ISO new england

memo

To:	New England Power Pool Participants Committee New England Conference of Public Utilities Commissioners New England States Committee on Electricity
From:	Gordon van Welie
Date:	January 25, 2013
Subject:	Information regarding Potential Benefits and Costs of Solutions to Address the Risks Associated with New England's Reliance on Natural Gas

Attached for your consideration are two memos that are intended to provide information to stakeholders and the New England states as they consider the ISO's proposals related to resource performance, including the natural gas challenges. Several stakeholders and the states asked for additional analysis regarding the potential benefits and costs related to the array of market design changes aimed at addressing the natural gas risks. The ISO retained Paul Hibbard of the Analysis Group to assist in the development of categories of potential benefits and costs related to a range of infrastructure options.

It should be noted that this information is outside of the NEPOOL Markets Committee (MC) process as it is intended as background information on the potential benefits and costs of a variety of outcomes resulting from market rule changes. As specific market design proposals are deliberated in the MC, if they are deemed to be "major initiatives," the ISO will perform additional quantitative and qualitative analysis. These memos may be used as inputs to that process.

I look forward to discussing these memos during the Participants Committee meeting on February 1. To that end, I have asked Paul Hibbard to join us for the discussion.

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To: ISO-NE

From: Paul Hibbard, Analysis Group

Date: January 24, 2013

Subject: Information from the Literature on the Potential Value of Measures that Improve System Reliability

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Background

The ISO has identified the region's reliance on natural gas for electricity generation as a key strategic risk. In several documents developed over the past two years as part of its Strategic Planning Initiative, ISO has detailed the potential reliability challenges posed by dependence on natural gas, and has identified a number of short, medium, and longer-term market and operational solutions to address the risks. Implementing the proposed changes is expected to provide substantial reliability and efficiency benefits.

There are a number of areas where implementing changes to address gas dependence risks will provide reliability and/or market efficiency benefits. Shorter-term market changes are designed to create incentives for improved availability and performance at existing generating assets, improve the coordination of natural gas and electricity market transactions, and increase the ability of control room operators to understand system conditions in a timely manner, thereby improving the efficiency of unit commitment and real-time dispatch. Longer-term market changes are designed to create incentives for investment in new capacity with more reliable performance and greater operational flexibility, reducing the power system's vulnerability to challenges associated with natural gas pipeline or electric system infrastructure conditions or contingencies. Over time, implementing such changes will deliver significant power system and market benefits, by:

- Increasing the visibility of electric and natural gas system conditions to control room operators;
- improving the efficiency of market and system operations,
- reducing out of merit commitment and dispatch of generating assets for energy and reserves,
- increasing reliability through reduced loss-of-load probability (LOLP)
- reducing the likelihood of the substantial public safety and economic impacts that flow from power outages, and
- providing financial signals for investment that encourage development of resources that will allow ISO to better manage system operation in the face of fuel uncertainties and greater integration of intermittent, renewable resources.

It is premature to attempt to quantify specific benefits at this time, as the market designs for solutions to the gas dependence risk are not yet complete, and market and system responses are not yet well understood. However, key factors in assessing potential impacts are the degree of vulnerability to the region associated with natural gas infrastructure conditions, and the value of avoiding loss of load through reliability improvements. This memo provides background on Analysis Group's assessment of the vulnerability, and information from economic literature related to estimates of value of lost load (VOLL). The purpose of providing this information at this time is to provide relevant background for policymakers and stakeholders to consider as market rule changes related to the natural gas dependence risk begin to be discussed in stakeholder and committee meetings.

Reliability Benefits

There are a number of ways that benefits flow from addressing the gas dependence risk. First, ISO must ensure that system infrastructure development, availability, and performance are sufficient to meet regional, NPCC, and NERC reliability obligations under appropriate load, resource availability, and fuel supply conditions. Failure to comply with these reliability requirements can lead to the imposition of substantial enforcement penalties. In addition to avoiding penalties, thought, there are important benefits associated with the public safety, convenience and economic damages avoided by reducing outage frequency and duration. Finally, the efficiency of regional markets is diminished when ISO has to commit or dispatch generation out of economic merit order due to fuel constraints – e.g., if control room operators are not reasonably certain that gas-fired units will have sufficient fuel for operation in real time if needed.[1]

The degree of uncertainty over fuel availability has become a tangible, challenging concern over the past year for ISO's control room operations.[2] ISO has highlighted in recent documents the drivers of such reliability concerns – namely, the combination of heavy dependence on operation of the region's natural gas-fired generating capacity throughout the year, and the increasingly-frequent constrained conditions for operation of the interstate natural gas pipeline system into and within New England. And while the risks are already present, changing system conditions in the coming years are likely to increase such risks.

