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ISO New England Dual Fuel Capabilities to Limit Natural Gas and Electricity Interdependencies

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Acronyms and Abbreviations

B&W	Babcock and Wilcox	MCR	Maximum continuous rating
BACT	Best achievable control technology	MISO	Midcontinent Independent System Operator, Inc.
BkWh	Billion kilowatt-hours	MM	Million
Btu	British thermal unit	MMBtu	Million British thermal units
CAA	Clean Air Act	MMcf	Million cubic feet (natural gas)
CAISO	California ISO	MRO	Midwest Reliability Organization
CEMS	Continuous Emission Monitoring System	MW	Mega-watt (electric)
CELT	Capacity, Energy, Loads, and Transmission	MWh	Mega-watt hour (electric)
CF	Capacity factor	NAAQS	National Ambient Air Quality Standards
CO	Carbon monoxide	NERC	North American Electric Reliability Corporation
CT	Connecticut	NETL	National Energy Technology Laboratory
DEEP	Department of Energy and Environmental Protection	NG	Natural gas
DFO	Diesel fuel oil	NGCC	Natural gas combined cycle
DLN	Dry low NO _x	NO _x	Nitrogen oxide
DOE	Department of Energy	NPCC	Northeast Power Coordinating Council
EIA	Energy Information Administration	NSR	New Source Review
EPA	Environmental Protection Agency	NYISO	New York Independent System Operator
EPRI	Electric Power Research Institute	O&M	Operation and maintenance
ERCOT	Electric Reliability Council of Texas	PHMSA	Pipeline and Hazardous Materials Safety Administration
ESPA	Energy Sector Planning and Analysis	PJM	PJM Interconnection, L.L.C.
FERC	Federal Energy Regulatory Commission	PM	Particulate matter
FGD	Flue gas desulfurization	psi	Pounds per square inch
FO	Fuel oil	psig	Pounds per square inch gage
FRCC	Florida Reliability Coordinating Council, Inc.	quads	Quadrillion btu
FUA	Fuel Use Act	RCRA	Resource Conservation and Recovery Act
Gal	Gallon	RFC	Reliability First Corporation
GE	General Electric	RGGI	Regional Greenhouse Gas Initiative
GT	Gas turbine	RTO	Regional Transmission Organization
GW	Giga-watt (electric)	SERC	SERC Reliability Corporation
HHV	Higher heating value	SO ₂	Sulfur dioxide
hr	Hour	SPP	Southwest Power Pool
HRSG	Heat recovery steam generators	STG	Steam turbine generator
I/O	Input/Output	U.S.	United States
ISO	Independent System Operator	UARG	Utility Air Regulatory Group
ISO-NE	New England Independent System Operator	WECC	Western Electricity Coordinating Council
kW	Kilo-watt	WP	WorleyParsons
kWh	Kilo-watt hour (electric)		
LAER	Lowest achievable emission rate		
LDC	Local distribution companies		
LNG	Liquefied natural gas		

Executive Summary

Since 2000, natural gas has seen tremendous growth as a fuel source for electricity generation in the United States (U.S.) with annual installations exceeding 20 GW in all but four years. It also accounts for an increasingly significant share of the nation's electricity generation, growing from around 15 percent in the early part of the 2000s to between 26 and 29 percent in the last three years. (1)

Increasing reliance on natural gas has led to concerns that an extreme weather event – which may cause curtailments in gas delivery – or a natural gas infrastructure failure could lead to local or regional electric reliability issues. (2) These concerns stem from differences in delivery methods of natural gas to electric generating units (EGUs) contrasted with the fuel delivery and storage methods for traditional baseload power systems (i.e. coal and nuclear units).¹ (3) Although it seems that there is an abundance of natural gas in a post-shale gas world, infrastructure limitations and differences in electric and natural gas markets persist that differentiate natural gas-fired generators from traditional baseload power generators. Such concerns can be partially mitigated by modifying natural gas EGUs for operation on secondary fuels and installing on-site fuel storage for the secondary fuel, thus ensuring continuity of operation in the case of a gas delivery problem.²

This report examines technical, regulatory, and market issues associated with operating power plants primarily fueled with natural gas, on a secondary fuel, such as fuel oil or liquefied natural gas (LNG). In addition, a regional case study was completed to identify the current and near-term potential for dual fuel operation in New England, along with a market impact analysis of potential cost savings during an extreme weather event. The New England Independent System Operator (ISO-NE) was selected as the study area based on a preponderance of natural gas-fired generators contributing to the regional generating capacity mix (nearly 50 percent natural gas), limited natural gas supply infrastructure, and the potential for natural gas delivery disruptions due to cold weather events, exacerbated by the lack of bulk natural gas storage in the region.^{3,4}

The analysis found:

- The technical challenges to dual fuel operation are limited, but regulatory and safety hurdles exist. Other issues, such as lack of physical space for tanks, could also be a barrier.
- Onsite storage of secondary fuels exists at approximately 58% of dual fuel equipped plants in ISO-NE. The majority of facilities so-equipped have enough storage for 1.5 to 8 days of full-load operation, while select facilities can operate for up to 18 or 29 days.

¹ Natural gas is delivered by pipeline for immediate (“just-in-time”) use at natural gas-fired power plants, traditionally with little or no onsite gas storage. This is contrasted with coal units which typically store 50 to 80 days of fuel onsite, and nuclear units which refuel every 18 to 24 months.

² Natural gas-fired units are particularly amenable to fuel-flexibility, designed for multi-fuel operation or easily retrofit for such operation, and secondary fuels – particularly liquid fuels – can be stored in greater volume and at lower cost than natural gas.

³ Peak natural gas usage in the Northeast United States occurs during winter, when gas is used for home heating. During extreme cold weather events, competition exists between gas for home heating and for power generation, and natural gas deliveries can be curtailed to power generators to ensure gas is available to customers for heating. Extreme cold weather can also impact pipeline and power plant operation.

⁴ New England lacks the geology for bulk natural gas storage in geologic formations, meaning that gas intended for use in ISO-NE may enter a pipeline several hundred miles away. This distance can result in a delays in natural gas delivery after the onset of a severe weather event.

- Eighty percent of all natural gas-fired generation in ISO-NE lies within 10 miles of an existing non-natural gas pipeline, including 75% of the non-dual fuel capable units. Connections to these pipelines could obviate some of the need for onsite secondary fuel storage.⁵
- Unit operation on a secondary fuel could be critical to electric system reliability within ISO-NE during an extreme winter weather event.
- Dual fuel operation in ISO-NE would have an impact on pricing during an extreme winter weather event, but this effect decreases as gas prices increase.

Overview

In the U.S., nearly 180 GW, or approximately 25 percent of all fossil fuel generation, is reported as having dual fuel capability, and over 140 GW of that amount is reported as using natural gas as the primary fuel. (4) Regionally, 70 percent of U.S. dual fueled units are located in PJM Interconnection, L.L.C. (PJM) (22.3%), Midcontinent ISO (MISO) (22.1%), SERC Reliability Corporation (SERC) (13.3%), and the Southwest Power Pool (SPP) (12.2%), with most units in PJM and MISO built prior to restructuring and the implementation of the electric markets.⁶ Newer dual fuel units have been built in SERC where cost recovery mechanisms are available. Dual fuel units spent less than 5 percent of their operating time on their secondary fuel in 2013, while since 2013, utilization of dual fuel capabilities (operating on secondary fuel) at natural gas-distillate fuel oil units has increased to nearly 20 percent across the U.S.⁷

Conversion of simple cycle turbines and natural gas combined cycle (NGCC) units to be able to operate on a secondary liquid fuel is relatively straightforward with the addition of secondary fuel nozzles, cooling purge air, and, potentially, additional emission controls. (5) The major equipment addition is the requirement to build secondary fuel storage tanks. Depending on the size of the generator, tank capacity in excess of 1 million gallons is often required to provide a meaningful operational duration. Dual fuel operational impacts of simple cycle and NGCC units are limited to additional maintenance of the secondary fuel train and a slight decrease in efficiency due to additional auxiliary power requirements.

Conversion of a coal or oil-fired boiler to dual fuel operation using natural gas as the secondary fuel is also relatively straightforward with the addition of natural gas injection and control equipment. With proper placement and orientation of the gas injectors, boiler operations are typically not impacted and the maximum continuous rating (MCR) can be maintained. However, firing natural gas may cause a 3-5 percent efficiency loss of MCR depending on the boiler configuration. (6)

⁵ In addition to proximity to potential secondary fuel pipelines, a significant portion – 67 percent of all natural gas-fired generation in ISO-NE – was found to be within 10 miles of liquefied natural gas (LNG) storage tanks. These tanks are critical to local distribution companies (LDCs) in meeting winter peak gas day loads for home heating, and therefore the gas may not be available during weather events.

⁶ In 1999 FERC issued Order 2000 which fostered participation in Regional Transmission Organizations (RTO) and Independent System Operators (ISO).

⁷ Data in this paragraph contains information for both natural gas-fired simple cycle and combined cycle units. Coal/natural gas co-firing units were excluded from this analysis.

Regional Assessment of ISO-NE

The ISO-NE region was selected for evaluation because of its increasing reliance on natural gas generation and the potential limits of natural gas transmission infrastructure's ability to provide sufficient gas to maintain electric grid reliability during high demand periods. The analysis identified each natural gas-fired plant in ISO-NE greater than 100 MW, identified those plants reported to be dual fuel capable, and used overhead imagery to estimate secondary fuel storage capacity to determine the potential duration of secondary fuel operation. Additionally, plants that currently do not have dual fuel capability were examined, using overhead imagery, to determine if they had sufficient onsite space to install secondary fuel storage. A summary of these findings is presented in Exhibit ES-1.

Exhibit ES-1 ISO-NE Dual Fuel Summary – Natural Gas-Fired Power Plants with Winter Nameplate Capacities (>100 MW)

State	No. Gas-fired Plants/Winter Capacity (MW)	Current Plants with Secondary Fuel Capability/Winter Capacity (MW)*	Plants with Space for Potential Fuel Storage/Winter Capacity (MW)	Plants with No Space for Potential Fuel Storage/Winter Capacity (MW)
Connecticut	5/3,264	3/2,050	1/402	1/812
Maine	4/1,533	1/183	1/540	2/810
Massachusetts	14/6,740	11/5,317	1/1,071	2/352
New Hampshire	2/1,357	1/560	1/797	0/0
Rhode Island	4/1,861	1/510	2/763	1/588
Vermont	0/0	0/0	0/0	0/0
Totals	29/14,754	17/8,620	6/3,572	6/2,562

* Includes plants that currently appear to have on-site fuel storage but are not listed in the Velocity database as dual fuel.

Each of the above plants was also evaluated to determine its proximity to other existing fuel pipeline infrastructure and LNG storage facilities. This analysis indicated that 59 percent of all ISO-NE gas-fired generation lies within 5 miles of a non-natural gas pipeline and 80 percent lies within 10 miles. This analysis also indicated that 26 percent of all ISO-NE gas-fired generation lies within 5 miles of LNG storage and 67 percent lies within 10 miles.

An electricity supply curve model was created for ISO-NE to determine the economic impact of natural gas-fired dual fuel capability. Several scenarios were developed for the “Polar Vortex” peak day in 2014⁸ when the ISO-NE electricity market price peaked at over \$737/MWh⁹. These scenarios included:

⁸ Peak ISO-NE day, January 7, 2014.

⁹ The average Summer peak price for the New England ISO is around \$82.65/MWh (4)

- Nominal operations – Plants operating using average fuel prices
- High gas – Natural gas plants operating using high natural gas spot price
- Dual fuel natural gas (NG)-fired and fuel oil plants operate at fuel oil (FO) spot price/all single firing NG plants offline. Dual fuel plants have switched to secondary fuel and fuel oil plants are operating at spot price. All remaining natural gas generation is offline, which simulates a shortage of natural gas supply
- Dual fuel and fuel oil plants operate at FO spot price; NG plants operate at NG spot price

Exhibit ES-2 presents the results of this modeling depicting a spot natural gas price of \$85/MMBtu and demand resource is bidding in at \$1,000/MWh.^{10,11,12} This model indicates that dual fuel capability can potentially decrease the peak electricity price during high natural gas spot price conditions by allowing dual fuel generators to operate using less expensive secondary fuel. The model also indicates that the effective peak load (accounting for generation forced outages/derates) cannot be met if all of the gas generation is forced offline due to natural gas shortages.

The economic dispatch analysis reveals that, during the Polar Vortex and at a natural gas spot price of \$85/MMBtu, having dual fuel capability reduces the price by about \$67/MWh at peak hour. A sensitivity analysis, presented later in this report, evaluated the impact of natural gas price on electricity price. This analysis indicated that for the averaged spot market price of \$102.875/MMBtu,¹³ the price reduction decreases from \$67/MWh to \$14/MWh. This decrease is caused by the shift in generator offers due to the change in gas price, which narrows the gap between the high gas and high gas/dual fuel scenarios.

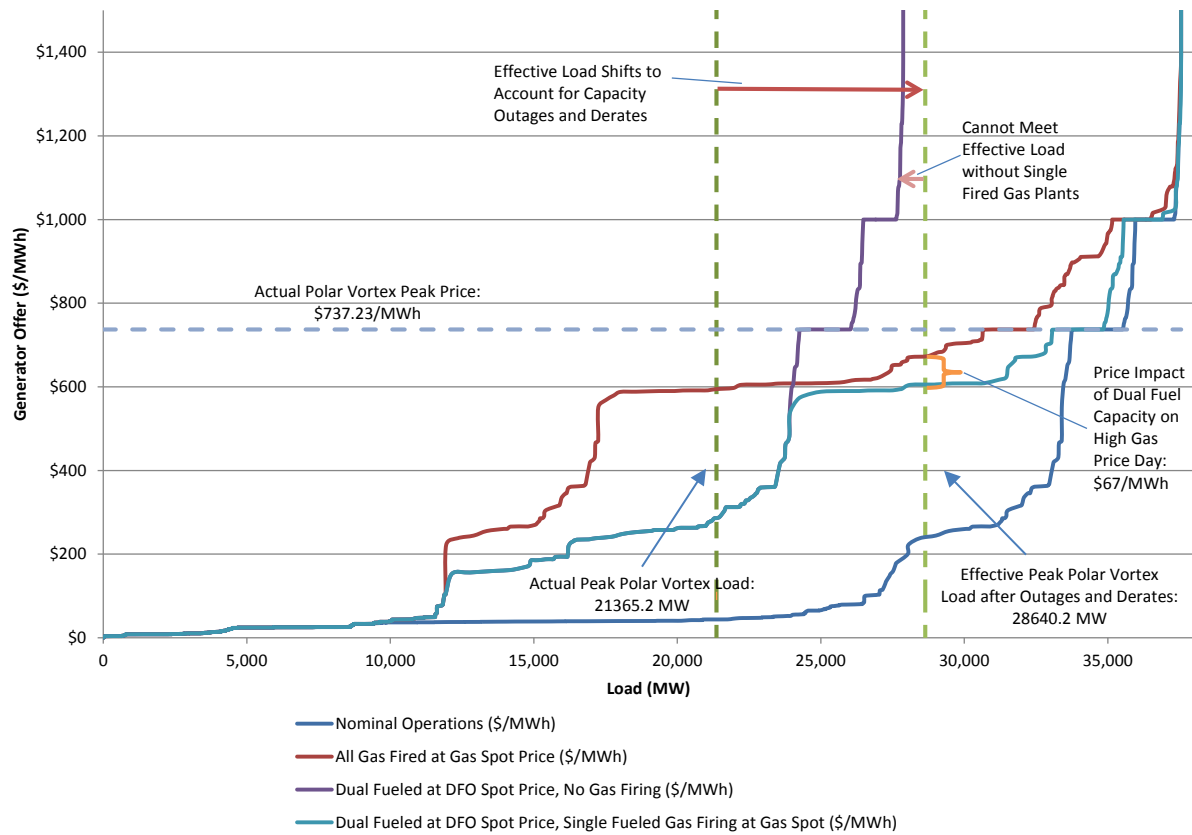
¹⁰ Demand response resources reduce peak electricity demand by offering to not consume electricity for a certain price. Historically in ISO-NE these resources have provided up to 2 GW to the resource mix.

¹¹ The average annual natural gas price in ISO NE is \$7.33/MMBtu and the average Winter natural gas price for 2014/2015 was \$10.70/MMBtu. (8)

¹² \$1000/MWh bid rate as defined in Section I.2.2. of the ISO-NE Transmission, Markets, and Service Tariff. (25)

¹³ Average natural gas spot market prices seen in New England and New York during the Polar Vortex.

Exhibit ES-2 Dispatch Curves for Natural Gas-Fired Capacity Scenarios at \$85/MMBtu Natural Gas Spot Price (4)



1 Introduction

Since 2000, natural gas has been used increasingly as a fuel source for electricity generation, with generation doubling over that timespan from 518 billion kilowatt-hours (BkWh) in 2000 to 1,029 BkWh in 2014. (1) This has corresponded with natural gas generation accounting for an increased share of the nation's electricity generation, growing from around 15 percent in the early part of the 2000s to between 26 and 29 percent in the last three years. (1)

Increased reliance on natural gas as well as the nature of natural gas delivery has led to concerns that an event such as extremely cold weather or a natural gas infrastructure failure could lead to local or regional electric reliability issues indicating a potential need for increased dual fuel operation from natural gas generating capacity. During the 2014 "Polar Vortex" event a major portion of the Northeast experienced a period of record cold. This extreme cold weather led to the unavailability of some natural gas deliveries and record high spot natural gas prices. These factors led several dual fuel capable generators to use their secondary fuels due to either cost or fuel availability. This, in turn, led to concerns that secondary fuel generation would not be available if the cold weather persisted and natural gas shortages developed.

Although Title II of the Power Plant and Industrial Fuel Use Act of 1978 (FUA) (7) requires that all new natural gas-fired capacity must be capable of operating on a secondary fuel, it does not require the capability to switch fuel in real time. However, the FUA does require that the plant be capable of generating electricity while burning the alternate fuel. Therefore, new plants are not required to have the additional infrastructure, such as fuel storage, to operate as dual fuel plants.

The study presented in this report was undertaken to better understand the current state of dual fuel generation in the U.S. Several of the overarching questions to be answered include the following:

- How many dual fuel capable generators are in the U.S., and where are they located?
- What types of systems are amenable to dual fuel operation?
- What are the secondary fuels, and how often are they used?
- What are the secondary fuel delivery and storage options/requirements?
- What are the required system modifications to enable dual fuel operation and what is the impact on efficiency?
- What are the market impacts of having dual fuel capabilities?
- What are the regulatory/permitting requirements for dual fuel conversion?

An analysis of the New England Independent System Operator (ISO-NE) region was completed in order to understand the generating capacity of dual fuel plants and the capabilities of current dual fuel plants in terms of the potential duration of dual fuel operations. This analysis also includes a regional determination of which non-dual fuel plants could be converted to dual fuel operation.

A dispatch model was completed to understand the regional market impact of available dual fuel generation by comparing various scenarios of differing fuel pricing and availability.

2 Existing Natural Gas Electric Generating Units Capable of Dual-fuel Operation

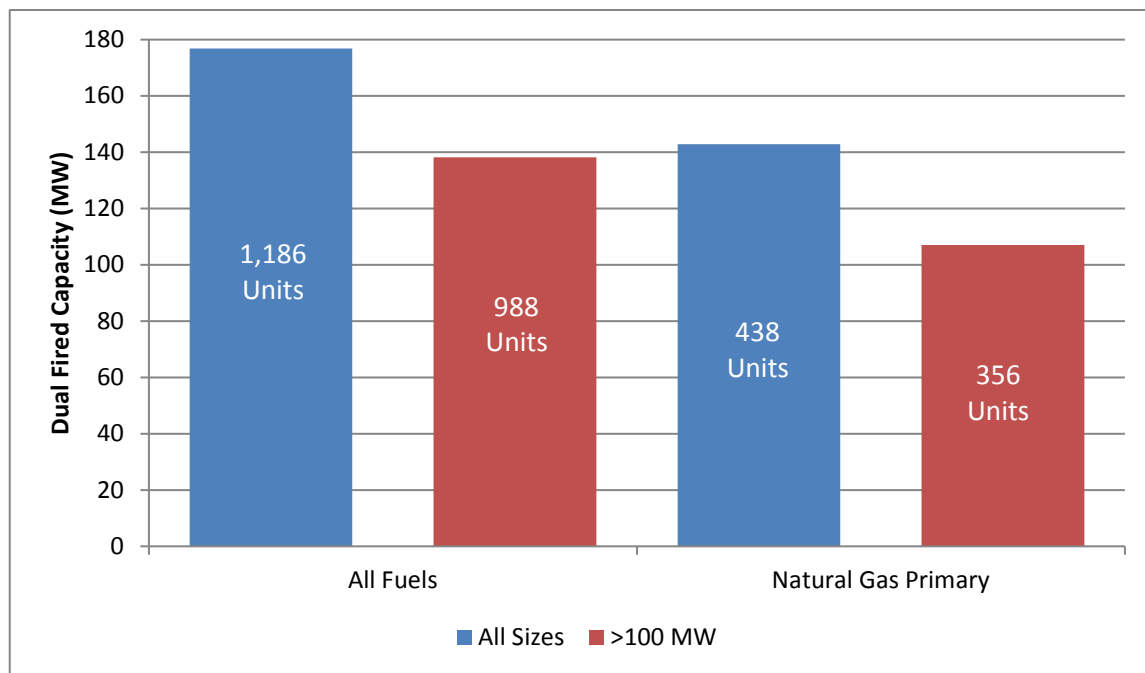
2.1 Number of Total Units and Capacity by ISO/RTO and Age

2.1.1 Current National Summary of Dual Fuel Plants

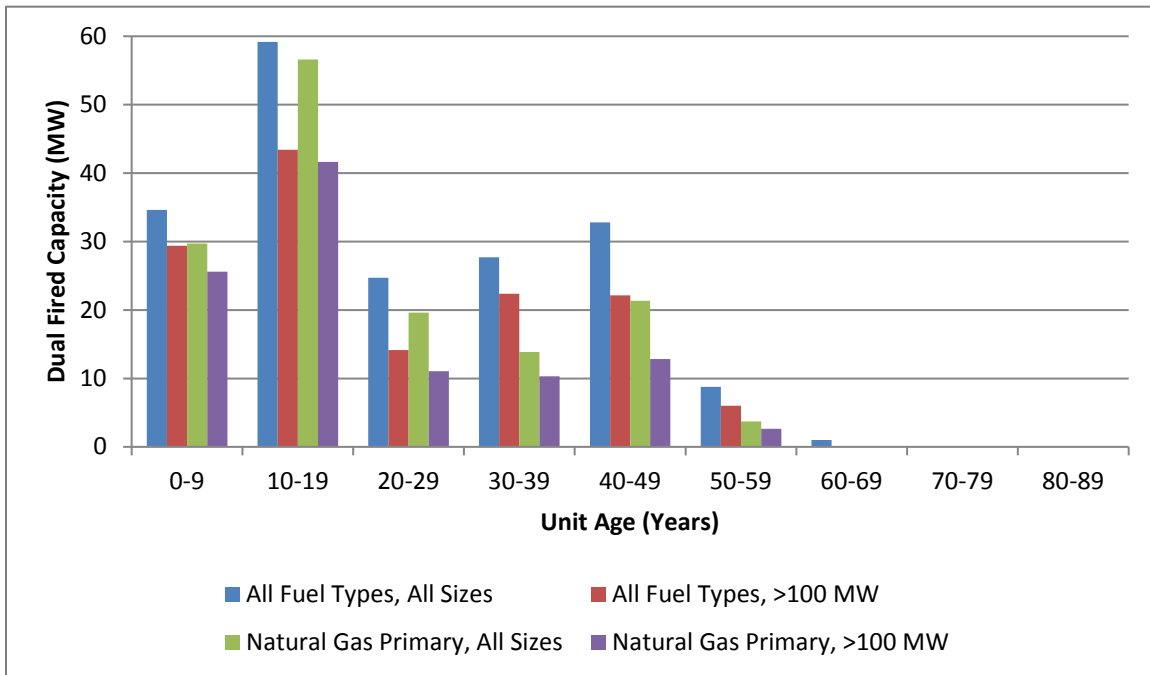
The first step in evaluating the potential impacts of dual fuel firing generators on the electric system was the identification of all such capable generators within the U.S. This data was collected from Ventyx's Velocity Suite Generating Unit Capacity query, which lists units that report as dual fuel capable in the various regulatory filings. (4)

Exhibit 2-1 shows that a majority of the capacity reporting as dual fuel capable domestically is natural gas-firing with all other fuels constituting only 19 percent of the total dual fuel capable capacity. The exhibit also shows that dual fuel capability is most likely to be found in generators larger than 100 MW. Breaking the data down by unit age (Exhibit 2-2) shows an increase in the installation of dual fuel capacity 10 to 19 years ago (1995-2005) which corresponds to the period of restructuring and the implementation of the electric markets.¹⁴

Exhibit 2-1 U.S. Fossil Fuel-Fired Electric Generating Units Reporting as Secondary Fuel Capable (4)



¹⁴ In 1996, FERC issued its Order No. 888, a final rule regarding electric industry restructuring and in 1999 FERC issued Order 2000, which fostered participation in Regional Transmission Organizations (RTO) and Independent System Operators (ISO).

