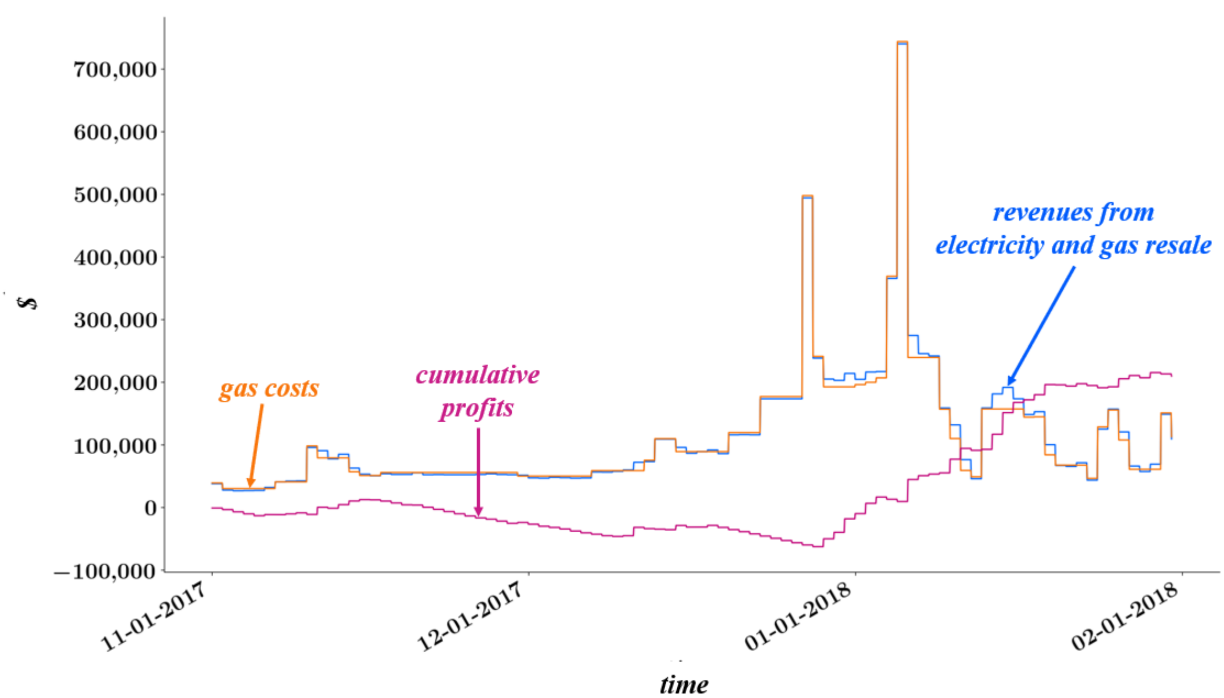


Figure 4-9: Daily financial results and cumulative profits under a resale price of 80 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

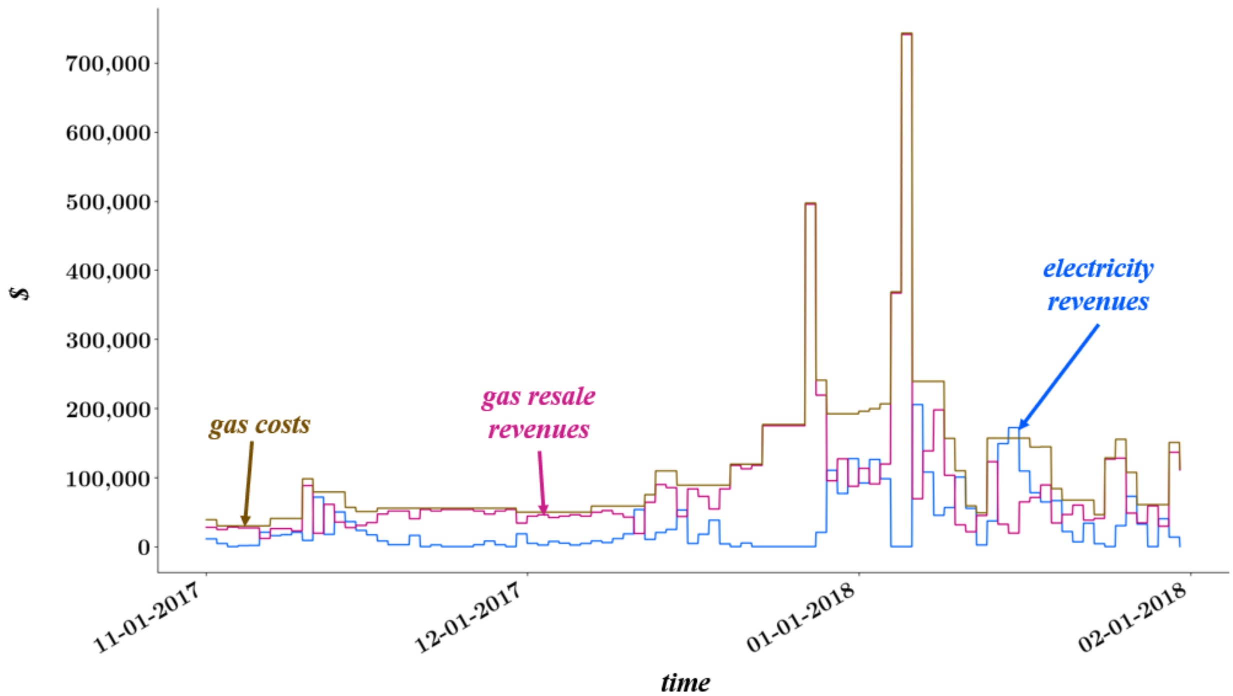


Figure 4-10: Daily costs and revenues under a resale price of 90 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