The recently-completed ICF Fuel Security Analysis demonstrates the current and future vulnerability of the New England power system to gas-infrastructure related disruptions in both summer and winter peaking periods, under a number of different scenarios. See for example Figure 1 for a summary of winter power surplus/deficiency expectations given available interstate pipeline capacity, net of regional heating and process needs.[3] The solutions that ISO has proposed to address these conditions – whether they improve control room operator knowledge of unit availability, lead to changes in generating unit fuel sources, change fuel procurement practices, increase available pipeline capacity, or lead to unit operational adjustments – will reduce the probability that load will be lost due to constraints or contingencies on the natural gas system.

Reliable electric service is not only important from the perspective of meeting NERC and NPCC standards – it provides public safety and economic benefits by facilitating uninterrupted provision of public support services and by allowing customers to undertake economic and personal activity without disruption. Diminishment of reliable service can include both disruptions to service, and degradation in service quality (voltage changes). By reducing the probability, frequency or duration of bulk power

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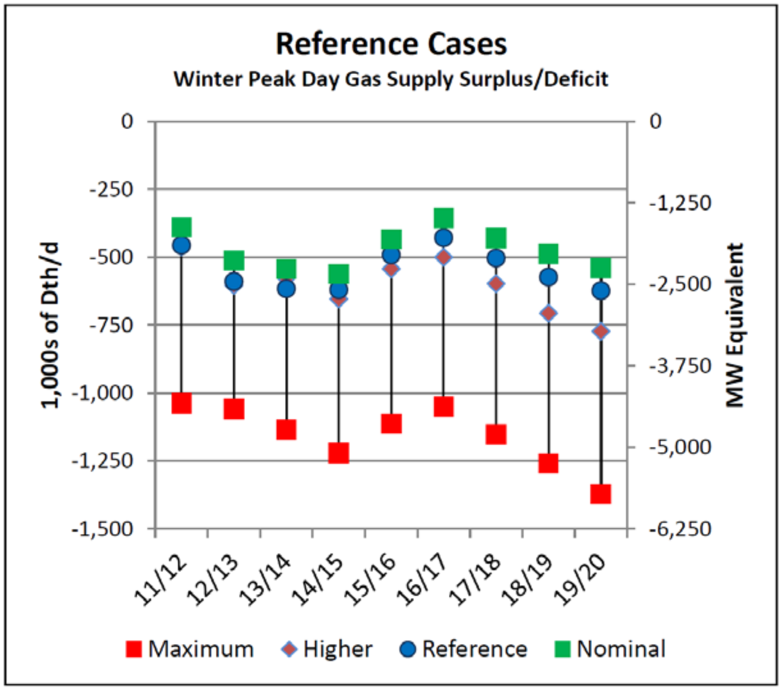
[1] See NEPOOL Participants Committee COO Report by Vamsi Chadalavada, November 2012, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2012/nov22012/coo_report_nov_2012.pdf

[2] See Presentation to New England Restructuring Roundtable by Pete Brandien, June 2012. http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2012/final_roundtable_june2012.pdf. Also, see memo to the NEPOOL Markets Committee by Dennis Robinson and Janine Dombrowski, August 1, 2012. http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_memo_08_01_12.pdf

[3] ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*, June 15, 2012, Figure ES-1.

system interruptions, the solutions proposed by ISO to address the reliability impacts of dependence on natural gas can convey potentially large public safety, convenience, and/or economic benefits.[4]

Figure 1



Value of Lost Load (VOLL) is the standard metric used to estimate the economic impact of disruptions in power service to customers, and thus can provide a measure of the magnitude of benefits associated with decreasing the likelihood of power system interruptions. There have been a number of studies completed to estimate VOLL, focused either on estimates of *expected* impacts in particular geographic locations, or on estimates of *damages* resulting from actual loss-of-load events. The studies reviewed for this memo are listed at the end of the memo. Review of these studies reveals that estimates of VOLL can vary significantly depending on what region one is studying; whether an interruption occurs on a weekend or weekday; what type of customer one is (i.e., residential vs. commercial/industrial); and how long the interruption lasts. In order to develop representative VOLL numbers for New England, we selected one of the studies reviewed that represents the middle of the range of all studies,[5] and that contains values that are comparable in magnitude to literature estimates of the costs of the 2003 Northeast blackout (which range from $4 billion to $10 billion (in $2003)).[6] Figure 2 presents numbers for New England based on these VOLL estimates, broken down by customer class and outage duration.

