ENSURING RELIABLE NATURAL GAS-FIRED POWER GENERATION WITH FUEL CONTRACTS AND STORAGE

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Disclaimer

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ACRONYMS AND ABBREVIATIONS

ASCC	Alaska System Coordination Council
BCF	Billion cubic feet
BES	Bulk electric system
Btu	British thermal unit
Btu/hr	British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/lb	British thermal units per pound
CAISO	California Independent System Operator
CC	Combined cycle
CEII	Critical Energy Infrastructure Information
CF	Capacity factor
CIP	Critical Infrastructure Protection
CNG	Compressed natural gas
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FD	Forced draft
FGD	Flue gas desulfurization
FRCC	Florida Reliability Coordinating Council
ft	Foot, feet
ft^3	Cubic foot, feet
gal	Gallon
gr/100 scf	Grains/100 standard cubic feet
GT	Gas turbine
Hg	Mercury
HHV	Higher heating value
in-mi	Inch-mile
INGAA	Interstate Natural Gas Association of America
ISO	Independent system operator
ISO-NE	ISO New England, Inc.
kJ/kg	Kilojoule per kilogram
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
lb	Pound
lb/hr	Pounds per hour
LDC	Local distribution company
LNG	Liquefied natural gas
m	Meter
M	Thousand
MAOP	Maximum allowable operating pressure
MESA	Mission Execution and Strategic Analysis
MISO	Midcontinent Independent System Operator, Inc.
MJ/scm	Megajoule per standard cubic meter
MMBtu	Million British thermal units
MMscf	Million standard cubic feet
MRO	Midwest Reliability Organization
MW, MWe	Megawatt electric
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NO_X	Nitrogen oxide
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
PC	Pulverized coal
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM	PJM Interconnection, LLC
psi	Pounds per square inch
RFC	ReliabilityFirst Corporation
RTO	Regional transmission operator
scf	Standard cubic feet
scf/hr	Standard cubic feet per hour
SCR	Selective catalytic reduction
SERC	SERC Reliability Corporation
SO_2	Sulfur dioxide
SNL	SNL Financial
SPP	Southwest Power Pool
tonne	Metric ton (1,000 kg)
TRE	Texas Reliability Entity
U.S.	United States
WECC	Western Electricity Coordinating Council
°C	Degrees Celsius

EXECUTIVE SUMMARY

This report finds that natural gas-fired power plants purchase fuel both on the spot market and through firm supply contracts; there do not appear to be clear drivers propelling power plants toward one or the other type. Most natural gas-fired power generators are located near major natural gas transmission pipelines, and most natural gas contracts are currently procured on the spot market. Although there is some regional variation in the type of contract used, a strong regional pattern does not emerge. Whether gas prices are higher with spot or firm contracts varies by both region and year.

Natural gas prices that push the generators higher in the supply curve would make them less likely to dispatch. Most of the natural gas generators discussed in this report would be unlikely to enter firm contracts if the agreed price would decrease their dispatch frequency. The price points at which these generators would be unlikely to enter a firm contract depends upon the region that the generator is in, and how dependent that region is on natural gas. The Electric Reliability Council of Texas (ERCOT) is more dependent on natural gas than either Eastern Interconnection or Western Interconnection.

This report shows that above-ground storage is prohibitively expensive with respect to providing storage for an extended operational fuel reserve comparable to the amount of on-site fuel storage used for coal-fired plants. Further, both pressurized and atmospheric tanks require a significant amount of land for storage, even to support one day's operation at full output. Underground storage offers the only viable option for 30-day operational storage of natural gas, and that is limited by the location of suitable geologic formations and depleted fields.

1 Introduction

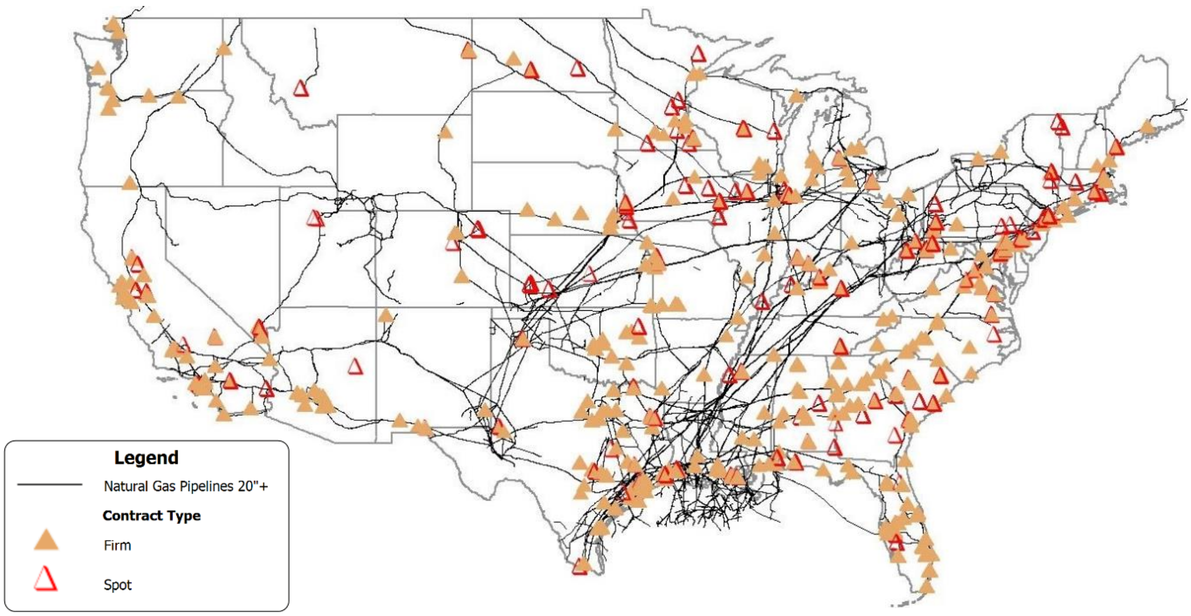
As the power system begins to rely more heavily on natural gas-fired capacity, it may be beneficial for gas-fired units to take steps to ensure their reliability, such as entering into firm fuel supply contracts or adding on-site storage to assure reliability. Coal-fired power plants maintain a ready supply of on-site fuel to sustain, at a minimum, several days of operation. Similarly, nuclear power is insulated from fuel-supply curtailments or other unexpected interruptions, as nuclear plants shut down for scheduled refueling every 18-24 months, otherwise running continuously. In contrast, natural gas-fired generating units rely on just-in-time delivery of fuel via pipeline. This difference makes natural gas-fired units more vulnerable to fuel-supply interruptions, which could negatively impact the reliability of the bulk electric system (BES).

This report explores the current state of fuel supply contracting and storage options for natural gas-fired generators. Section 2 of this report analyzes recent fuel purchase contract details for natural gas generators to determine whether existing generators utilize firm or spot (interruptible) contracts and whether there is a market or geospatial pattern that can be discerned. Section 3 combines this knowledge with black-start generation requirements to assess whether there may be a relationship between black-start capability, the procedure to recover from a total or partial shutdown of the BES, and natural gas contract type. Section 4 uses dispatch supply curves to examine both supply and demand side requirements needed to push generators toward entering fuel supply firm contracts. Section 5 reports on what technologies currently exist for on-site operational natural gas storage, along with their cost.

2 FUEL CONTRACTS

Natural gas-fired generators are scattered throughout the United States (U.S.), although the majority are located near major natural gas transmission pipelines, as shown in Exhibit 2-1, from ABB Velocity Suite (Velocity)[a]. Exhibit 2-1 also shows that both firm and spot (interruptible) contracts appear throughout the United States.

Exhibit 2-1 Natural gas pipelines and fuel contracts (Velocity)



Natural gas can be purchased either via a long-term "firm" contract service or interruptible "spot" market service. Under a firm contract, pipeline customers pay a higher price for natural gas in exchange for guaranteed service. In the case of peak demand or a pipeline outage, firm transport customers receive shipments first. Pipelines are financed and constructed based on long-term contracts that guarantee throughput. Natural gas customers who purchase gas on the spot market do not pay for guaranteed service and are the first to have service interrupted. Whichever type of service a generator chooses has reliability implications for the BES, as a generator that is needed during periods of peak electricity demand should have guaranteed fuel delivery.

Exhibit 2-2 shows the results of a heat map analysis of the presence of firm contracts in the United States. Firm contracts are most prevalent in South Carolina, Florida, the Pacific Northwest, Northern California, and the Texas/Louisiana Gulf Coast.

[a] Monthly Plant Fuel transactions query, which uses *Schedule 2 of the U.S. Energy Information Administration Form EIA-923* as a source.

Exhibit 2-2 Heat map of firm contracts

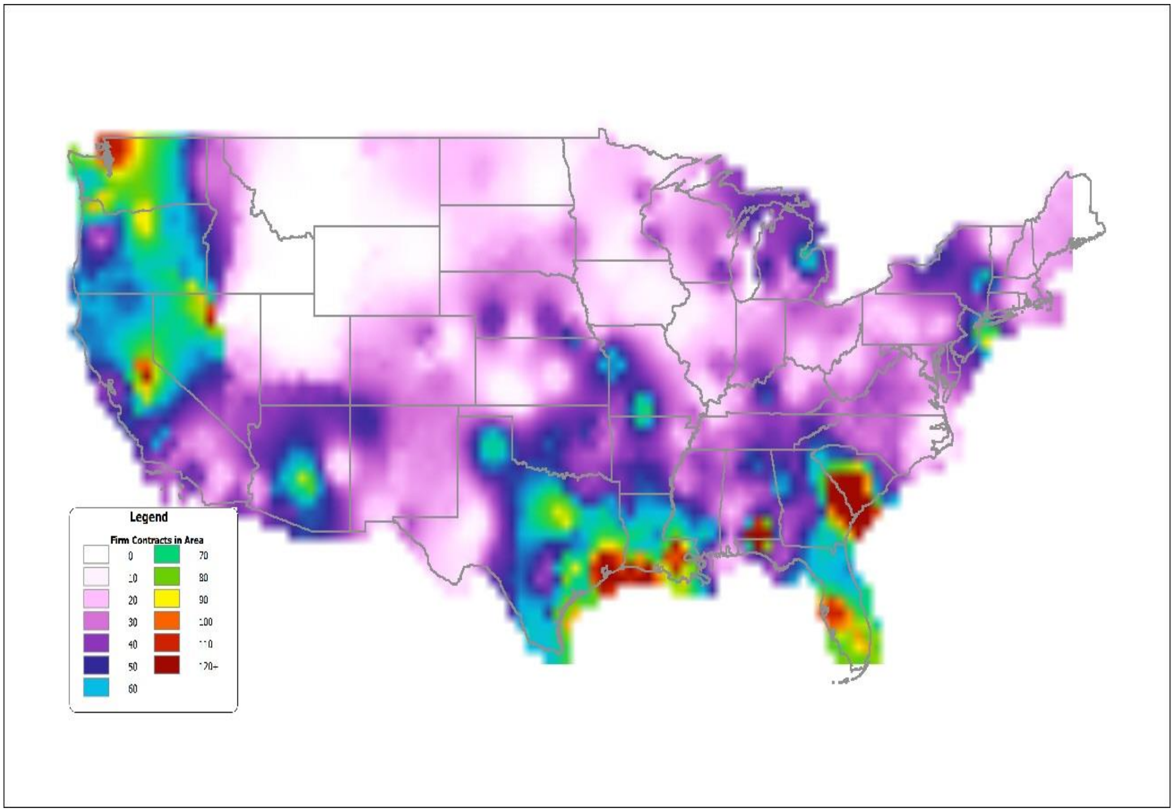


Exhibit 2-3 shows the number of fuel contracts for natural gas-fired generators by type, pulled from SNL Energy (SNL)[b]. Exhibit 2-3 shows that the number of spot fuel contracts is significantly higher than contract fuel contracts. It also shows that the number of both types of contracts decreased slightly from 2012-2015. While Velocity Suite data was consistent with data from SNL, the data from Velocity was excluded from the results and analysis presented in this report because approximately 50 percent of the contract records in Velocity reported a \$0/MMBtu[c] purchase price, which would significantly skew the cost analysis later in this section.

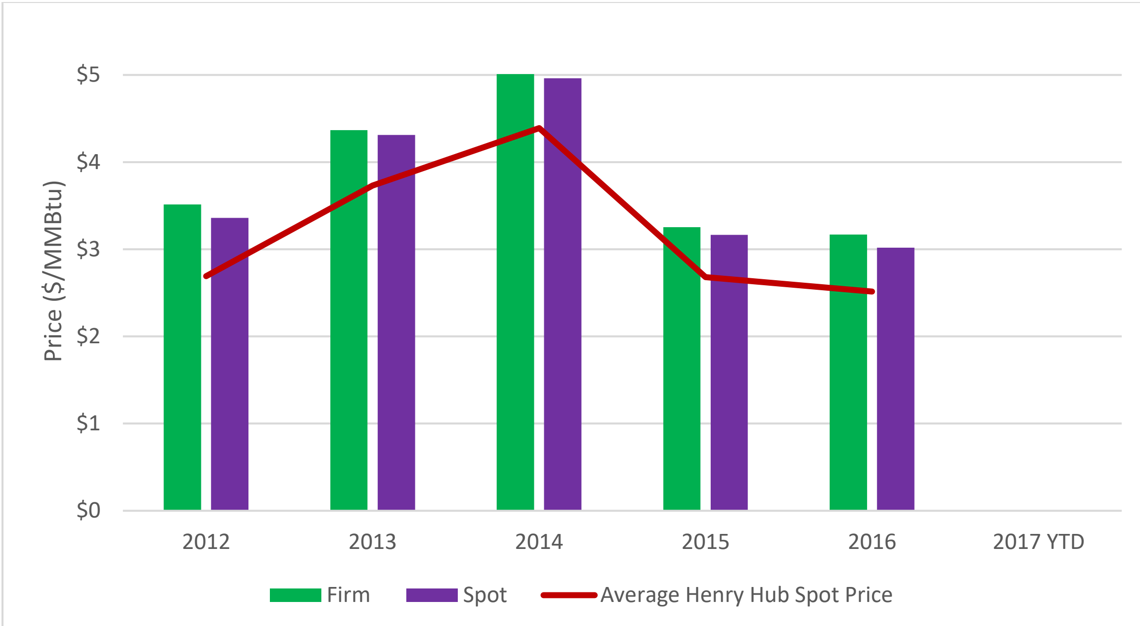
[b] Monthly Fuel Deliveries query, which uses *Form EIA-423* as a source.