Exhibit 2-2 U.S. Electric Generating Units Reporting as Secondary Fuel Capable (by Age) (4)

Unit	Number of Units by Age (Years)								
	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80-89
All Fuel Types, All Sizes	339	784	371	240	615	182	61	7	3
All Fuel Types, >100 MW	60	188	63	47	66	28	0	0	0
Natural Gas Primary, All Sizes	155	468	268	143	439	70	5	0	0
Natural Gas Primary, >100 MW	53	180	56	24	37	12	0	0	0

From a power system operating area perspective, the largest volumes of dual fuel capable capacity in both number of units and capacity are located in PJM Interconnection, L.L.C. (PJM) and the non-market areas of SERC Reliability Corporation (SERC). Exhibit 2-3 and Exhibit 2-4 illustrate the system disposition of dual fuel capability by market area and NERC region. It is key to note that the overlapping boundaries of North American Electric Reliability Corporation (NERC) regions and market footprints create a wrinkle in any analysis of dual fuel capability using NERC regions, as generators in different market areas may experience different economic pressures and load service obligations. For instance, while a generator in the Dominion Virginia Power zone of PJM would reflect as a SERC generator from a NERC region perspective, from a market perspective, it would reflect as a PJM generator. Issues with using only the NERC perspective arise most severely when parts of a region remain regulated and without a power market-based dispatch, while other parts are market dispatched. This is because differences in dispatch method and market rules may or may not incentivize operators to build and maintain

dual fuel capability. Additionally, NERC regions are strictly for reliability planning and have no ability to dispatch generation.

Exhibit 2-3 U.S. Electric Generating Units Reporting as Secondary Fuel Capable (All Fuel Types, All Sizes) (4)

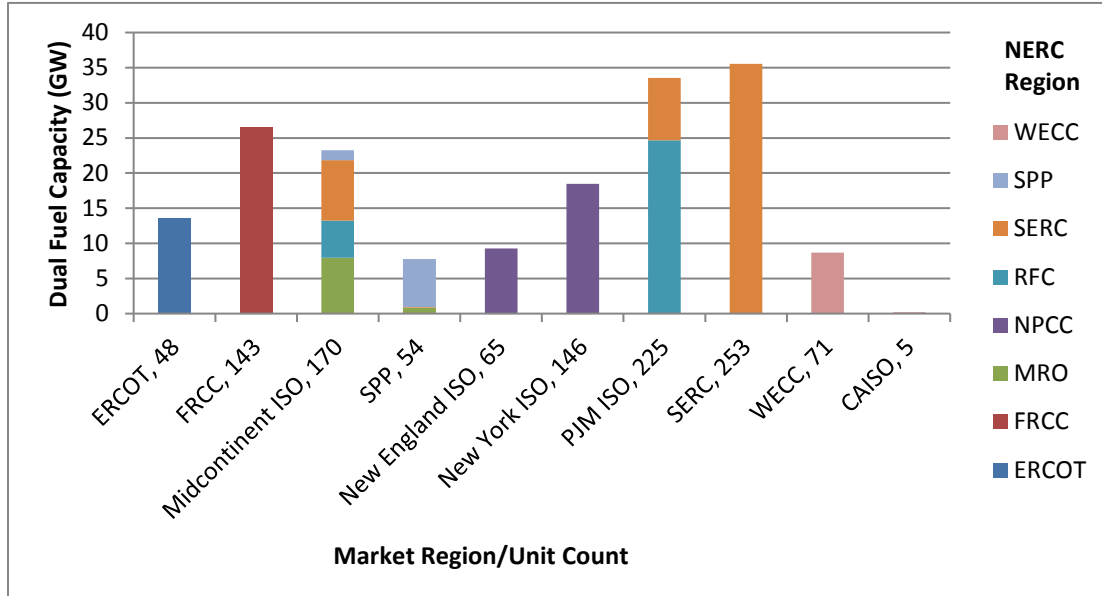


Exhibit 2-4 U.S. Electric Generating Units Reporting as Secondary Fuel Capable (Natural Gas Primary, All Sizes) (4)

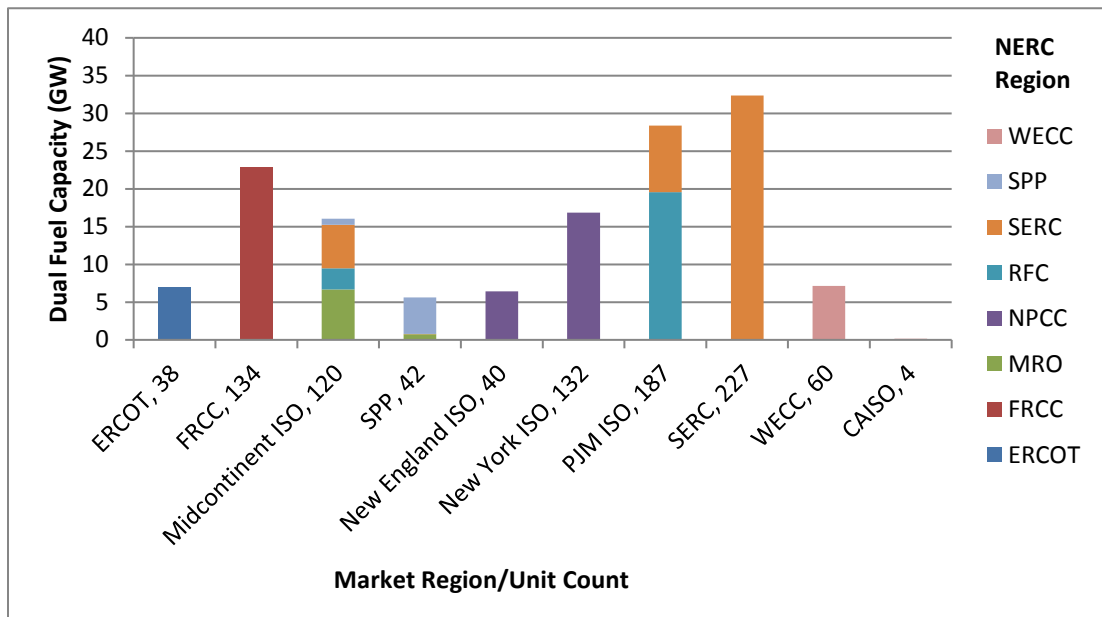
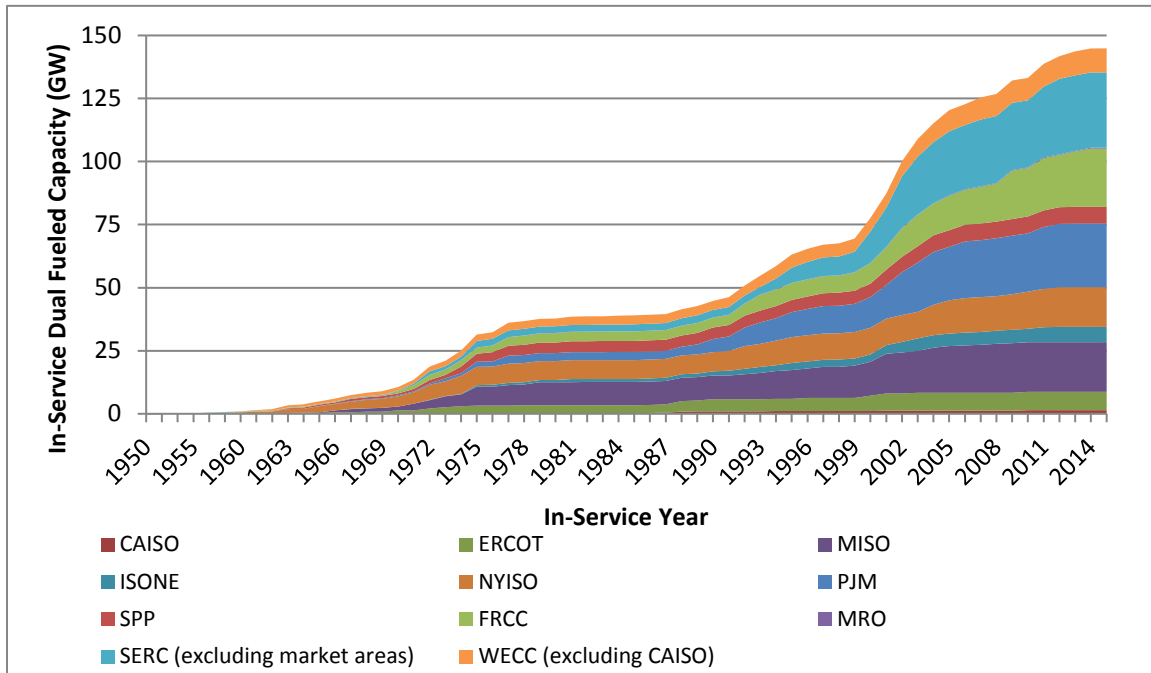


Exhibit 2-5 reflects the natural gas-fired dual fueled capacity that will be available at the 2015 summer peak and its market location. Forty-five percent of all U.S. dual fuel units are located in PJM and Midcontinent ISO (MISO); however, this only accounts for 37 percent of all U.S. capacity. Because these areas are home to large generating fleets, the amount of dual fuel

capacity represents only a minor percentage of the total fleet in these areas. As previously illustrated in Exhibit 2-2, the data presented in Exhibit 2-5 again shows that most natural gas dual fueled capacity has entered service since deregulation occurred in the early 2000s, with the largest growth occurring in PJM and SERC.

Exhibit 2-5 Dual Fueled Capacity Available at 2015 Summer Peak (4)



Further breaking the data down to the transmission zonal level shows that dual fuel capable generators represent a significant percentage of the capacity in several zones across the country (Exhibit 2-6). The highest concentration of these zones lies along the Eastern Seaboard with many zonal fleets comprised of a dual fuel majority. This exhibit shows that while a large percentage of dual fuel capacity may reside within PJM and MISO, the highest concentrations of dual fuel prevalent zones are in Florida and New England. Comparing fleet compositions as a percentage of the 2013 peak load (Exhibit 2-7) reveals that dual fuel capacity is available to serve a large percentage of the load across most of the country. While both of these exhibits tend to indicate that a case study analysis of dual fuel capacity should focus on Florida, the lack of competitive market structures in this region reduces the avenues of exploring the market incentivization and value of dual fuel installation since dual fuel capacity is regulated as cost-of-market. As a result, the next region of high concentration, ISO-NE, became the focus area of the regional analysis presented in Sections 4, 5, and 6.

Exhibit 2-6 Natural Gas-Fired Dual Fueled Capacity as a Percentage of Transmission Zone Capacity (4)

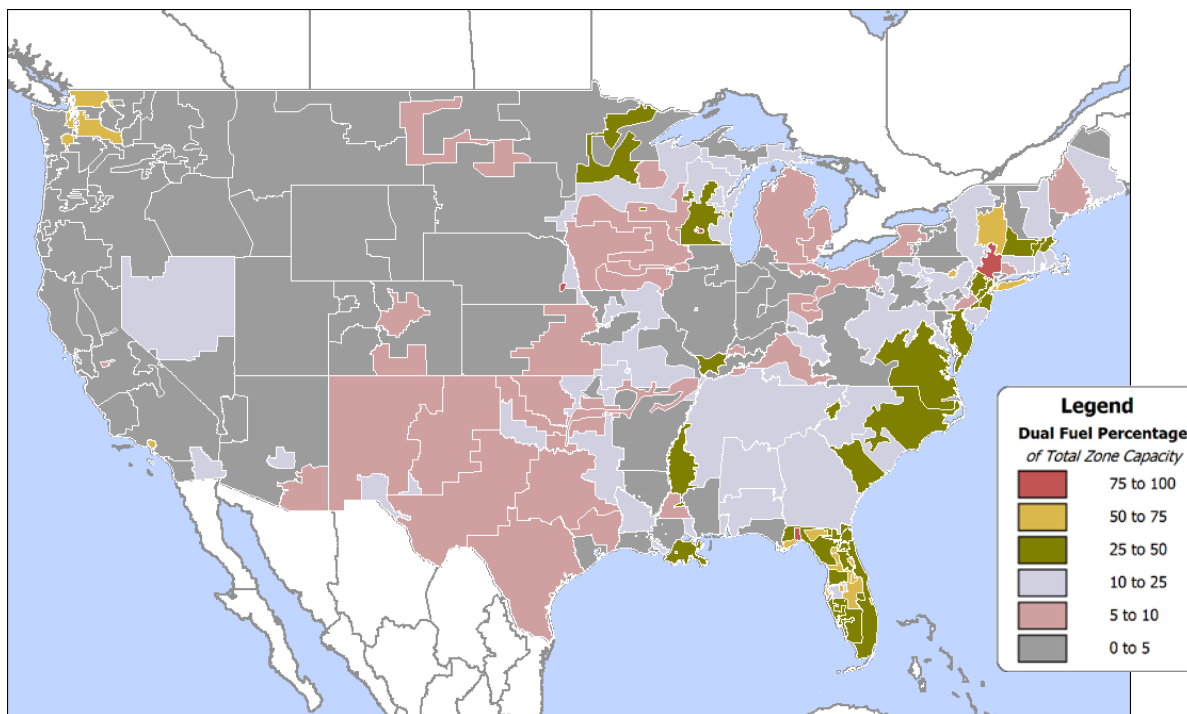
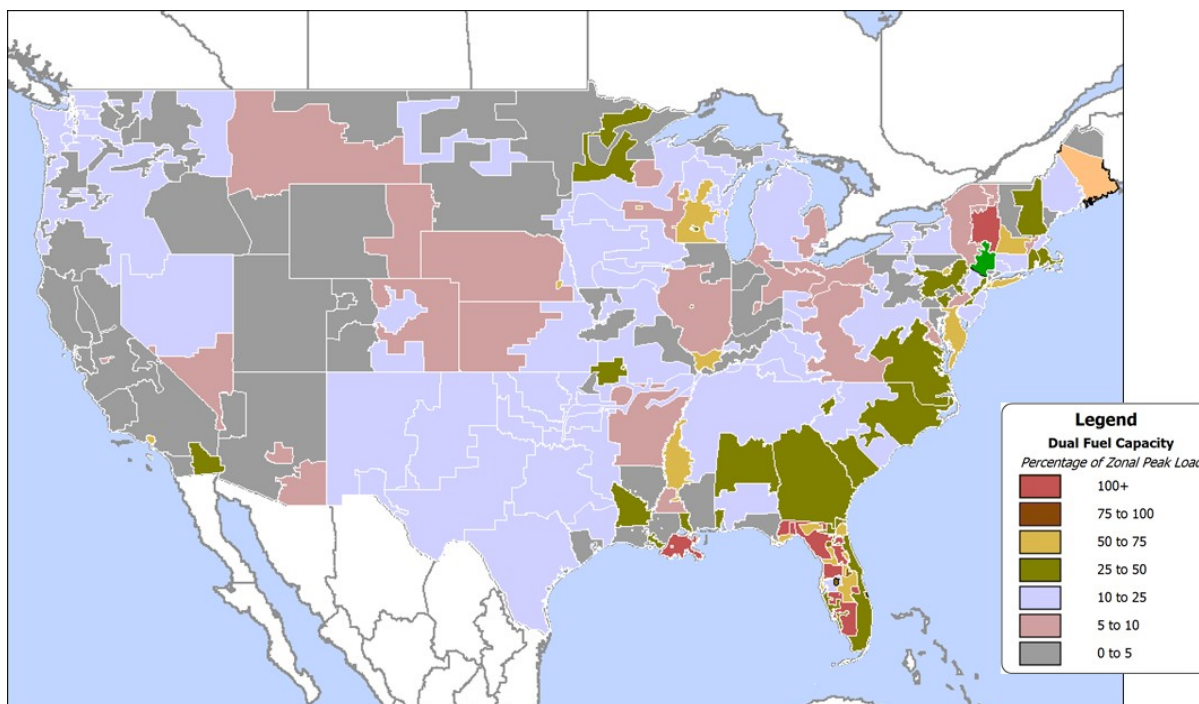


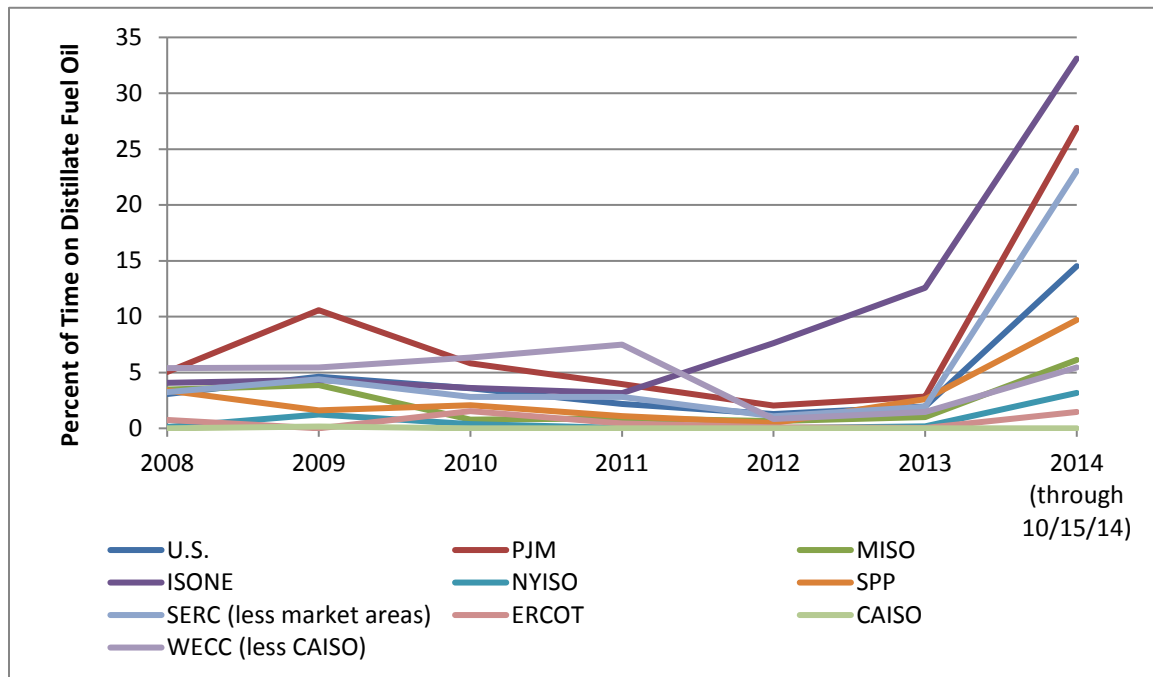
Exhibit 2-7 Natural Gas-Fired Dual Fueled Capacity as a Percentage of 2013 Transmission Zonal Peak Load (4)



2.2 Breakdown of Fuel Usage by Primary and Secondary Fuels

Looking only at natural gas units with distillate fuel oil as the secondary fuel, a major increase can be seen since 2013 in the amount of time that units are operating on fuel oil, as shown in Exhibit 2-8. These values are calculated based on the emissions data collected from Continuous Emission Monitoring Systems (CEMS)¹⁵ and not the unit-reported secondary fuel.¹⁶

Exhibit 2-8 Natural Gas – Distillate Fuel Oil Unit Perspective



The reported secondary fuels for all types of generators in the U.S. include the following:

- Biomass Gases - digester gas, methane, other biomass gases
- Biomass Solids - animal manure and waste, solid byproducts, other solid biomass not specified
- Blast Furnace Gas
- Coal
- Distillate Fuel Oil - all diesel, No. 1 fuel oil, No. 2 fuel oil, No. 4 fuel oil
- Jet Fuel

¹⁵ CEMS are used as a means to comply with air emission standards such as the United States Environmental Protection Agency's Acid Rain Program and other state and federal emission programs and standards. Facilities employ CEMS to continuously collect, record, and report the required emissions data.

¹⁶ Unit reported secondary fuels used throughout this report are drawn from the EIA Form 860. Secondary fuels reported by EPA CEMS are based not on unit reporting, but extrapolation based on the unit CO₂ emissions rate in lb/MMBtu during a hourly measurement period: 110 to 141 = Natural Gas; 142 to 149.999 and 163.001 to 169.999 = Mixed Fuel; 150 to 163 = Light Oil; 170 to 176 = Heavy Oil; 195 to 270 = Coal; Other = Unknown. Unknown fuel operations may be a sign of unit operational issues, start-up, poor quality fuel, or any number of items that may occur even if the unit is combusting natural gas.