The estimates in this memo are presented for illustration purposes only, and to provide a sense of the potential magnitude of economic impacts of outages. A closer approximation would require assumptions, data and calculations specific to New England states' economic activity, and system conditions and prices consistent with the time frame under review. The public safety and economic impacts of outages experienced across New England states in recent years also provide important indications of benefits of power system reliability, and could serve as benchmarks to inform state- and region-specific analyses. Nevertheless, a review of the literature on VOLL suggests that the range of estimated economic impacts associated with loss of load (and thus benefits of avoiding such interruptions) could reach into billions of dollars for a region the size of New England.

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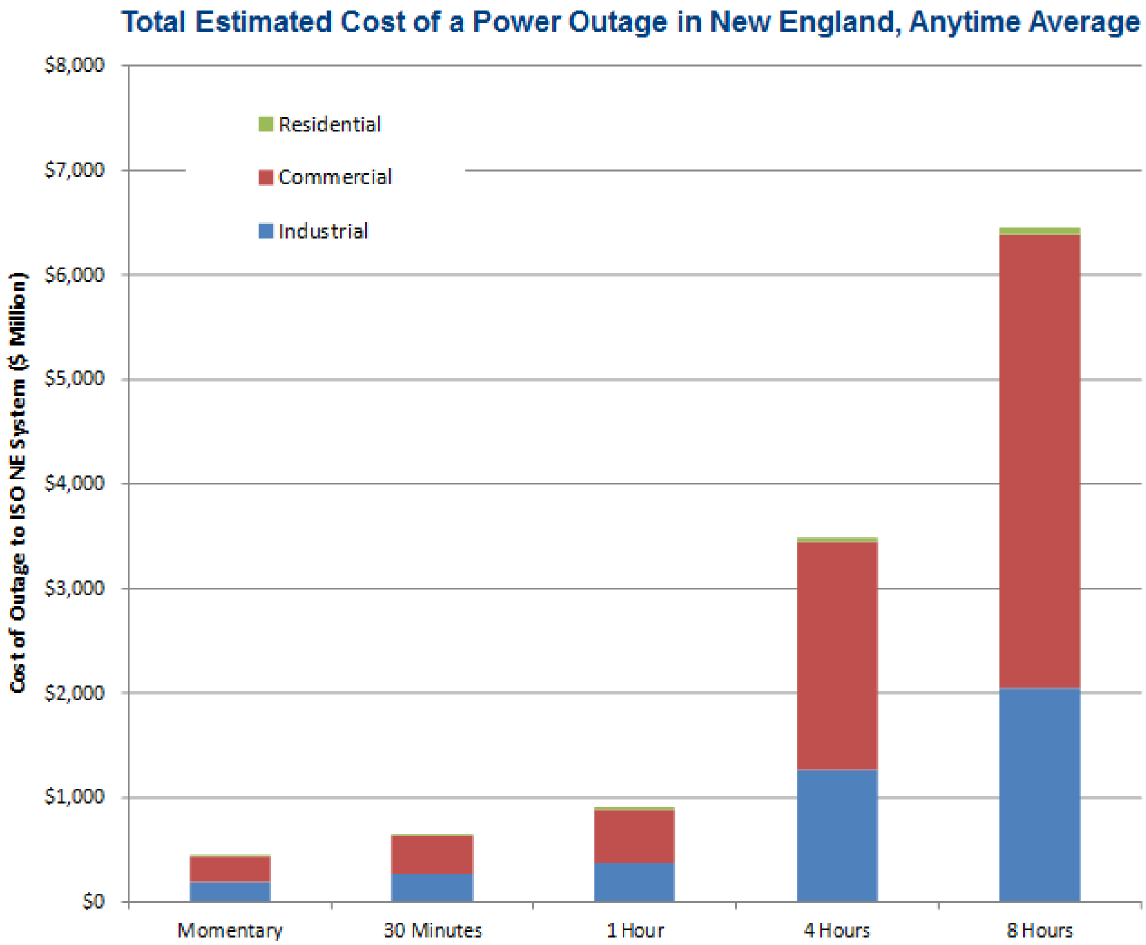
[4] Most customer outages are due to the impact of accidents, storms or other events on local electric utility distribution systems. However, outage also can result from the loss of bulk power system assets – transmission lines or generating units.

[5] Specifically, we constructed New England numbers using the estimates in Sullivan et. al.