[c] It is unclear why some prices were reported at \$0/MMBtu in Velocity. It may be due to a reporting error, or inconsistency in the way that Velocity gathers and publishes their data.

Exhibit 2-3 Number of fuel contracts (SNL)

Exhibit 2-4 and Exhibit 2-5 show the weighted average contract price from SNL. In Exhibit 2-4, the year 2014 shows a spike in firm contract price, and the year 2016 shows significantly lower prices for firm contracts. It is likely that the 2014 spike in firm contract prices was a market response to the service interruptions that impacted generation early in that year during the Polar Vortex [1], while the sharp decline into 2016 was likely the result of a combination of oil price collapse in late 2015 [2], sustained low natural gas costs [3], and a decrease in utility natural gas hedging. [4]

Exhibit 2-4 Weighted average contract price (SNL)



In Exhibit 2-5, the daily price for gas followed the same pattern as Exhibit 2-4, with daily gas prices over $14,000/BCF/day in 2014, but currently down to just above $8,000/BCF/day, its lowest level since before 2012.

Exhibit 2-5 Daily weighted average contract price (SNL)

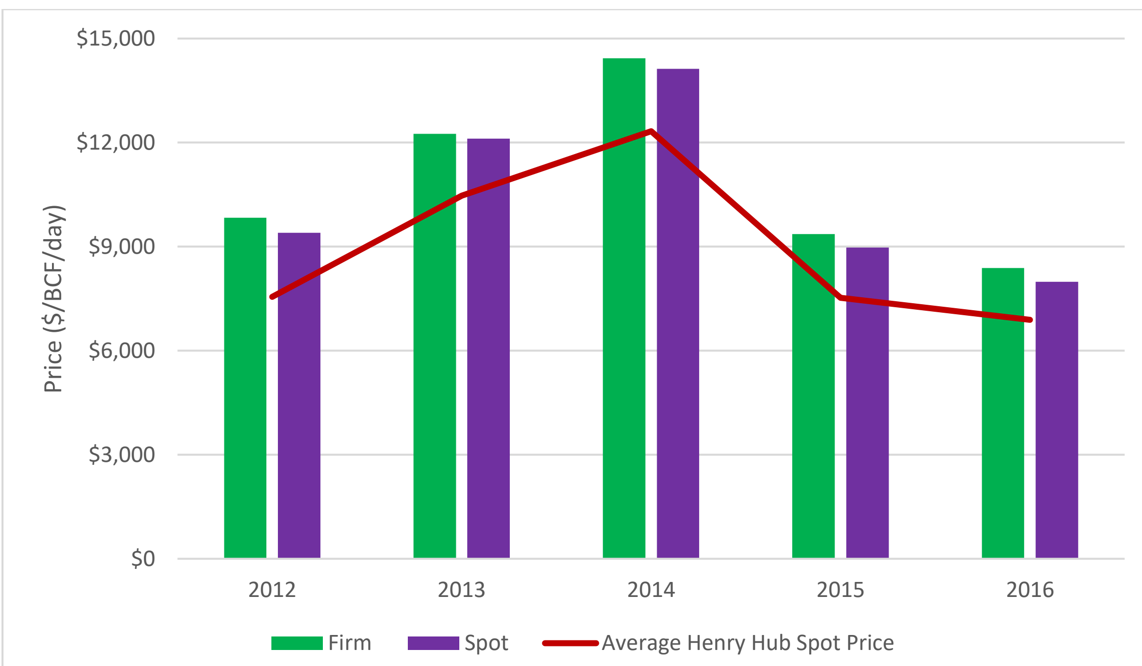


Exhibit 2-6 again shows data from SNL, this time on the amount of fuel purchased by contract type. In each of the last five years, the amount of fuel purchased on the spot market is higher than the amount of fuel purchased through firm contracting.

Exhibit 2-6 Amount of fuel purchased per day (SNL)

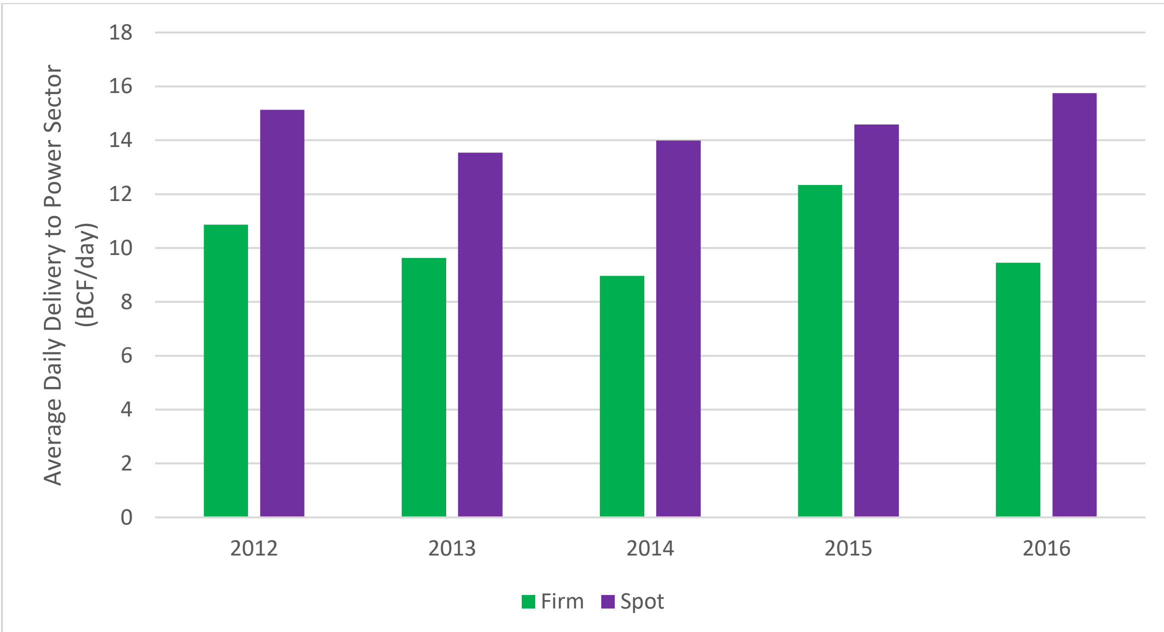


Exhibit 2-7 disaggregates the fuel contracts by North American Electric Reliability Council (NERC) region: Alaska System Coordination Council (ASCC), Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Interconnection. This analysis excludes the ASCC, as its system is unique and not interconnected to the others. Although the number of contracts varies greatly by region, in all years and all regions, most contracts are procured via the spot market. Additionally, the percent of natural gas purchased under firm contracts has declined in MPCC, RFC, and WECC, indicating that in those regions natural gas plants are trending toward purchasing via the spot market.

Exhibit 2-7 Percent of fuel contracts 2012-2016 by NERC Region (SNL)

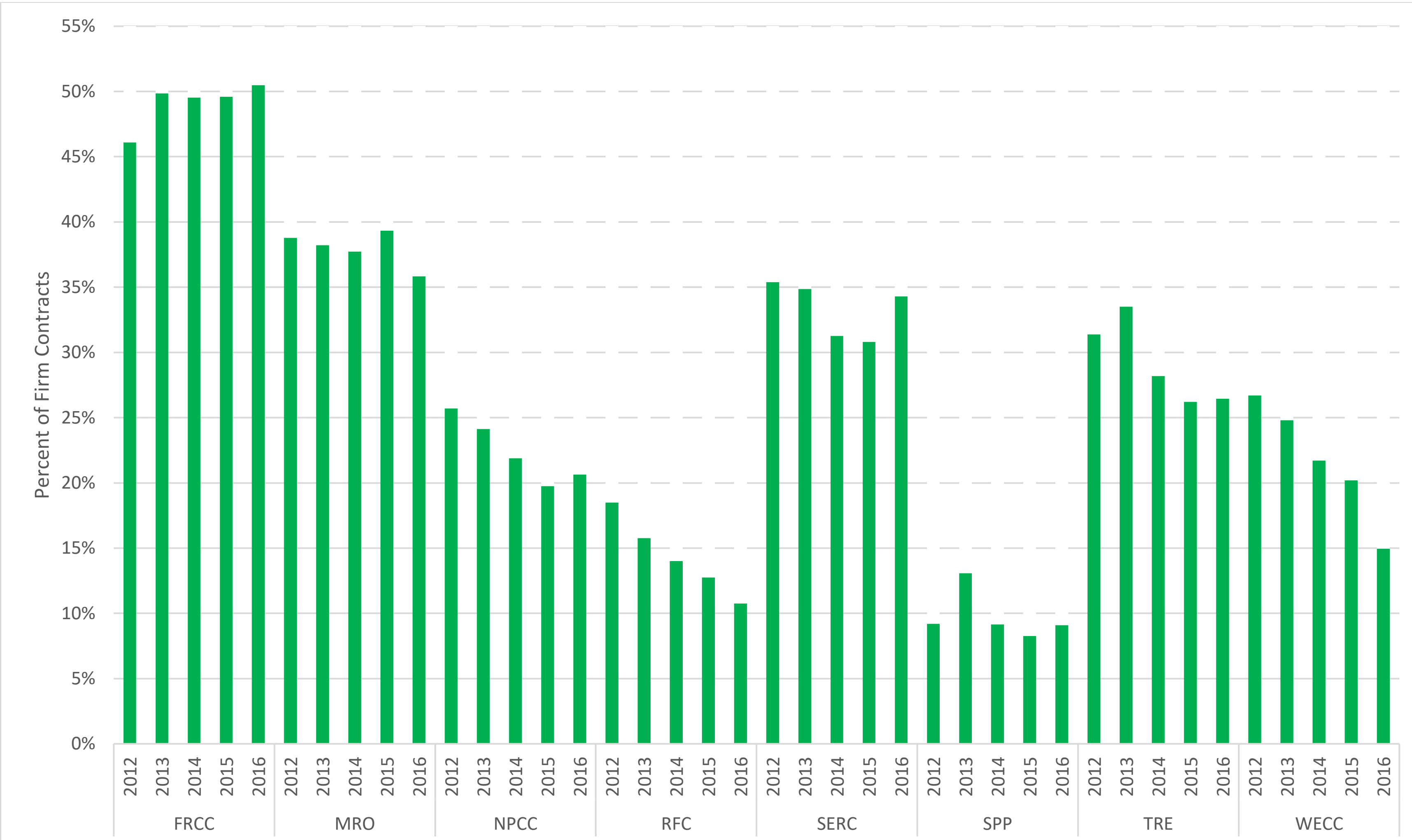


Exhibit 2-8 shows the average contract price by NERC region. This reveals some outliers. Both SERC and Western Interconnection have higher prices than the other regions. In Western Interconnection's case, there are high firm contract prices, coupled with low spot prices, while the reverse is true in SERC, with this trend holding true for most of the last five years. The significant difference in Western Interconnection pricing between sources is due to a few outlier prices reported in each source. Without these outliers, the Western Interconnection prices are closer to other regions. In SERC, there are a few outlier spot prices, which raises the average price much higher than surrounding region. Without more information on these outlier prices, it is hard to speculate on the reasons behind them.

Exhibit 2-8 Average contract price 2012-2016 by NERC Region (SNL)

