Addressing Gas Dependence
July, 2012

This paper reviews the reliability issues posed by New England's increasing dependence on gas-fired generators, and proposes a number of solutions to mitigate the risks.

Section 1: Introduction and Executive Summary

In the fall of 2010, ISO New England (ISO-NE) launched a Strategic Planning Initiative to focus the region on developing solutions to five identified risks to the continued reliable, efficient operation of the bulk power system and wholesale electricity markets. One of these risks is related to increased reliance on natural gas-fired capacity. Addressing this risk has become a priority, given the reliability challenges that are already in evidence, as described below.

ISO-NE described the risk as follows:

> *Increased Reliance on Natural Gas-Fired Capacity*, related to the risk to the New England electric system associated with reliance on natural-gas-only resources, as sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure.

In fact, gas dependence is a reality and is increasing for a number of reasons, including low gas prices. Given these low prices, generators are using Marcellus shale gas where possible to reduce their costs, which, in turn, results in low wholesale prices that ultimately benefit consumers.

While the increase in gas-fired generation has economic, environmental and operational benefits that the region wants to preserve, these benefits come at a cost. Specifically, given current and anticipated levels of gas usage, potential gas unavailability threatens the reliability of the electric system due to the limited-capacity pipelines used to transport gas, potential gas supply interruptions, and the "just-in-time" nature of the resource.

The reliability risks are also attributable to the difference between gas and electric system operational requirements and market mechanisms. For example, the gas system is designed to meet the needs of firm contract holders (typically the Local Distribution Companies), which draw more slowly and predictably from the pipeline system than generators. On the market design side, the electricity markets currently do not have sufficient incentives for generators to choose "firm" (non-interruptible) contracts for gas delivery; however, non-firm customers (typically gas generators) can be interrupted if there are issues meeting gas demand, which leads to electric reliability issues. All of these factors, and examples of the related reliability consequences, are detailed in Section 3 below.

To maintain the benefits provided by the increasing utilization of gas-fired generation, ISO-NE believes that the region must acknowledge the significant role that the natural gas transmission system now plays in the New England electricity system – and the associated challenges. In other words, both the gas and electric industries must make adjustments to ensure the reliability of both systems and the efficiency of both markets.

As described in Section 4, ISO-NE has identified a set of solutions to pursue with stakeholders. These include long-term changes to the Forward Capacity Market and the Forward Reserve Market to create better incentives for generators to perform in accordance with their operating characteristics. Generators may achieve this performance by making alternative firm fuel arrangements, such as investing in oil inventory, or entering into firm gas transportation contracts. The latter may, in turn, encourage pipeline expansion, thereby addressing current pipeline limitations.

In the short-term, to ensure reliability in the period before the changes to the Forward Capacity and Reserve Markets can improve performance incentives, ISO-NE is proposing to engage in a supplemental procurement to ensure that oil and gas generators maintain adequate levels of firm fuel capability. This is necessary to mitigate the immediate risks posed by the current system constraints, as described in this document, and to ensure that there are sufficient resources available to respond to dispatch instructions, particularly under stressed power system or gas system conditions.

ISO-NE also proposes enhancements to the flexibility of the electricity markets by changing the rules to permit generators to modify their offers intra-day to reflect fuel costs, and by moving the timing of the Day-Ahead Market to better coordinate with the gas industry's timelines. These changes are intended to address the divergence between generators' commitments and gas nominations, which often result from the uncertainty generators face in acquiring gas before they know their generation commitment and dispatch. These changes will also provide the ISO control room with necessary information on a timely basis to operate the power system reliably.

Finally, ISO-NE would like to address the problems created by the short notice of pipeline maintenance and supply disruptions, which are of particular concern given the start times required by many of the non-gas fired generators in New England. To facilitate better information flow, ISO-NE proposes to require more information from generators regarding their fuel status, thereby improving the accuracy of supplemental generation commitments and allowing ISO-NE to provide data on specific generator commitments to the pipelines. In addition, ISO-NE will seek better information on gas pipeline maintenance in order to enhance the accuracy of the day-ahead unit commitment process and to continue coordination efforts with the gas pipelines.