Figure 2



<u>Studies reviewed and data used in VOLL estimates include the following:</u>

- Centolella, Paul, et al., "Estimates of the Value of Uninterrupted Service for The Mid-West Independent System Operator", prepared for MISO.
- Electricity Consumers Resource Council (ELCON), "The Economic Impacts of the August 2003 Blackout," February 9, 2004.
- LaCommare, Kristina Hamachi and Joseph Eto, "Understanding the cost of power interruptions to U.S. electricity customers," report no. LBNL-55718, Berkeley, California: Lawrence Berkeley National Laboratory, 2004.
- Primen, "The Cost of Power Disturbances to Industrial & Digital Economy Companies," submitted to the Electric Power Research Institute, June 29, 2001.
- Sullivan, Michael J. et al., "Estimated Value of Service Reliablity for Electric Utility Customers in the United States," report no. LBNL-2132E, Berkeley, California: Lawrence Berkeley National Laboratory, June 2009. (This is the source used for our estimates).
- U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004.
- United States Energy Information Administration, Form 826 Data

To: ISO-NE

From: Paul Hibbard, Analysis Group

Date: January 24, 2013

Subject: Information on the Range of Costs Associated with Potential Market Responses to Address the Risks Associated with New England's Reliance on Natural Gas

Background

The ISO has identified the region's reliance on natural gas for electricity generation as a key strategic risk. In several documents developed over the past two years as part of its Strategic Planning Initiative, ISO has detailed the potential reliability challenges posed by dependence on natural gas, and has identified a number of short, medium, and longer-term market and operational solutions to address the risks. Implementing the proposed changes is expected to provide substantial reliability and efficiency benefits.

Implementing the proposed changes may also impose new costs. Some potential costs can be quantified; others may only be identified qualitatively, or may be highly variable or uncertain. For most of the proposed changes it is premature to carry out formal impact analysis or to identify with specificity the benefits and costs that may flow from the proposed rule changes, as the market designs for the solutions are not yet complete, and likely market responses are not yet well understood. Nevertheless, states and stakeholders have sought information and data on the potential drivers of costs related to market rule changes to address gas dependence risks.[1]

This memo provides qualitative and quantitative background information on categories of potential costs associated with new infrastructure alternatives to address gas dependence risks. It is a summary of various studies, reports, and analyses conducted by third parties and available in the public domain, related to natural gas and dual-fuel infrastructure options that could emerge from market rule changes, along with estimates developed by Analysis Group based on information and data provided by ISO-NE or contained in these studies and reports. The list of studies reviewed is presented at the end of this memo. Creating longer-term expectations around fuel certainty and unit performance could lead to such natural gas and/or power system investments, and these investments could in turn be reflected in capacity and reserve market pricing. The degree to which this occurs will depend on the infrastructure options, market need, and the ultimate price of the most competitive resource options that can meet system capacity needs and unit performance obligations.

[1] See, e.g., Memo from New England States Committee on Electricity, *State Feedback and Requests in Connection with ISO-NE's Addressing Gas Dependency Paper*, August 22, 2012, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/gas_dependency_analysis_request_aug_22_2012.pdf.

Infrastructure Options and Elements of Cost

There are a number of potential infrastructure responses to market rule changes to address gas dependence risks; cost data for several of these are presented in this memo, including the following:[2]

- Increases in dual-fuel capability or operations
  - From existing dual-fuel capable units
  - From existing units with dual-fuel capability that is currently mothballed or underutilized
  - From newly developed dual-fuel capability at existing gas plants
- New natural gas interstate pipeline capacity
- New in-region LNG storage
- Storage/transportation arrangements tied to existing LNG facilities

The effectiveness and viability of these potential solutions – from reliability and market perspectives – depends on (1) relative costs (fixed and variable), (2) feasibility and timeline for development, and (3) operational characteristics. In the sections that follow, information and data are presented for each of these factors, and for each of the options identified. Specifically, we review:

1. *Costs* – life-cycle costs, including upfront costs and annual operations costs.[3] In order to allow for comparison across options, cost data are reported on a common dollars per kW-month basis. The cost estimates provided are high-level, first-order estimates based on data provided by ISO-NE, and publicly-available information on recent development projects. Figure 1 describes how, in this document, categories of costs are identified and normalized to allow comparison.

Figure 1

Capacity (MW)	200	Each facility is sized to serve a quantity of gas-fired capacity
Upfront Cost		
Project cost ($)	1,000,000	**Upfront costs** reflect siting, permit, engineering, facilities, technology and testing
Total Upfront Costs ($)	1,000,000	
Annual Costs		
O&M ($)	1,500,000	**Annual Costs** include O&M, carrying costs of fuel storage, technology and air permit testing
Carrying Cost ($)	1,000,000	
Total Annual Costs ($)	2,500,000	
PV		
Lifetime	20	
Discount Rate	9%	
Present Value ($)	23,821,364	Present value of lifetime costs of technical option reflect assumed lifetime and discount rate
Present Value per MW ($)	119,107	
Cost per kW-month ($)	1.09	Cost of technical options are normalized in terms of costs per kW-month

2. *Development timeline/feasibility* – the time required between conceptualization and commercialization for the options reviewed varies widely. The analysis presents qualitative assessments of development feasibility and barriers to implementation that would affect when specific alternatives would be available to influence reliability and market outcomes.