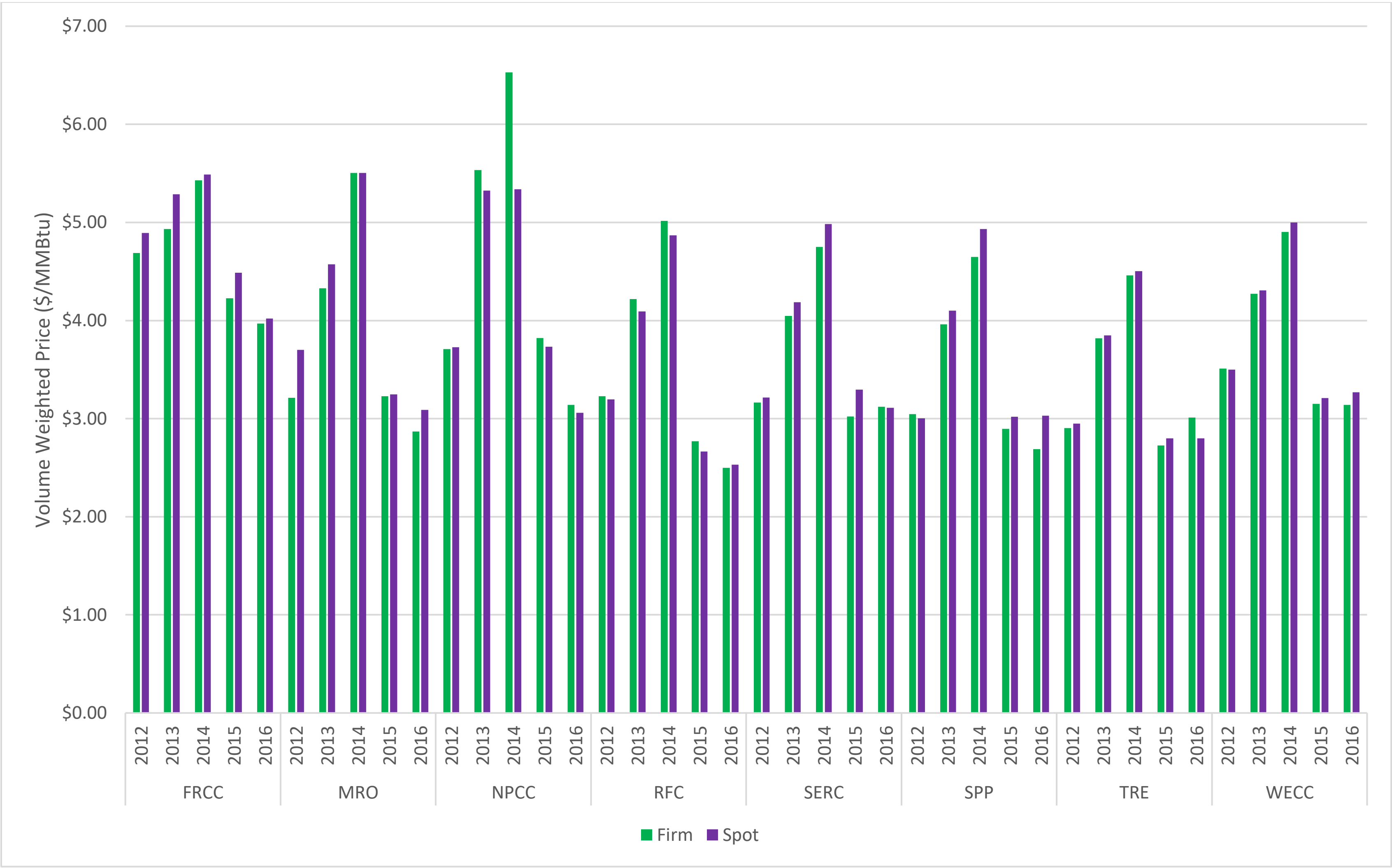
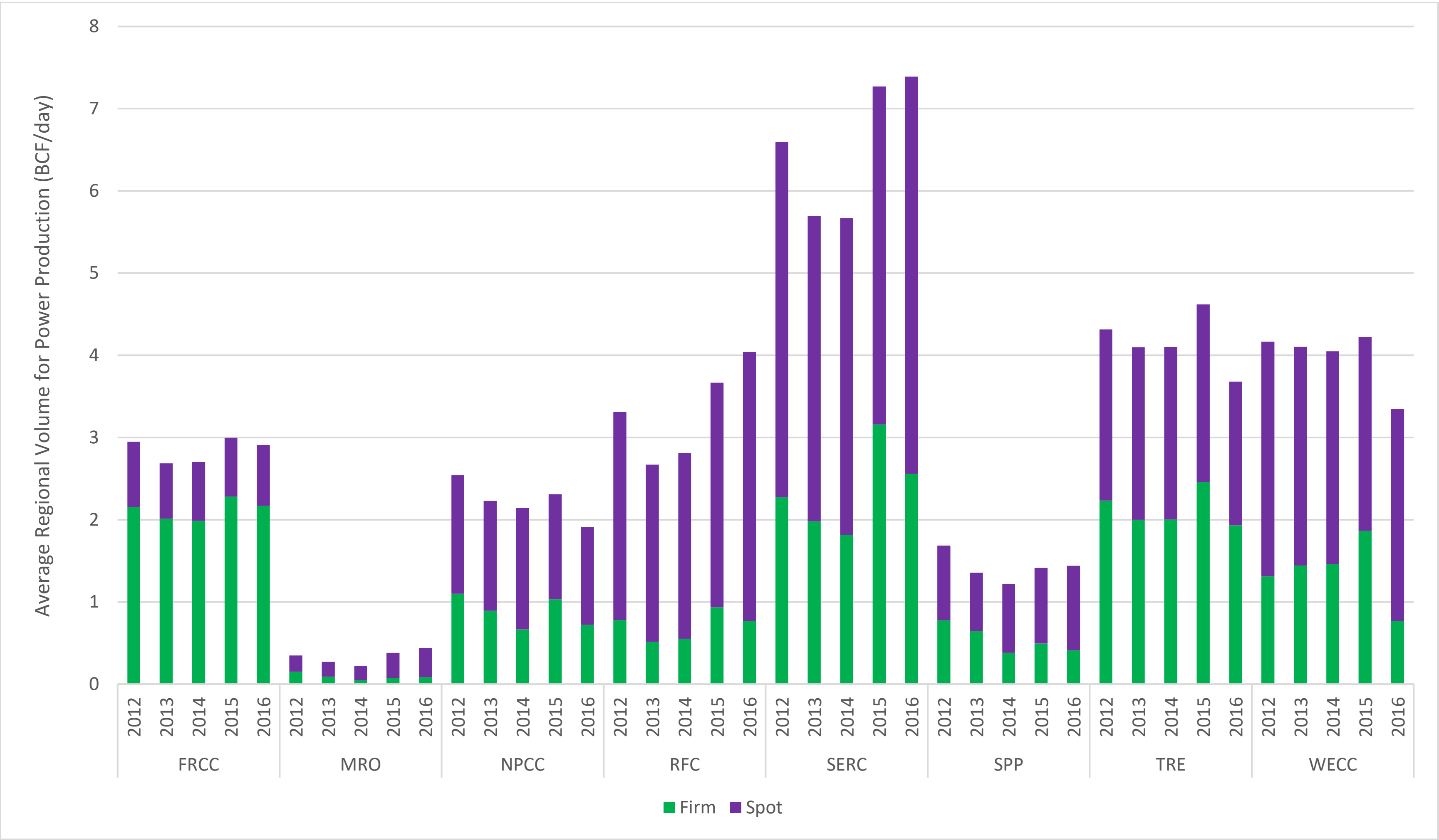


Exhibit 2-9 shows the amount of fuel purchased by NERC region. Generators in FRCC purchase more than two-thirds of their fuel through firm contracts, while those in RFC and SERC rely primarily on spot market purchases. It should be noted that in FRCC, natural gas generation constitutes nearly all pipeline demand, and plants do not have to compete with local distribution companies (LDCs) for firm transport service. In other regions, generators rely on a more even mix of firm and spot contracts. Pipeline outages are infrequent, and in most regions natural gas-fired generators do not frequently experience natural gas interruptions or curtailment. With respect to gas availability, relying on the spot market is a low-risk decision for most of these generators. For generators in NPCC, which has highly constrained pipelines with simultaneously high heating and electricity demands, choosing firm transportation would not necessarily mean that natural gas-fired generators experience fewer curtailments. Under a firm contract, pipeline customers pay a higher price for natural gas service. In the case of peak demand or a pipeline outage, firm transport customers receive shipments first. However, if there is insufficient supply to meet the demand of all firm transport customers, heating needs take precedence over generation and pipeline operators will not choose to curtail natural gas service to LDCs except as an absolute last resort.

Exhibit 2-9 Amount of fuel purchased 2012-2016 by NERC Region (SNL)



3 BLACK START

Black start is the procedure to recover from a total or partial shutdown of the BES. This entails isolated power stations being started individually, then gradually reconnecting to each other to form an interconnected system again. Under emergency conditions, black-start stations can independently start, synchronize, and connect to the grid. Not all power stations have, or are required to have, this black-start capability.

Historically, many coal-fired and almost all hydroelectric plants were designated as black-start sources to restore network interconnections. These coal-fired plants utilize on-site auxiliary generators that would provide station service power to start the main power station generators. A hydroelectric station needs very little initial power to start (just enough to open the intake gates). Certain types of combustion turbines, including natural gas-fired, can be configured for black start, providing another option.

Often, generating units may be designated as either “black-start capable” or “black-start certified.” Black-start certified refers to black-start resources that are linked to NERC Critical Infrastructure Protection (CIP) and/or other NERC reliability standards. For a generation unit to be considered black-start certified, it must meet criteria set by NERC. NERC reliability standard EOP-005-2 – *System Restoration from Black Start Resources* requires that each transmission operator have a restoration plan for using black-start resources following the shutdown of the BES. [1] The restoration plan must, among other things, include procedures of restoring interconnections with other transmission operators and identify each black-start resource. NERC’s reliability standard also requires that all black-start resources be tested at least once every three years to verify that they can meet the requirements of the restoration plan.

A regional transmission operator’s (RTO)/independent system operator’s (ISO) restoration plan does not necessarily include all generating units within its footprint that can provide black-start services, as some black-start capable units may not pursue certification. Further, an RTO/ISO typically only provides compensation for black-start generation it needs to fulfill the requirements of the restoration plan, meaning that a unit may have the capability to provide a black start, but doesn’t need to become a certified participant in the restoration plan.

Most RTOs/ISOs procure black-start services through their energy and ancillary service markets. Ancillary service markets allow the RTO/ISO to procure non-energy services that are necessary for maintaining the reliability of the BES, such as reactive power supply and reserves. The RTO/ISO provides compensation to black-start resources that are included in the restoration plan, with compensation generally funded by a fixed fee or charge assessed as part of the RTO/ISO transmission service tariff.

Each RTO/ISO procures and compensates black-start resources differently. Most designate generating facilities in the restoration plan as black start based upon their location and capabilities, choosing the facilities that are deemed necessary to re-energize a specific portion of the BES following a blackout, and that are the most market efficient in the procurement process. Such facilities must supply the real and reactive power required to reenergize the initial transmission lines, and be able to meet initial load.

After identifying black-start needs and technical requirements, PJM Interconnection, LLC (PJM) procures black-start generation through a request for proposal issued every five years. PJM evaluates the proposals it receives based on critical load requirements, and location, cost, and operational considerations. Compensation for black-start units is based on a formula rate that reimburses a generator for the cost of providing black-start services. [2] New York ISO (NYISO) periodically reviews its black-start needs and selects generators to provide black-start services. [3] For ISO New England (ISO-NE) and California ISO (CAISO), a generator that wishes to provide black-start service must submit an application showing that it meets the necessary criteria. In ISO-NE, if the generator's application is accepted, it becomes eligible for compensation based on a standard rate as defined by the ISO-NE tariff. [4] [5] In Midcontinent ISO (MISO), a generator that meets the technical requirements for providing black-start service may enter a service agreement with MISO for provision of said service. Black-start generators receive their cost-based revenue requirements for providing black-start service. [6]

As the number of coal-fired power plants declines, natural gas-fired generators are beginning to provide black-start services in their place. This raises concerns about the fuel surety of natural gas-fired generation, and whether they can be relied on to provide power in an emergency. Thus, the question of whether black-start generation has an incentive to procure firm fuel contracts or purchase fuel for on-site storage becomes important.

PJM compensates black-start units for storing liquefied natural gas (LNG), propane, and/or oil on-site. [7] ISO-NE requires that black-start resources have access to a fuel supply that will allow it to run at full capacity, although it does not specify whether this requires natural gas generators to maintain on-site storage as backup. [4] MISO, CAISO, and NYISO do not make any prescriptions regarding either pipeline access or on-site storage for natural gas-fired generators.

It is difficult to assess whether there is a relationship between the existence of firm natural gas contracts and RTO/ISO compensation for black-start generation, because the exact location of black-start certified generators is not made public due to market sensitivity and Critical Energy Infrastructure Information (CEII) identification requirements. Without this information, it is not possible to assess whether a higher percentage of natural gas-fired generators that obtain firm contracts also provide black-start services. NERC does not require black-start certified natural gas-fired units to obtain fuel through firm contracts.

4 GENERATION SUPPLY CURVES

Generation supply curves are graphs that show the accumulated generation able to dispatch in a region, ordered by price. Generators able to dispatch at a lower price will be lower on the supply curve, and thus, will dispatch more frequently. Higher priced generators will dispatch less. Exhibit 4-1 through Exhibit 4-9 show how increases in the price of natural gas change the dispatch order in each of the three U.S. interconnections—Electric Reliability Council of Texas (ERCOT), Eastern Interconnection, and Western Interconnection. Vertical load lines are placed on these supply curves showing the historic amounts of minimum load, the 5th percentile load, average load, 95th percentile load[d], and the maximum load for each region.

Fuel price changes directly affect generation pricing, and as a result, will shift the position of affected generators on the supply curve. A generator whose fuel pricing has shifted it significantly higher on the supply curve may be less likely to dispatch at that price point. This analysis aims to examine the points at which these generators might be less likely to enter into a firm contract due to lowered rates of dispatch. The strongest indicator of this likelihood is where these generators fall in relation to the historical load lines on the supply curves. A generator above the 95th percentile line is only likely to dispatch 5 percent of the time for a year, and a generator above the maximum load line is unlikely to ever dispatch. Units labeled Natural Gas consist of steam and internal combustion generating units, Natural Gas-CC are combined cycle units, and Natural Gas-GT are gas turbine units.

The base price at the time the data was pulled was \$2.92/MMBtu. Additional price points of \$4.00 and \$6.00/MMBtu were selected based on historic Energy Information Administration (EIA) numbers. An average of the monthly electric power price of natural gas from EIA for 2008-2012 is close to \$6.00, while that same average from 2012-2016 is close to \$4.00. As shown in Exhibit 4-1, at current natural gas prices, some ERCOT natural gas-fired generation is dispatched to meet minimum load, and is spread throughout the supply curve, with most being below the maximum load. At \$4.00/MMBtu, some natural gas-fired generation (Exhibit 4-2) is dispatched before the load reaches the 5th percentile, with nearly half the natural gas-fired generation dispatching past the 95th percentile. At \$6.00/MMBtu (Exhibit 4-3), some natural gas-fired generation is dispatched just after the load reaches the 5th percentile, with natural gas-fired generation dispatching past the average load. In this case, over half of the gas-fired fleet dispatches past the 95th percentile, serving as peaking capacity.

[d] The 5th percentile load is the value at which 5 percent of the recorded historical load values fell under for the period in question. The 95th percentile load value is the value at which 95 percent of the historic load values fell under for the period in question.