Like all market structures, New England's wholesale electricity markets must be dynamic in nature, by keeping pace with changing conditions, such as fuel sources, generation advances and fuel diversity. As this paper highlights, a decision to act on changes to markets to adjust for the characteristics of natural gas delivery must be made in the near future to ensure ongoing reliability.

While ISO-NE is willing to lead this market evolution, there are limits to what ISO-NE, alone, can achieve. ISO-NE should signal its performance expectations to generators through its market design and make appropriate adjustments to optimize the use of available infrastructure. This will give generators the incentives to seek firm fuel supplies. The gas industry has an opportunity to be the provider of that firm fuel by improving the services it offers to the electric system, including considering changes to the gas day to better align with the electric day load cycle, and improving the range of services offered to generators. Still others, including the Federal Energy Regulatory Commission, the States and Local Distribution Companies, will have a role to play. For example, the States could require regulated entities, including Local Distribution Companies, to invest in additional storage, pipelines, or firm contracts, and recover those costs by charging generators for those services.

ISO-NE recognizes that all of these changes will require a significant commitment from the region, and looks forward to reviewing this paper with stakeholders as a first step in that process.

Section 2: New England's Gas Dependence

During the 1990s, the region's electricity was produced primarily by oil, coal and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity.

In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. Currently, during median load periods, nearly the entire fleet of dispatchable resources is made up of gas-fired generators, and a portion of the quick-start generators that would be called to respond to a loss of generation is also dependent on the same supply of natural gas.

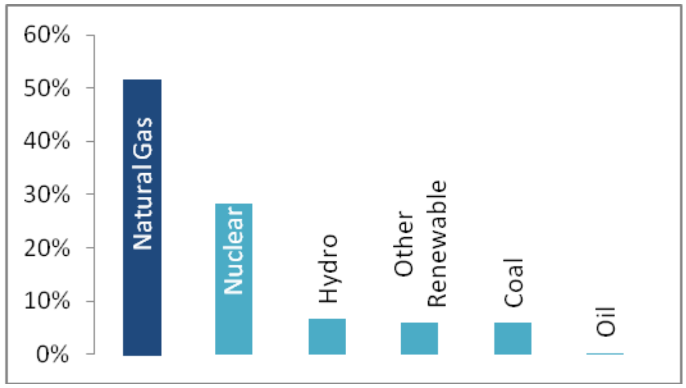


Figure 1-- 2011 Energy Production

The shift to gas-fired generation is largely attributable to the price of generating electricity with gas, which is now much lower than oil or coal-fired generation. Current gas industry estimates are that North American shale gas reserves hold a 100-year supply; this increase in supply has pushed natural gas futures prices on the NYMEX to 10-year lows. Moreover, production from the Marcellus shale region in Pennsylvania and New York has moved significant amounts of gas supply much closer to the New England region, alleviating the need for long-haul pipeline transport from the traditional production regions near the Gulf of Mexico or western Canada. The low price of gas and its increased use by generators have resulted in a dramatic reduction in total wholesale market costs, from nearly $13 billion in 2008 to approximately $7.6 billion in 2011. In the first six months of 2012, these costs are about $2.6 billion.[1]

In addition to the ample, low-cost supply of natural gas, other factors will contribute to the continuing dominance of natural gas-fired generation in New England's fleet. These include the addition of variable energy resources on the system, which will require greater flexibility in other generation resources to regulate the system. Moreover, the region's older oil-and coal-fired power plants could opt for retirement in the near future due to market pressures and the costs of complying with environmental regulations.

Section 3: Resulting Electric Reliability Issues

Over the past ten years, as the region's dependence on gas has increased, so have the reliability challenges. These challenges exist not only because of the lack of diversity of fuel sources, but also due to the "just-in-time" nature of the natural gas supply chain. In other words, New England generators have migrated away from on-site fuel storage in the form of oil and coal, where disruptions in fuel delivery chains were able to be coordinated over days and weeks. Generators are now dependent on just-in-time fuel delivery from the gas pipelines, and limitations or interruptions in this supply chain have an immediate impact on the operation of the power system.

[1] These figures come from the Internal Market Monitor's Markets Reports. Total wholesale market costs are the sum of energy costs, Net Commitment Period Compensation, and the costs of the regulation, reserves and capacity markets.