- Kerosene
- Landfill Gas
- Natural Gas
- Other - batteries, chemicals, coke breeze, hydrogen, pitch, sulfur, tar coal, miscellaneous technologies
- Other Gas - butane, coke-oven, refinery, other processes
- Petroleum Coke
- Propane
- Refuse, Bagasse, or other Non-wood Waste
- Residual Fuel Oil - bunker C fuel oil, No. 5 fuel oil, No. 6 fuel oil
- Waste Heat
- Waste Oil and Other Oil - liquid butane, crude oil, liquid byproducts, oil waste, liquid propane, re-refined motor oil, sludge oil, tar oil
- Wood Waste Liquids - red liquor, sludge wood, spent sulfite liquor, other wood related liquids not specified
- Wood/Wood Waste Solids - paper pellets, railroad ties, utility poles, wood chips, other wood solids

Generation plants using natural gas as the primary fuel as reported in the Ventyx Velocity database indicate that the following are used as secondary fuels:

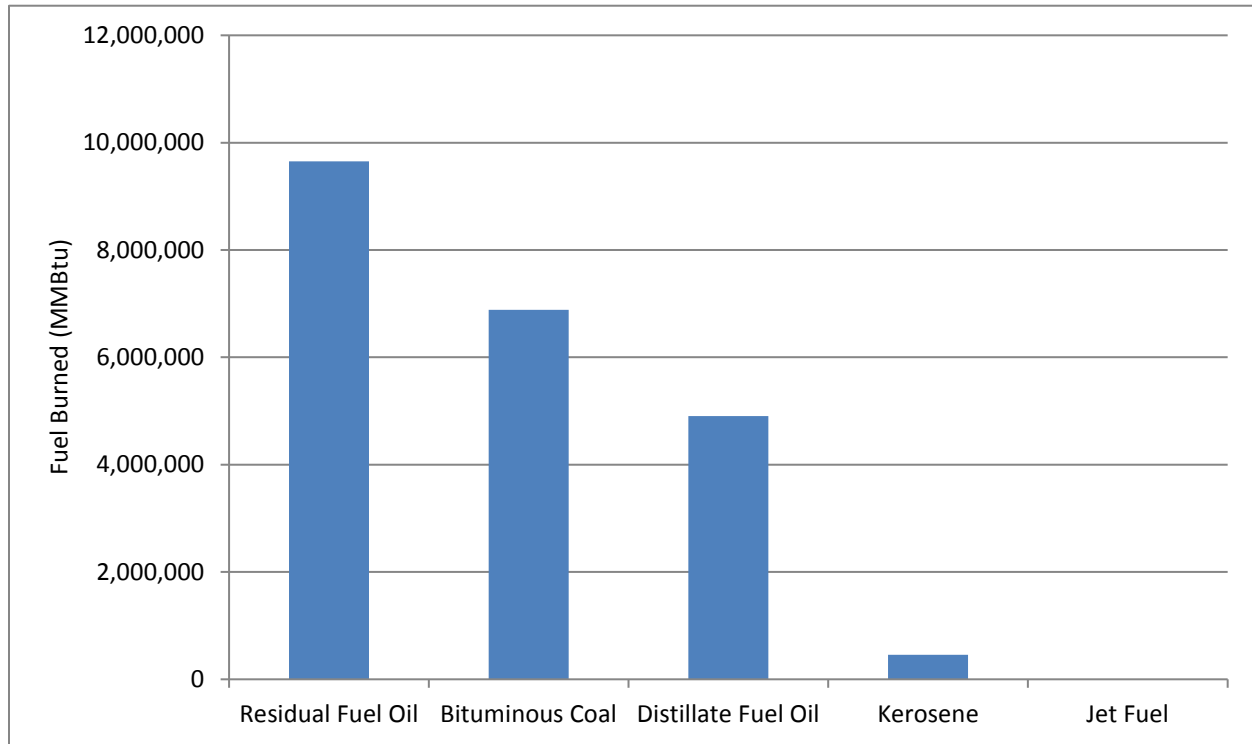
- Biomass Gases - digester gas, methane, other biomass gases
- Distillate Fuel Oil - all diesel, No. 1 fuel oil, No. 2 fuel oil, No. 4 fuel oil
- Kerosene
- Other Gas - butane, coke-oven, refinery, other processes
- Residual Fuel Oil - bunker C fuel oil, No. 5 fuel oil, No. 6 fuel oil
- Waste Heat
- Waste Oil and Other Oil - liquid butane, crude oil, liquid byproducts, oil waste, liquid propane, re-refined motor oil, sludge oil, tar oil

Exhibit 2-9 shows fuel consumed by natural gas primary plants as reported by SNL¹⁷. (8) Fuel burn usage for 2013 was aggregated from plants reporting as dual fuel capable, natural gas primary plants with a nameplate capacity of 100 MW or greater. A total of 263 natural gas plants with a total nameplate capacity of 143,245 are shown with the amounts of secondary fuels burned shown as a subset. The fuel burn was then converted to British thermal units for the sake

¹⁷ SNL Financial is a provider of news, financial data, and analysis on business sectors in the global economy.

of comparison. The British thermal unit figures for each fuel type were also gathered from SNL, on a per plant basis, along with the amount of fuel burned. The exhibit shows that in 2013, residual fuel oil was the principal secondary fuel burned by natural gas primary plants.

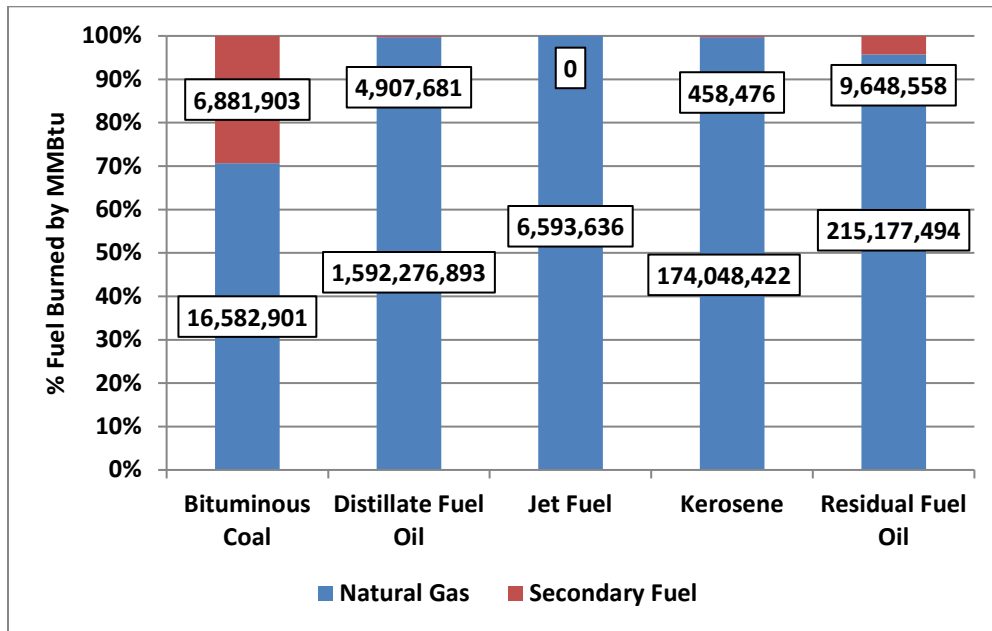
Exhibit 2-9 U.S. Fuel Usage: Dual Fuel Capable Natural Gas-Fired Plants (>100 MW Capacity) 2013 (8)



Fuel type	Natural Gas	Kerosene	Residual Fuel Oil	Bituminous Coal	Distillate Fuel Oil	Jet Fuel
Number of plants	263	11	32	3	215	2
Nameplate capacity (MW)	143,245	7,722	22,443	1,739	110,317	1,023
Fuel burned (MMBtu)	2,146,101,663	458,476	9,648,558	6,881,903	4,907,681	0

Exhibit 2-10 shows the amount of primary and secondary fuel burned, separated by each secondary fuel type. The data labels on this graph are the amount of fuel burned by million Btu (y-axis) and reported secondary fuel (x-axis). This graph shows that while more total residual fuel oil was burned in 2013, natural gas plants with coal as a secondary fuel burned more secondary fuel as a percentage of total Btu for that plant type.

Exhibit 2-10 U.S. Fuel Usage: Dual Fuel Capable Natural Gas-Fired Plants by Secondary Fuel Type (>100 MW Capacity) 2013 (8)



3 Dual Fuel Technical Aspects

This section examines the equipment requirements for dual fuel capable power generation plants, specifically simple cycle gas turbines, combined cycle gas turbines with steam generators, subcritical steam boiler turbine generators, and supercritical steam boiler turbine generators. The secondary fuel requirements were determined for a range of system sizes and heat rates from published information for each system type assuming No. 2 fuel oil as the secondary fuel.

3.1 Equipment Impacts

In general, all dual fuel power plants must have secondary fuel storage and the necessary piping and infrastructure to inject the secondary fuel into the combustor. Often, ancillary equipment is required to prevent damage to the secondary fuel injectors when they are not in use. Depending on the secondary fuel used, additional pollution control equipment may be required.

3.1.1 Dual Fuel Gas Turbine (Simple Cycle and Natural Gas Combined Cycle)

Infrastructure Requirements

Dual fuel power plants using a gas turbine, both simple cycle and natural gas combined cycle (NGCC), typically use natural gas as the primary fuel and a liquid fuel (No. 2 fuel oil, residual fuel oil, etc.) as the secondary fuel. For these plants each fuel stream (liquid and gas) has separate infrastructure requirements, as outlined in Exhibit 3-1. (5)

Exhibit 3-1 Gas Turbine Dual Fuel Infrastructure Requirements

Fuel	Piping/Infrastructure	Combustor	Control System	Emissions Control
Natural Gas Fuel	- Natural gas regulator - NG Filters/liquid separators	- Combustor fuel manifold modifications - Fuel injector modifications - Gas injector purge air	- Flow control hardware including flow control valves and block and vent safety valves - Control software and I/O	If using a dry low NO_x (DLN) system, additional equipment/controls required
Liquid Fuels	- Fuel delivery (pipeline, truck unloading) - Fuel storage tanks and impoundments - High pressure pump - Piping and filtration from storage tank to combustor - Other associated equipment including flow divider, stop valves, servo valves, etc. - Atomizing/purge air compressor	- Liquid fuel lines and injectors - Purge/atomizing/cooling air - Check valves in fuel lines	- Flow control hardware for control of liquid fuel, purge air, and water injection - Control software and I/O	Possible requirements for water injection for NO_x control

The major infrastructure requirement for dual fuel simple cycle and NGCC plants is the requirement for secondary fuel storage. For larger generation units, this storage requirement may require in excess of 1 million gallons to provide sufficient run-time, as discussed later in this report.

An often overlooked requirement is that the fuel injectors in the combustor section of the turbine that are not being used (gas or oil) require constant purge air to prevent damage to the injectors. Also, check valves must be installed in the fuel lines to prevent back-flow of hot combustion gasses into the fuel lines.

3.1.2 Impacts of Dual Fuel on Gas Turbines/NGCC Operations

As discussed above, a major operational issue is the purge air requirement to prevent damage to fuel injectors that are not in use. This requires that the purge air compressors run continuously, which may add 100-300 kW to the auxiliary power requirement. (9) The purge air may also change the combustion dynamics, causing instabilities and pressure increases; increases of up to 2 psi have been measured. (5) Inadequate purge air caused by uneven distribution can lead to fuel injector damage – requiring additional maintenance. These issues, although not serious, have led several dual fuel plants to modify the combustor to eliminate the secondary fuel

injectors, converting the plant from dual fuel to a single fuel configuration when dual fuel operation is not deemed critical.

Another major maintenance issue often cited in dual fuel plant operation is the requirement for fuel line check valves. These check valves often stick or leak and, with as many as 60 check valves per installation, can significantly add to routine maintenance requirements. (5) Liquid fuel injector plugging due to charring may also require additional attention and may be prevented using high pressure nitrogen purging during liquid fuel shutdown.

Secondary fuel operation may also change how the system operates. Fuels with different combustion properties may require different fuel/air ratios which change the mass flow through the system. Also, sulfur in liquid fuel can cause corrosion, especially in NGCC heat recovery steam generators (HRSG), and unfiltered particulate can lead to orifice plugging and excessive CO production.

This additional complexity can add as many as two days to a planned maintenance outage.

3.1.3 Gas Turbine to Dual Fuel Conversion Costs

The cost to convert a gas turbine into a dual fuel unit varies by the size of the gas turbine and whether the conversion occurs in the factory during fabrication or in the field after installation. Estimates of dual fuel conversion costs were developed through multiple discussions between WorleyParsons Group Inc., General Electric (GE), and Siemens during 2009-2010.¹⁸ These conversion cost estimates are as follows:

- \$1.5 - \$2.0 million conversion cost for a GE factory installed 7FA unit in 2010 dollars (simple cycle 211-227 MW)
- \$3.0 - \$3.5 million conversion cost for a Siemens factory installed 5000F4 unit in 2010 dollars (simple cycle up to 232 MW)
- \$9 million for a field installed Siemens model FD3 unit in 2009 dollars (nominal simple cycle 180 - 190 MW)

Using these costs, the factory-installed dual fuel capability conversion costs between \$7,500 - \$16,000/MW and the field-installed dual fuel modifications costs approximately \$54,000/MW in 2014 dollars.

3.1.4 Dual Fuel Steam Turbine Generator (Coal/Fuel Oil/Natural Gas Primary Fuel) Infrastructure Requirements

Dual fuel steam turbine generators consist of a boiler designed to fire coal, fuel oil, or natural gas as the primary fuel and modified to operate using a secondary fuel. As with the gas turbines, infrastructure additions include piping, control valves, fuel injectors, etc. Purge air also is required to protect the fuel injectors that are not in use.

Coal-fired plants may also be modified by adding bypass ducting around the coal-specific air pollution control equipment (baghouse, flue gas desulfurization (FGD), etc.). This allows

¹⁸ These estimates are from proprietary information obtained from WorleyParsons Group Inc.

operation with reduced parasitic load and operation and maintenance (O&M) costs when using natural gas. Additional coal plant modifications may require superheater modification; however, this can typically be avoided through proper natural gas burner placement/orientation. (6)

3.1.5 Dual Fuel Steam Turbine Generator Operational Impacts (Converting from Coal/Oil to Natural Gas)

Because natural gas combustion characteristics are different than coal or oil, care must be taken to ensure proper placement and orientation of the natural gas injectors to prevent localized overheating of boiler components. With proper placement of the gas injectors, few operational issues are typically encountered. Plant operation is often simplified because fuel preparation (coal blending and crushing, fuel oil heating, etc.) is not required and some pollution control equipment (FGD, baghouse, etc.) operation is not required.

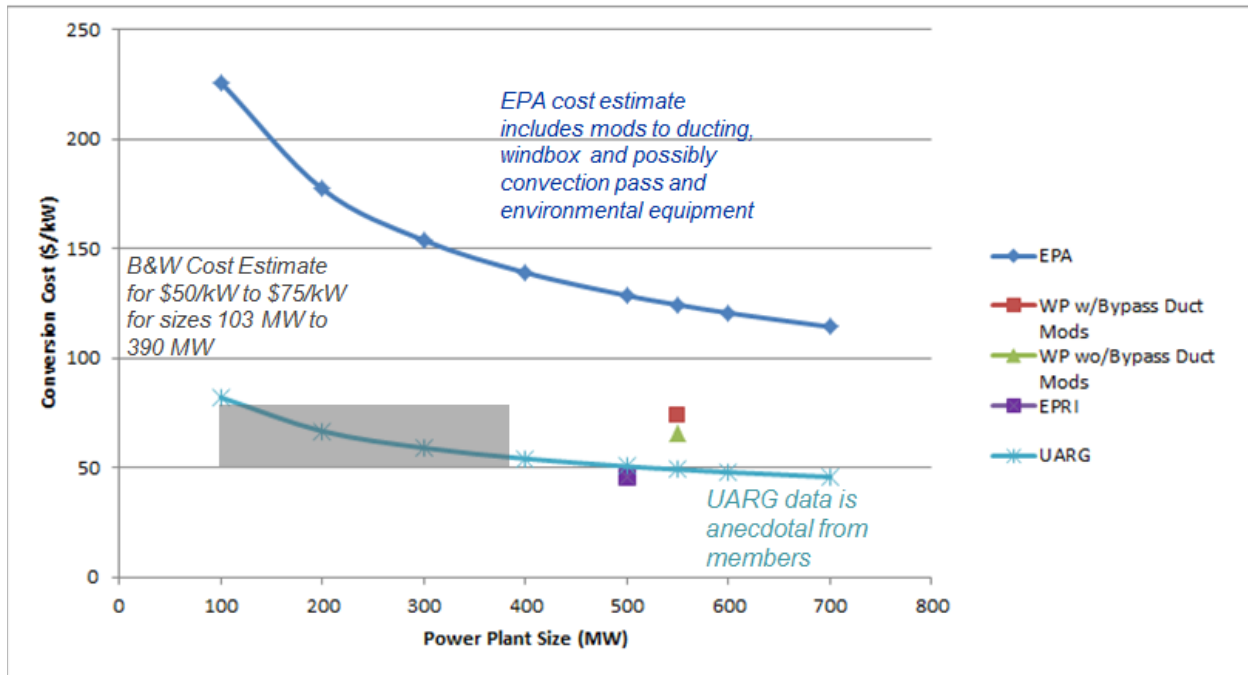
3.1.6 Impacts on Efficiency (Converting from Coal/Oil to Natural Gas)

Typically there is a 3-5 percent decrease in boiler efficiency with natural gas (NG) compared with oil or coal firing at maximum continuous rating (MCR), depending on boiler configuration; however, some of this efficiency penalty is offset by a significant auxiliary power savings when not operating on coal. (3)

Even with the efficiency penalty, a boiler originally designed to fire coal or oil can maintain MCR when operating on NG. However, the MCR will decrease for an NG-fired boiler operating on oil due to the smaller heat transfer area and the plant net output (MW) will decrease due to the decreased MCR. (3)

3.1.7 Dual Fuel Steam Turbine Generator Conversion Costs (Converting from Coal to Natural Gas)

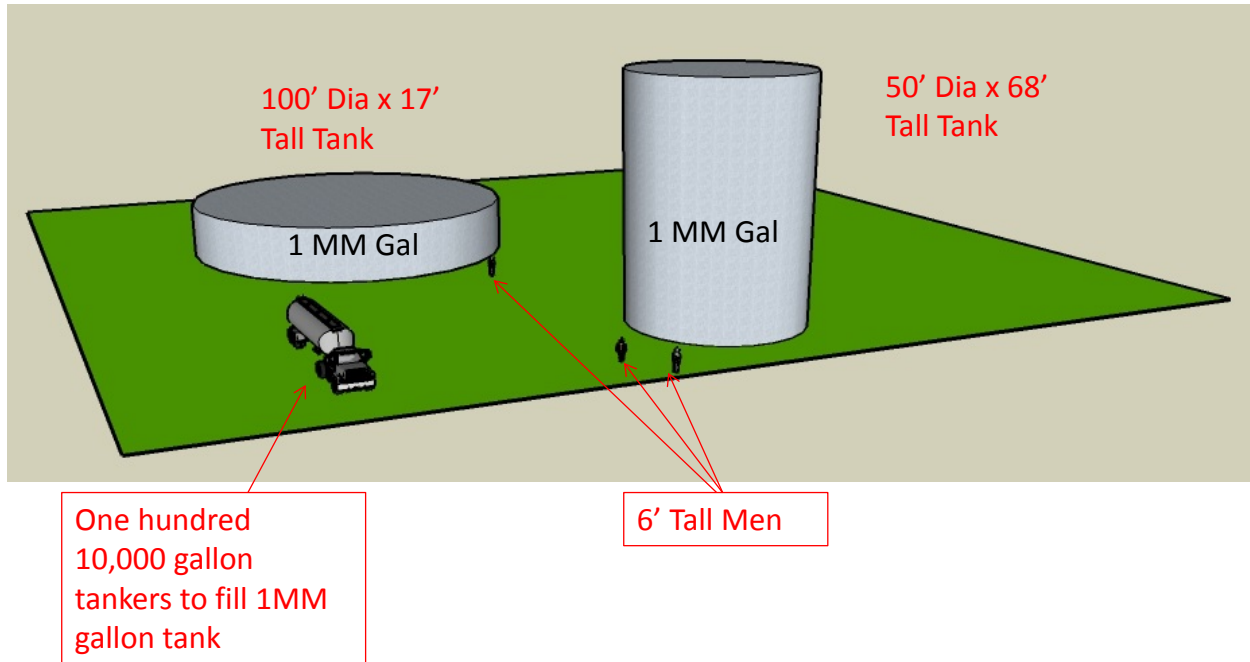
The costs to convert a coal boiler to dual fuel using natural gas can vary significantly depending on the size and design of the plant. Exhibit 3-2 presents several cost estimates for the conversion of a coal boiler to natural gas.

Exhibit 3-2 Coal-Fired Boiler Conversion Cost (10) (11) (12)

3.2 Secondary Fuel Requirements

In order to understand the secondary fuel storage infrastructure requirements for typical natural gas-fired units, it is necessary to estimate the secondary fuel burn rate for each type of plant (simple cycle, NGCC, subcritical steam turbine generator (STG), and supercritical STG). To do this, nominal heat rates for different sized systems were collected and plotted for each generation type. These nominal heat rates were then used to develop fuel burn rate curves for each of the plant types and for a range of plant sizes. A detailed description of this methodology can be found in Appendix A. Based on this analysis, it was determined that a 500 MW NGCC plant operating on No. 2 fuel oil as a secondary fuel would require approximately 1 million gallons of fuel to operate 24 hours at 100 percent capacity. Exhibit 3-3 is a depiction of the relative scale of 1 million gallon storage tanks.