[2] It should be noted that there may be additional or alternative outcomes of market rule changes focused on natural gas dependence that are not identified or evaluated in this memo.

[3] In addition to these infrastructure development and operational costs, the integration of such new infrastructure would likely have an impact (positive or negative) on *system costs* over time. Such impacts could arise, for example, from changes in system unit commitment and dispatch in some or all hours of the year given the integration of new resources, and/or changes in system transmission costs. These system cost impacts are not reviewed in this memo.

3. *Operational characteristics* – not all options reviewed provide equal assurance of fuel delivery or generation availability, and so they present different implications for resource availability that may or may not affect market valuation. For example, options differ in their (1) ability to ensure fuel delivery for prolonged or frequent curtailments, (2) ability to support reserve-quality resources, and (3) ability to withstand interstate natural gas pipeline contingencies. The analysis presents qualitative assessments of operational constraints that would affect how specific alternatives would influence reliability and market outcomes.

In the sections that follow, we summarize results for each of the infrastructure options identified above.

Dual-Fuel Capability

All natural gas-fired units are capable – in theory – of dual fuel (DF) operation. However, they can differ significantly in the amount of work that would be required to establish operational DF capability, and in the costs that would be incurred to establish and use DF capability. Existing facilities fall into three basic categories:

1. Facilities that currently have DF capability – such units require *on-going* costs to (a) actively maintain alternate fuel burners, including burner and air permit testing, and (b) maintain sufficient fuel supply for an adequate period of operation (from the perspective of reliability needs under natural gas curtailment or contingency circumstances). These annual on-going costs are estimated at roughly $1 million per year. Absent market incentives to maintain this capability and a means to recover these on-going costs, DF capability has been, or likely will be, decommissioned.
2. Facilities with decommissioned DF capability – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs including modest technical upgrades, as needed, to bring alternate fuel burners back to operational status, as well as testing to obtain or reinstitute air permits, and to ensure burner operability. These one-time up-front costs are estimated at roughly $2 million for a 250 megawatt (MW) unit.
3. Facilities with no DF capability – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs involving major technical upgrades to add alternate fuel burners and fuel storage capability, including testing of new burners and acquiring necessary permits. These one-time up-front costs are estimated at roughly $21 million for a 250 megawatt (MW) unit.

Figure 2 presents a summary of the cost estimates and assumptions used to develop these estimates, including up-front costs, annual costs, and present value cost per kW-month. Results range from approximately $0.48/kW-mth for units with DF capability, to $1.25/kW-mth for units with no DF capability, including levelized capital costs of installing new infrastructure.

There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to DF capability, and differences between DF options, including the following:

Figure 2

	Dual Fuel Capable	Under- or Unutilized Duel Fuel Capability	No Dual Fuel Capability
Capacity (MW)	260	260	260
Upfront Costs			
Unit Cost ($/MW)		3,600	81,000
Total Development Cost ($)		936,000	21,060,000
Testing ($)		979,050	979,050
Total Upfront Cost ($)	0	1,915,050	22,039,050
Annual Costs			
O&M ($)	200,000	200,000	200,000
Annual Testing ($)	979,050	979,050	979,050
Fuel Carrying Cost ($)	307,862	307,862	307,862
Days Fuel Supply	3	3	3
Fuel Cost ($/MMBtu)	22.8	22.8	22.8
Total Annual Costs ($)	1,486,912	1,486,912	1,486,912
Lifetime (Years)	20	20	20
Discount Rate	9%	9%	9%
Present Value ($)	13,573,340	15,488,390	35,612,390
Present Value per MW ($)	52,205	59,571	136,971
Annualized Cost per kW-mth ($)	0.48	0.54	1.25