Exhibit 4-1 Current natural gas price ($2.92/MMBtu) in ERCOT

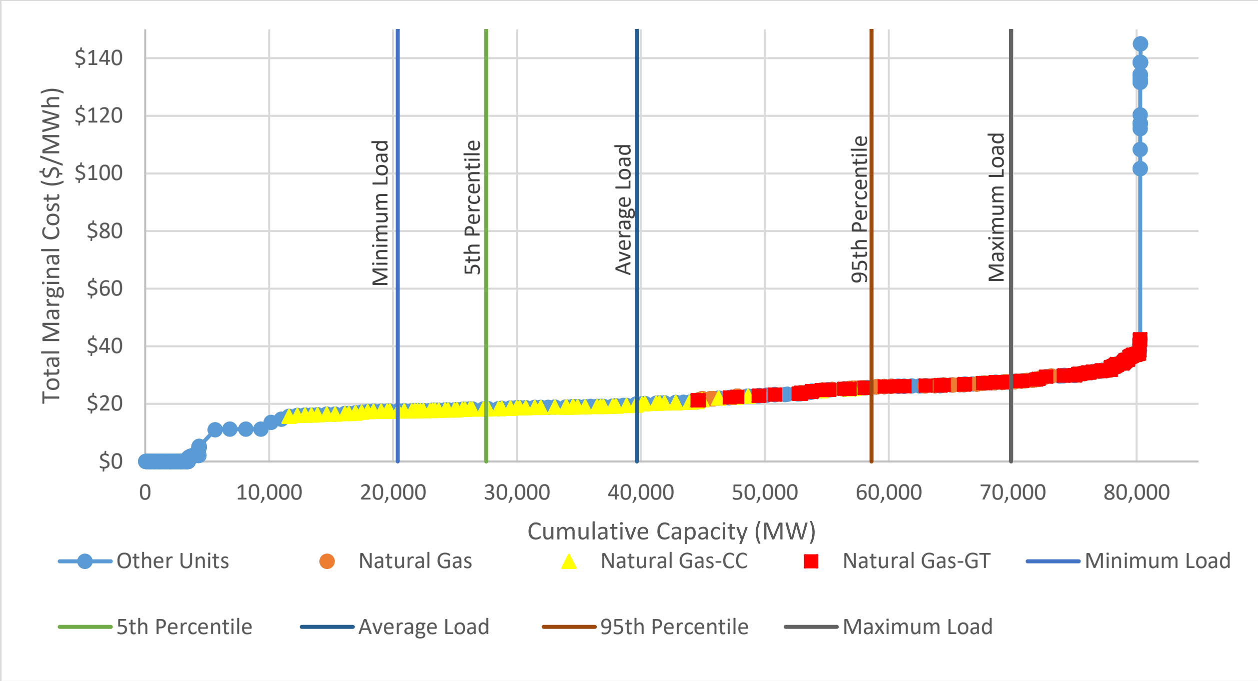


Exhibit 4-2 $4.00/MMBtu natural gas price for ERCOT

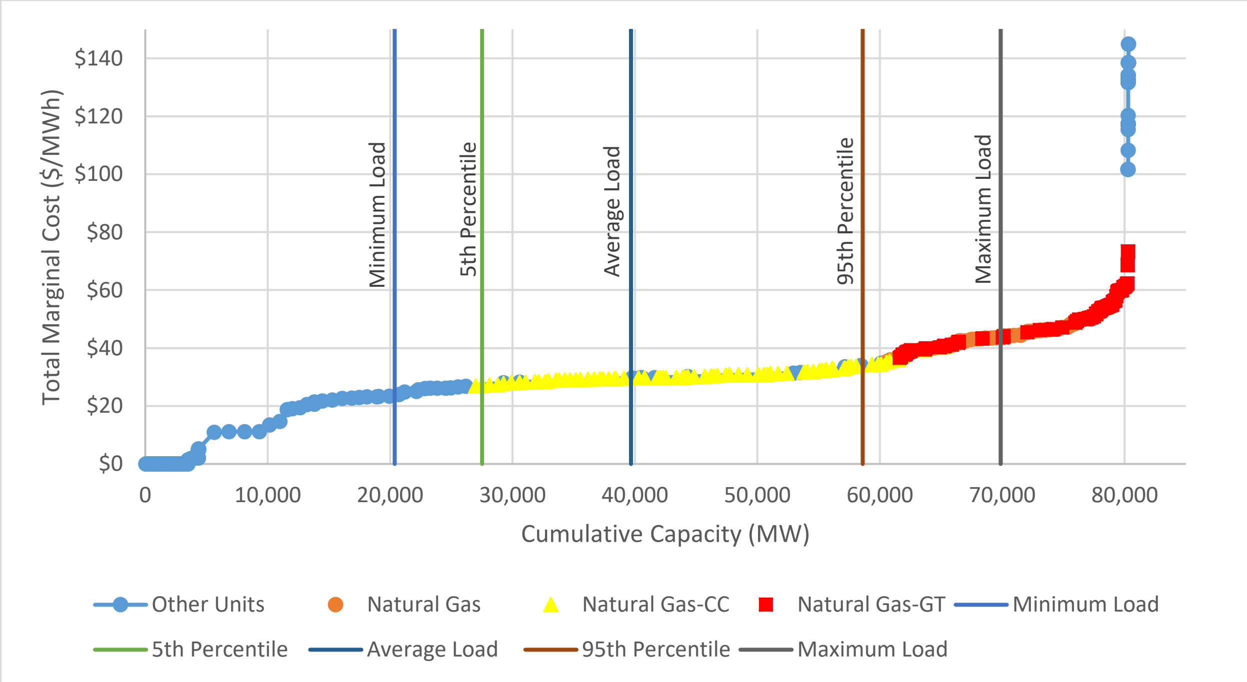
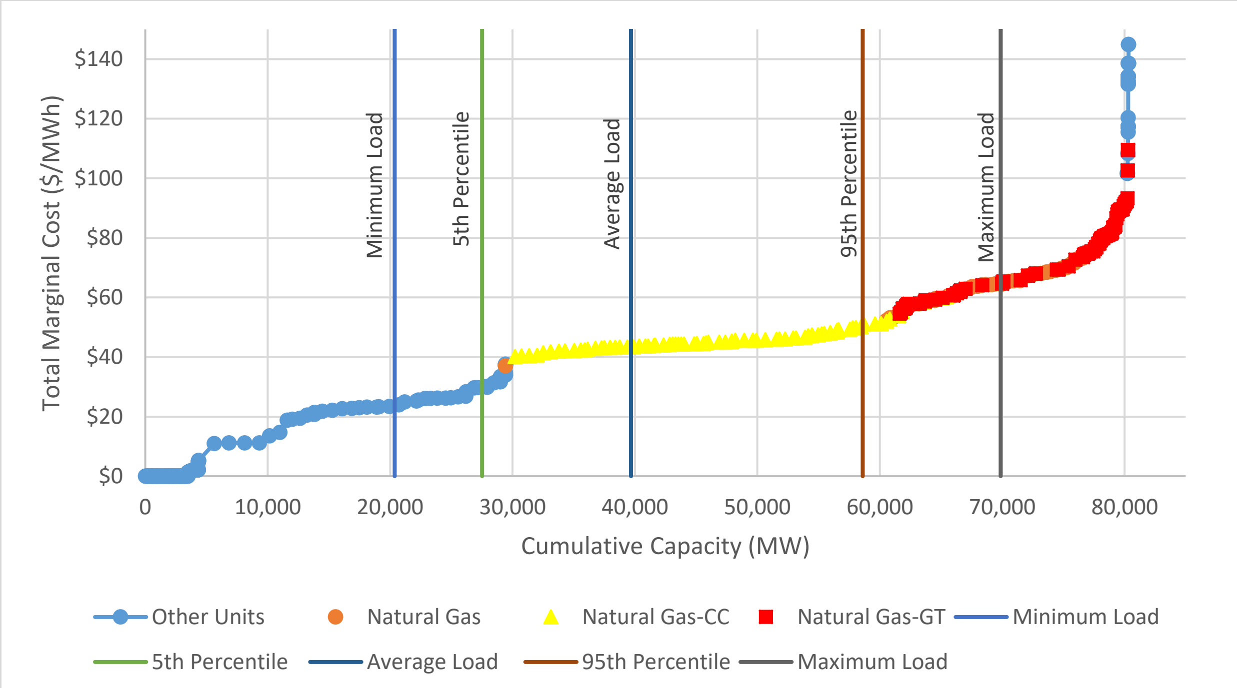


Exhibit 4-3 $6.00/MMBtu natural gas price for ERCOT



For the Eastern Interconnection[e], some natural gas-fired generation is dispatched, along with a mix of other fuel types, to meet minimum load at the current natural gas price (Exhibit 4-4). At $4.00/MMBtu, natural gas begins to dispatch at about average load, with over half above the 95th percentile load (Exhibit 4-5) showing that the Eastern Interconnection is less natural gas dependent than ERCOT. At $6.00/MMBtu, while some natural gas begins dispatching just after the 5th percentile load, most natural gas does not begin to dispatch until about halfway between average and 95th percentile load (Exhibit 4-6). Most of the natural gas generation in this case dispatches past the 95th percentile, with over half past the maximum load.

[e] The supply curves for the entire Eastern Interconnection are a synthetic blend, because there are six separate dispatch systems in this interconnection.

Exhibit 4-4 Current natural gas price for ($2.92/MMBtu) for Eastern Interconnection