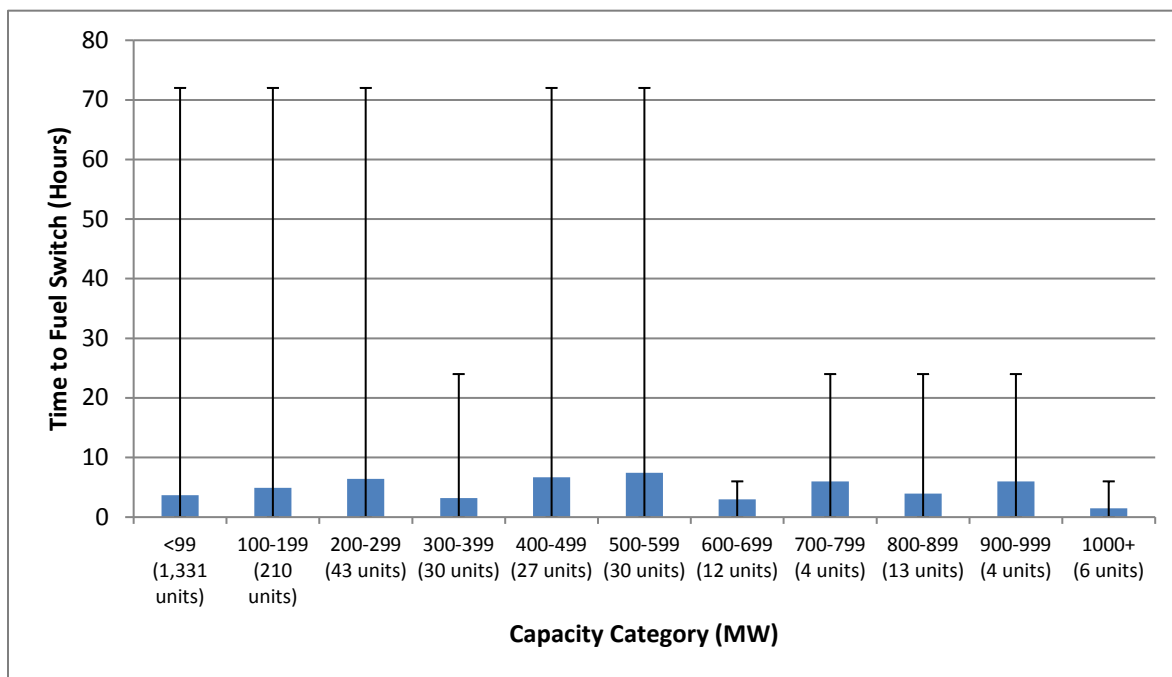
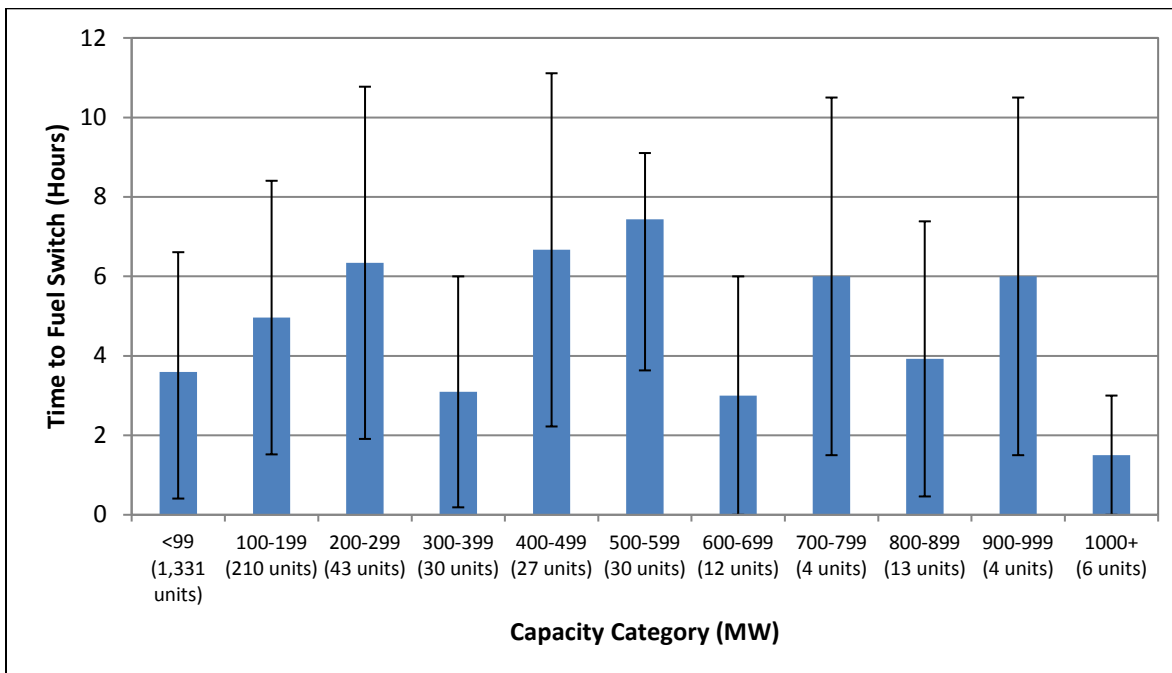
Exhibit 3-3 Approximately 1 Million Gallons of Fuel Oil Required to Operate a 500 MW Plant for 1 Day



3.3 Time Required to Switch Fuels

Comparing the range of time that it can take a natural gas-fired dual fuel unit to fuel switch reveals a large variation between units, with some units able to switch instantaneously and others requiring up to 72 hours, as shown in Exhibit 3-4. The average unit takes between 4 and 8 hours to switch fuels regardless of size. Error bars on this exhibit show the range from minimum to maximum switching times.

Normalizing the switching time across the natural gas-fired dual fuel fleet, all of the capacity categories except 500-599 MW tend toward the average switching time range, as shown in Exhibit 3-5. Error bars on this exhibit show an average of the maximum and minimum switching times.

Exhibit 3-4 Time to Switch Fuels by Unit Size (4)**Exhibit 3-5 Normalized Time to Switch Fuels (4)**

4 Regional Analysis of Dual Fuel Capability

The ISO-NE region was selected for the evaluation of dual fuel capability because of the number of dual fuel units in the region and for its increasing reliance on natural gas generation, as well as its potential for natural gas shortages due to limited gas transmission pipelines into the area and limited geologic storage. Exhibit 4-1 provides a breakdown of the natural gas generating units in ISO-NE detailed by state. The summary is further divided into units greater than 100 MW because it is assumed that providing dual fuel capability to those plants less than 100 MW would not be economically feasible. Units greater than 100 MW compose over 87 percent of the gas-fired generation in ISO-NE.

Exhibit 4-1 ISO-NE Natural Gas-Fired Power Plants Summary (4)

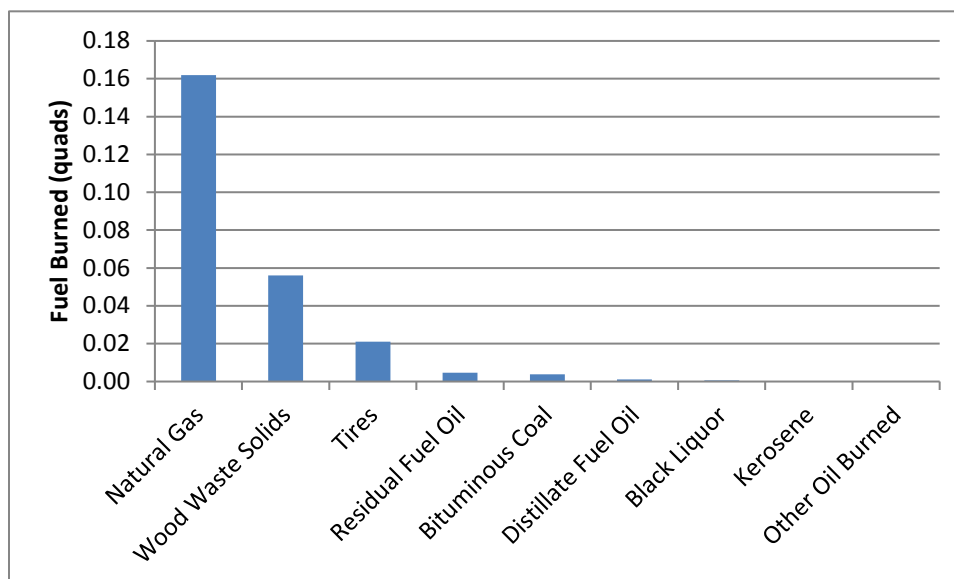
State	No. Gas-fired Plants/ Winter Capacity (MW)*	Current Plants with Secondary Fuel Capability/ Winter Capacity (MW)*	Plants with Space for Potential Fuel Storage/Winter Capacity (MW)	Plants with No Space for Potential Fuel Storage/Winter Capacity (MW)
Connecticut	5/3,264	3/2,050	1/402	1/812
Maine	4/1,533	1/183	1/540	2/810
Massachusetts	14/6,740	11/5,317	1/1,071	2/352
New Hampshire	2/1,357	1/560	1/797	0/0
Rhode Island	4/1,861	1/510	2/763	1/588
Vermont	0/0	0/0	0/0	0/0
Totals	29/14,754	17/8,620	6/3,572	6/2,562

*Includes plants that are currently operating and grid connected.

4.1 Available Secondary Fuels

A summary of dual fuel generation in the ISO-NE region for the years 2013 and 2014, across all fuel types and generator sizes helps paint a picture of fuel usage in a region with a strong reliance on natural gas. The effects of the Polar Vortex in January of 2014 also show how this system was affected, from the perspective of dual fuel usage. Exhibit 4-2 shows fuel burned, in quadrillion Btu, across all dual fuel capable plants in the ISO-NE region that reported a secondary fuel in 2013. Exhibit 4-3 shows the total number of plants and the nameplate capacity of those plants, by the listed primary fuel type, as well as the listed secondary fuels in those plants in 2013.

**Exhibit 4-2 ISO-NE Fuel Usage: Plants Reporting as Dual Fuel Capable
(All Sizes and Fuel Types) 2013 (8)**



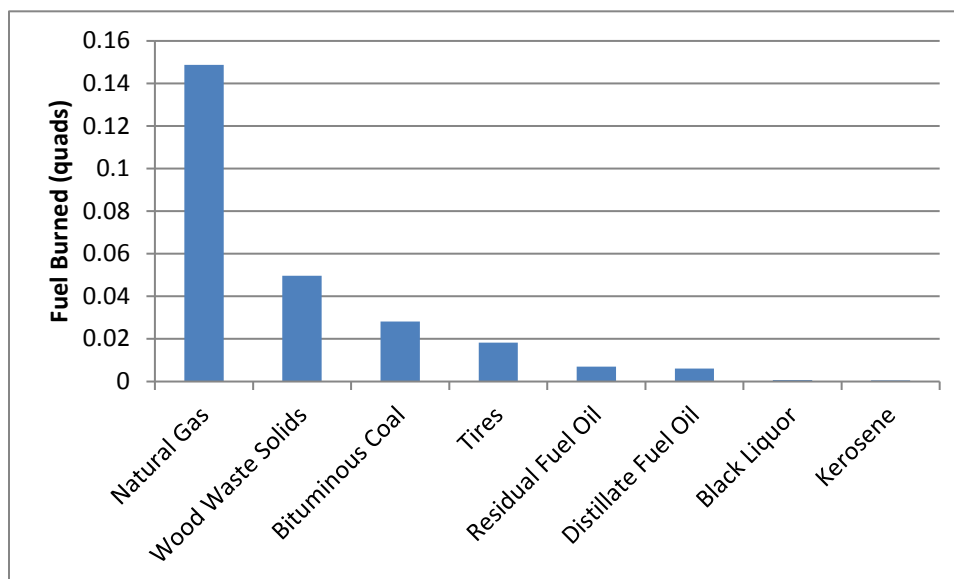
Fuel Burned (MMBtu)								
Natural Gas	Wood Waste Solids	Tires	Residual Fuel Oil	Bituminous Coal	Distillate Fuel Oil	Black Liquor	Kerosene	Other Oil Burned
161,958,933	56,017,136	21,116,777	4,654,610	3,840,248	1,116,846	673,152	248,184	214,859

Exhibit 4-3 Count and Capacity: ISO-NE Dual Fuel Plants by Primary Fuel Type 2013 (8)

Primary Fuel	Number of plants	Nameplate Capacity (MW)	Secondary Fuels
Black Liquor	4	336	Natural Gas, Tires, Wood Waste Solids
Kerosene	3	569	Natural Gas
Natural Gas	23	8,647	Distillate Fuel Oil, Residual Fuel Oil
Residual Fuel Oil	3	1,348	Natural Gas
Wood Waste Solids	5	419	Bituminous Coal, Distillate Fuel Oil, Natural Gas

Exhibit 4-4 shows fuel burned, in quadrillion Btu, across all dual fuel capable plants in the ISO-NE region that reported a secondary fuel in 2014. Exhibit 4-5 shows the total number of plants and the nameplate capacity of those plants, by the listed primary fuel type, as well as the listed secondary fuels in those plants in 2014.

**Exhibit 4-4 ISO-NE Fuel Usage: Plants Reporting as Dual Fuel Capable
(All Sizes and Fuel Types) 2014¹⁹ (8)**



Fuel Burned (MMBtu)							
Natural Gas	Wood Waste Solids	Bituminous Coal	Tires	Residual Fuel Oil	Distillate Fuel Oil	Black Liquor	Kerosene
148,684,353	49,723,601	28,259,351	18,304,917	7,012,069	6,082,837	707,653	472,750

Exhibit 4-5 Count and Capacity: ISO-NE Dual Fuel Plants by Primary Fuel Type 2014 (8)

Primary Fuel	Number of plants	Nameplate Capacity (MW)	Secondary Fuels
Black Liquor	4	336	Natural Gas, Tires, Wood Waste Solids
Distillate Fuel Oil	2	1,584	Residual Fuel Oil
Kerosene	3	569	Natural Gas
Natural Gas	24	7,936	Distillate Fuel Oil, Jet Fuel, Residual Fuel Oil
Residual Fuel Oil	1	493	Natural Gas
Wood Waste Solids	5	419	Bituminous Coal, Distillate Fuel Oil, Natural Gas
Bituminous Coal	1	1,133	Natural Gas

Exhibit 4-6 and Exhibit 4-7 show the fuel usage breakdown as a percentage of MMBtu burned by primary fuel type for 2013 and 2014 respectively. The fuel type listed on the primary axis below each bar is labeled as primary fuel on the exhibit. These exhibits show that while four plants listed black liquor as their primary fuel type, they actually burned very little black liquor.

¹⁹ 2014 does not include December, as that data was not available when this report was prepared. (8)

These exhibits also show a drop in natural gas burned as a percentage of total Btu from 2013 to 2014. This drop is likely an effect of the extreme weather during the beginning of 2014.

Exhibit 4-6 ISO-NE Fuel Usage: Fuel Burned by Primary Fuel Source (All Sizes and Fuel Types) 2013 (8)

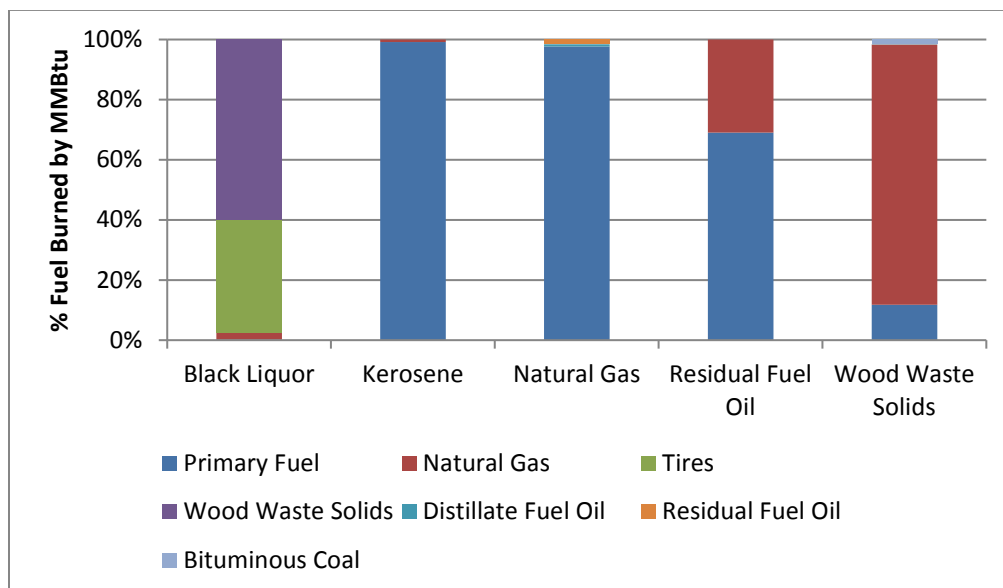


Exhibit 4-7 ISO-NE Fuel Usage: Fuel Burned by Primary Fuel Source (All Sizes and Fuel Types) 2014²⁰ (8)

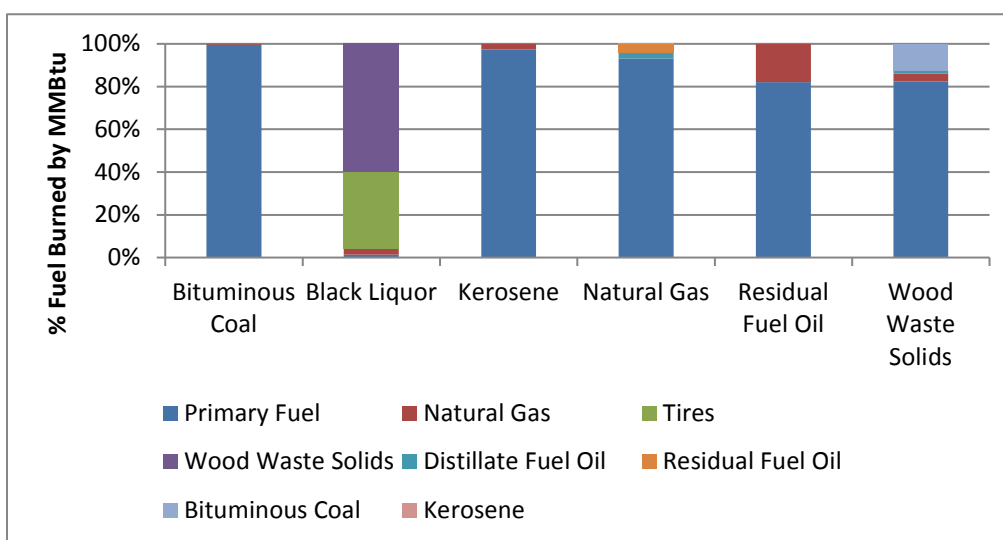


Exhibit 4-8, Exhibit 4-9, and Exhibit 4-10 show fuel usage in the region from natural gas primary dual fuel plants from October 2013 to April 2014. These exhibits show the effects of the Polar Vortex gas prices on fuel usage. Each exhibit shows a drop and recovery in natural gas burned during that time period. In these exhibits, there are 19 NG/DFO plants, 2 NG/Kerosene plants,

²⁰ 2014 does not include December, as that data was not available when this report was prepared.

and 3 NG/RFO plants. The higher number of plants, as well as the price differences between these fuels may account for the difference in usage between DFO and the other secondary fuels during the polar vortex.

Exhibit 4-8 ISO-NE Fuel Usage During the Polar Vortex: Natural Gas/Distillate Fuel Oil (8)

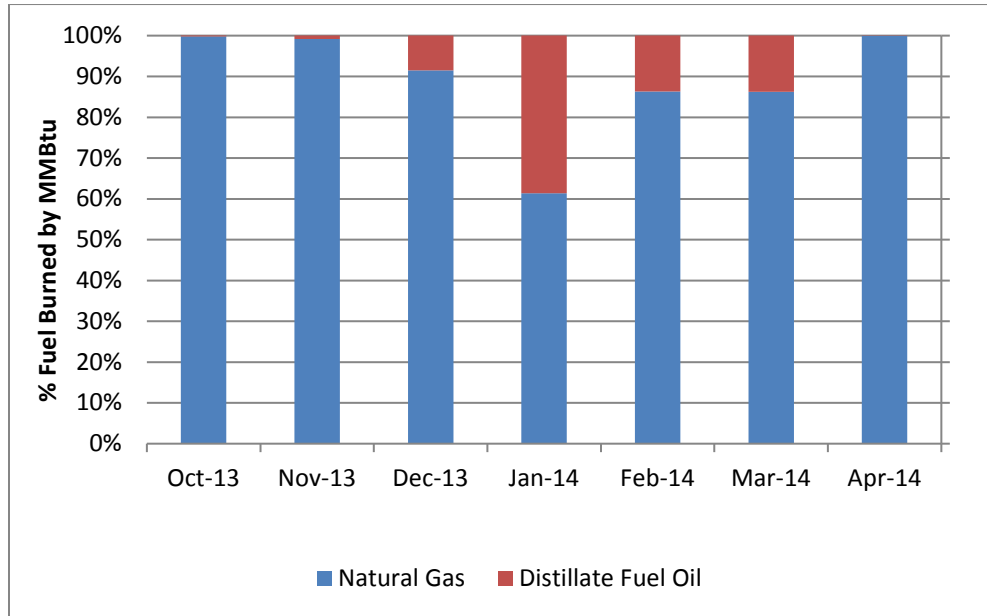


Exhibit 4-9 ISO-NE Fuel Usage During the Polar Vortex: Natural Gas/Kerosene (8)

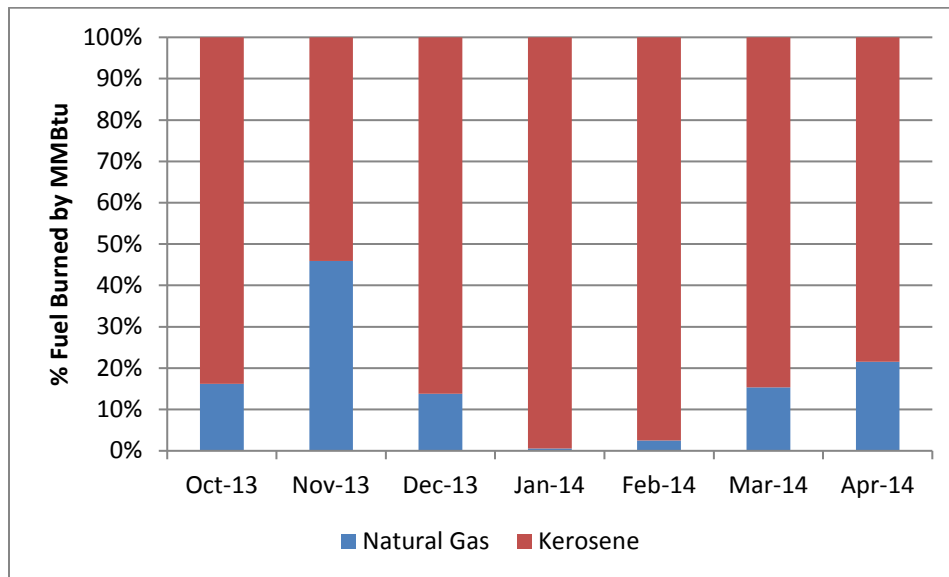
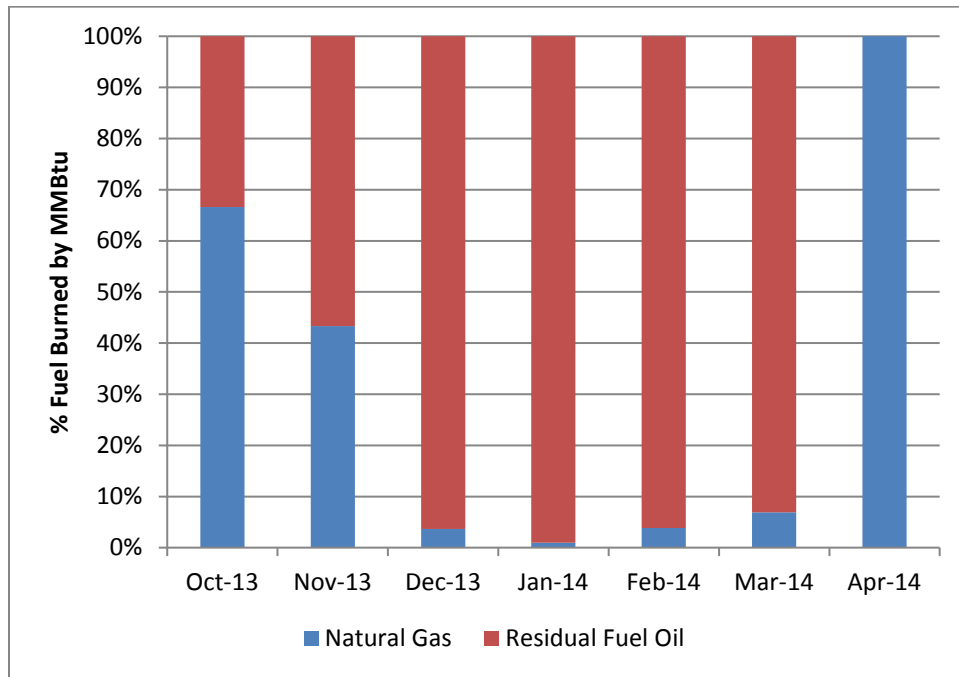


Exhibit 4-10 ISO-NE Fuel Usage During the Polar Vortex: Natural Gas/Residual Fuel Oil (8)

4.2 On-site Secondary Fuel Storage

To determine which natural gas-fired plants had secondary fuel storage, each state's storage tank databases were examined. Only two states contained publically accessible data which had information on amounts of on-site fuel storage. To determine secondary fuel storage capacity for the remaining plants, Google Earth overhead imagery was used (see Exhibit 4-11). An overhead image of each plant was examined for the presence of storage tanks. Images of plants were compared with available storage tank data to evaluate the accuracy of using overhead imagery to estimate storage tank capacity. The data set for one plant, referred to as Plant 1, contained a site drawing showing storage tanks and the contents and storage capacity of each tank as shown in Exhibit 4-12. Several key observations from the Plant 1 drawing and storage tank database include:

- Non-impounded storage tanks contain water either for the steam cycle in a combined cycle plant or for emergency firefighting purposes
- Fuel storage tanks have some sort of impoundment or containment structure to prevent fuel run-off in the event of a tank leak
- The storage tank's capacity could be reasonably estimated by measuring the diameter of the storage tank

To estimate the capacity of a storage tank, Google Earth's measurement tool was used to determine the diameter of the tank as illustrated in Exhibit 4-13. That diameter was then used to calculate the volume of the tank using an estimated tank height of 30 feet. Although it is probable that tanks may have heights different than 30 feet, this approximation appears reasonable for this evaluation.