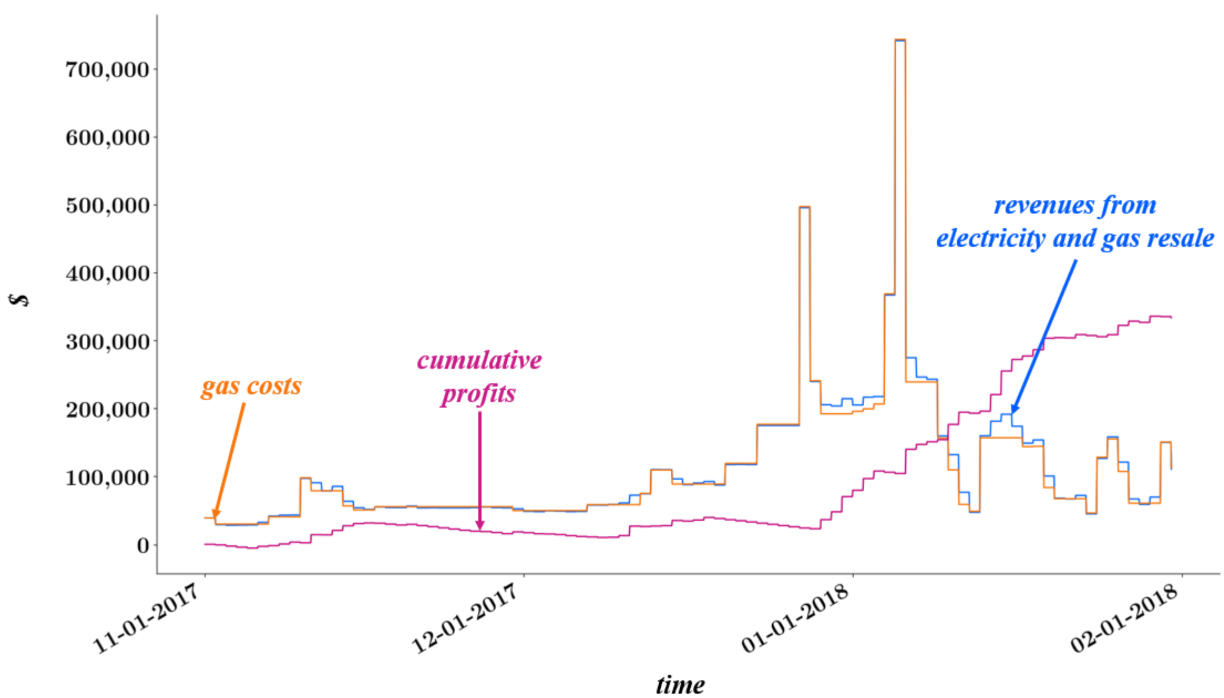


Figure 4-11: Daily financial results and cumulative profits under a resale price of 90 % of the interruptible rate for the small combined–cycle gas turbine over the study period.

The large, 645–MW combined–cycle generator has a heat rate of 6,414 Btu/kWh. For the base case study results, we use the Algonquin system data in [64] to represent the impacts of the pipeline capacity limits. We tabulate the key metrics of the base case in Table 3.

Table 4-4: Base case results for the large combined–cycle generator

total revenues [$]	gas costs [$]	gas consumption [MMBtu]	total profits [$]
10,882,270	7,812,394	645,377	3,069,878

Figure 4-12 displays the daily natural gas amounts that are available for the large generator without any violations of the pipeline capacity limits. Figure 4-13 illustrates the hourly LMP values used to determine the daily generator offers together with the daily offers, which also depend on the daily natural gas prices. Figure 4-14 displays the daily costs and revenues for the generator operating under the proposed contract with a resale price at 70 % of the interruptible price. The corresponding daily financial results and cumulative profits are shown in Figure 4-15. Figure 4-16 displays the daily costs and revenues for the generator operating under the proposed contract with a resale price equal to 80 % of the interruptible price. The corresponding daily financial results and cumulative profits are shown in Figure 4-17. The plots in Figure 4-18 and in Figure 4-19 display the daily costs and revenues, and the daily financial results and cumulative profits, respectively, for the case the large generator operates under the proposed contract with a resale price at 90 % of the interruptible price. We summarize the cumulative financial results over the study period for these cases in Table 4-4.