As discussed below, the challenges are exacerbated by the insufficient market incentives for firm gas contracts, pipeline limitations, generator commitments and dispatch that do not match fuel nominations, timing differences between the gas and electric industries, gas supply disruptions, and pipeline maintenance.

Non-Firm Contracts

Natural gas is sold through brokered markets, and, in a separate transaction, is transported through an interstate pipeline system. The pipelines offer a number of transportation services that vary in priority (and expense). The charges for these services are based on tariffs that are approved by the Federal Energy Regulatory Commission and provide regulated rates of return to pipeline owners.

The pipelines sell most of their highest priority, most expensive "firm" pipeline capacity to Local Distribution Companies (LDCs). Each day, the capacity that is not utilized by the LDCs and other firm customers is available for purchase.

Currently, although generators have an obligation to perform in accordance with their offers and their declared operating characteristics, the performance incentives in the wholesale electricity market design are not strong enough to cause generators to procure firm fuel supplies – gas or oil – and to operate in accordance with their obligations. Until recently, these generators have largely been able to meet their obligations under normal operating circumstances, i.e. when the power or gas system is not stressed, without firm fuel. Currently, however, when conditions become constrained or there isn't operating flexibility on the gas pipeline,[2] the interruptible generator customers may not be able to secure fuel to operate in accordance with their operating characteristics to meet the firm electrical demands of the grid. These fuel limitations generally happen with little time for electric system operators to adjust, and can affect the reliability of the power system.

Gas pipeline industry representatives have made clear that electric system reliability is threatened so long as generators continue to rely only on less expensive, interruptible "non-firm" gas transportation, and that the pipelines will not hesitate to solve their operational problems by interrupting these customers. In fact, New England's first major issue with the availability of gas-fired generators occurred when pipelines interrupted non-firm customers, including gas-fired generators, in January 2004 during severe winter weather and record electricity demand. Gas prices spiked, but generators that could get gas had no mechanism to update their electricity offers to reflect the higher intra-day fuel prices. As a result, wholesale electricity prices were generally below break-even levels for even the most efficient gas-fired generators buying gas in the spot market.

Pipeline Limitations

During their peak winter days, the pipelines are fully utilized with not enough infrastructure to meet the needs of the gas-fired fleet. Even on non-peak days, both the Tennessee and Algonquin pipelines, which supply lower-cost gas from the Marcellus shale region, are often loaded to capacity to meet generator needs in New England. This concentration places more pressure on the pipelines.

In a study last year, ICF International confirmed ISO-NE's concerns about pipeline limitations.[3] The study assessed the capacity of the natural gas pipelines to supply generators under winter and summer design conditions looking out several years, and concluded that, "[i]n each of the scenarios and cases

[2] Much like the electric power industry, natural gas pipeline operators must balance injection and withdrawals to maintain reliable operations.
[3] See the ICF report at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf.

examining gas supply and demand under winter design day conditions, there is not enough gas supply capability remaining to meet the anticipated power sector gas demand."

The study also noted that the additional pipeline capacity that exists in non-winter periods, which is currently used by New England's gas-fired generators, will diminish as the LDC load continues to grow. Notably, the study was conducted assuming that all pipelines are fully available in each scenario (i.e., no contingencies, maintenance, etc.) and that flows on the various pipelines are perfectly coordinated in order to maximize the throughput on the pipeline system. Given those assumptions and the use of theoretical maximums, ICF has acknowledged that the study overestimates gas availability.[4]

Input from regional pipeline companies and electric system operating experiences substantiate the study's conclusions. The pipelines have confirmed that the pipes coming into New England from supply points to the west, including the Marcellus shale fields, are becoming constrained or operating near capacity in periods other than the winter. For example, as reported by the Algonquin Pipeline at its 2012 customer meeting, the number of days that the pipeline is restricted through the Crowell compressor station increased from a single day during the 2009/2010 winter to over a hundred days during the 2011/2012 winter. The Tennessee Pipeline has also experienced a significant increase in the number of days that the pipeline is restricted through compressor station 245 (upstate New York). Winter restrictions have increased from 42% during the 2009/2010 winter to over 99% of the days during the 2011/2012 winter. In addition, the Tennessee Pipeline has begun experiencing restrictions during the summer months. Specifically, summer restrictions have increased to 78% of the days in the summer of 2011. In contrast, in 2009, there were no restricted summer days.