This methodology was checked using the Plant 1 data and overhead imagery. In this case the imagery indicated one tank with a containment structure. Measurement of the tank diameter, combined with calculation methodology, estimated a tank capacity of 991,000 gallons.

Exhibit 4-11 Methodology Check of Plant 1 (13)



Exhibit 4-12 Site Drawing of Plant 1 (14)

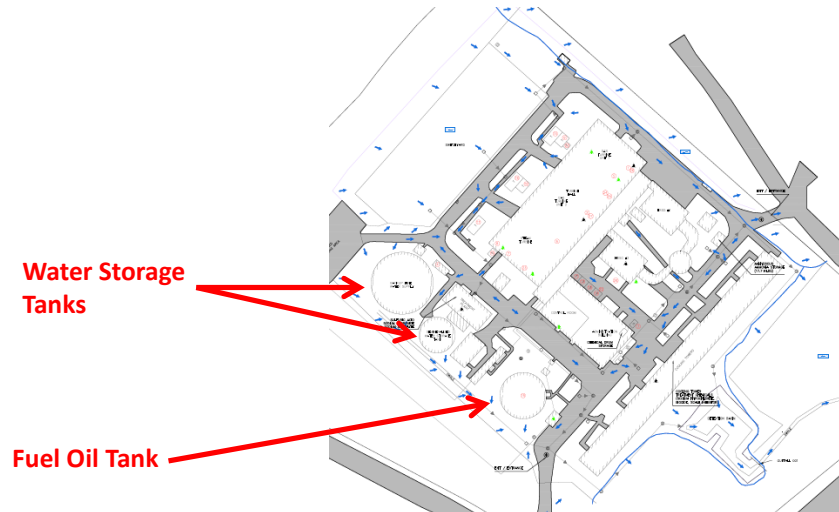
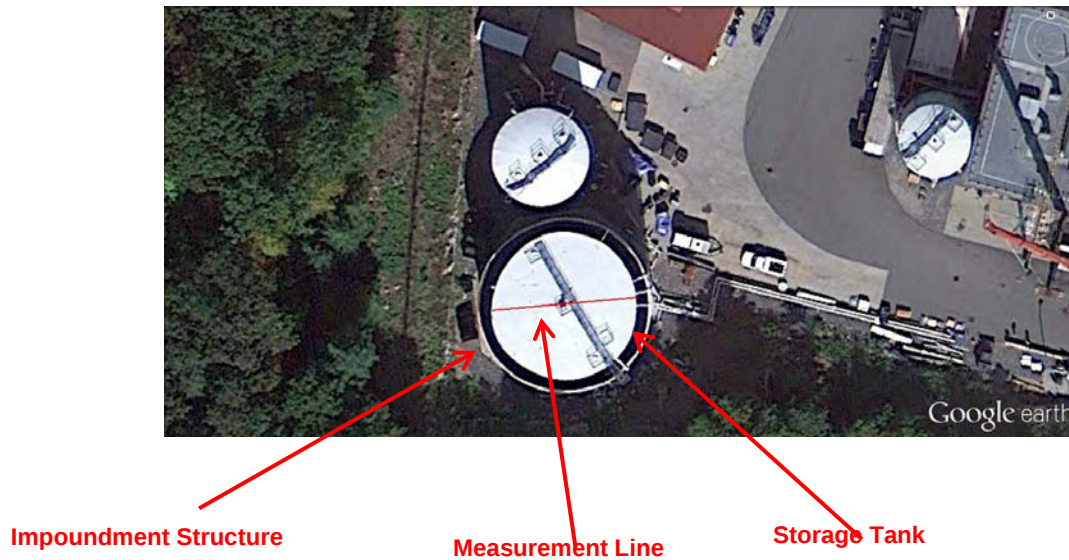


Exhibit 4-13 Overhead Imagery Tank Measurement Methodology (15)

The data identified that the impounded tank was for fuel oil and its working capacity was 939,451 gallons. Therefore, the overhead imagery tank capacity estimate was within 5.2 percent of its actual working capacity and within 2.4 percent of its maximum capacity.

Using the methodology outline above, each natural gas plant within ISO-NE with a nameplate capacity greater than 100 MW was evaluated for the presence of fuel storage tank(s); for those facilities that had fuel storage, the fuel storage capacity was calculated.

Based on the calculated fuel storage capacity, the potential secondary fuel operational duration was estimated using the calculated fuel burn rates for each unit size as shown in Appendix A. Plants that were identified as having on-site fuel storage, with their estimated operating times, are presented in Exhibit 4-14.

Exhibit 4-14 ISO-NE Dual Fuel Plants Greater Than 100 MW (4)

State	Number of plants/ Winter Capacity (MW)	Estimated Oil Storage (gal)	Estimated Operating Time range (hr)
Connecticut	1/620	5,508,000	195 (8 days)
Maine	1/180	881,000	72 (3 days)
Massachusetts	10/5,020	21,283,179	38-691 (1.5-29 days)
New Hampshire	1/560	939,451 ^R	39 (1.6 days)
Rhode Island	1/510	6,762,000 ^R	289 (12 days)

^R Reported oil storage capacity

Two of the plants (Plant 2 and Plant 3) listed in Exhibit 4-14 are located adjacent to significant fuel storage facilities. Since these generating plants are listed as dual fuel capable, it is assumed that the secondary fuel is supplied by these storage facilities. As can be seen in Exhibit 4-15 and Exhibit 4-16, it is nearly impossible to estimate the secondary fuel operational duration because it is unknown how much fuel is available for power generation.

Two other plants (Plant 4 and Plant 5) have significantly different calculated storage capacities compared to published storage capacities. As can be seen in Exhibit 4-17, Plant 4 has two fuel storage tanks with a total calculated capacity of ~1.7 million gallons. One of the tanks appears to be not maintained and may be abandoned, resulting in a revised storage capacity of ~800,000 gallons. This could indicate that the reported 90,000 gallon storage capacity may have been intended to be 900,000 gallons.

Plant 5 was calculated to have ~600,000 gallons but was reported to have 1.2 million gallons. Imagery analysis showed the plant to only have one impounded tank. Therefore, in order to be capable of storing 1.2 million gallons, that tank would have to be 60 feet tall, which is unlikely.

Exhibit 4-15 Overhead View of Plant 2 (15)



Plant 2 – 3 units totaling
2,253 MW

Multiple nearby
large storage tanks

Exhibit 4-16 Overhead View of Plant 3 (15)



Exhibit 4-17 Selected Dual Fuel Sites with Storage Capacity Differences from Previously Reported (15)**Plant 4**

2 tank capacity
calculated at 1,736,000
gal. vs. 90,000 gal.
previously reported

This one
possibly
abandoned



The imagery analysis also indicated that three plants, Exhibit 4-18, appeared to have on-site fuel storage capability but were not listed in the Ventyx Velocity database as dual fuel capable. Two of these plants (Plant 6 and Plant 7) were listed in other publications as having fuel storage. This discrepancy may indicate that these plants were retrofitted to remove their dual fuel capabilities or that the status is simply misreported in the 2013 Energy Information Administration (EIA) Form 860.

Exhibit 4-18 ISO-NE Non-Dual Fuel Plants >100 MW (Appearing to Have Dual Fuel Capability) (4)

Plant Name	Winter Capacity (MW)	Estimated Oil Storage (gal)	Estimated Operating Time (hr)	Previously Report Storage (gal)
Plant 6	857*	634,523	16.5	840,000
Plant 7	569**	745,000	29 (1 day)	1,200,000
Plant 8	246	440,641	37 (1.5 days)	N/A

* Three ~285 MW CSs

** Two ~285 MW CSs

4.3 Plants That Could Be Converted to Dual Fuel

To determine which plants in ISO-NE have the potential to become dual fuel-fired plants, the analysis focused on current non-dual fuel natural gas plants greater than 100 MW. Overhead imagery was again used to determine the plant's potential to install secondary fuel storage tanks. Each non-dual fuel plant was evaluated to determine if there was sufficient area within the existing plant boundary for the construction of an impounded storage tank. Many of the plants had areas outside of the plant boundary; however, no information was available on the acquisition limitations of the property.

Based on the analysis outline above, six additional plants were identified, with a total winter capacity of 3,572 MW that have space for storage tanks as shown in Exhibit 4-19.

Exhibit 4-19 ISO-NE Natural Gas-Fired Plants >100 MW That Have Space for Secondary Fuel Storage (4)

Plant Name	Winter Capacity (MW)	Notes
Plant 9	402	Room in existing tank area and area east of plant
Plant 10	540	Area east of plant that appears to be within plant boundary
Plant 11	1,071	Room within plant boundary - south
Plant 12	797	Room inside boundary - northwest
Plant 13	478	Has two 1MM gal #2 FO tanks listed as "closed"
Plant 14	285	Room inside boundary
Total	3,572	

The remaining six plants in ISO-NE, composing a total of 2,562 MW of winter capacity, that do not appear to have available room for fuel storage tanks are presented in Exhibit 4-20. A summary of all natural gas plants in ISO-NE greater than 100 MW is provided in Exhibit 4-21.

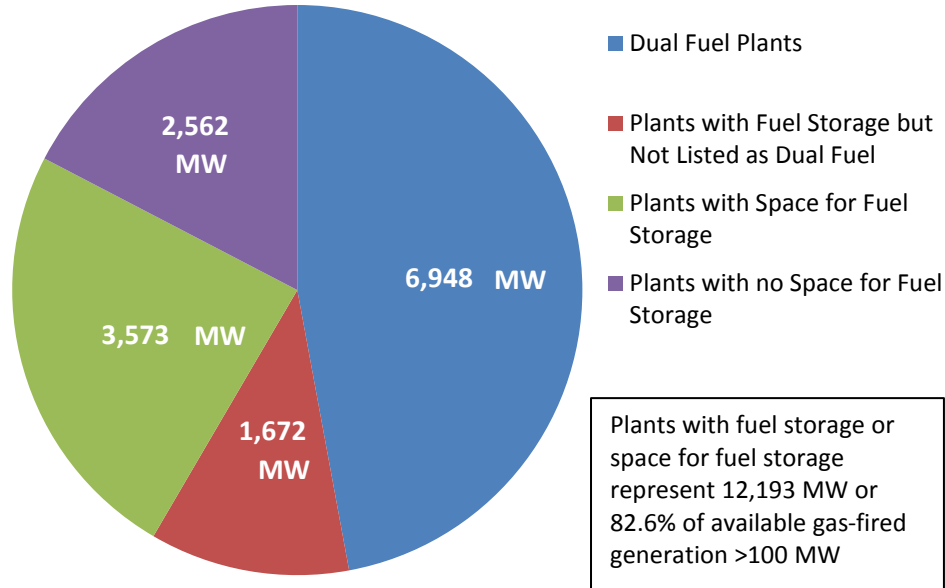
As can be seen in Exhibit 4-21 and Exhibit 4-22, out of a total of 29 plants (14,754 MW), 17 plants (8,620 MW) or 58.4 percent currently have dual fuel capability with an additional 6 plants (3,572 MW) having space for fuel storage tanks. The remaining 6 plants (2,562 MW) that do not have room for fuel storage represents 17.4 percent of total gas generation greater than 100 MW. A graphical representation of the dual fuel plant summary for ISO-NE is provided in Exhibit 4-22.

Exhibit 4-20 ISO-NE Natural Gas-Fired Plants >100 MW That Do Not Have Available Space for Fuel Storage (4)

Plant Name	Winter Capacity (MW)	Notes
Plant 15	812	Near PSEG Bridgeport Station with three units burning coal and WFO w/ four 150" diameter tanks piped to their units. Pipeline could be easily added to these gas-fired units
Plant 16	256	No room within plant boundary; however, adjacent empty property
Plant 17	554	No room within plant boundary. Bounded on two sides by rights-of-way and other facilities. Some farm land to the north west
Plant 18	170	No room on site, possible area on other side of abandoned railroad tracks
Plant 19	182	No room within plant boundary; however, adjacent empty property
Plant 20	588	No room within plant boundary; however, adjacent empty property
Total	2,562	

Exhibit 4-21 ISO-NE Dual Fuel Summary – Natural Gas-Fired Power Plants with Nameplate Capacities >100 MW (4)

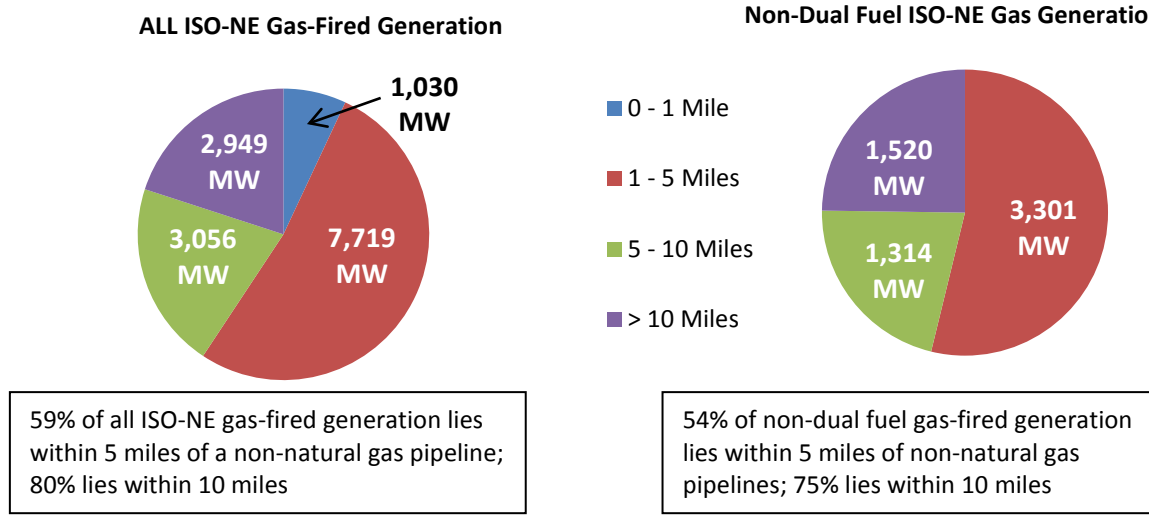
State	No. Gas-fired Plants/ Winter Capacity (MW)	Current Plants with Secondary Fuel Capability/ Winter Capacity (MW)*	Plants with Space for Potential Fuel Storage/Winter Capacity (MW)	Plants with No Space for Potential Fuel Storage/Winter Capacity (MW)
Connecticut	5/3,264	3/2,050	1/402	1/812
Maine	4/1,533	1/183	1/540	2/810
Massachusetts	14/6,740	11/5,317	1/1,071	2/352
New Hampshire	2/1,357	1/560	1/797	0/0
Rhode Island	4/1,861	1/510	2/763	1/588
Vermont	0/0	0/0	0/0	0/0
Totals	29/14,754	17/8,620	6/3,572	6/2,562

Exhibit 4-22 ISO-NE Dual Fuel Summary: Natural Gas-Fired Units >100 MW (4)

4.4 Availability of Secondary Fuel Sources

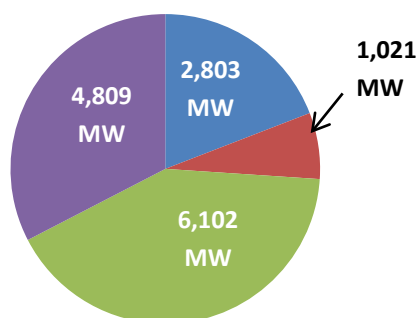
In many cases a secondary fuel could be delivered by tank truck. However, if the secondary fuel is to be relied upon on a regular basis or if extended operation on the secondary is planned, then proximity to secondary fuel pipelines is required. For this analysis, data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) was used to determine the proximity of current non-natural gas pipelines to existing natural gas-fired ISO-NE generation. It is assumed that a PHMSA regulated non-natural gas pipeline is transporting, or is capable of transporting, a secondary fuel. Exhibit 4-23 presents the distance from a natural gas-fired generator to the nearest non-natural gas pipeline. The chart on the left encompasses all natural gas generation in ISO-NE while the one on the right details the information for only those gas-fired plants previously identified as not being dual fuel capable. As can be seen, 80 percent of all gas-fired generation and 75 percent of non-dual fuel capable generation lies within 10 miles of an existing non-natural gas pipeline.

Exhibit 4-23 Distance from Non-Natural Gas pipelines to ISO-NE Natural Gas-Fired Generators >100 MW (4)

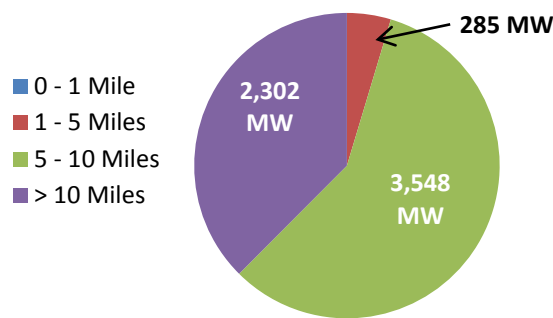


Another potential secondary fuel could be liquefied natural gas (LNG).²¹ To evaluate this potential source, the distance between natural gas-fired generators and current LNG storage tanks was calculated using data from the Ventyx Velocity database. Exhibit 4-24 presents the minimum distanced from a natural gas-fired generator to the nearest LNG storage tank. The chart on the left presents the information for all ISO-NE generators greater than 100 MW while the one on the right provides the information for only those plants that were identified as not dual fuel capable. The data indicate that 67 percent of all natural gas generation and 62 percent of non-dual fuel capable generation lies within 10 miles of an LNG storage tank. The output from these tanks, however, may not be available to power generators as these facilities are critical to local distribution companies (LDC) in meeting winter peak day gas requirements for residential and other users, historically providing about 30 percent of LDC requirements. (19)

²¹ The Canaport LNG terminal in Saint John, New Brunswick, Canada and the Distrigas LNG terminal in Everett, Massachusetts are key gas supply facilities for ISO-NE during peak winter and summer operating conditions providing natural gas supplies into the extents of the ISO-NE system and into pipeline constrained areas around Boston. According to GDF Suez, Mystic Power Generating Station, the largest generating station in ISO-NE, is directly connected to and fully reliant on the Distrigas LNG terminal for its fuel supply. (44) (45)

Exhibit 4-24 Distance from LNG Storage to ISO-NE Natural Gas-Fired Electric Generators >100 MW (4)**All ISO-NE Gas-Fired Generation (14,754 MW)****Non-Dual Fuel ISO-NE Gas-Fired Generation (6,135 MW)**

26% of all ISO-NE gas-fired generation lies within 5 miles of LNG storage; 67% lies within 10 miles



5% of non-dual fuel gas-fired generation lies within 5 miles of LNG storage; 62% lies within 10 miles

5 ISO-NE Electricity Market Impacts

Since New England is natural gas pipeline constrained, the impacts of dual fuel generation were examined from system planning and market impact perspectives. The first analysis focused on examining the ability of the ISO-NE system to meet a traditional 1-in-10 loss of load planning criteria²² in the near and far terms with variable natural gas availability during peak load. The second analysis examined the market impact of dual fuel capacity on ISO-NE electric market pricing under variable natural gas prices.