Table 4-5: Cumulative financial results for different resale price values for the 645–MW combined–cycle generator

resale price [% of interruptible price]	total revenues	revenues from electricity [$]	revenues from gas resale [$]	gas costs [$]	gas consumption [MMBtu]	total profits [$]
70	119,805,000	59,158,660	60,636,340	109,960,700	707,810	9,834,247
80	120,814,310	59,158,660	61,655,650	109,960,700	707,810	10,853,560
90	121,833,620	59,158,660	62,674,960	109,960,700	707,810	11,872,870

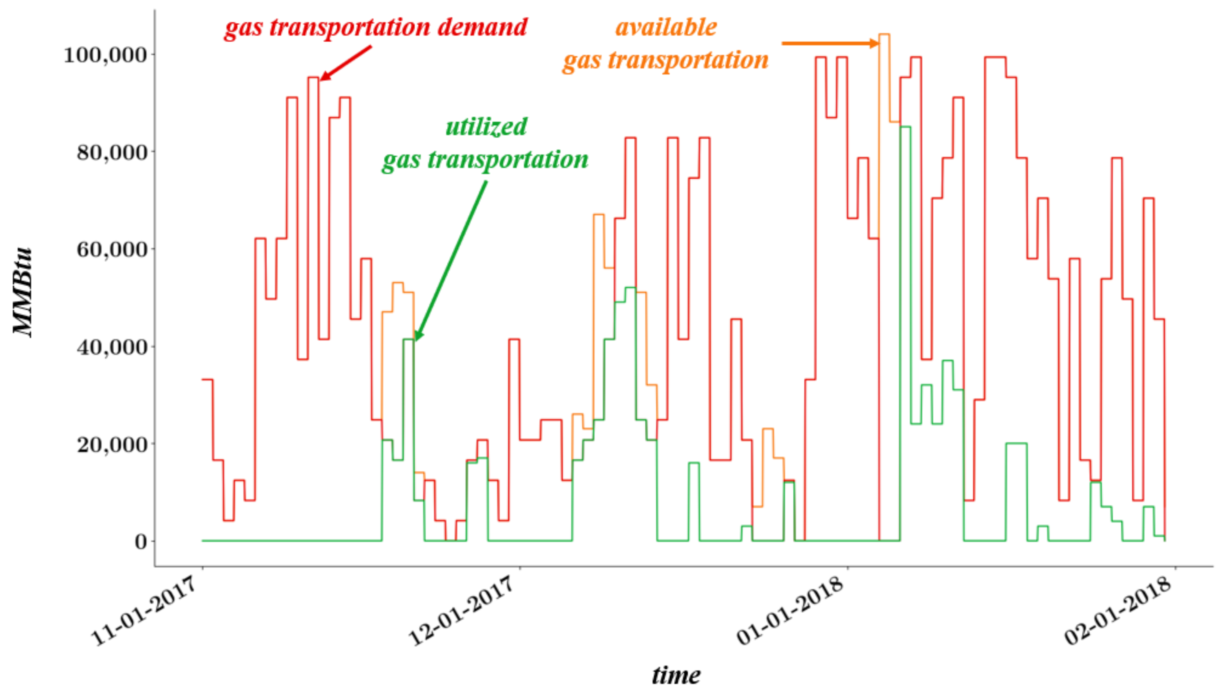


Figure 4-12: Daily amounts of available gas for the 645–MW combined–cycle generator are determined with the explicit consideration of the pipeline capacity limits; utilized gas transportation refers to the actual transportation used by the generator operating with an interruptible contract; gas transportation demand is the result of the gas required to meet the day–ahead dispatch submitted in the generator's offers and sets the transportation the generator obtains under its firm transportation contract.

Unlike in the small generator studies, the larger generator easily outperforms the base case financial results to bring about higher profits. The plots in Figures 4-15, 4-17 and 4-19 show the behavior of the daily cumulative profits vis–à–vis the dispatch revenues the generator collects. Even though there are periods during which the costs exceed the revenues, for the entire study period, the generator benefits from the proposed contract deployment even with the surplus natural gas resale at significantly lower prices to another gas customer. These results are good indicators that there are potential benefits that can be realized under the proposed contract, and that its performance depends on how severe and frequent the natural gas supply interruptions are. As the plots in Figure 4-4 and Figure 4-12 indicate, the lack of natural gas transportation has greater impact on the larger generator since it requires larger volumes of the fuel. For the small generator case, there are fewer hours with fuel shortage. The generator size difference is the key driver of the better financial performance of the larger generator than that of the small generator over the study period of the simulations discussed in this section.