- The actions needed to firm up DF capability with operable or unused capability can likely be performed relatively quickly – burner upgrades are fairly limited in scope; there are relatively few barriers to securing sufficient fuel supply (other than cleaning unused storage tanks and securing cost recovery for fuel carrying costs); and minimum testing time is needed to maintain burner operability and permit status. This means that adding/activating such capability could possibly be completed by winter 2013/2014.
- Actions to install DF capability at units that do not have it are more involved and would require more time – including development, permitting, and construction activities. Such capability would likely not be able to be online until winter 2014/2015 at the soonest.
- In some cases there are or would be variations in output and risk of outage when actively switching from gas- to oil-firing. Some units – in particular those burning heavy fuel oil as a secondary fuel, need to power down before switching, and thus would provide less flexibility than units that can switch on the fly. In addition, there is an increased risk of outage with switching, particularly when alternate fuels are used infrequently.
- It is anticipated that regulatory limits on oil firing to address air quality concerns would generally allow for sufficient operability of DF units to cover electric system reliability needs (while some units may only be allowed to operate on oil when gas is unavailable, most units can operate within permit limits for an annual number of hours equivalent to weeks, a month, or months of continuous operation).
- Finally, storage capacity (relative to burn at continuous full output) and storage refilling methods and rates can be an important element of maintaining resource availability, particularly during winter cold-snap conditions. DF units can have very different capacities and refill rates.

- Generally speaking, facilities served by oil pipelines or rail would be able to maintain burn if needed, and/or refill relatively quickly. But most facilities are served by truck refills, which can require days or weeks to refill to storage representing three days of continuous output.[4] For example, assuming tanker truck capacity of 9,000 gallons (generally on the high end) and representative heat rates, it would take 20 trucks per day to support continuous output of 130 MW.

New Interstate Pipeline Capacity

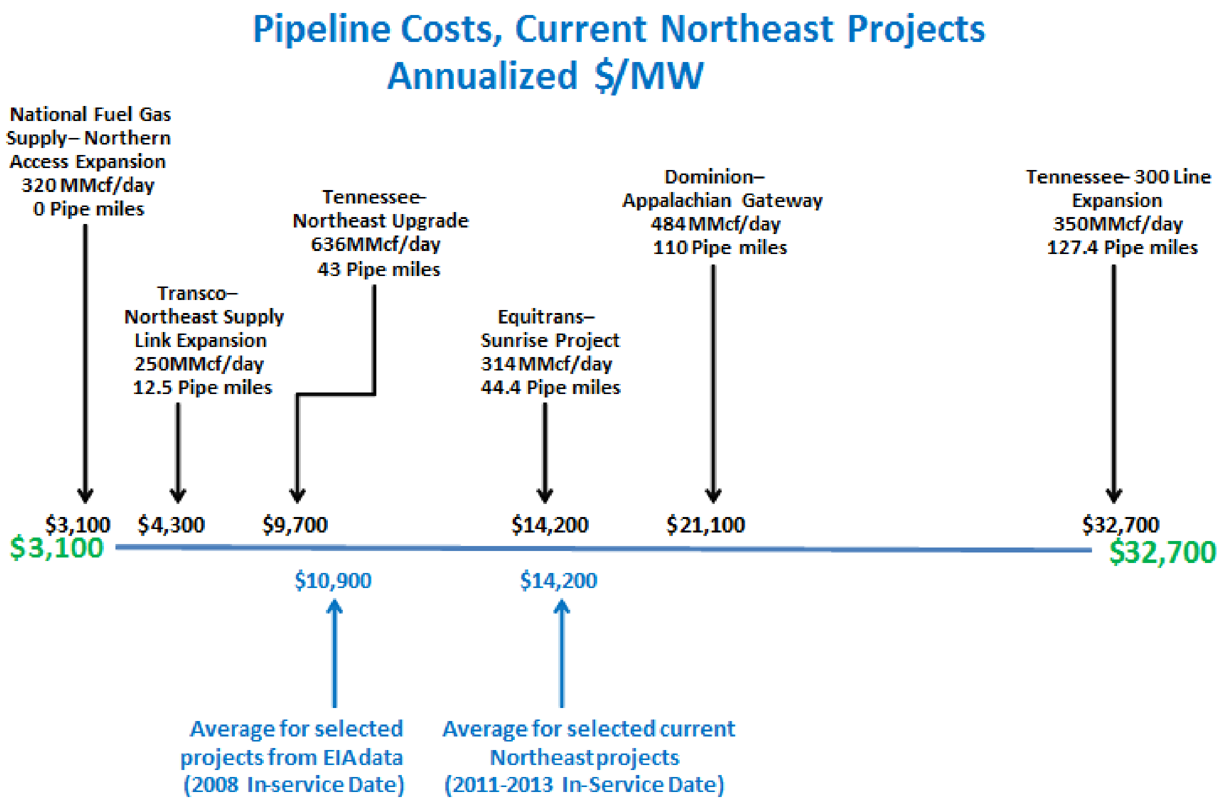
Relatively little firm service is available on the primary pipelines serving New England, so additional firm natural gas supply will likely require the construction of additional pipeline capacity. Increased natural gas pipeline capacity could support the transport of additional fuel supplies to the region, and so would reduce the risk of curtailment to gas-fired generators, relative to current market conditions. Additional pipeline capacity to provide firm gas supply can be achieved through various changes to the interstate pipeline system to relieve pipeline congestion or add incremental capacity, ranging from new compressor stations along existing pipe, to looping, to the construction of new pipelines from key gas sources (e.g., the Marcellus Shale region). The cost of various changes are difficult to identify absent engineering studies, and depend on the extent to which lower-cost technical changes to expand the capacity of the existing pipeline assets have already been exhausted. In recent months, pipeline owners have suggested that most low-cost changes have likely already occurred.