5.1 Generating Resource Analysis

The impact of dual fuel generating capacity was analyzed for its ability to allow ISO-NE to satisfy projected peak winter demands and maintain traditional 1-in-10 loss of load planning criteria under multiple gas availability sensitivities. The analysis utilized ISO-NE's 2014 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) as the basis for the sensitivity analysis. (20) Reported capacity from the CELT report was summed by source with non-natural gas firing capacity representing the aggregate of traditional fossil- and biomass-fired, nuclear, and hydroelectric generating capacity. Natural gas-fired capacity was split into two separate categories: non-dual fuel capable natural gas-firing and dual fuel capable natural gas-firing. Units in these categories represent all types of gas-fired resources including combined cycle, steam turbine, combustion turbine, internal combustion, and fuel cell. Imported (planned and maximum) generation, wind, and demand resource capacities were also identified as separate categories because these resources are traditionally variable and may not be available or responsive at the levels projected in the CELT Report during peak load periods.

Scenarios were calculated assuming different natural gas capacity availability levels to identify the minimum threshold capacities for ISO-NE to satisfy load and 1-in-10 loss of load planning requirements. Exhibit 5-1 shows the impact of four potential gas availability scenarios in each of

²² This metric is a 1 day loss of load in 10 years, based upon a probability model that considers generator loss probability and load probability. (43)

the next four years and Exhibit 5-2 shows the impact of the same four scenarios in the far-term (2022-2024). The results clearly indicate that the ISO-NE system is heavily reliant upon its entire resource mix and imports to maintain reserve margins and meet projected peak winter demands.

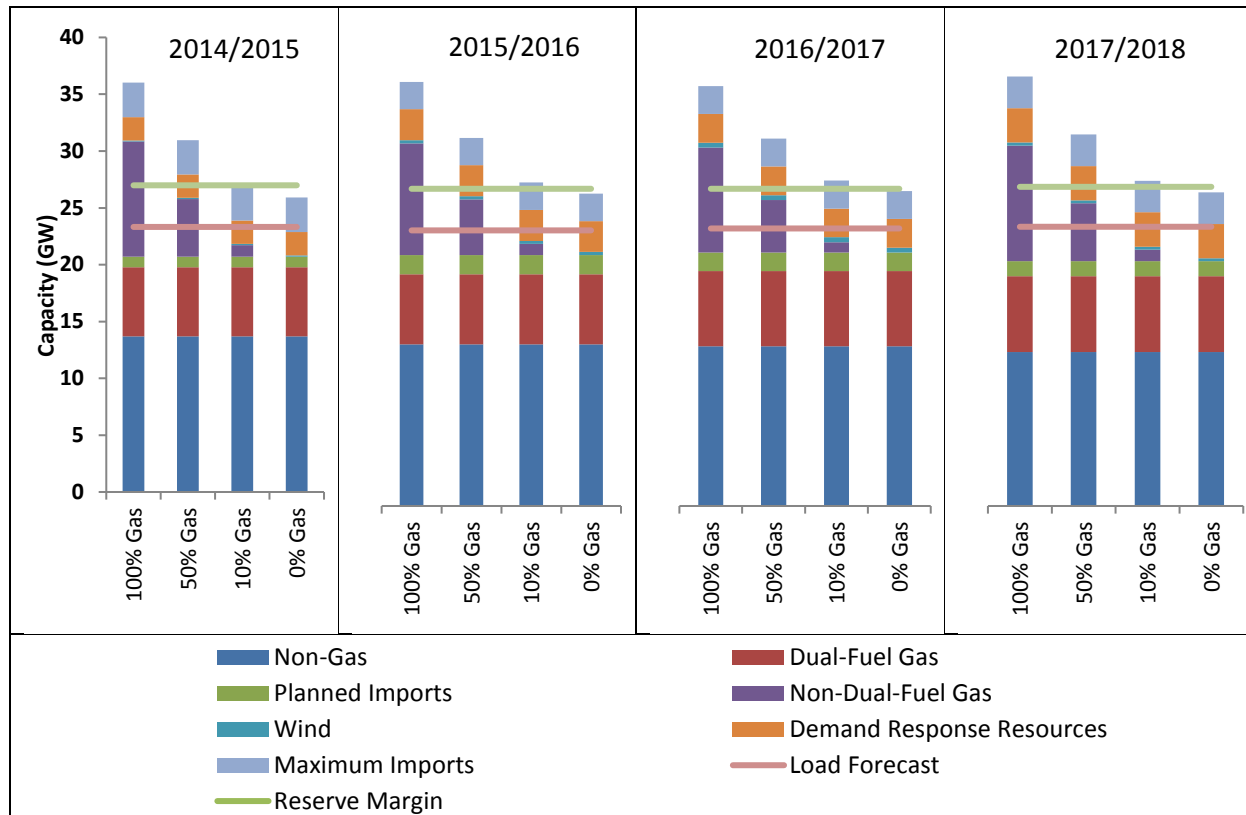
As illustrated, a curtailment that reduces the amount of non-dual fuel natural gas-fired capacity by 50 percent or more will cause the ISO-NE system to rely on power imports to meet both reserve margins and peak load. Once curtailments reduce the amount of non-dual fuel capable natural gas-fired capacity by more than 90 percent, ISO-NE will be unable to maintain its planning reserve margin without nearing its maximum import limit²³ with the full participation of demand resources as well as wind production at projected levels. A full natural gas curtailment that reduces the amount of available non-dual fuel capable natural gas-fired capacity to zero would result in a complete inability to maintain reserve margins and the ability to only clear peak demand by less than 3 GW. Since this analysis assumes that all capacity resources and imports are available at planned and maximum levels, less the natural gas-fired capacity variable, additional losses in generating capacity due to forced outage or inability to return from maintenance would result in a significant loss-of-load potential.

For perspective, this model assumes nearly 10 GW of non-dual fuel natural gas-fired capacity, 3 GW of demand response resources, and 4 GW of import capability. Considering the planned and forced capacity outages (7.2 GW) (21) and demand response resource response rates (77.2 percent) (22) witnessed during the peak hour of the 2014 Polar Vortex, the ISO-NE system safely operated at an effective 23 percent gas availability with both primary and dual fuel in use. Removing dual-fired capacity from the curtailment scenarios reveals the importance of dual fuel from a reliability perspective, as ISO-NE becomes unable to maintain reserve margins if less than 71 percent of natural gas single firing capacity is available. At less than 35 percent availability, the system becomes unable to meet demand. De-rating demand response resources increases these threshold levels by an additional 4 percent to 75 percent and 39 percent, respectively.²⁴

²³ Maximum import limit is a physical limitation dictated by the transmission system technologies in use.

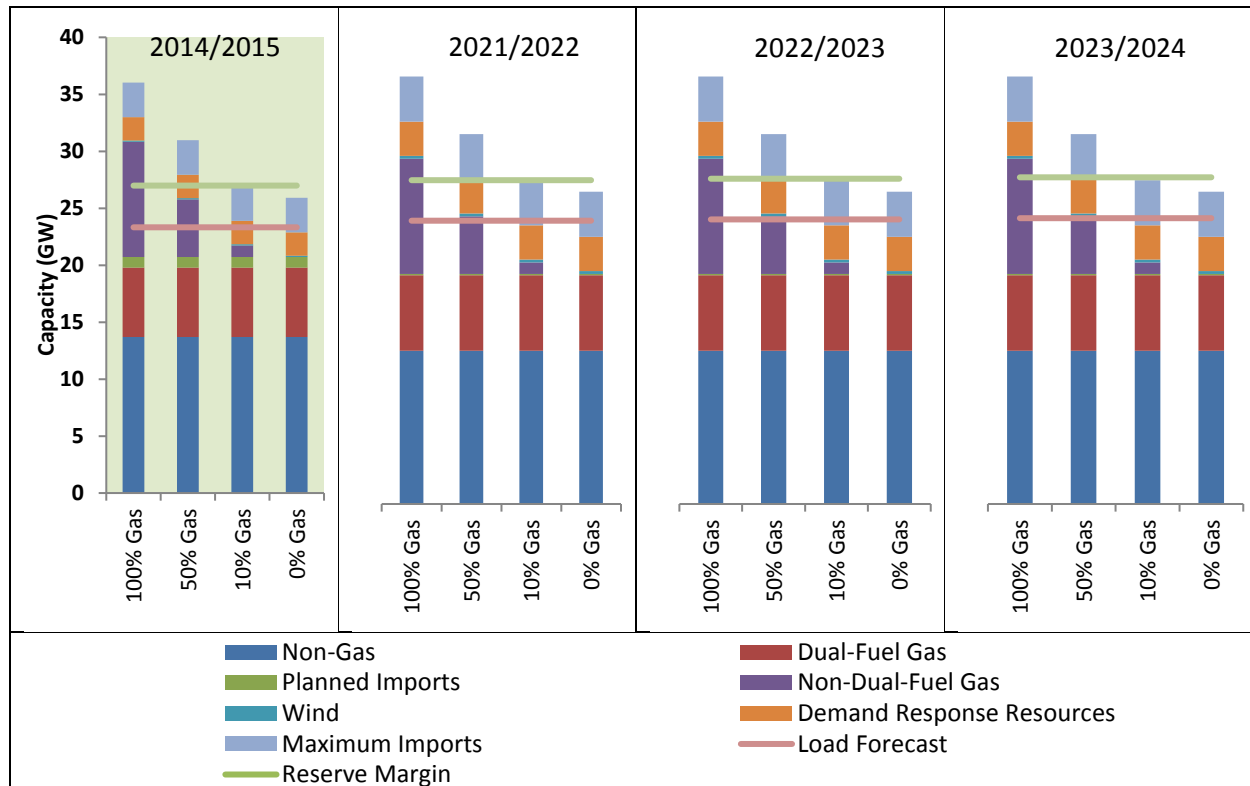
²⁴ The importance of other non-natural gas-fired capacity should not be understated or considered non-essential in these scenarios. These scenarios assume that all non-natural gas-fired capacity will respond as expected when needed. Similar analyses could be performed including dual fueled capacity and reducing the availability of non-natural gas-fired capacity or any combination thereof to determine the minimum availability levels required to maintain reserve margins and to satisfy load. This analysis solely considers the impacts of natural gas-fired and dual fueled capacity because it is assumed that other non-natural gas-fired capacity maintains ample on-site fuel reserves for multiple days of operation, whereas natural gas-fired capacity requires fuel delivery on demand and dual fueled capacity requires advance notice to be available on secondary fuel when needed.

Exhibit 5-1 ISO-NE Near-Term Forecasted Resource Availability (with Variable Natural Gas Availability)²⁵ (20)



²⁵ 100 percent gas case is based on values identified within the ISO-NE CELT report. Reduced gas cases are modeled de-rates based on these values.

Exhibit 5-2 ISO-NE Far-Term Forecasted Resource Availability (with Variable Natural Gas Availability)*²⁶ (20)



*2014/2015 included for comparison

5.2 Electricity Market Impact of Dual Fuel Capability

Beyond any potential reliability value that dual fuel capacity may have, it also has an economic value in the energy market. Because the largest impact of dual fuel capacity is likely to occur during the winter peak electric demand and gas curtailments, an analysis was developed that examined four dispatch scenarios at different spot market prices for natural gas and distillate fuel oil. Utilizing unit level hourly production O&M cost data, 10-year average capacity factors, and heat rates from Ventyx Velocity Suite (4), hypothetical generator offer prices were determined for each unit in the ISO-NE system. Sensitivities were then performed on the bid price of natural gas single firing and dual fuel natural gas-firing generators based on four potential operating scenarios.

The first scenario established the baseline for nominal system operation during an average operating day. In this scenario, the fuel component of the generator bid for all units was considered to be the 12-month average fuel cost for each unit from Ventyx Velocity Suite. (4) The second scenario ignored the potential dual fuel capabilities and assumed that the fuel cost component of natural gas-firing units would be the spot market price multiplied by the unit heat rate in MMBtu/MWh. This scenario establishes a cost baseline for pure natural gas operation.

²⁶ 100 percent gas case is based on values identified within the ISO-NE CELT Report. Reduced gas cases are modeled de-rates based on these values.

The third scenario considered the impact of dual fuel capacity on system prices during a complete natural gas curtailment that forces all non-dual fuel capable natural gas-firing units offline. In this scenario, the fuel component of the bid price for dual fuel capable units was considered to be the spot market price for distillate fuel oil multiplied by the unit heat rate in MMBtu/MWh. The fourth scenario considered the more likely scenario of dual fuel capacity switching from natural gas to fuel oil as an economic decision to avoid high natural gas spot market prices while non-dual fuel capable natural gas-firing capacity bids based on these high prices.

Since the focus of this analysis was on periods of high electric demand and potential natural gas curtailment, the analysis focused on the peak demand experienced in ISO-NE during the Polar Vortex of 2014. Focusing on this event allowed for a means of testing the dispatch results through comparison to historical system load and pricing data from the event. Because more than 7 GW of capacity outages and de-rates occurred during this period, the economic calculation point was not the point of actual peak load experienced during the Polar Vortex, but an effective load point that adjusted the actual load for outages and de-rates. Each scenario modeled also included the actual peak hour transmission imports (1,756.5 MW) (23) as an effective generator at the actual market clearing price (\$737.23/MWh). (24) Additionally, all demand resource resources were assumed to bid at the energy offer cap, \$1,000/MWh, as defined in Section I.2.2. of the ISO-NE Transmission, Markets, and Service Tariff. (25)

Exhibit 5-3 provides a comparison of the scenarios with the natural gas spot price assumed to be \$85/MMBtu and the fuel oil spot price assumed to be \$22/MMBtu as actually occurred in New England during the Polar Vortex. While none of the scenarios align to the peak hour price seen during the Polar Vortex, two key findings are revealed: (1) without natural gas single firing units, ISO-NE would not have had sufficient capacity to meet peak demand during the Polar Vortex; and (2) at a natural gas spot price of \$85/MMBtu, the price impact of dual fuel capacity is about \$67/MWh. In an attempt to identify the natural gas price where the results of the fourth scenario would align with the actual market clearing price, additional sensitivities were developed to test different natural gas spot market prices.

Exhibit 5-4 illustrates the results of the fourth scenario using the natural gas spot market prices seen in New England and New York during the Polar Vortex, along with results for an averaged New England/New York spot market price (\$102.875/MMBtu). This comparison revealed that the results produced by the average price align to within 0.8 percent of the actual market clearing price. Repeating all the scenarios for the averaged spot market price indicates that the price impact of dual fuel capacity is reduced to \$14/MWh as the generator offers shift, due to the change in gas price, which narrows the gap between the high gas and high gas/dual fuel scenarios. Unlike what occurs in the \$85/MMBtu natural gas price case, a shift in either direction along the dispatch curves in the \$102.875/MMBtu case results in an increase in the price impact of dual fueled capacity (Exhibit 5-5) as the effective load falls near inflections in the dispatch. These charts illustrate the effects of dual fuel operation on generator offers and load serving, as well as showing how natural gas price affects the difference that dual fuel operation makes. At the averaged spot price of \$102.875/MMBtu, the price difference between all gas fired operation and dual fuel operation is small. However, removing those gas-fired generators means that effective load cannot be met.

Exhibit 5-3 Dispatch Curves for Natural Gas-Fired Capacity Scenarios at \$85/MMBtu Natural Gas Spot Price (4)

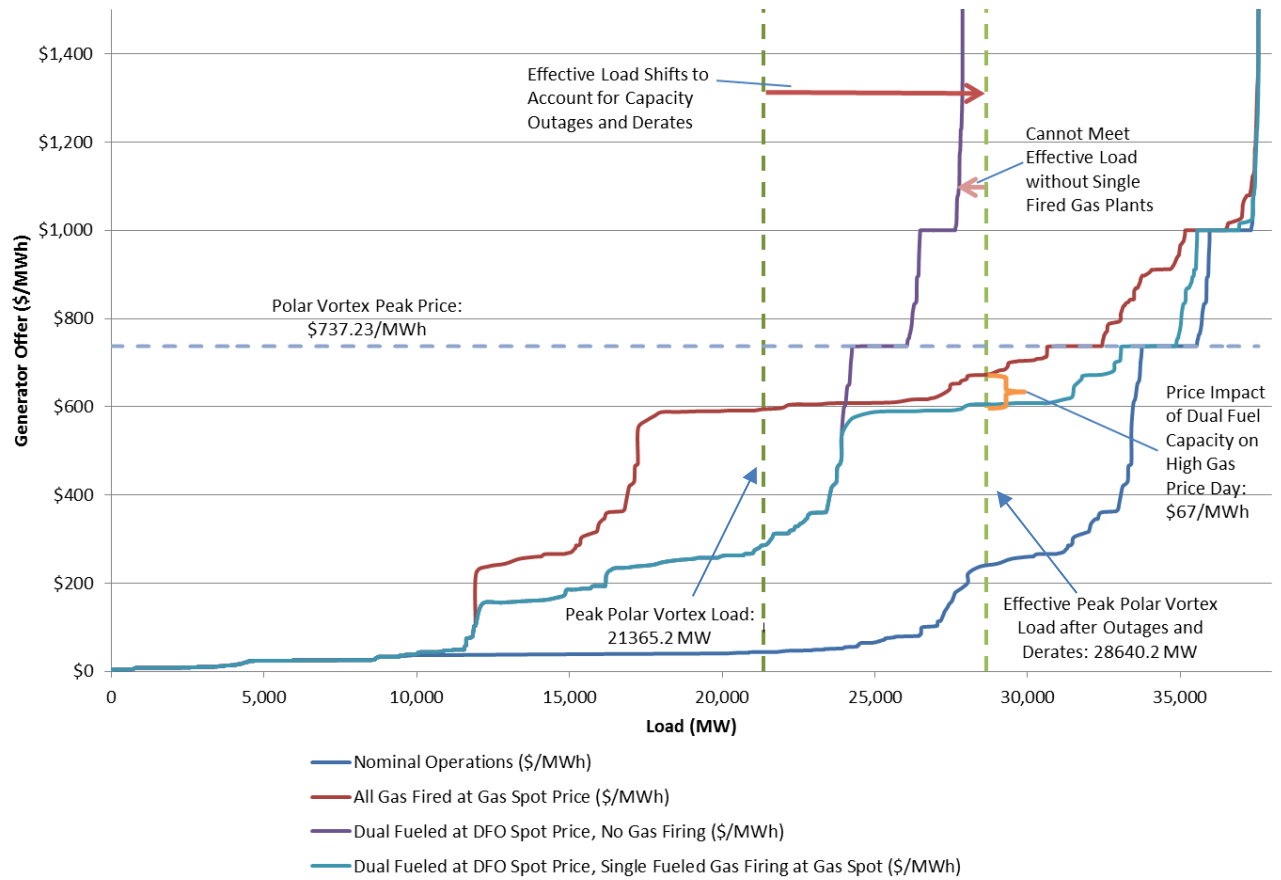


Exhibit 5-4 Comparison of Dispatch Curves at New England, New York, NE/NY Composite Natural Gas Spot Price Scenarios (4)

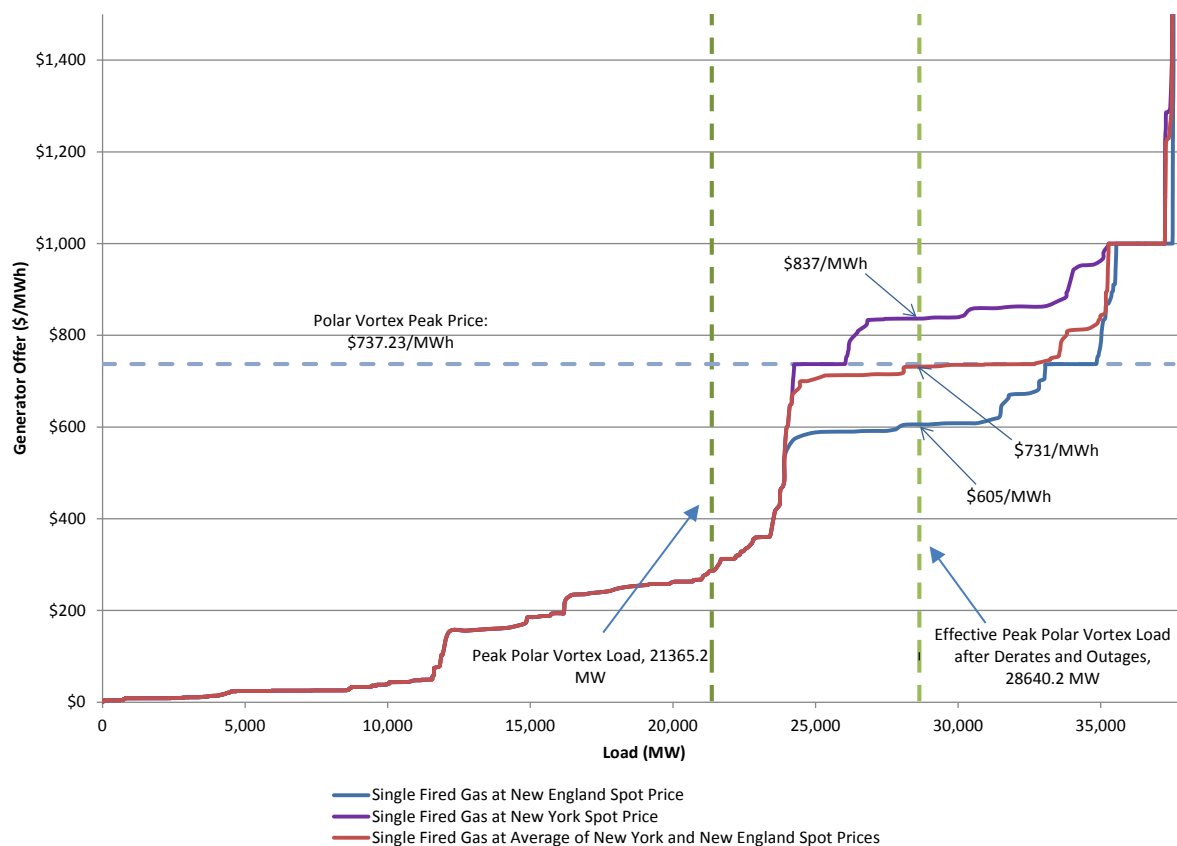
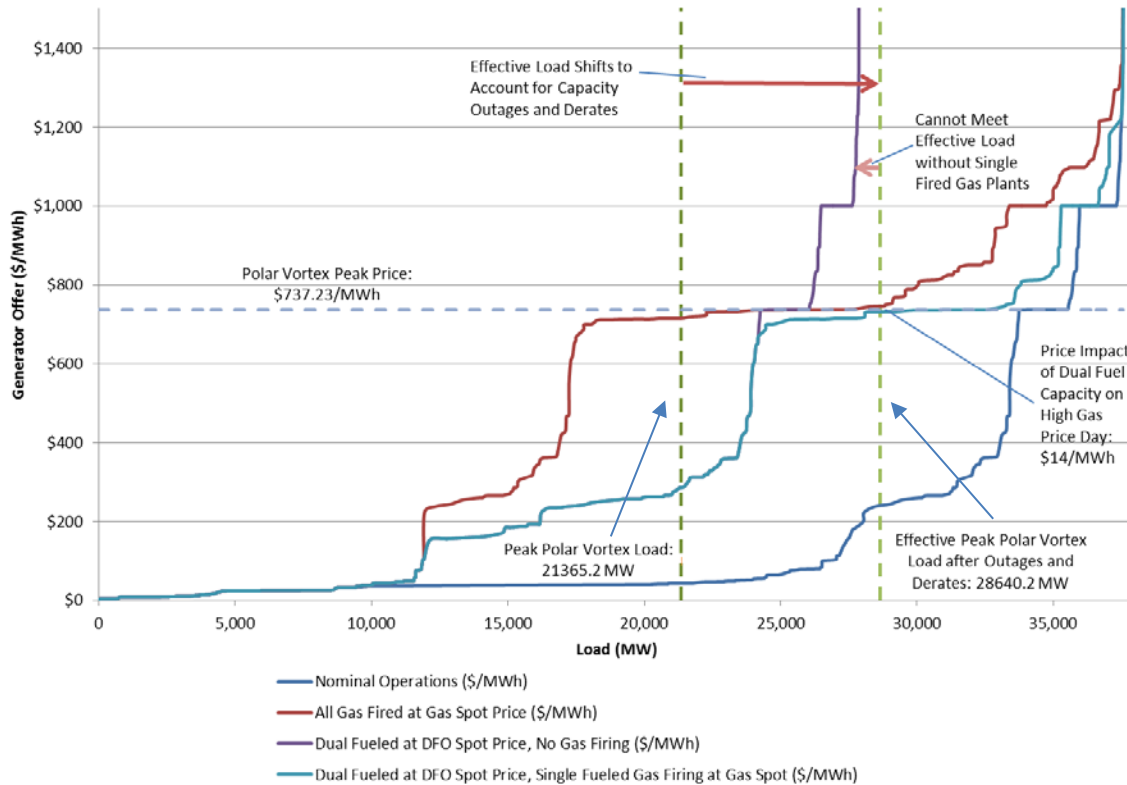


Exhibit 5-5 Dispatch Curves for Natural Gas-Fired Capacity Scenarios at \$102.875/MMBtu Natural Gas Spot Price (4)

6 Dual Fuel Market Rules and Permitting Requirements

6.1 Electricity Market Rules and Issues

As can be seen in the above analysis, during severe winter events it is critical that existing generating resources are available for dispatch. Because of this, ISO-NE adopted a Federal Energy Regulatory Commission (FERC)-approved Winter Reliability Program in the winters of 2013/14 and 2014/15 to address reliability problems that may have arisen during severe winter weather as a result of increased demand combined with fuel resource constraints. As part of the Winter Reliability Program, ISO-NE offered out-of-market incentives to plants that burn petroleum. By increasing the use of petroleum, particularly by dual fuel plants, ISO-NE aimed to reduce its reliance on natural gas, thereby limiting the system's vulnerability to natural gas shortages.