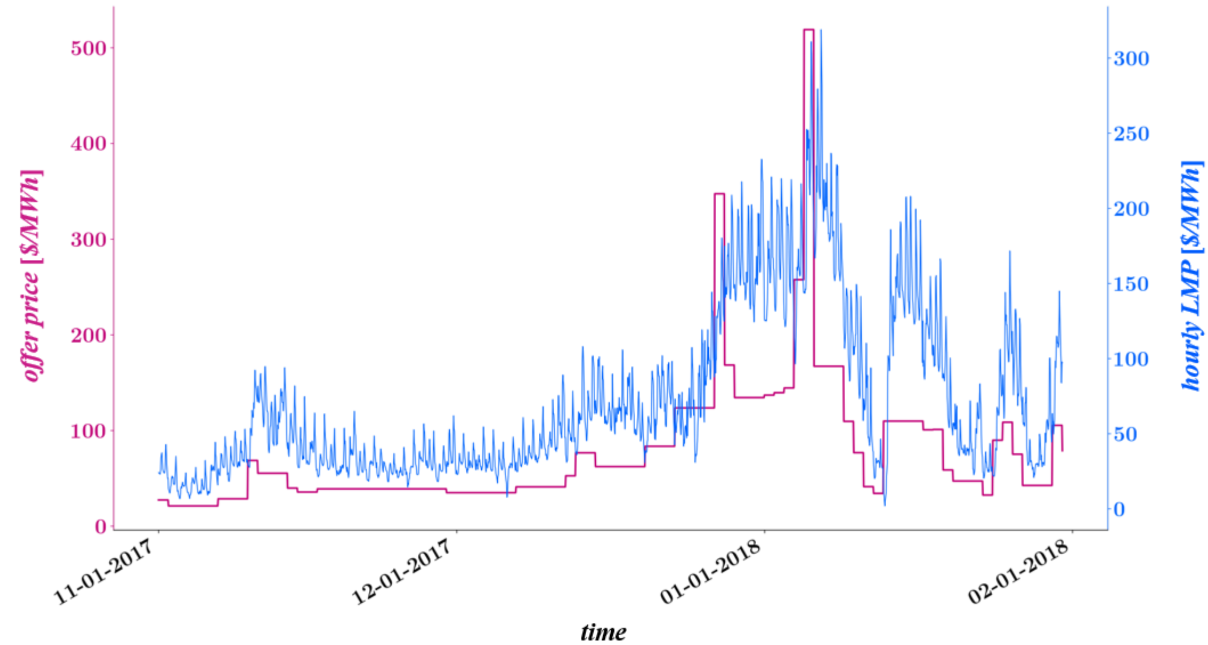


Figure 4-13: Daily generator offers based on the natural gas price and the hourly day–ahead market LMPs for the 645–MW combined–cycle generator over the study period.

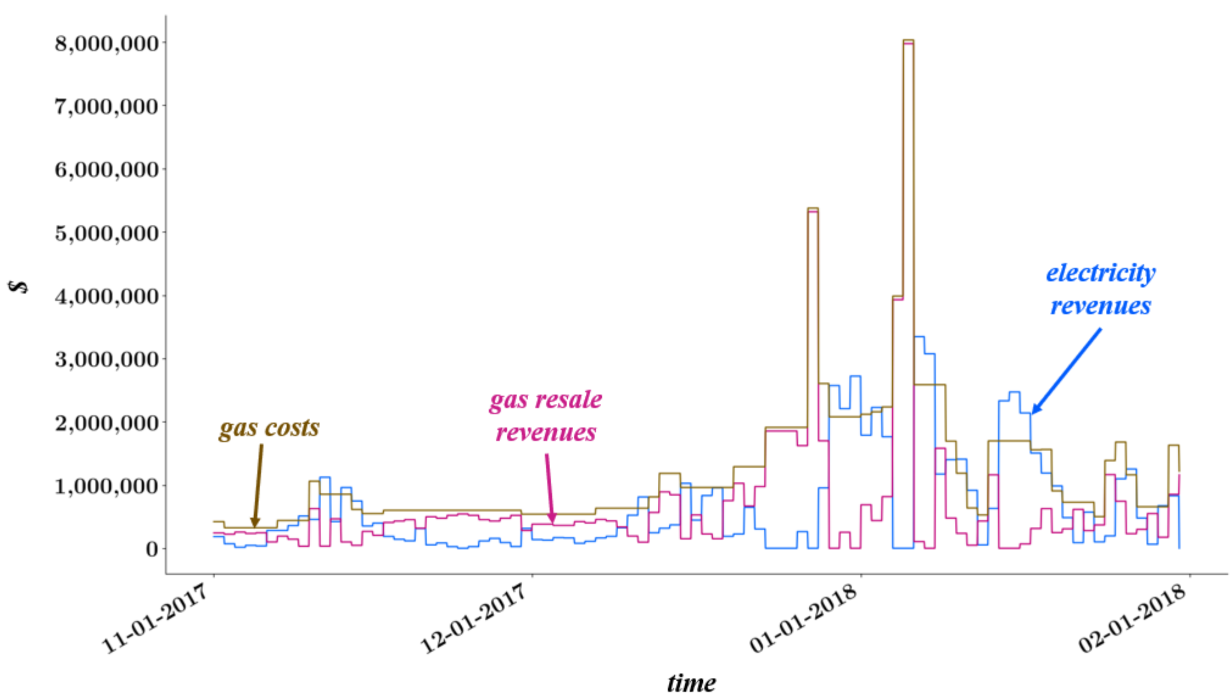


Figure 4-14: Daily costs and revenues under a resale price of 70 % of the interruptible rate for the 645–MW combined–cycle generator over the study period.