Absent further expansion of pipeline capacity, New England will likely experience more limitations on gas delivery to generators and, during winter cold conditions, may experience more extreme disruptions, even with all supply sources fully committed.

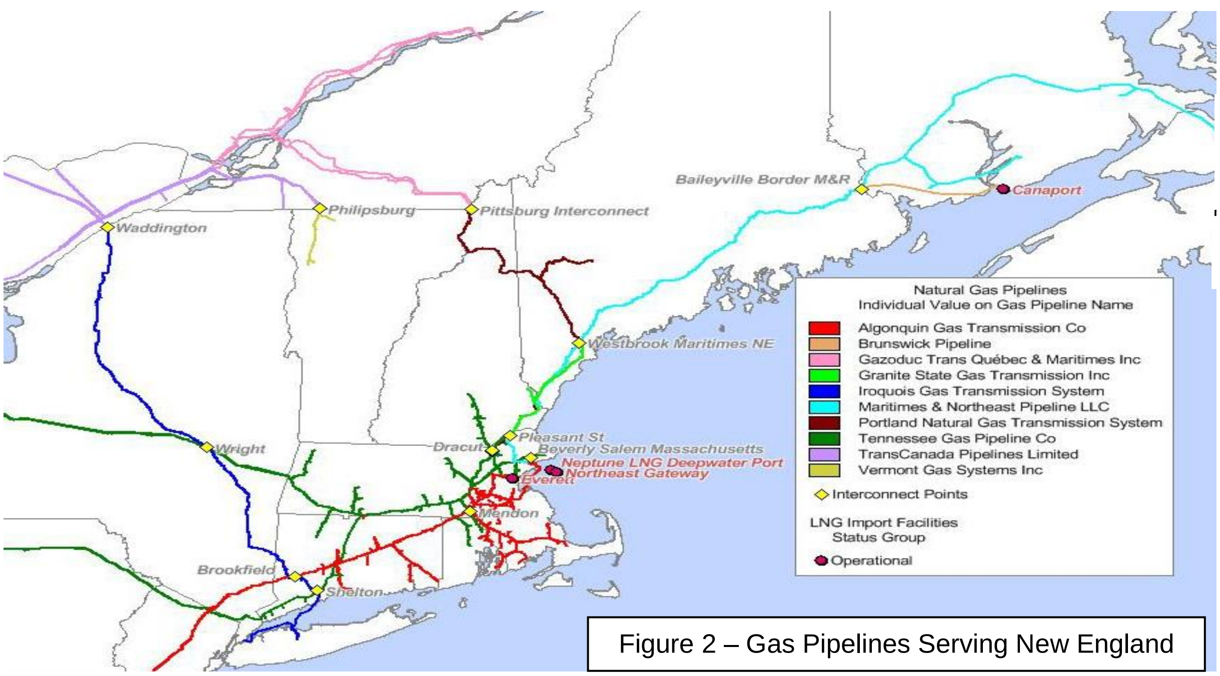


Figure 2 – Gas Pipelines Serving New England

[4] ISO-NE is planning a second gas study that will aim to more realistically assess pipeline and gas availability.

Although the pipelines are at or near capacity, they will not expand until firm customers commit. Unlike the electric industry, which builds infrastructure in anticipation of demand, the gas industry requires signed contracts from firm customers before building or expanding pipeline infrastructure.[5] In fact, the Federal Energy Regulatory Commission, which must approve pipeline projects, bases its decision that a pipeline project is in the public convenience and necessity in large part on the existence of firm contractual commitments. Accordingly, to the extent growth is due to gas-fired generation, pipelines will not expand to accommodate this growth unless the electricity markets provide generators with the incentives (comprising both revenues and penalties for non-performance) to support firm contracts in sufficient volumes to support pipeline expansion.

Conditions in January 2011 highlighted the vulnerability of New England's bulk power system to the capacity limitations of the regional gas pipeline network. Beginning January 14 and continuing through January 24, cold weather conditions resulted in pipelines restricting gas availability to generators. On numerous occasions during this period, generators notified ISO-NE of their reduced ability to produce electricity and often subsequently placed themselves out-of-service due to a lack of gas supply.