First, in order to improve the performance of petroleum-fired generation, generators who committed to maintaining certain levels of oil inventory and submitting supply offers into the markets were given monthly payments to offset the costs of their oil inventory. As a safeguard measure, any generators participating in the program who failed to meet performance standards had their monthly payment reduced by an amount commensurate with their unavailability, and were also assessed a charge for any committed generation not in inventory. Second, ISO-NE paid dual fuel resources for the costs of a successful test to show that the resource could switch fuels within five hours or less. Third, ISO-NE relaxed certain market monitoring rules to make

fuel-switching less risky for generators. Usually, these rules prevent generators from offering into the markets based on their higher priced fuel without first obtaining approval from the Internal Market Monitor.²⁷ Under the Winter Reliability Program, plant operators had the ability to choose which fuel to use, regardless of price. (26)

In May 2014, FERC accepted an ISO-NE proposal in Docket ER14-1050 to restructure its forward capacity market, starting with the 2018 capacity auction to implement “Pay for Performance” rules that would permanently replace the Winter Reliability Program and encourage improved generator performance through financial penalties for non-performance. (27) This proposal recommended implementing a two-settlement process where capacity resource payments would be composed of a Capacity Base Payment and a Capacity Performance Payment. The Capacity Base Payment would be determined through the established forward capacity market, while the Capacity Performance Payment would be determined based on a resource’s forward position in the capacity market and its actual performance.

While the acceptance of “Pay for Performance” rules created a permanent solution to the recurring need for the Winter Reliability Program, its delayed implementation created a need for an interim solution. In its acceptance of the 2014/15 Winter Reliability Program, FERC directed the ISO-NE to start the stakeholder process to develop an interim market-based solution to replace the Winter Reliability Program. While these discussions were held as directed, ISO-NE did not guarantee the development of a solution. As a result, the New England Generators Association filed for and received clarification from FERC in Docket ER14-2407 that the interim market-based solution be developed for implementation in the winter of 2015/16. (27) In response to this clarification, ISO-NE filed a request for rehearing and requested that the Winter Reliability Program be allowed to continue through 2018 due to its success in 2013/14 and 2014/15. (28) FERC accepted this request for rehearing, followed by a second filing by ISO-NE under Docket ER15-2208 proposing tariff changes to incorporate the program through 2018, which was accepted on September 11, 2015.

6.2 Dual Fuel Regulatory and Permitting Issues

Generally, dual-fuel plants must comply with a number of local regulations, including zoning requirements that govern the siting and construction of fuel tanks, and environmental codes that may place restrictions on fuel storage locations. The most significant regulatory issue facing a dual-fuel plant conversion, however, is obtaining an air permit.

In the New England region, which historically has relied heavily on petroleum-fired generation, the shift away from petroleum to natural gas-fired generation has been largely the result of increasing concerns over air quality. Substantial restrictions have been placed on the use of fuel oil, either as a primary or as a backup fuel. These restrictions include maximum burning times, maximum sulfur content, and maximum allowable emissions of particulate matter (PM), sulfur dioxide (SO₂), and nitrogen oxide (NO_x).

State agencies have the primary responsibility for implementing the requirements of the federal Clean Air Act of 1970 and Clean Air Act Amendments of 1990 through delegation of authority

²⁷ The Internal Market Monitor provides critical functions in support of FERC, state regulators and New England stakeholders to ensure the success of the wholesale electricity markets. <http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>

under Federal rules. State agencies are also tasked with implementing any additional environmental regulations enacted by their state. The U.S. Environmental Protection Agency (EPA) developed National Ambient Air Quality Standards (NAAQS), and the Clean Air Act was designed to maintain or achieve air quality levels that met those standards. NAAQS have been established for “criteria pollutants” PM, SO₂, and NO_x, which are the primary pollutants emitted by fossil fuel-fired facilities. Regions where the current levels of emissions are above their NAAQS are known as non-attainment areas, and facilities located there usually face stricter regulations.

The New England states have some of the most stringent regulations governing the use of fuel oil. This is in part because most of the region is considered a non-attainment area for ozone. Additionally, all of the New England states belong to the Regional Greenhouse Gas Initiative (RGGI), a market-based regulatory program to reduce greenhouse gas emissions. RGGI regulates the CO₂ emissions of all fossil fuel-fired generation plants that are 25 MW or greater. (29)

In order to convert a facility to dual fuel operation, said facility must obtain an air quality permit under either the federal or a federally-approved state New Source Review (NSR) program. The requirement to obtain a permit under NSR applies to any new facility or any facility undergoing a major modification, such as conversion to dual-fuel. The EPA oversees the federal NSR program and also approves any state NSR program. All New England states operate state NSR programs that have received EPA approval and delegation of permitting authority.

Under an NSR program, the state environmental authority reviews a facility’s projected post-modification future emissions before granting a permit. To obtain a permit, a facility must show that it will use emission control technologies that meet either Best Achievable Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) standards. BACT is generally applied in attainment area states, while LAER is applied in non-attainment area states, although this can vary depending on the regulations of the particular state. (31)

In addition to pollution control requirements, the NSR permit also specifies the facility’s maximum amount of emissions allowed. For a dual fuel facility, this is partially achieved by restricting the amount of petroleum burned, since petroleum is the higher emitting fuel. Although they may vary, most permits limit the number of hours per year that a facility is allowed to burn petroleum-based fuel. Permits may also restrict the type of fuel that is burned, allowing the facility to only use ultra-low sulfur diesel fuel. A permit may prohibit a facility from switching to petroleum unless natural gas is curtailed, and the strictest permits only allow a dual fuel facility to switch from natural gas to petroleum during a declared power emergency. Exhibit 6-1 provides a representative sample of restrictions on dual fuel operations found in air quality permits issued in Connecticut and Massachusetts, where the most dual fuel plants in New England are located.

Exhibit 6-1 Air Permit Restrictions on Selected Dual Fuel Facilities (32) (33)

Facility	Fuels	Operating Restrictions
Connecticut Municipal Electric Energy Cooperative's Pierce Station (CT)	Uses natural gas as primary fuel, with ultra-low sulfur diesel as the secondary fuel	Restricted to fuel switching events for a max 30 hours per year. May only use diesel when natural gas supply is curtailed or otherwise unavailable
Devon Power, LLC (CT)	Uses natural gas as primary fuel, with ultra-low sulfur diesel as the secondary fuel	The four 40 MW units located at the facility may not operate more than a combined 72 hours/day. In July, they are limited to a combined 56 hours/day
Waterbury Generation, LLC (CT)	Uses natural gas as a primary fuel, with kerosene as the secondary fuel	Generator is only permitted to operate on kerosene when natural gas is curtailed or otherwise unavailable
Berkshire Power (MA)	Uses natural gas as primary fuel, with ultra-low sulfur diesel as the secondary fuel	Restricted to operating a maximum of 300 hours on a rolling 12-month basis, and only under certain conditions. From May 1 through September 30 (ozone season), the facility may only burn diesel in event of power emergency
Northeast Energy Associates' Bellingham Cogeneration (MA)	Uses natural gas as primary fuel, with ultra-low sulfur diesel as the secondary fuel	May operate up to 720 hours (30 days) per year on diesel

A natural gas plant converting to dual fuel operation would need to obtain approval to add fuel storage tanks to its facility. EPA regulates underground storage tanks under the Resource Conservation and Recovery Act (RCRA). (34) Similar to air quality permitting, EPA approves state programs to oversee underground storage tanks and enforces the federal regulations. EPA's regulations pertain to the construction, installation, operation, and decommissioning of underground storage tanks in a manner that minimizes chances of an oil spill or leakage. EPA also requires facilities to have an oil spill contingency plan, including equipment and training for cleaning up a fuel spill. (35) Above ground storage tanks are not subject to federal regulation, although most states have state level regulations governing them. These state regulations are mainly concerned with oil spill prevention and cleanup.

Finally, converting to a dual fuel plant requires multiple physical changes to a facility in addition to the storage tanks. These changes are subject to local zoning and land-use approvals, as well as any other state regulations. For example, if a plant expects to install underground pipes connecting the storage tank to the generator, that may also be regulated by the state. A local land-use permit would be necessary for any plant adding a docking area for trucks to dispense fuel into the storage tanks.

As a representative example of the regulatory processes a facility must go through, in Connecticut an owner would first arrange a pre-application meeting with a Connecticut Department of Energy and Environmental Protection (DEEP) engineer. The owner would then submit permit applications to DEEP for NSR review and Title V²⁸ air quality operating permit modifications, if applicable. Once approved, this application would cover the facility's compliance with all air quality regulations, both state and federal. According to DEEP's website, an application is usually processed within 180 days. (36)

If the owner is planning to add an underground tank for fuel storage, they must register with DEEP. The storage tank will be subject to inspection and inventory must be recorded daily. Further, a designated storage tank operator must receive required training from DEEP in order to operate the storage tank. An above ground storage tank in Connecticut must implement a spill prevention, control, and countermeasure program, as required by EPA and administered by DEEP. (37)

7 Key Findings

The evaluation of ISO-NE natural gas electricity generating plants greater than 100 MW indicated that:

- ISO-NE has 16,750 MW natural gas capacity, roughly 50 percent of its resource mix
- Out of a total of 29 plants (14,754 MW), 17 Plants (8,620 MW) or 58.4 percent currently have dual fuel capability
- An additional 6 plants (3,572 MW) have space for fuel storage tanks indicating that they probably could be converted to dual fuel
- The remaining 6 plants (2,562 MW) that do not have room for fuel storage represent 17.4 percent of total gas generation greater than 100 MW

The examination of the secondary fuel transportation infrastructure shows that 80 percent of all gas-fired generation and 75 percent of non-dual fuel capable generation lie within 10 miles of a current non-natural gas pipeline that could transport a liquid secondary fuel. The data also indicate that 67 percent of all natural gas generation and 62 percent of non-dual fuel capable generation lie within 10 miles of a LNG tank.

The generating resource analysis indicates that the ISO-NE system is reliant upon its entire generation resource mix and imports to maintain reserve margins and meet projected peak winter demands. The analysis indicates that a curtailment that reduces the amount of non-dual fuel natural gas-fired capacity by 50 percent or more will cause the ISO-NE system to rely on power imports to meet both reserve margins and peak load. Additionally, if curtailments reduce the amount of non-dual fuel capable natural gas-fired capacity by more than 90 percent, ISO-NE will be unable to maintain its planning reserve margin without nearing its maximum import limit with the full participation of demand resource resources and wind production at projected levels.

²⁸ Title V of the Clean Air Act (CAA) as incorporated in U.S. Code as Title 42, Chapter 85 including changes enacted since 1990.

A large natural gas demand, possibly caused by home heating requirements²⁹ or gas infrastructure failure, that leads to a complete natural gas curtailment to power generators would result in the inability to maintain reserve margins and the ability to only clear peak demand by less than 3 GW. Removing dual-fired capacity from the curtailment scenarios reveals that ISO-NE becomes unable to maintain reserve margins if less than 71 percent of the 10.1 GW of natural gas single firing capacity is available. At less than 35 percent availability, the system becomes unable to meet demand.

The ISO-NE economic dispatch modeling revealed that without natural gas single firing units, ISO-NE would not have had sufficient capacity to meet peak demand during the Polar Vortex of 2014. The modeling also found that at a natural gas spot price of \$85/MMBtu, the price impact of dual fuel capacity is about \$67/MWh.

Repeating the modeling scenarios for the averaged spot market price of \$102.875/MMBtu indicates that the price impact of dual fuel capacity is reduced to \$14/MWh as the shift in generator offers due to the change in gas price narrows the gap between the high gas and high gas/dual fuel scenarios. A shift in either direction along the dispatch curves in this case results in an increase in the price impact of dual fueled capacity.

²⁹ Natural gas heating accounts for approximately 3.4 Bcf of demand in New England on an average winter day, with colder winter day heating demand exceeding 4.5 Bcf. Natural gas-fired generation requires an additional 1+ Bcf on top of heating and other demands for natural gas. Historically, heating oil has been the predominant source for home heating in New England, however, this is no longer the case. According to data from the U.S. Census Bureau American Community Survey, the number of homes in New England relying on heating oil-based heat has decreased from 42% to 33% from 2004 to 2014, while the number of homes relying on natural gas-based heat has risen from 31% to 34% over the same period. (41) When the impacts of the ISO-NE generating resource mix on electric heat provision are considered, the amount of heating supplied by natural gas has actually risen from 35% to 39%, while heating oil has decreased from 43% to 33%, illustrating the critical nature of natural gas pipeline curtailment concerns. (42)

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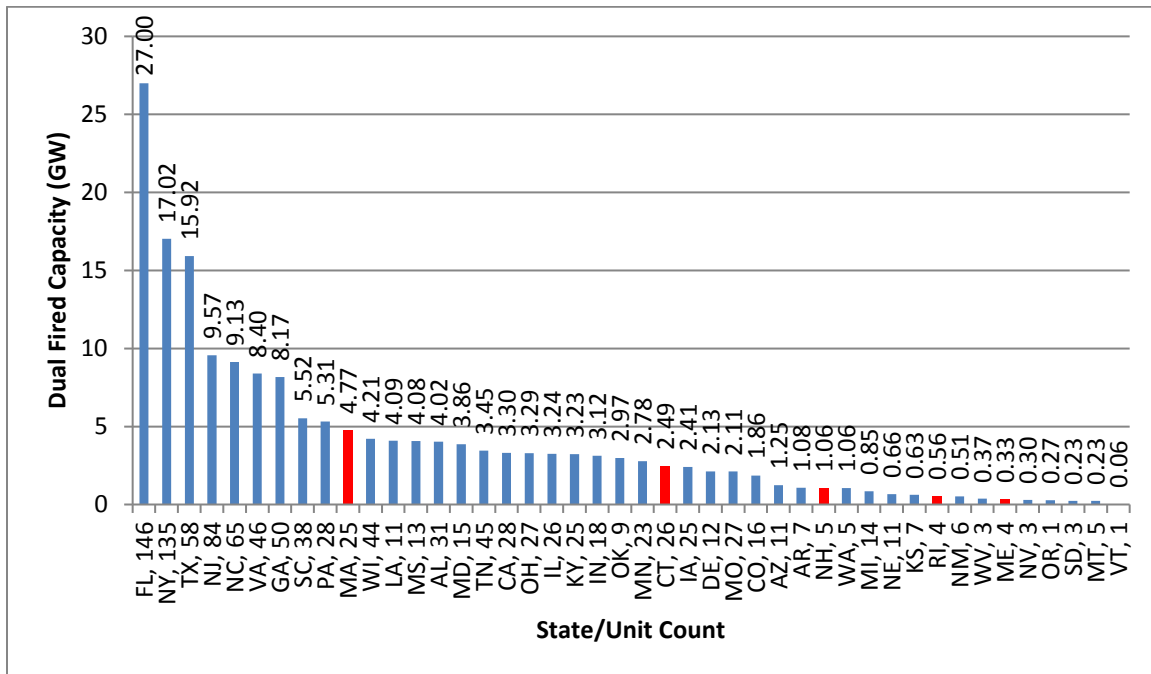
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Appendix A: State Level Dual Fueled Capacity Perspective

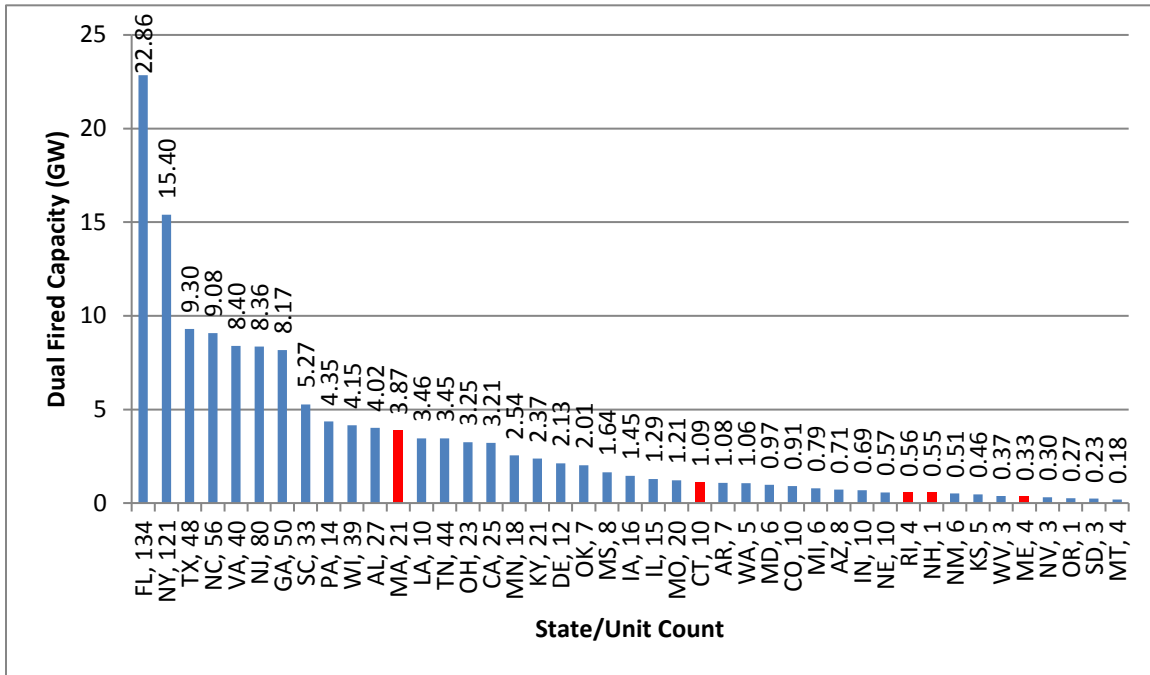
Breaking down dual fueled capacity on a state-by-state basis reveals that the largest quantities of dual fuel-firing capacity are located in states that have a high risk for natural disasters that may interrupt primary fuel deliveries. For instance, many of the generators in Florida that are dual fuel capable date from before the state's natural gas pipeline infrastructure was sufficiently developed to provide redundant sources of supply in the event of a major hurricane. (38) Beyond potential constraints in primary fuel deliveries driving dual fuel installations, most installed dual fuel capabilities are due to the ready availability of an economical secondary fuel source in close proximity to the generator.

Exhibit A-1 U.S. Generating Plants Reporting as Secondary Fuel Capable (All Fuel Types and Sizes)¹ (4)



¹ Red bars indicate the states that compose Independent System Operator-New England (ISO-NE).

Exhibit A-2 U.S. Generating Plants Reporting as Secondary Fuel Capable (Natural Gas Primary, All Sizes)¹ (4)



¹ Red bars indicate the states that compose ISO-NE.

Appendix B: Fuel Requirement Calculation Methodology

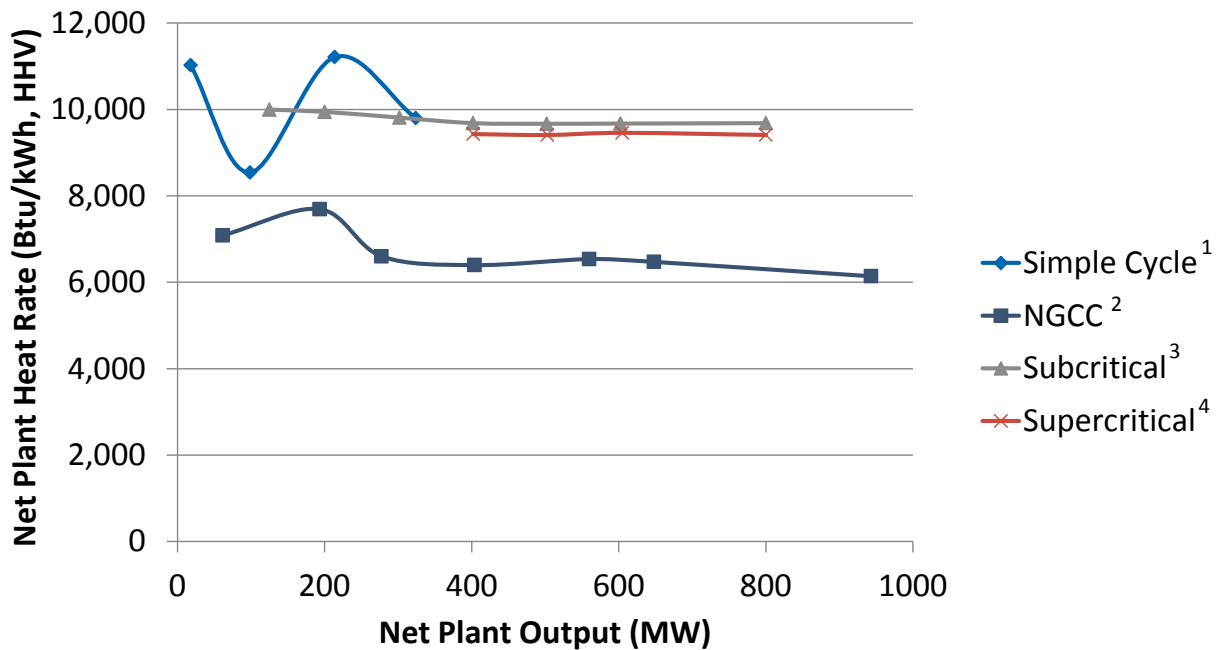
Nominal heat rates for differently sized systems were collected and plotted for each generation type as shown in Exhibit B-1.