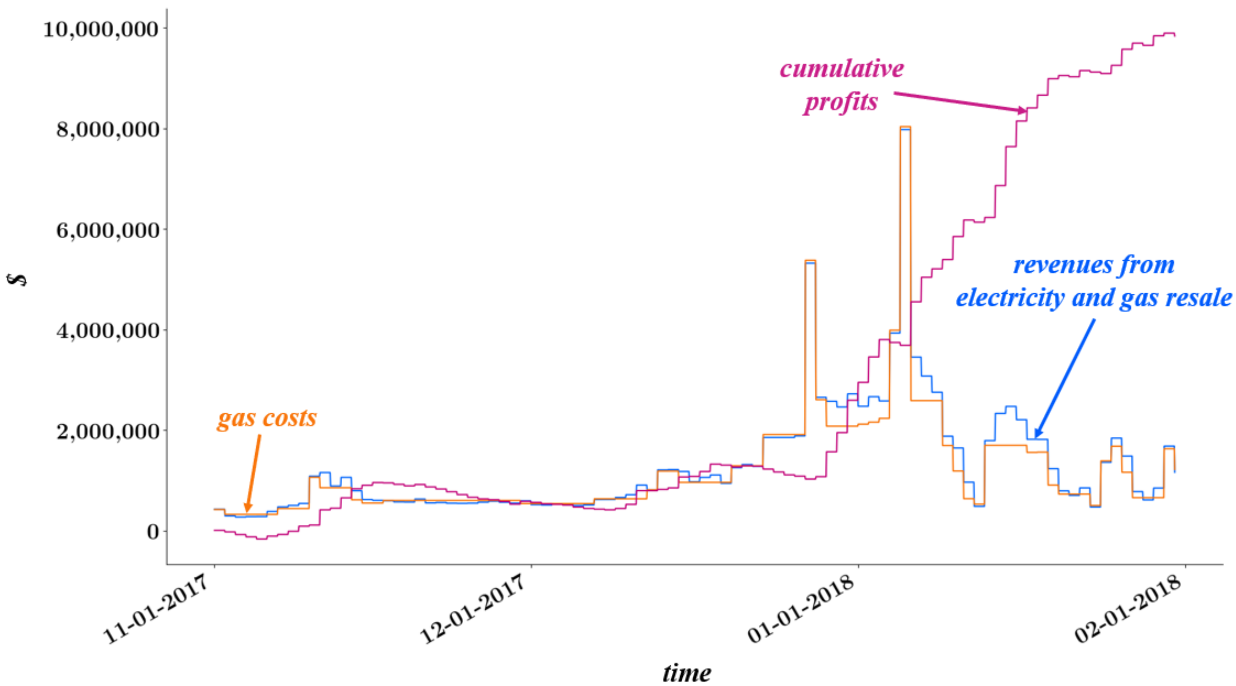


Figure 4-15: Daily financial results and cumulative profits under a resale price of 70 % of the interruptible rate for the 645—MW combined–cycle generator over the study period.