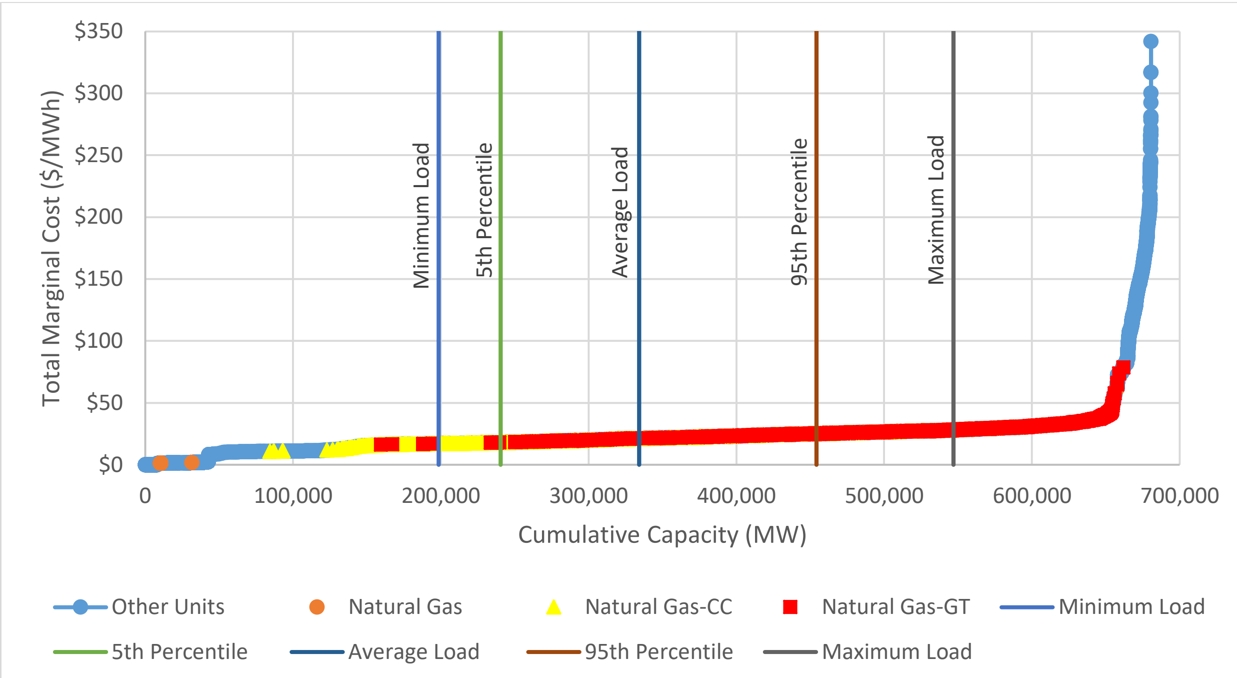


Exhibit 4-5 $4.00/MMBtu natural gas for Eastern Interconnection

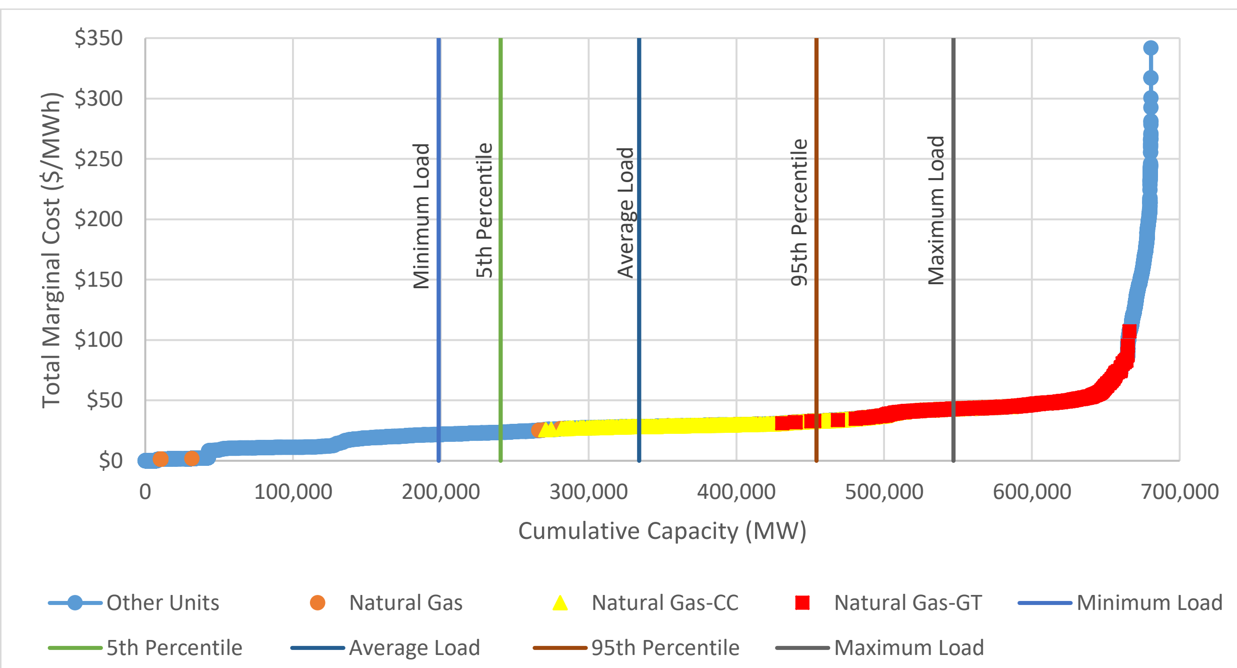
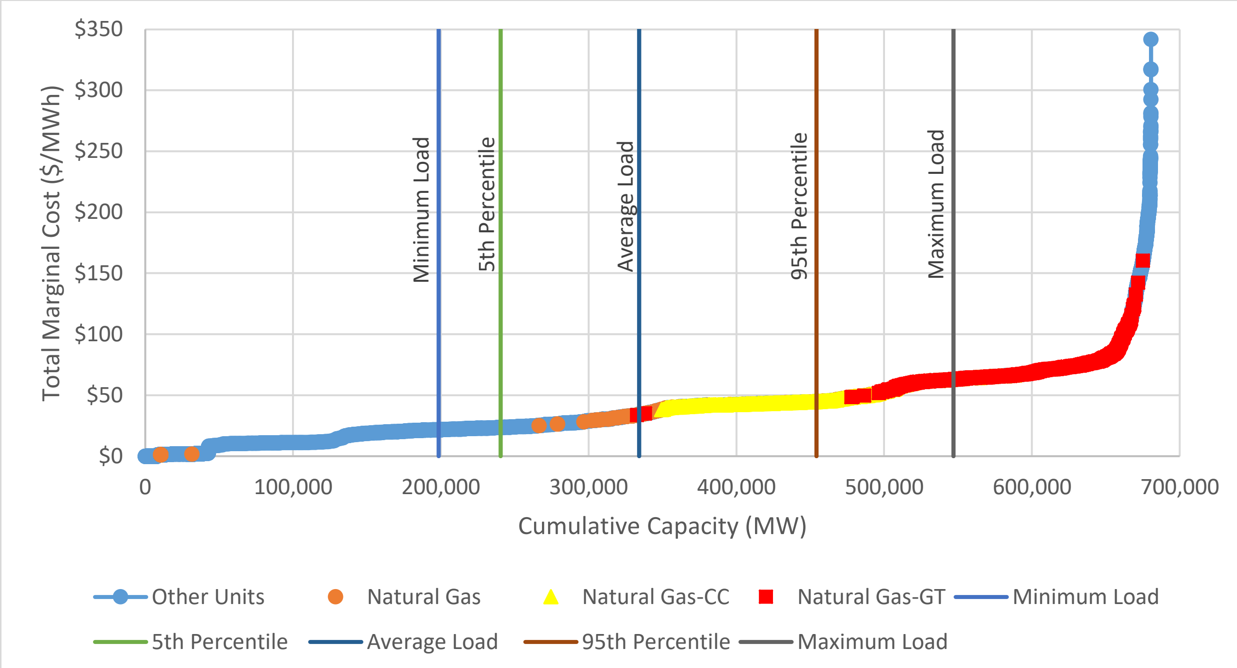


Exhibit 4-6 $6.00/MMBtu natural gas price for Eastern Interconnection



For the Western Interconnection[f], natural gas-fired generation begins dispatching to meet minimum load at current prices, with dispatch spread throughout the curve (Exhibit 4-7). At \$4.00/MMBtu, natural gas begins dispatching halfway between the 5th percentile and the average load.

Exhibit 4-8). At \$4.00/MMBtu, roughly two thirds of the natural gas generation dispatches above the 95th percentile load, with over half of all the maximum load point. At \$6.00/MMBtu, almost all-natural gas generation dispatches above the average load with 65 percent of the gas fired capacity being above the 95th percentile (Exhibit 4-9).

[f] Supply curves for all Western Interconnection are a synthetic blend, because there are two separate full energy markets and 38 balancing authorities in this interconnection.

Exhibit 4-7 Current natural gas price ($2.92/MMBtu) for Western Interconnection

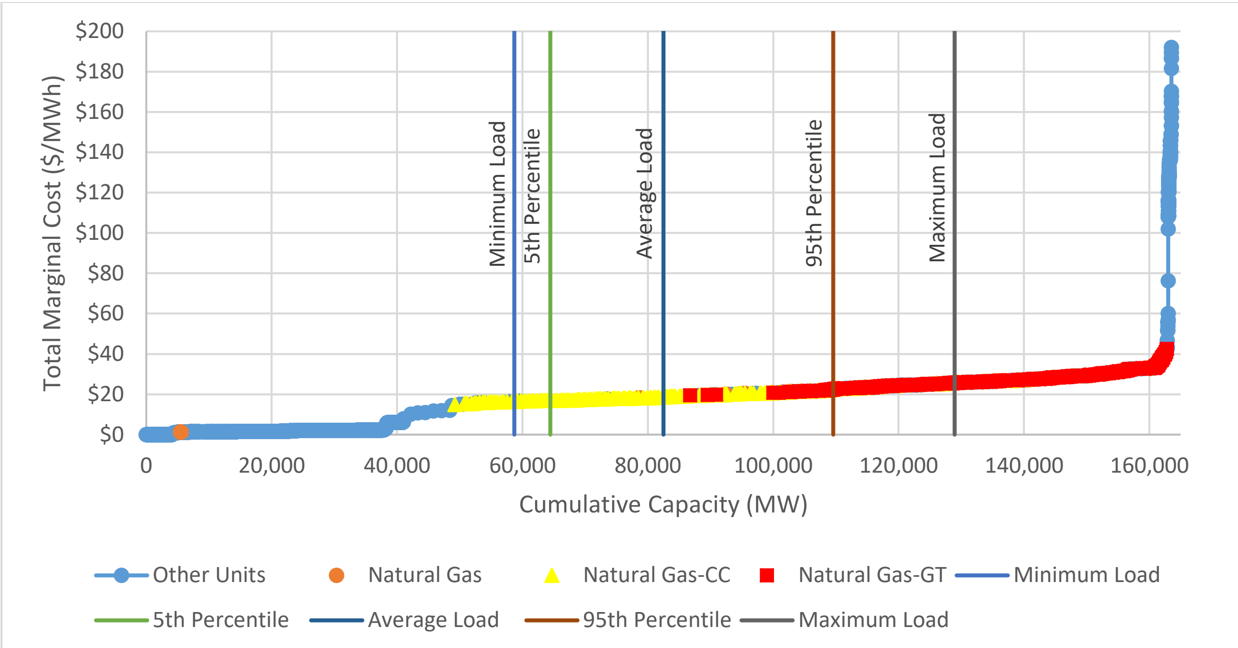


Exhibit 4-8 $4.00/MMBtu natural gas price for Western Interconnection

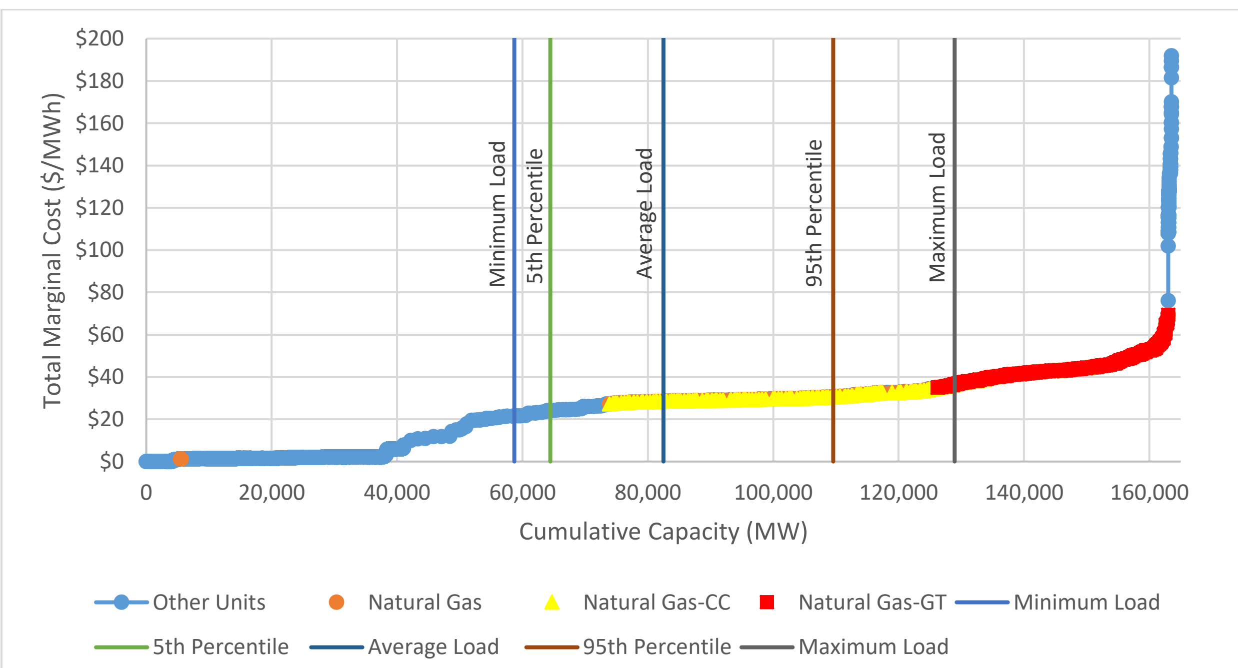
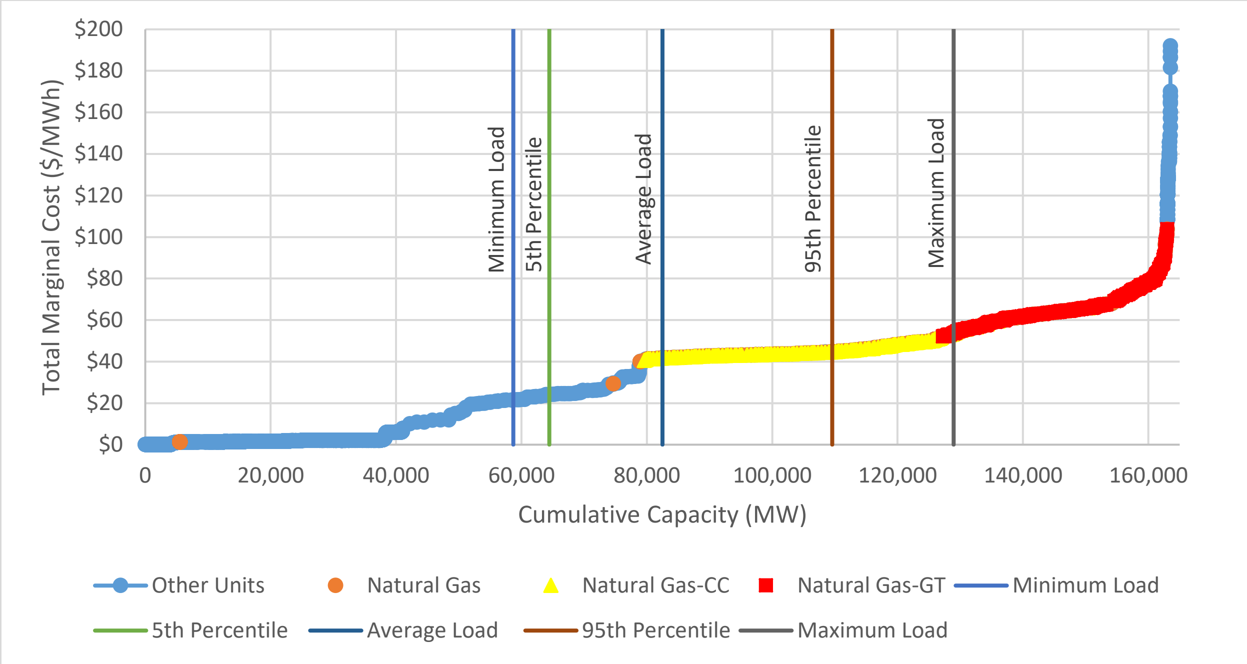


Exhibit 4-9 $6.00/MMBtu natural gas price for Western Interconnection



The supply curves serve to highlight how natural gas generators fall at different natural gas price points. Natural gas prices that push the generators higher in the supply curve would make them less likely to dispatch. The price points at which these generators would be unlikely to enter a firm contract depends upon the region in which the generator is located. For the ERCOT region, this price would appear to fall between $4.00 and $6.00, closer to $4.00. At the $4.00 price point, a sizable portion of the generators have shifted below the natural gas generators, with the dispatch prices being close to the previous graph. At the $6.00 price point, a sizable portion of them have shifted higher, with almost no other generation above the natural gas units, except for peaking oil units. For the Eastern Interconnection region, the price point would be closer to the $4.00 point, but between $4.00 and $6.00. At the $4.00 price point, roughly half the generation is about the maximum load point, while some remain under the 95th percentile load. At the $6.00 point, most have shifted above the 95th percentile load point. For the Western Interconnection, most of the generation has shifted above the average load value by $4.00, with 75 percent being above the 95th percentile load point by $6.00. Most of the natural gas generators shown in these supply curves would be unlikely to enter firm contracts if the agreed price would price them out of dispatching often. That point appears to fall in between $4.00 and $6.00 for the studied regions.

5 Natural Gas Storage Technology

One way to overcome the challenges associated with the just-in-time nature of natural gas fuel delivery is to increase on-site storage of natural gas for natural gas-fired generators. This section identifies the potential capacity for on-site storage by assessing the options for storing natural gas available to natural gas-fired generators.

Using information developed for a prior National Energy Technology Laboratory (NETL) report, *Assessment of the Impact of Natural Gas Co-firing on Coal Plant Life Extension*,[9] as a starting point, this report estimates the storage needs of an average natural gas-fired plant. This section

- Extrapolates the natural gas conversion impact on coal-firing plant heat rate;
- Determines the current average heat rates for coal-firing plant size groupings;
- Plots coal pile requirements vs. plant size for 30-day supply at 100% capacity factor (CF);
- Adjusts the heat rate basis on previous analysis and determines natural gas requirements by plant size;
- Plots natural gas requirements vs. plant size for a 1- and 30-day supply at 100 percent CF;
- Determines one-day storage size requirements for various storage types; and
- Estimates costs for various storage types.