The range of potential upfront costs to increase pipeline capacity from Marcellus and other lower-cost natural gas reserve regions is wide, and depends on the location of constraints being relieved, and/or the overall size and route of the project. See Figure 3.

In addition to up-front costs, annual costs are incurred for operations and maintenance on the pipeline system. In Figure 4 below, estimates of the annualized cost per MW are presented using for the purposes of calculation the average up-front cost of selected current Northeast region projects (based upon the projects reviewed, as presented in Figure 1), and the estimated annual costs for O&M expense. This estimate, based on an assumed increase in pipeline capacity of nearly 400,000 dekatherms per day, is approximately $1.17/kW-mth of equivalent electrical generating capacity.

[4] Three days of continuous output was chosen only to construct a representative calculation. Market performance obligations and/or reliability needs could require less than three days of continuous output.

Figure 3



There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to the reliability and economic value of increasing pipeline capacity, including the following:

- The timeline for new pipeline capacity siting, permitting, and construction is on the order of several years. Consequently, this is not an option that can provide meaningful power system reliability benefits for several years, at least.
- Under current FERC rules and past practices for funding new pipeline capacity, new projects typically will not go forward without up-front financial commitments from customers to take firm delivery service for all – or most – of the new capacity. Entering into such long-term financial commitments for natural gas transportation is challenging for electric generators under current market conditions.
- Current pipeline capacity firm commitments are held almost entirely by natural gas local distribution companies (LDCs) for the benefit of natural gas ratepayers, and with the guarantee that such capacity will be used to meet the need of LDC end-use customers for heating and process needs as needed, particularly at the time of winter peak conditions. This means that while substantial amounts of such capacity may be released to secondary markets for use by electric

generators throughout the year, it cannot be counted on during winter peak or cold-snap conditions.

- Incremental gas supplies from the Marcellus, at current prices, would result in substantially lower per MWh operating costs than equivalent oil or LNG fuel burns. Increasing pipeline capacity would increase access to lower-cost natural gas reserve regions (e.g., Marcellus) throughout the year, and this could have the effect of decreasing power system costs during any hours when supply from such regions would otherwise be constrained.

New and Existing LNG Storage Capability

There are two options tied to liquefied natural gas that have been identified as opportunities to firm up natural gas fuel supply to natural gas-fired generating facilities in New England: (1) the construction of new land-based LNG storage facilities with liquefaction capability dedicated to providing backup gas fuel supply to power plants,[5] and (2) new services associated with spare capacity – to the extent it exists – at the two major LNG terminals serving the region (Distrigas of Massachusetts Corp, or DOMAC, located in Boston, and Canaport, located in Canada).

New LNG Storage Capacity

In order to develop cost assessments, we reviewed the costs of three recently-sited facilities of roughly equal storage capacity; the facilities we reviewed offered the best combination of size, performance (vaporization and liquefaction), and cost when utilized as a backup fuel supply.

The cost of a new LNG storage facility includes up-front development costs, annual operating costs, and the carrying cost of the stored fuel. Our estimates are based on the three facilities reviewed, sized to a generic facility with (a) a vaporization rate sufficient to provide backup fuel supply for approximately 540 MW of capacity; (b) 60,000 cubic meters (cm) of storage, equivalent to roughly 14 days of operation at the assumed vaporization rate; (c) a liquefaction rate that would be sufficient to refill enough supply to operate the facility (540 MW) for one day, in 14 days. See Figure 4.