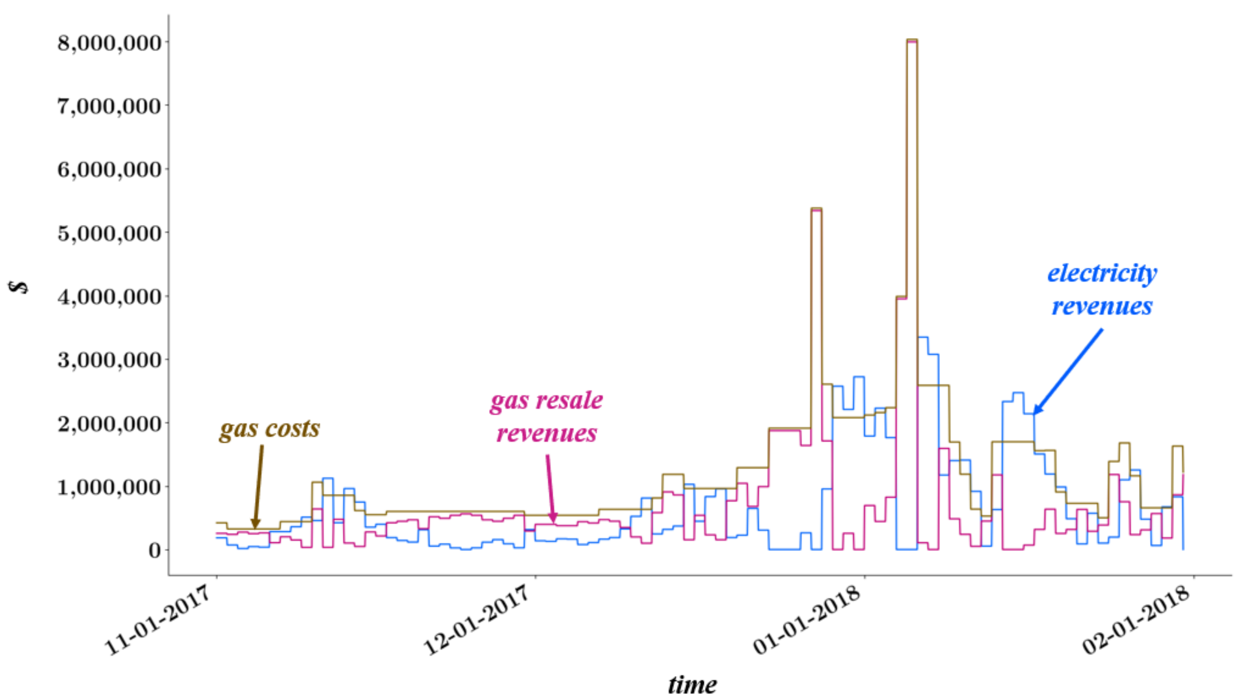


Figure 4-16: Daily costs and revenues under a resale price of 80 % of the interruptible rate for the 645–MW combined–cycle generator over the study period.

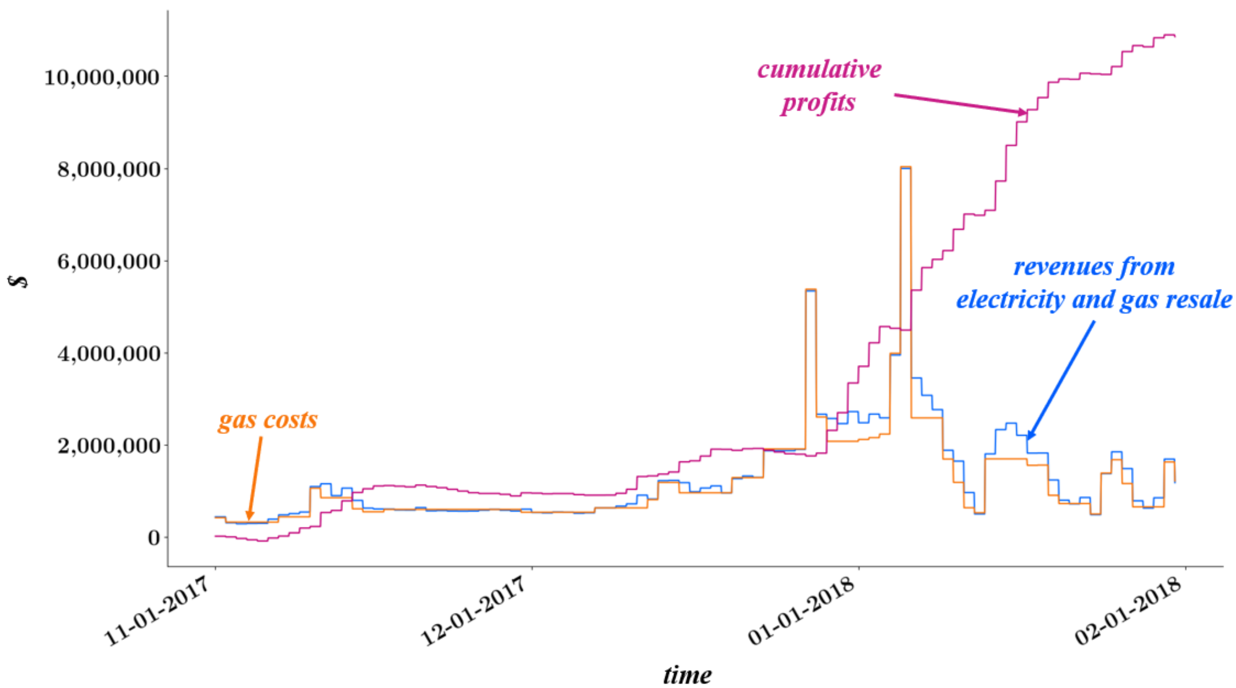


Figure 4-17: Daily financial results and cumulative profits under a resale price of 80 % of the interruptible rate for the 645–MW combined–cycle generator over the study period.