Assumptions for the composition of natural gas are in shown in Exhibit 5-1. [12]

Exhibit 5-1 Natural gas composition

Component		Volume Percentage
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Total		100
Heating Value	**Lower**	**Higher**
kJ/kg	47,454	52,581
MJ/scm	34.71	38.46

[9] That paper is unpublished at this time.

Btu/lb	20,410	22,600
Btu/scf	932	1,032

Case 9 from NETL's *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3* ("Bituminous Baseline Report") – a subcritical pulverized coal (PC) plant with a nominal net output of 550 MWe is used as the baseline.[h] [12] Natural gas co-firing modifications include

- New gas burners, igniters, and scanners;
- Gas pressure reducing, metering, and piping;
- Updates to the boiler burner management system;
- Updates to the instrumentation and control system and installation of new NOx analyzers;
- Installation of bypass ductwork and damper around baghouse and flue gas desulfurization (FGD); and
- Miscellaneous electrical upgrades.

GateCycle™ software was used to model the modified reference plant burning low sulfur, high-Btu bituminous coal, with natural gas co-firing, ranging from 25 percent to 100 percent.

[h] The subcritical plant case was selected, because it represents the worst case as far the required amount of fuel storage required per kW produced.

Exhibit 5-2 Power summary

Power Summary (Gross Power at Terminals, kWe)				
	100% Coal (Base)	**25% Gas**	**50% Gas**	**100% Gas**
Steam Turbine Power, kWe	582,600	582,600	582,600	582,600
Total (Steam Turbine) Power, kWe	582,600	582,600	582,600	582,600
Auxiliary Load Summary, kWe				
Coal Handling and Conveying	410	320	220	0
Pulverizers	2,670	2,180	1,630	0
Sorbent Handling & Reagent Preparation	770	630	470	0
Ash Handling	520	430	320	0
Primary Air Fans	1,180	880	560	1,220
Forced Draft Fans	2,050	2,140	2,230	1,880
Induced Draft Fans	7,980	7,970	7,950	7,870
SCR	50	50	50	50
Baghouse	70	70	70	0
Wet FGD	2,710	2,310	1,770	0
Miscellaneous Balance of Plant	2,000	2,000	2,000	2,000
Steam Turbine Auxiliaries	400	400	400	400
Condensate Pump	890	890	890	890
Circulating Water Pump	5,250	5,250	5,250	5,250
Ground Water Pumps	530	530	530	530
Cooling Tower Fans	2,720	2,720	2,720	2,720
Transformer Losses	1,830	1,830	1,830	1,830
Total Auxiliaries, kWe	32,030	30,600	28,890	24,640
Net Power, kWe	550,570	552,000	553,710	557,960
Boiler Efficiency	88.74%	87.54%	86.30%	84.56%
Net Plant Efficiency (HHV)	37.16%	36.75%	36.35%	35.89%
Net Plant Heat Rate, Btu/kWh	9,184	9,286	9,390	9,511
Condenser Cooling Duty, MMBtu/hr	2,432	2,432	2,432	2,432

Exhibit 5-2 shows the power summary; Exhibit 5-3 shows the summary of results for consumables and emissions. The assumptions used in Exhibit 5-2 and Exhibit 5-3 are as follows:

1. Primary fans will be reused as forced draft (FD) fans for the 100% natural gas-fired case;
2. There is 98% SO_2 removal for all coal cases;
3. Selective catalytic reduction (SCR) is retained for NOx control for all co-fired cases, including 100% gas case; no gas recirculation system will be installed for NOx control;
4. NOx is controlled to 0.07 lb/MMBtu for all cases;
5. Natural gas has a 0.003 lb/MMBtu particulates emission factor;
6. Natural gas has a 0.5 gr/100 scf sulfur content; and
7. A detailed evaluation of FGD operation with natural gas co-firing was not conducted; the auxiliary power figures for the wet FGD are estimates only.

Exhibit 5-3 Consumables and emissions summary

Consumables and Emissions Summary				
	100% Coal (Base)	25% Gas	50% Gas	100% Gas
Consumables				
As-Received Coal Feed, lb/hr	371,536	282,471	191,020	0
Natural Gas, lb/hr	0	56,703	115,035	234,804
Limestone Sorbent Feed, lb/hr	18,658	14,185	9,593	0
Coal HHV Input, MMBtu/hr	5,057	3,844	2,600	0
Natural Gas Input, MMBtu/hr	0	1,281	2,600	5,307
Total Fuel HHV, MMBtu/hr	5,057	5,125	5,200	5,307
Emissions				
SO_2, lb/MMBtu (HHV)	0.037	0.028	0.019	0.001
SO_2, lb/MMBtu (Gross)	0.320	0.250	0.170	0.013
NOx, lb/MMBtu (HHV)	0.07	0.07	0.07	0.07
NOx, lb/MMBtu (Gross)	0.61	0.62	0.62	0.64
Particulates, lb/MMBtu (HHV)	0.01	0.01	1.00	0.00
Particulates, lb/MMBtu (Gross)	0.11	0.09	0.07	0.03
Hg, lb/MMBtu (HHV)	0.00	0.00	0.00	Negligible
Hg, lb/MMBtu (Gross)	0.00	0.00	0.00	Negligible
CO_2, lb/MMBtu (HHV)	1,734	1,577	1,417	1,073
CO_2, lb/MMBtu (Gross)	1,834	1,655	1,491	1,120

The results indicate that the boiler efficiency decreases from 88.74 percent during 100 percent coal firing to 84.56 percent when operating on 100 percent natural gas. Net plant heat rate increases by 3.44 percent. However, the net plant efficiency only decreases by 1.27 percentage points primarily due to the decrease in auxiliary loads allowing for a net power generation increase of 7.4 MWe.

Fully-loaded tested heat rate data was collected from Velocity (shown in Exhibit 5-4) for coal-fired plants that 1) utilize coal as the fuel more than 95 percent of the time, 2) are greater than 200 MW, and 3) have five-year average capacity factors (CFs) greater than 50 percent. Plants were grouped by size and coal type, and the averages of fully-loaded heat rates for each group were calculated.

Exhibit 5-4 Coal-firing unit heat rates (Velocity)

Size Group (MW)	Fully-Loaded Tested Heat Rates (Btu/kWh)		
	Bituminous	Subbituminous	Combined
200	10,141	10,259	10,191
300	10,300	10,272	10,288
400	10,228	10,603	10,340
500	10,053	10,295	10,103
600	9,754	9,902	9,802
700	9,875	10,252	10,021
800	9,810	9,857	9,817
900+	9,570	-	9,570

The assumed heating values for bituminous and subbituminous are 13,610 Btu/lb and 8,652 Btu/lb, respectively. Exhibit 5-5 shows the 30-day coal supply requirements for plants of diverse sizes.

Exhibit 5-5 30-day coal supply requirement

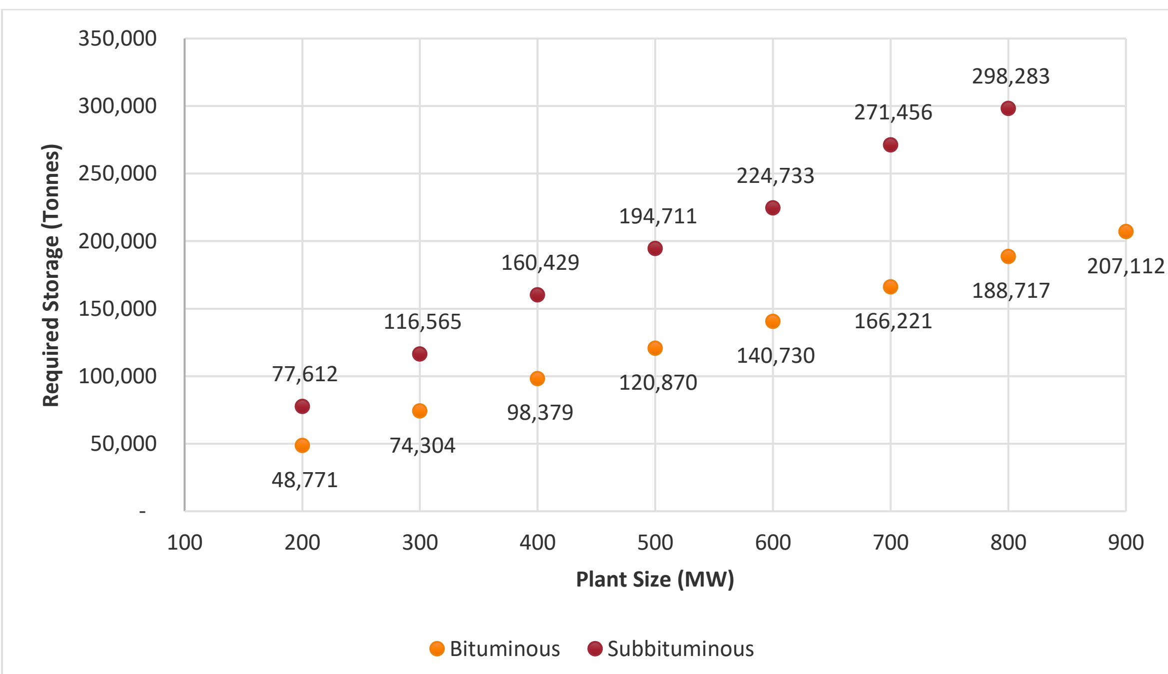


Exhibit 5-6 and Exhibit 5-7 show the rates of fuel usage by natural gas-fired plants according to size. It assumes a 100 percent load factor and a natural gas heating value of 22,600 Btu/lb.

Exhibit 5-6 Natural gas fuel requirements

Average Plant Size (MW)	Average Heat Rate – Coal (Btu/kWh)	Average Heat Rate – Natural Gas (Btu/kWh)	Firing Rate (Btu/hr)	Natural Gas Requirement (lb/hr)	Natural Gas Requirement (scf/hr)
200	10,191	10,554	2,110,811,930	93,399	2,045,360
300	10,288	10,655	3,196,354,598	141,432	3,097,243
400	10,340	10,708	4,283,347,142	189,529	4,150,530
500	10,103	10,463	5,231,462,303	231,481	5,069,246
600	9,802	10,151	6,090,720,795	269,501	5,901,861
700	10,021	10,378	7,264,602,320	321,443	7,039,343
800	9,817	10,167	8,133,388,567	359,884	7,881,190
900	9,570	9,911	8,919,842,585	394,683	8,643,258

Exhibit 5-7 Natural gas requirements

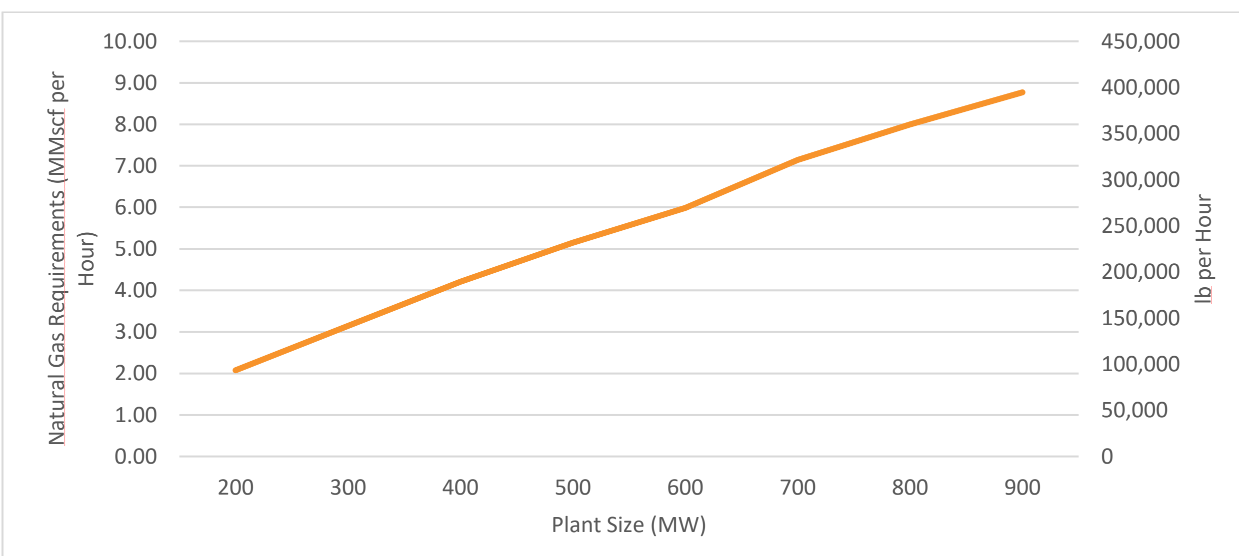


Exhibit 5-8 compares the quantity of fuel that would need to be stored for each fuel type, depending on the size of plant and number of days' supply.

Exhibit 5-8 Fuel storage requirements summary

Plant Size (MW)	Coal – Bituminous		Coal – Subbituminous		Natural Gas			
	1-Day Supply (Tonnes)	30-Day Supply (Tonnes)	1-Day Supply (Tonnes)	30-Day Supply (Tonnes)	1-Day Supply (Tonnes)	30-Day Supply (Tonnes)	1-Day Supply (MMscf)	30-Day Supply (MMscf)
200	1,626	48,771	2,587	77,612	1,019	30,567	49	1,473
300	2,477	74,304	3,886	116,565	1,543	46,287	74	2,230
400	3,279	98,379	5,348	160,429	2,068	62,028	100	2,988
500	4,029	120,870	6,490	194,711	2,525	75,757	122	3,650
600	4,691	140,730	7,491	224,733	2,940	88,200	142	4,249
700	5,541	166,221	9,049	271,456	3,507	105,199	169	5,068
800	6,291	188,717	9,943	298,283	3,926	117,780	189	5,674
900	6,904	207,112	-	-	4,306	129,169	207	6,223

There are four primary types of natural gas storage: 1) underground storage, 2) pressure vessel, 3) low pressure tanks, and 4) liquefied storage. The most ordinary form of underground storage is depleted natural gas wells, which can often store large quantities of natural gas. Salt domes are also used for storing natural gas underground. These types of underground storage are not often suitable for power plant storage, due to the requirement of either locating power plants adjacent to the formations or having sufficient pipeline infrastructure available to transport the gas from the storage formation to the plant. Large underground storage formations may also have operational constraints that limit when gas withdrawals can occur and the extraction rate of these withdrawals.