Figure 4

Capacity	
LNG Volume (cubic meters)	60,000
NG Energy Capacity (MMBtu)	1,262,400
Flow capabilities	
Maximum discharge rate (MMBtu / day)	91,300
Maximum liquefaction rate (MMBtu / day)	6,333
Variable Operating Costs	
Liquefaction cost ($ / MMBtu)	1.6
Storage and regasification cost ($ / MMBtu)	0.4
Backup Fuel Supply Capability	
MW-Days of Backup Fuel Supply Stored	7,514
Max MW per Day (given liquefaction rate)	543
Days to Refill (Liguefy) Sufficient Supply for Max MW per Day	14
Assumed Heat rate (Btu / kwh)	7,000

Based on the recently-completed facilities, up-front costs range from $1,850 to $2,450 per cm of storage, amounting to approximately $128 million for the generic facility, including siting, permitting,

[5] With respect to new LNG Storage, we focus on on-land facilities with liquefaction capability similar in size to many peak-shaving LNG storage facilities in existence today. We do not review facilities without liquefaction, as refill rates for storage without liquefaction are estimated to be too slow to provide a reliable back up fuel supply. We also do not review new large-scale LNG terminals given the demonstrated and likely barriers to the siting of such facilities within New England.

engineering, and capital costs. Variable costs include fuel carrying costs and operating costs related to liquefaction, storage and regasification. This translates to a cost on the order of approximately $2.47/kW-mth). See Figure 5.

There are a number of factors related to timing, deployment, and operational characteristics that are important to consider with respect to LNG storage capability, including the following:

Figure 5

Capacity (MW)	543
Upfront Cost	
Project cost ($)	127,666,667
Cost per cubic meter	2,128
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	633,920
Initial Fuel Cost (including liquefaction) ($)	7,043,561
Total Annual Costs ($)	2,133,920
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	147,146,257
Present Value per MW ($)	270,988
Annualized Cost per kW-mth ($)	2.47

- Siting and development of a LNG storage facility could require multiple years, even under relatively easy siting conditions. Storage facilities of this size are modest-sized industrial facilities, so in some cases and/or locations opposition to siting at the local level could further lengthen the development timeline.
- The mix of liquefaction and vaporization rates introduces certain constraints on the market value of such facilities, and also on their reliability benefit. At the assumed (and achievable) vaporization rate, it would take between 7 and 20 days to fully discharge the tank. However, the liquefaction rate limits the ability to refill the tank after discharge. Specifically, it could take more than 190 days to fully refill the tank after discharge. Consequently, such a facility could provide backup fuel for an extended curtailment (or multiple shorter curtailments), but that backup capability could be significantly limited for subsequent curtailments after full discharge.

Existing LNG Facilities

With respect to the existing DOMAC and Canaport facilities, it has been suggested that backup fuel supply to electric generators could be provided through arrangements to essentially store fuel and inject it into the pipelines upon request by electric generators, from these two facilities.[6] Reliance on such services would require excess storage and regasification capacity at the terminal in question, and delivery service on Algonquin or Tennessee to the gas-fired generator's connection point on the pipelines. In addition, for Canaport service there would need to be delivery service on the Maritimes and Northeast pipeline. The stored gas, and the capacity to inject and deliver it, would need to be available as and when needed by the gas generator.

[6] In theory, these same services could be supplied by the offshore Neptune and Northeast Gateway terminals, through tankers "parked" at the intake pipes, or from existing local gas distribution company (LDC) peak shaving storage capacity. However, we did not review this separately given the potentially prohibitive costs of using tankers (on top of the other costs that would be faced by Canaport or DOMAC), and given the dedication of LDC storage facilities to serve natural gas LDC customers on peak.

In this case, there are essentially no up-front costs. All services would be on existing facilities to the extent capacity exists. An estimate of annual costs can be derived by estimating (1) the opportunity cost of storing LNG instead of selling it in higher-value markets (i.e., Europe); (2) the carrying cost reflecting interest on the value of stored fuel; and (3) if firm service is required to meet reliability requirements, a transportation charge for moving gas from storage to delivery point.

We have not attempted to estimate the type and cost of pipeline transportation charges, given the uncertainty around the type of service, and rate that would be charged within the constraints of existing pipeline capacity. However, given the price differential between gas markets in Europe and New England, and the carrying cost of the fuel, we estimate that the price for services would be on the order of $157/MW-day of operation.

<u>List of Sources Reviewed</u>

Sources of information relied on for the Dual Fuel section include the following:

- ESS Group, “Dual-Fuel Generating Capacity and Environmental Constraints Analysis,” Interim Report, prepared for ISO-NE, April 1, 2005.
- Settlement between NYISO and TransCanada, Ravenswood for recovery of on-going costs of maintaining dual fuel capability, April, 2011
- PJM Cost of New Entry (CONE), incremental cost for dual fuel capability on new generation units, 2011
- Handy-Whitman Index of Public Utility Construction Costs
- Analysis Group estimates based on these reports, and on data provided by ISO-NE

Sources of information relied on for the New Interstate Pipeline section include the following:

- INGAA publication #17742 (sourced from North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF International for INGAA, June 28, 2011)
- “2012 Worldwide Pipeline Construction Report,” Pipeline & Gas Journal, January 2012
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