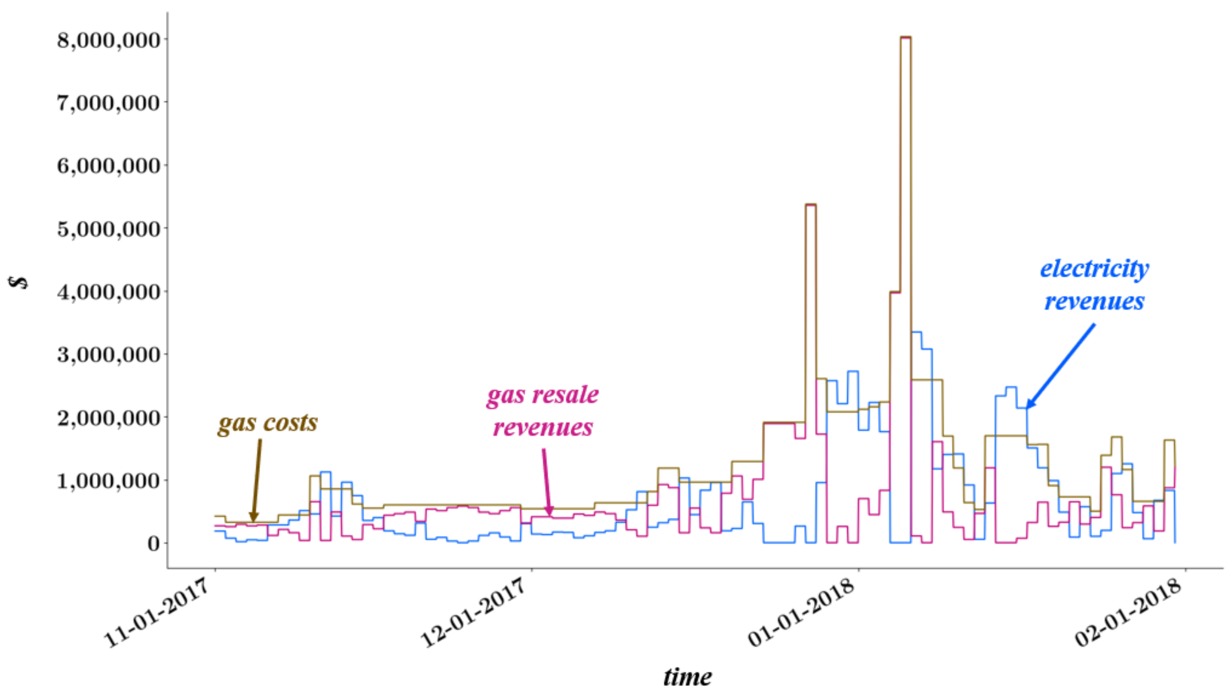


Figure 4-18: Daily costs and revenues under a resale price of 90 % of the interruptible rate for the 645–MW combined–cycle generator over the study period.

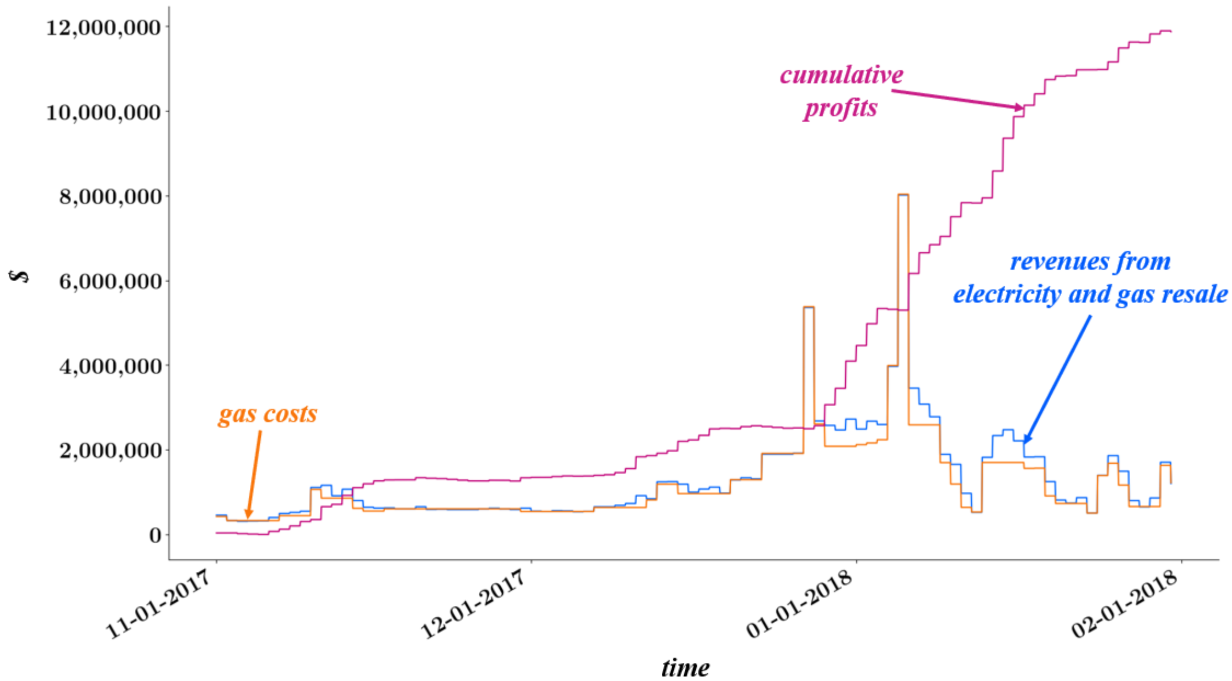


Figure 4-19: Daily financial results and cumulative profits under a resale price of 90 % of the interruptible rate for the 645–MW combined–cycle generator over the study period.

4.3 Concluding Remarks

We have evaluated the outcomes of two generators operating with and without the proposed contract. Under the assumed conditions, the generators are able to acquire firm gas transportation and remain making a profit. In the last cases, the generator in fact obtains a much higher profit than in the base case, even when the resale price is 70% of the interruptible rate. For the smaller generator, it is important to address the fact that implementing this contract when gas transportation is not scarce does not contribute to the unit's profits significantly. Therefore, this contract is to be deployed during periods of expected natural gas scarcity, such as severe low-temperature weather events.