High pressure storage can be in the form of either tubes or tanks. For high pressure tubes, small tubes are typically bundled together. They are suitable for applications such as storage for a compressed natural gas (CNG) fueling station, but their small size makes them unsuitable for power plant applications. High pressure tanks can be spherical or cylindrical, with larger high-pressure vessels being typically spherical in design. Low pressure tanks operate at near atmospheric pressures and temperatures and are typically cylindrical in design.

The last category, LNG storage, can store natural gas in large quantities, but it requires liquefaction infrastructure and is highly energy intensive to maintain cryogenic temperatures. However, it is not suitable for power plant application unless the plant is located near an LNG facility.

Exhibit 5-9 shows the relative tank size needed to hold sufficient natural gas to support one-day operation for a natural gas combined cycle unit at full output. The number of high pressure tubes required is so great it excludes any serious consideration as a storage solution due to cost and space requirements. The number of high pressure and spherical tanks required are approximately the same for a given sized plant, while fewer atmospheric tanks would be needed because of their large volume. Atmospheric tanks, however, have a large footprint and would require a significant amount of land area to provide a single day's storage as also shown in Exhibit 5-9.

Exhibit 5-9 Relative tank size for one-day natural gas storage

Plant Size (MW)	High Pressure Tubes	High Pressure Tank		Spherical Tank		Atmospheric Tank	
	5,000 psi (# of tubes)	30,000 gal at 5,000 psi (# of tanks)	10 ft dia x 15 ft Required Area (Acres)[a]	26 ft diameter at 1,750 psi (# of tanks)	26 ft dia Required Area (Acres)[b]	50,000 m^3 [1,765,735 ft^3] (# of tanks)	100 ft dia x 50 ft Required Area (Acres)[c]
200	4,024	36	0.3	37	2.3	28	18
300	6,093	55	0.5	55	3.4	43	21.5
400	8,165	73	0.7	74	4.6	57	28.5
500	9,973	90	1	90	5.6	69	34.5
600	11,611	104	1	105	6.6	81	40.5
700	13,848	124	1.2	125	7.8	96	48
800	15,504	139	1.3	140	8.8	108	54
900	17,004	152	1.4	154	9.6	118	59

[a] assumed 5 ft between tanks
[b] assumed 25 ft between tanks
[c] assumed 50 ft between tanks

Exhibit 5-10 and Exhibit 5-11 show storage tank costs. Both exhibits show that the cost of storing natural gas on-site is high with Exhibit 5-10 presenting the costs of atmospheric pressure tanks and Exhibit 5-11 illustrating the potential costs associated with providing one-day storage. Even a small natural gas plant would be required to spend tens of millions of dollars to purchase an adequate amount of storage tanks for a single day's worth of natural gas.

Exhibit 5-10 Storage tank costs (atmospheric pressure)

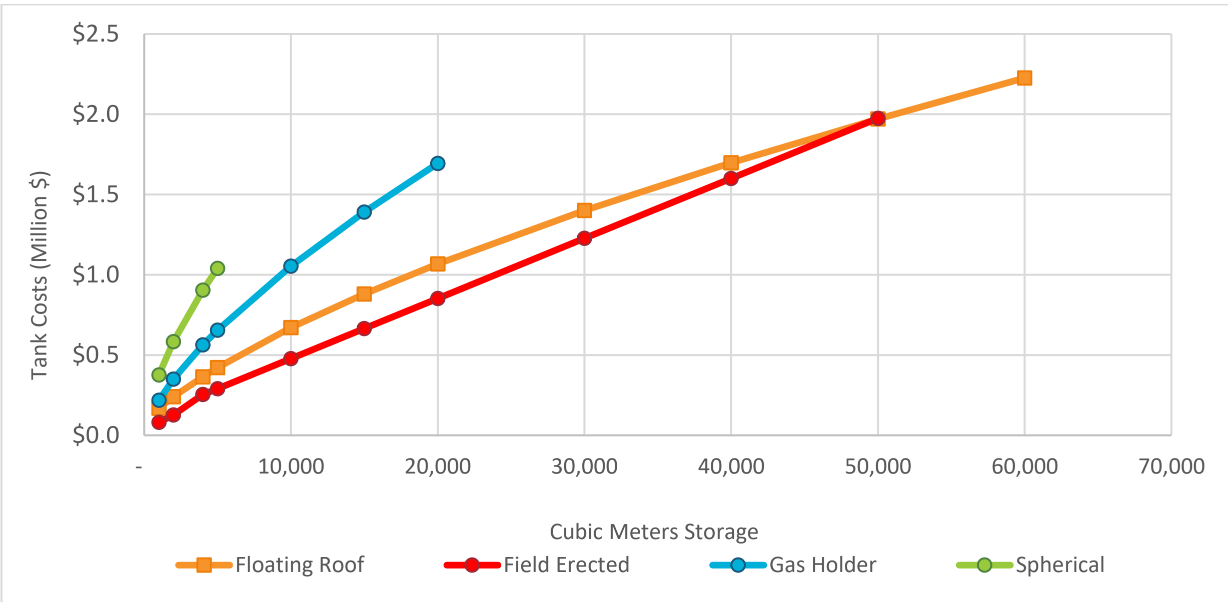


Exhibit 5-11 Above ground natural storage costs for one-day storage

Plant Size (MW)	Spherical Tank 26-ft diameter at 1,750 psi			Atmospheric Tank 50,000 m^3 [1,765,735 ft^3]			Comparison CC Plant with No Storage Overnight Capital Cost[3] (2012$M)
	Number of Tanks	Equipment Cost[1] ($M)	Cost @ 85% Cap. Factor over 20 yrs ($/MWh)	Number of Tanks	Equipment Cost[2] ($M)	Cost @ 85% Cap. Factor over 20 yrs ($/MWh)	
200	37	51.8	1.93	28	55.30	1.86	183.4
300	55	77	1.91	43	84.93	1.90	275.1
400	74	103.6	1.93	57	112.58	1.89	366.8
500	90	126	1.88	69	136.28	1.83	458.5
600	105	147	1.82	81	159.98	1.79	550.2

700	125	175	1.87	96	189.60	1.82	641.9
800	140	196	1.82	108	213.30	1.79	733.6
900	154	215.6	1.78	118	233.05	1.74	825.3

[1] $1.4 million from Aspen cost estimating, not including erection costs.
[2] $1.975 million, field erected from http://www.mhhe.com/engcs/chemical/peters/data/ce.html.
[3] EIA, Table 1. Updated estimates of power plant capital and operating costs, http://www.eia.gov/outlooks/capitalcost/.

Exhibit 5-12 describes natural gas pipeline pressure under normal operating conditions.

Exhibit 5-12 Natural gas transmission pipelines

Decade of Construction[1]	Pipe Diameter (inches)	Maximum Allowable Operating Pressure (MAOP)[2] (psi)	Natural Gas Mass[3] (lb/ft of pipe)	Natural Gas Heating Value[4] (MMBtu/ft of Pipe)	Natural Gas Heating Value[5] (MMBtu/mile of Pipe)
Pre - 1940	24	720	7.6	0.15	908
1940 - 1949	28	720	10.3	0.21	1,236
1950 - 1959	30	860	14.5	0.29	1,731
1960 - 1969	36	860	20.9	0.42	2,493
1970 - 1979	36	1,020	25.4	0.51	3,028
1980 - 1999	42	1,440	51.5	1.0	6,150
2000 - 2009	48	1,600	76.1	1.5	9,080
Present	48	1,750	84.4	1.7	10,068

[1] MAOP changes based on decade of construction.
[2] MAOP is a Pipeline and Hazardous Materials Safety Administration (PHMSA)-defined regulatory term.
[3] International Organization for Standardization created ISO 2213-2, which is the standard for calculating natural gas compressibility using the AGA8-92DC equation. The values calculated in the table were based on 15°C and 96.5% methane with minor specie of ethane, propane, butane, pentane, and hexane.
[4] Calculated at maximum allowable operating pressure. Typical distribution piping systems operate at lower pressures.
[5] Based on a natural gas higher heating value of 22,600 Btu/lb.

Exhibit 5-13 and Exhibit 5-14 show pipeline storage capacities to support one-day operation for a natural gas combined cycle unit at full output; Exhibit 5-15 shows average pipeline construction costs.

Exhibit 5-13 Pipeline nominal storage capacities for one-day operation at 100% load factor

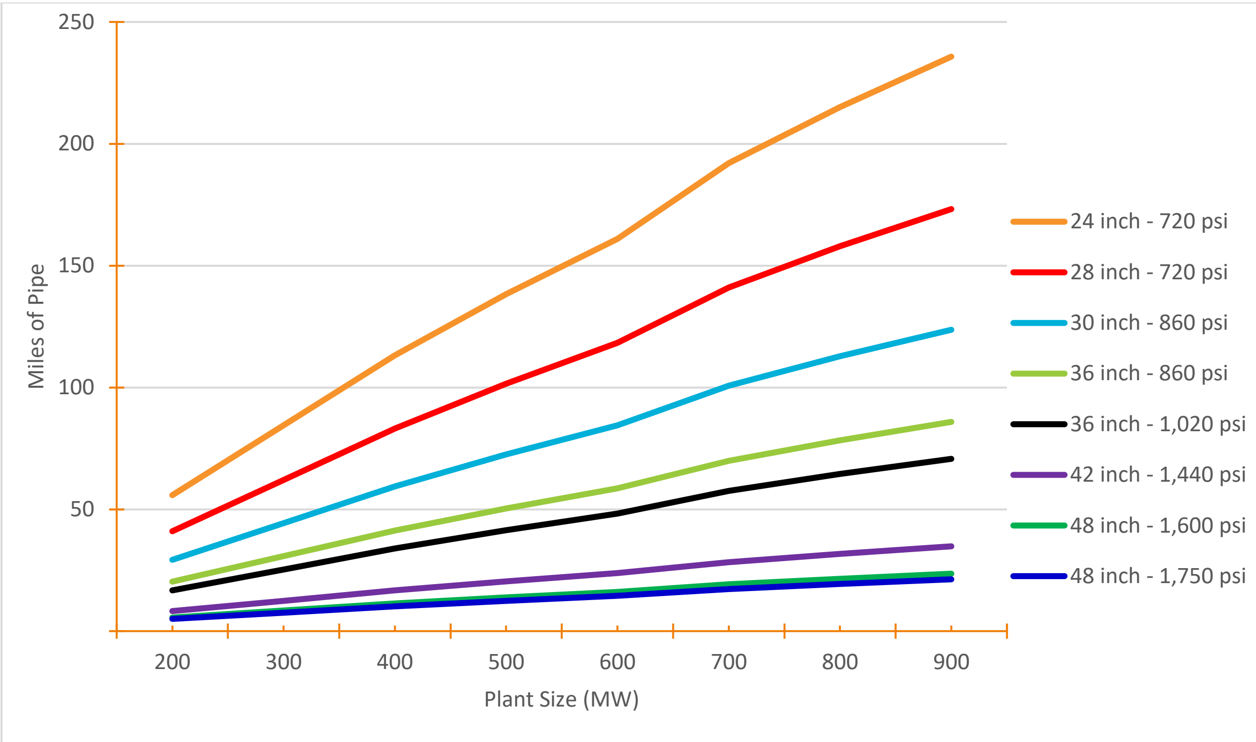


Exhibit 5-14 Pipeline nominal storage capacities for one-day operation at 500 MW plant at 100% load factor

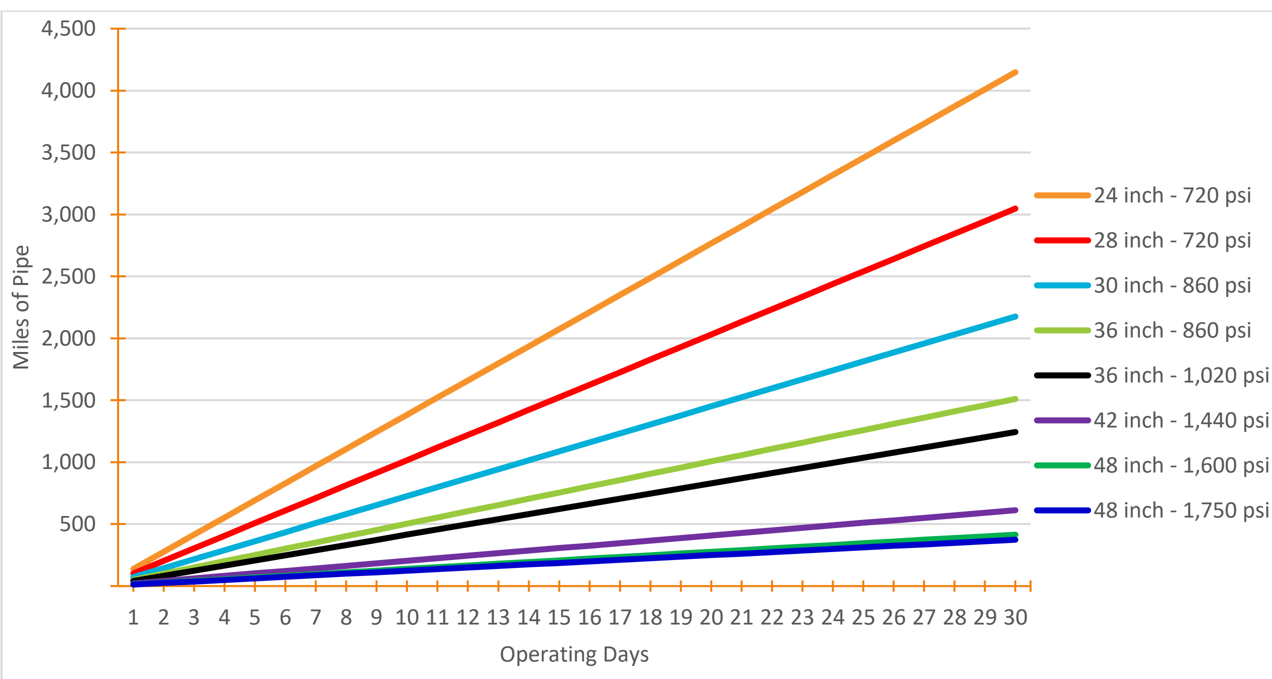


Exhibit 5-15 Pipeline construction costs

Pipeline Diameter (Inches)	Cost* ($M/mi)
24	3.72
28	4.34
30	4.65
36	5.58
42	6.51
48	7.44

* Average cost of $155,000/ inch-mile from Interstate Natural Gas Association of America (INGAA) 2014 report. [9] Reported costs can vary widely based on location and circumstances. Oil and Gas Journal reported 2014 pipeline costs ranged from $9,618 - $295,793 per inch-mile.