Exhibit B-1 Nominal Heat Rate Sources

Simple Cycle	Combined Cycle	Subcritical Steam Turbine Generator	Supercritical Steam Turbine Generator
Nominal heat rates from Gas Turbine World Simple Cycle Specs for the following turbines: • GE LM1800e (2011), Net Plant Output 17.9 MW • GE LMs100PB (2010), Net Plant Output 98.4 MW • GE 7FA (2009), Net Plant Output 213.8 MW • MHI M501J (2011), Net Plant Output 323.7 MW	Nominal heat rates from Gas Turbine World Combined Cycle Specs for the following turbines: • GE LM6000PF (2006), Net Plant Output 61.4 MW • GE S109E (2008), Net Plant Output 193.2 MW • GE 107FA (2008), Net Plant Output 277.3 MW • MHI MPCP1 (M501GAC) (2011), Net Plant Output 404.0 MW • GE 207FA (2008), Net Plant Output 559.7 MW • GE 207FA (2009), Net Plant Output 647.8 MW • MHI MPCP2 (M501J) (2011), Net Plant Output 942.9 MW	Nominal heat rates from GE Steam Turbine Generators, 100 MW and Larger, 1,800-2400 psig, single reheat: • 125.0 MW • 200.0 MW • 301.7 MW • 401.6 MW • 502.0 MW • 602.3 MW • 800.0 MW	Nominal heat rates from GE Steam Turbine Generators, 100 MW and Larger, 3,500 psig, single reheat: • 402.2 MW • 502.8 MW • 604.7 MW • 800 MW

Using the information in Exhibit B-1, heat rates were plotted for each of the cycle types (simple and combined cycle and sub- and supercritical steam turbine generators (STG)) and shown in Exhibit B-2.

Exhibit B-2 Comparison of HHV Heat Rates by Facility Type



¹ Gas Turbine World Simple Cycle Specs (60 Hz)

² Gas Turbine World Combined Cycle Specs (60 Hz)

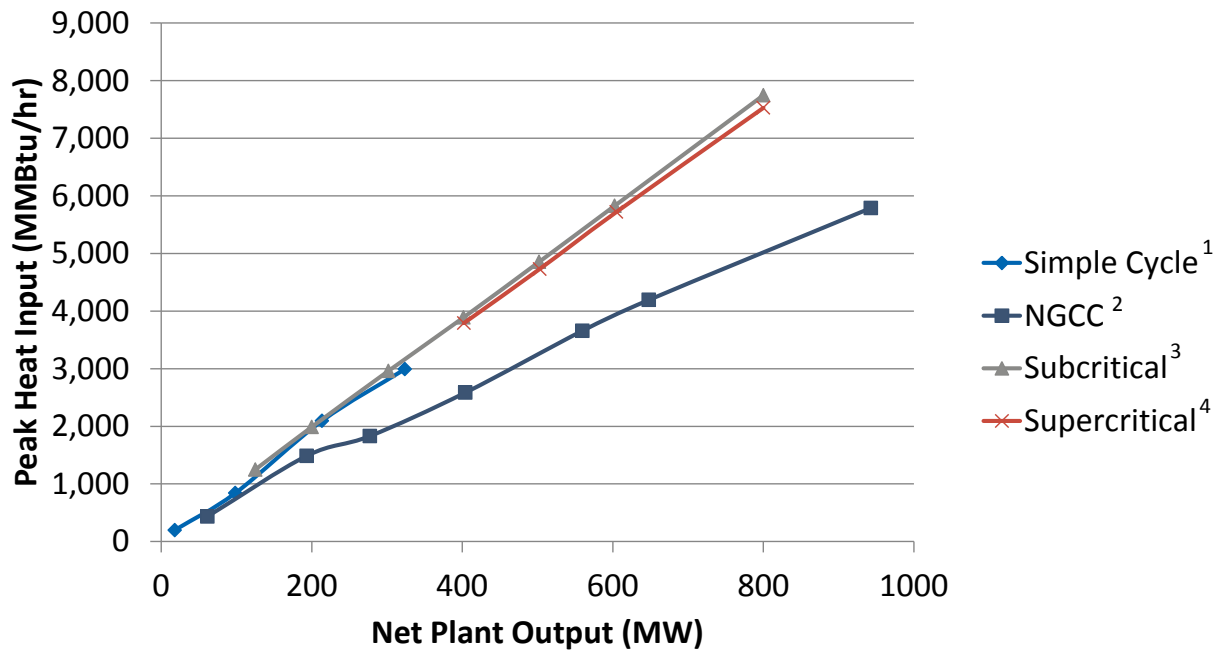
³ GE Steam Turbine Generators, 100 MW and Larger, Sub-critical, 1,800-2,400 psig, single reheat

⁴ GE Steam Turbine Generators, 100 MW and Larger, Super-critical, 3,500 psig, single reheat

Fuel Oil Feed Rate Calculation

- Heat rate information used to calculate fuel oil usage
- Fuel oil heating value of 5.8 MMBtu/bbl, 42 gallons per bbl
- Daily fuel usage for each system size was plotted
- Linear approximations were developed for each types, as shown in Exhibit B-3:
 - o Simple Cycle, $y = 1.6052x + 0.4991$
 - o Combined Cycle, $y = 1.0381x + 32.223$
 - o Subcritical STG, $y = 1.6472x + 9.1582$
 - o Supercritical STG, $y = 1.6142x + 2.2265$

Exhibit B-3 Fuel Oil Feed Rate



(Fuel heating value = 139,795 Btu/gal)

¹ Gas Turbine World Simple Cycle Specs (60 Hz)

² Gas Turbine World Combined Cycle Specs (60 Hz)

³ GE Steam Turbine Generators, 100 MW and Larger, Sub-critical, 1,800-2,400 psig, single reheat

⁴ GE Steam Turbine Generators, 100 MW and Larger, Super-critical, 3,500 psig, single reheat Backup Fuel Requirement

Linear approximations were used to calculate daily backup fuel requirements per day for each plant type and size from 100 MW-900 MW as shown in Exhibit B-4 through Exhibit B-7.

Exhibit B-4 Simple Cycle Plant Secondary Fuel Oil Required by Plant Size

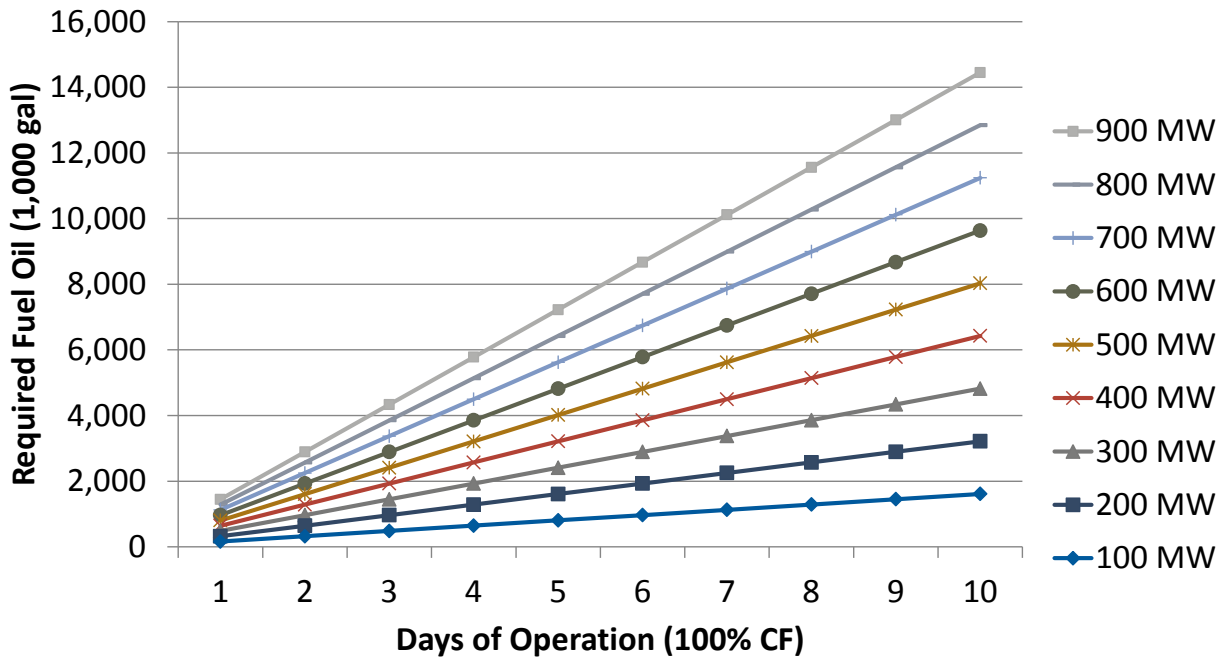


Exhibit B-5 Combined Cycle Plant Secondary Fuel Oil Required by Plant Size

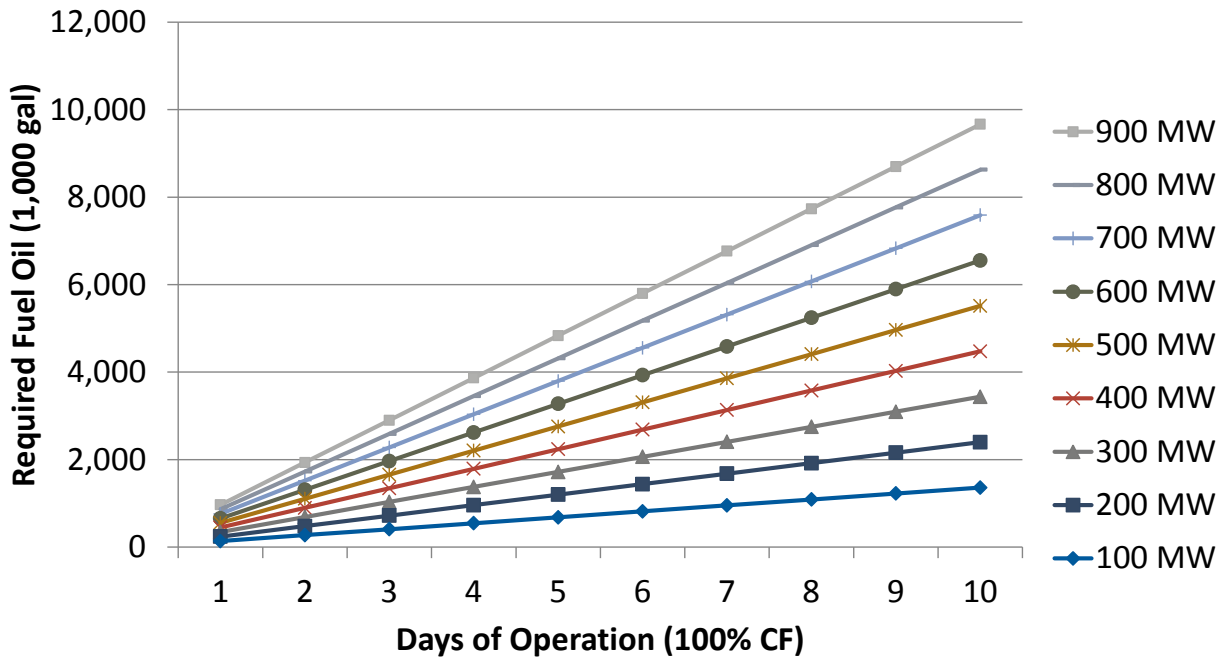


Exhibit B-6 Subcritical Steam Turbine Plant Secondary Fuel Oil Required by Plant Size

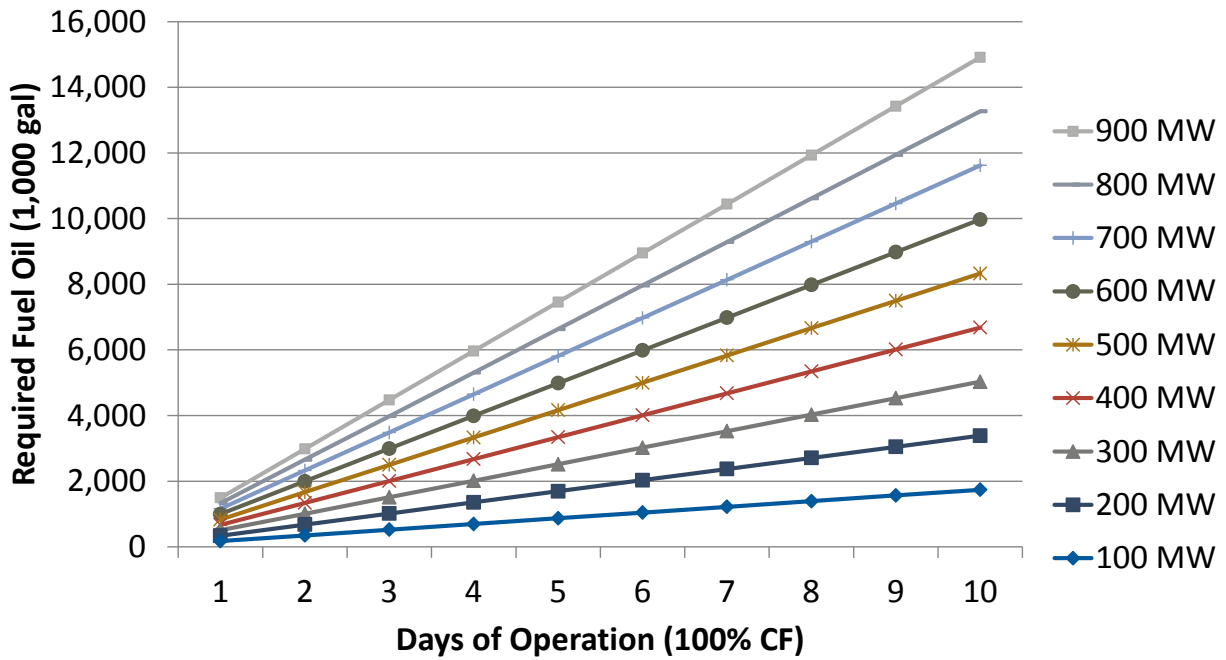
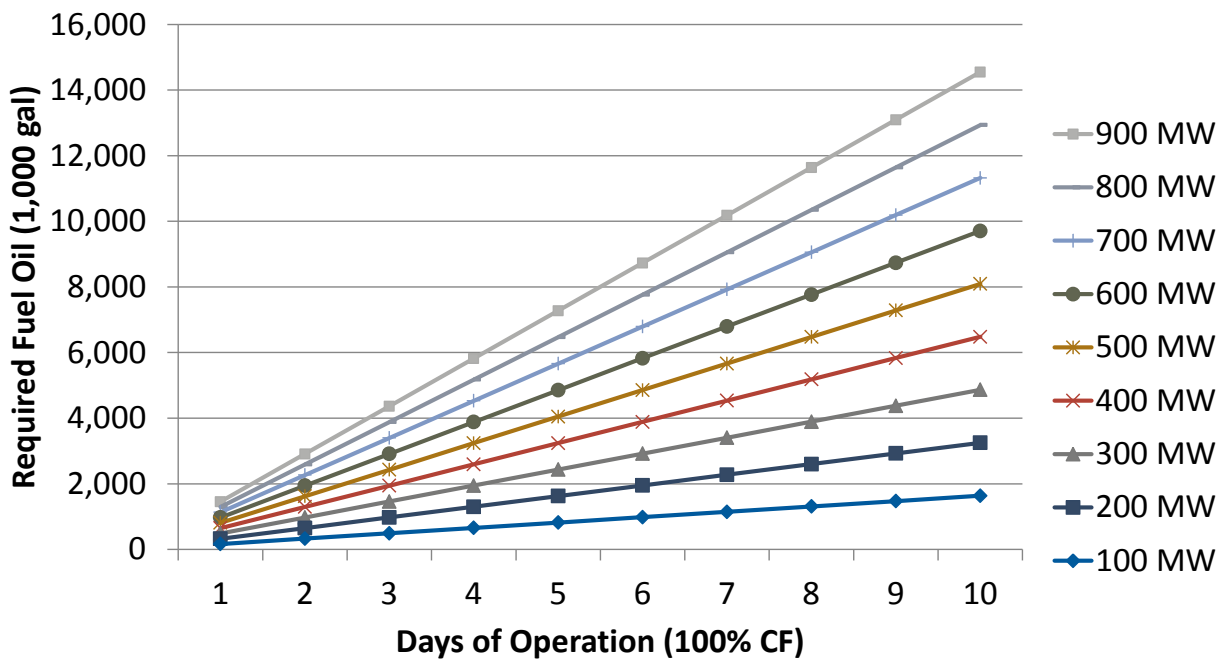


Exhibit B-7 Supercritical Steam Turbine Plant Secondary Fuel Oil Required by Plant Size



Appendix C: Case Study: Complexities of Dual Fuel Analyses

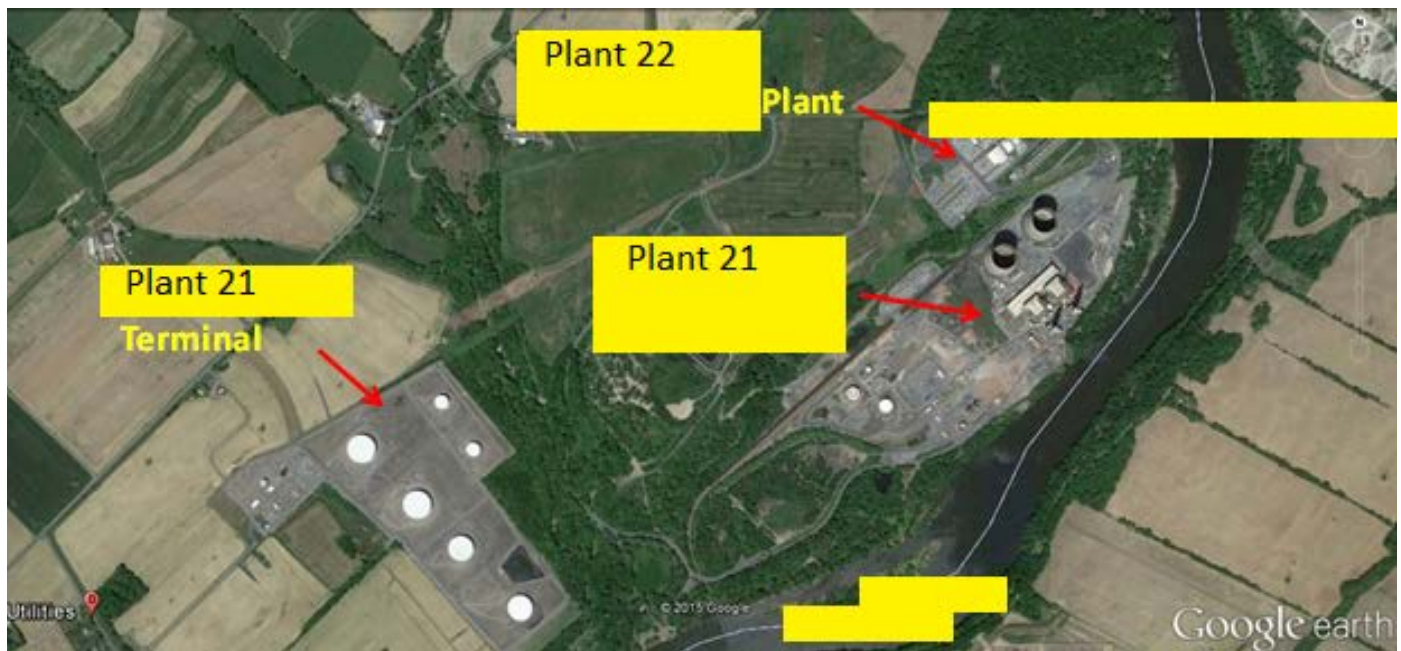
Attempting to discern an individual unit's dual fuel capability can be complicated by multiple factors as illustrated by Plant 21.

Factors include:

- Originally built with two 150 MW boilers (now deactivated)
- Two 851 MW oil-fired boilers added and then converted to dual fuel
- Four 24 MW gas turbines on site
- Adjacent Plant has three gas-fired combine cycle units with a total 658 MW capacity
- Adjacent site has a tank farm with ~60 million gallon storage capacity
- The original fuel oil supplied via an 84-mile-long 18-inch-diameter heated pipeline delivering No. 2 and No. 6 residual fuel oil. A portion of the pipeline was converted to transport oil or natural gas
- A second 26-mile-long, 20-inch-parallel gas line was added followed by the addition of another 4.5-mile, 20-inch gas line
- All of the fuel pipelines are interconnected through an intra-plant pipe network supplying fuel to both Plants

Overhead imagery of the complex is presented in Exhibit C-1.

Exhibit C-1 Plant 21 (15)



Discerning power plant fuel source can be difficult because:

- Power plants may have multiple sources of fuels even if only on a single pipeline
- Multiple types of power plants can be co-located
- Transportation pipelines may be permitted to carry multiple types of fuels
- Power plants may be located near fuel storage facilities which may or may not have available fuels

In the case of the plant 21 facility, fuel can come from multiple sources including:

- Natural Gas – from transmission line in adjacent county via dual use 18-inch pipeline
- Natural Gas – from transmission line in adjacent County via dual use 18-inch pipeline
- Natural Gas – Williams Transco via separate parallel 20-inch pipeline
- No. 2 and No. 6 residual fuel oil via dual use 18-inch pipeline from Sunoco's Marcus Hook refinery

The 18-inch pipeline is also permitted to transport nitrogen which is used when converting pipeline from oil to natural gas. Additionally, four intra-plant pipelines distribute fuels to both plants.

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