Benefits may arise on both bulk power system and the natural gas players. Natural gas infrastructure benefits from its increased utilization, as the firm natural gas transportation contract provides a steady and continuous revenue stream to pipelines and gas vendors. From the electric power system perspective, the contract may lower electricity costs as it allows more gas-fired units to submit offers during gas scarcity periods. Furthermore, the deployment of the proposed contracts is also significant to power system security, as more gas-fired units are available to provide energy, ramping capability and other ancillary services.

In a practical implementation of this contract, it is possible that an additional rate is imposed due to the delivery of gas to another location. This would, in fact, decrease the benefits from the proposed contract. Nevertheless, the contract implementation may provide concrete benefits during gas transportation scarcity periods. Indeed, the proposed contract can be a useful mechanism to mitigate the uncertainty in gas supply and gas prices. As such, this mechanism is a vehicle to improve the grid operational flexibility of today's grids.

5. Conclusions

The power system's increased reliance on natural gas, which is expected to continue to grow, exposes it to risks of fuel shortage or unexpectedly high fuel costs. Gas generators lacking firm contracts for fuel delivery may have to procure gas from the spot market at much higher prices than those on which they based their offers into the wholesale market. As the electricity system operators strive to maintain reliability, their actions to redispatch resources or import power may result in high wholesale prices for electricity during times of gas scarcity. This project focused on (1) the development of a better understanding and the quantitative assessment of the economic risks borne by generators and system operators and (2) the evaluation of the potential benefits of strategies to mitigate such risks.

Assessing the risk is challenging because severe disruptions in gas delivery up to now have been rare events. In California, the sustained leak in the Aliso Canyon gas storage facility had far-reaching effects while in the eastern U.S. and Texas, gas shortages have occurred during severe cold-weather events. The inherent difficulty of forecasting future severe weather events or infrastructure failures and their economic impacts is exacerbated in this context by the lack of publicly available data on the gas infrastructure and market prices at levels of temporal and spatial detail that are useful for operational studies.

In Section 2 we identified and described the sources of gas data that are available. Because comprehensive data on the natural gas infrastructure are scarce, we also summarized the small to moderate-sized test data sets that are frequently used in the literature for operational and planning studies. To aid further research in this area, the development of more extensive data sets, similar to and and capable to interface with the IEEE Reliability Test Systems, would be very helpful. Historical or synthetic representative data on gas availability and prices, similar to the NREL wind data sets, would also be helpful for further research on the economic risks and their mitigation.

In Section 3 we developed and demonstrated methodology to assess the impacts of uncertainty in gas spot prices on the probability distribution of grid dispatch costs. This approach consists of estimating the joint distribution of electricity demand and gas spot prices, related by their joint dependence on weather, then sampling from that distribution for input into a Monte Carlo simulation of economically dispatching generation resources, including gas generators subject to fuel supply disruptions. The simulated distributions of dispatch cost with and without gas price uncertainty can be compared via a probability metric or by computing the difference in risk measures. We then compared alternative risk mitigation strategies by reformulating the dispatch optimization model to include one strategy or the other and running the simulations again. In a numerical case study based on winter conditions in New England we found that, for the same investment cost, the addition of a gas storage facility would reduce the risk of high dispatch costs more than converting gas units to dual fuel capability. We do not claim that this conclusion will hold universally but present the numerical results to illustrate the use of the methodology, which is generally applicable. In future research, the dispatch model could be modified to represent some gas generators as having firm contracts for gas delivery while others rely on interruptible contracts, and the choice to enter into firm contracts could be evaluated as another risk-mitigation strategy.
A way that generators might reduce their risks is to arrange for firm gas delivery. For the proposed firm gas transportation contracts presented in Section 4, we have identified conditions under which

the proposed contract increases the gas–fired generator's profit or not. We have focused our studies in the New England region, whose natural gas transportation infrastructure is sorely inadequate, particularly under severe winter conditions.

Future work in this area includes the construction of a more detailed representation of the cost elements related to pipeline operations. For example, the case in which additional transportation costs are incurred to deliver the surplus gas has yet to be investigated. Moreover, the scope of our analysis was restricted to the timely, day–ahead nomination cycle of the natural gas transportation. Also, additional nomination cycles may be modeled to capture the benefits associated with the opportunities that may be advantageously utilized by both the gas-fired generator and the industrial customer so as to avoid interruptions. We note that in our analysis, we use historical LMP values and determine the dispatch of the gas generator rather than undertake the simulation of each day's day-ahead hourly markets based on the offers submitted by all the market players, including the gas–fired generator of interest. As such, the incorporation of the proposed contract in a detailed, stochastic process-based production costing tool to evaluate the benefits that a gas–fired generator may obtain with and without the proposed contract can provide valuable insights on the effective deployment of the contract. Such future studies can provide useful guidelines for generators to formulate offers of the gas-fired generators that replace interruptible supply by the proposed contract to provide them improved assurance of recovery of the increased fuel costs under such contracts. Indeed, stochastic production simulation with the incorporated representation of the proposed contract can also be used to study a wide range of *what if* questions under various sources of uncertainty.

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