Exhibit 5-16 shows the costs to construct enough pipeline to support one-day natural gas combined cycle operation at full output.

Exhibit 5-16 Pipeline cost for one-day storage at $155,000/in-mi

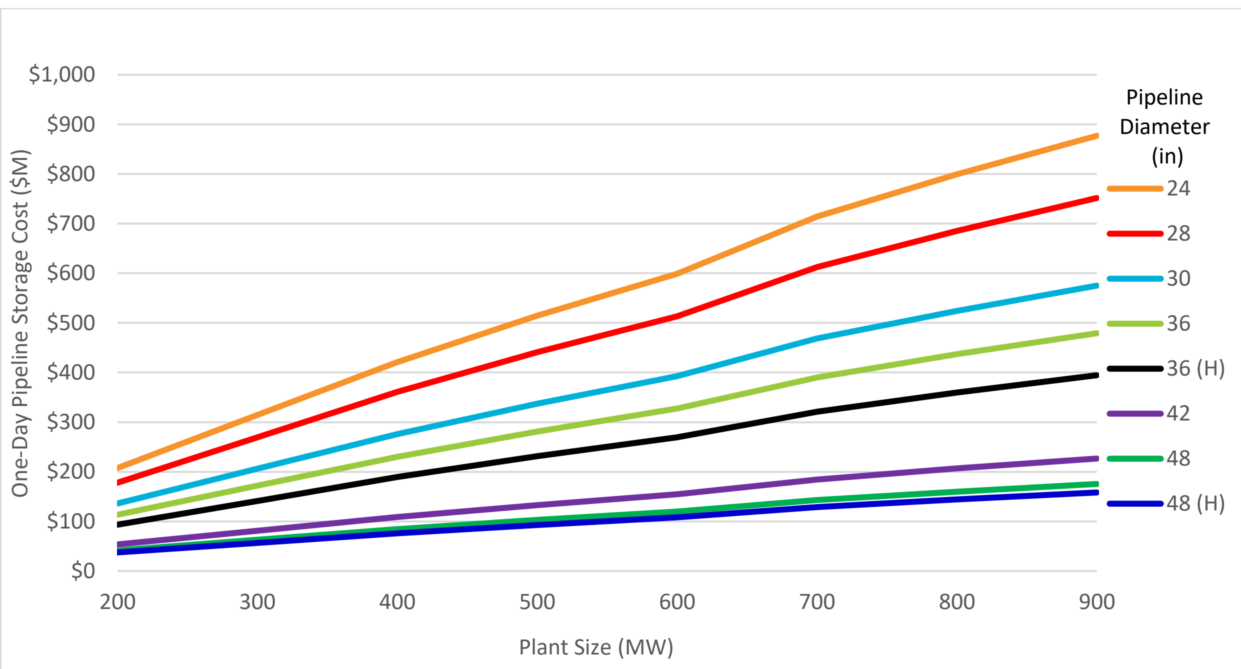


Exhibit 5-17 shows the costs of expanding or developing underground storage, which can hold much larger capacities than either above-ground storage or pipelines. Exhibit 5-18 shows the amount of storage that is needed to hold a 30-day operating supply of natural gas. Future work would be to identify the number of storage fields that could meet a 30-day storage for generators, along with other geological, geographical, and other criteria.

Exhibit 5-17 Underground storage costs

Field Type	Expansion of Existing Field ($M per BCF)*	Development of New Field ($M per BCF)*
Salt Cavern	$26	$31
Depleted Reservoir	$15	$18
Saline Aquifer	$30	$37

* Working gas capacity[i], 2012$, not including any additional transmission and distribution pipeline costs, from INGAA [9]

Exhibit 5-18 30-day storage requirements

Plant Size (MW)	30-Day Storage Requirement (BCF)
200	1.47
300	2.23
400	2.99
500	3.65
600	4.25
700	5.07
800	5.67
900	6.22

Exhibit 5-19 and Exhibit 5-20 compare the total and amortized capital costs for developing different types of storage capable of supplying enough natural gas to operate various-sized generators at full capacity. Depleted reservoirs are the lowest cost storage option, while 24-inch pipelines are the highest.

This analysis indicates the development costs associated with gas storage to provide one-day plant operation can be very high. The exception is the use of underground storage, which can store large amounts of gas but may be limited by geological or

[i] Working gas capacity represents the amount of recoverable gas from the reservoir, which varies by type of reservoir. Typical working gas percentages of total reservoir capacity are 70 – 80 percent for salt caverns, 50 percent for depleted oil/gas fields, and 20 – 50 percent for aquifer storage fields. [11]

operational constraints. Existing large, high pressure pipelines can provide some backup capability, but the amount may be limited by other consumers along the pipeline route.

Exhibit 5-19 Comparative one-day storage development costs

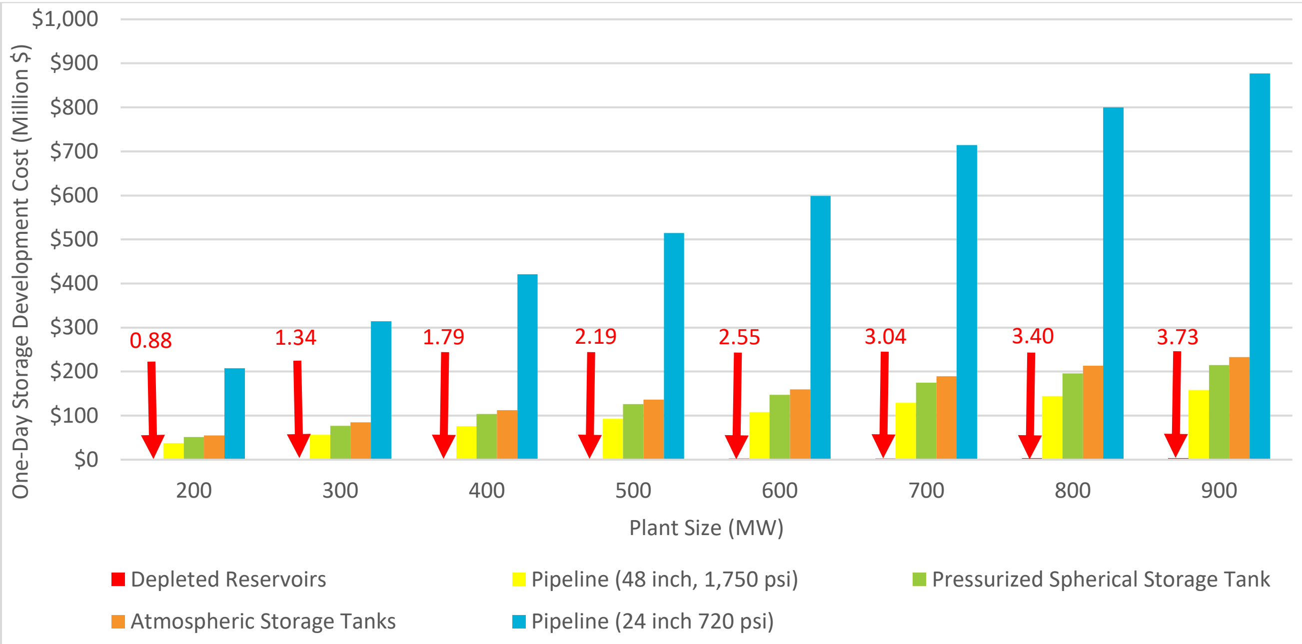


Exhibit 5-20 20-Year amortized storage development cost for one-day operational natural gas storage (natural gas combined cycle at 85% annualized capacity factor)

Cost Adder ($/MWh)				
Plant Size (MW)	**26-Foot Diameter Spherical Tank at 1,750 psi**	**Atmospheric Tank 50,000 m^3 [1,765,735 ft^3]**	**48-inch Pipeline at 1,750 psi**	**Depleted Natural Reservoir**
200	1.93	1.86	1.26	0.030
300	1.91	1.90	1.27	0.030
400	1.93	1.89	1.28	0.030
500	1.88	1.83	1.25	0.029
600	1.82	1.79	1.21	0.029
700	1.87	1.82	1.24	0.029
800	1.82	1.79	1.21	0.029
900	1.78	1.74	1.18	0.028

For comparison, the cost created by plant side storage of a coal for one day of operation is shown in **Error! Reference source not found.**. The costs assume the demurrage of one day of supply at the plant side on the delivering transportation mode.[j] This is not current practice and is shown only to create an equivalent comparison for the amortized cost of natural gas storage shown in Exhibit 5-20. It is assumed that the cost of on-site coal storage is included with land costs, while unloading, conveyance, and feeder costs are incurred regardless of coal pile size or storage mode. Based on this assumption, the avoided demurrage cost represents the intrinsic value of on-site coal storage.

Comparing the demurrage and amortized gas storage development cost reveals that both the railcar and barge storage options for coal are costlier than the depleted field storage option for natural gas on a dollar per megawatt basis across all plant sizes. Depleted storage, however, while considered in this paper, is not currently a viable option to support power generation because of operational limitations that restrict the ramping and cycling of depleted field facilities to 2-3 cycles per year. [14] Because of this, the most economic gas storage method to support power generation is through linepack, though even that method remains approximately 50 percent more expensive than storing coal. Since commodity prices for coal and gas are currently within a few cents of parity on a BTU basis, inventory cost of the commodities can be neglected. Under current market conditions, where technology costs are the significant driver in investment decisions, the cost of linepack storage has proven acceptable to some natural gas plant developers because they can continue to compete as baseload resources at high capacity factors.[k]

Exhibit 5-21 Amortized Benefit of On Site Coal Storage for One Day of Operation (Coal Fired Unit at 85% Annualized Capacity Factor)[l]

Plant Side Demurrage Cost ($/MWh)		
Plant Size (MW)	**Coal Hopper Railcar (102 Tons)** [15]	**River Barge (1,500 tons)** [16]
200	0.829	0.094

[j] Demurrage is a shipping industry term for the penalty charge assessed by for the detention of cars/barges by shippers or receivers of freight beyond a specified free time. [18] Because rail cars are traditionally unloaded upon delivery to a coal-fired power plant, the normal free time allotted under standard rail contract terms is four hours. [19] The normal free time allotted for barge unloading is 5 days, exclusive of Sundays and holidays. [20] While not the case, this analysis assumes the incurrence of demurrage costs to maintain one day of operational coal supply. Demurrage charges for rail range from $50 per car per day on Norfolk Southern lines to $200 per car per day on Union Pacific Lines. [23] [24] This analysis utilized the demurrage rate from BNSF Railway, $150 per car per day, because BNSF was the largest carrier of coal in 2016. [22] The barge demurrage rate utilized was $250 per barge per day. [21]

[k] As gas and coal prices move away from per Btu price parity with an increase in natural gas price, the fuel cost differential becomes a larger component of the dispatch price, meaning that market economics favoring natural gas storage for power may erode because commodity prices would need to be included in this assessment.

[l] Calculations to determine the volume of coal required for one day of operation utilize the 2016 class average heat rates for each of the megawatt classes illustrated in the table and the average heat content for coal delivered to coal-fired power plants in 2016.

300	0.818	0.093
400	0.816	0.092
500	0.802	0.091
600	0.771	0.087
700	0.809	0.092
800	0.773	0.088
900	0.765	0.087

6 SUMMARY

The report provides a high-level assessment of the state of natural gas contracts and potential for on-site storage. These topics directly impact the reliability of the BES, as generation shifts from reliance on coal and nuclear baseload to natural gas, which has fuel delivered just-in-time through pipelines. This increases the BES's vulnerability to fuel delivery outages or curtailments. Additional firm natural gas transport and storage could help to address this vulnerability.

Most natural gas-fired generators are located near major natural gas transmission pipelines, and most natural gas contracts are procured on the spot market. Although there is some regional variation in type of contract used, a strong pattern does not appear to emerge. Whether natural gas prices are higher with spot or firm contracts varies by both region and year.

ERCOT is more dependent on natural gas than Eastern Interconnection and Western Interconnection. Most of the natural gas generators shown in these dispatch curves would be unlikely to enter firm contracts if the agreed price would decrease their dispatch frequency. That point appears to fall in between $4.00/MMBtu and $6.00/MMBtu for the studied regions.

Above-ground storage is prohibitively expensive with respect to providing a long period of operational reserve fuel storage comparable to the amount of on-site storage used for coal-fired plants. Further, both pressurized and atmospheric tanks require a significant amount of land for storage, even at one-day operating capacity. Underground storage offers the only viable option for 30-day storage of natural gas, and that is limited by the location of salt domes and depleted natural gas wells.

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