Generator Commitments And Dispatch That Do Not Match Fuel Nominations

Based on system conditions, it may be necessary for gas-fired generators within New England to utilize more natural gas than they have nominated going into the operating day. To date, the design of the northeast pipelines has not included "no-notice" service. In general, the pipelines require that supply be procured and scheduled in advance to match actual consumption.

The overall impact of generators' withdrawal of more gas than they have nominated depends on the operating conditions facing the pipeline at that time. On many days, the impact is minimal, if the pipeline has sufficient capacity to deliver the gas and time to recover from the over-draw before the next operating day. However, during periods of pipeline maintenance, outages or heavy system demands, the pipelines will have limited ability to meet additional demand.

In general, ISO-NE is only notified of a problem after it has issued dispatch instructions to the units. This notification generally comes from the gas pipelines and not the generator. For example, on the afternoon of December 10, 2010, without notice to ISO-NE, the gas pipelines had to reduce the supply of gas to generators within New England, equivalent to approximately 900-1000 MW. In particular, one pipeline reported serious problems with gas pressure with the potential to interrupt gas flow to certain generators due to gas-fired generators over-drawing their gas nominations. An additional 800 MW of gas-fired generation was at risk over the peak load hour due to questionable gas supplies.

The pipelines have repeatedly indicated that, due to the increased demands on their systems, they are now fully exercising their rights under their tariffs, and the use of flow control and valve shutoffs will be more common going forward when generators place the pipeline system at risk by over-drawing gas to meet their electric side obligations. In one such communication, on January 19, 2011, a representative of one of the gas pipelines held a conference call with gas-fired generators in New England and New York. The discussion focused on the low pressures caused by New England and

[5] The media has reported on at least one potential new pipeline for New England. Spectra, the developer, has indicated that this project is in the marketing phase, during which prospective customers are contacted to gauge their level of interest and willingness to enter into firm contract commitments. Spectra has confirmed that the project will not proceed without these commitments.

New York generators over-drawing their scheduled gas from the pipeline. The pipeline representative stressed that the over-usage of gas was unacceptable and the pipeline would be taking more extreme actions to protect the reliability of the pipeline system, with the most serious of these actions being the actual closing of gas flow valves to the worst-offending power plants.

The pipelines have been true to their word. On January 19, 2012, ISO-NE committed approximately 250 MW of fast-start generation during the morning peak period. Approximately one hour later, the pipeline operator informed ISO-NE that the units had not scheduled gas and would be ordered off-line if gas was not scheduled. Fortunately, this order was coincident with the economic de-commitment of the generators.

On March 2, 2012, due to planned transmission outages in the Rhode Island area, gas-fired generation was ordered on-line to provide first contingency protection. These generators obtain their natural gas supply from the Algonquin pipeline. When another transmission line in the area had an unplanned outage, additional generation was required for contingency protection. The additional generator also obtained its gas supply from Algonquin. Extensive communications were required between ISO-NE and the generator to ensure that the necessary gas was procured. Before noon, the Algonquin pipeline issued a Critical Capacity Constraint notification due to high system demand and pipeline imbalances, requesting that all customers utilize only the gas that they had scheduled until further notice. At about the same time, the Tennessee pipeline, which also supplies gas to units in Rhode Island, issued an Operation Flow Order Balancing Alert for the New England area. Due to concerns about gas pipeline conditions, ISO-NE ordered additional non-gas fired generation on-line to maintain system operating reserves,[6] and implemented an Abnormal Conditions Alert. The likelihood of post-contingency load shedding to protect the affected area's transmission system was high during this event; fortunately, ISO-NE was able to coordinate with the Tennessee pipeline to maintain gas supply to the necessary generators.

In addition to using more than their scheduled gas, generators also use gas in a different pattern than the pipelines expect. Gas pipeline operators evaluate their capability to deliver gas based on a generator utilizing 1/24th of its daily nomination in each of the hours of the gas day; however, peaking and other generators are often committed by ISO-NE to meet peak loads in the afternoon. Accordingly, a peaker may nominate gas for an entire gas day, but burn its allotted volume during a few hours in the afternoon.

While pipeline operators may be able accommodate the disparity between scheduled versus actual usage if the pipeline system has time to recover gas pressures, the pipelines in the northeast have not been designed for these imbalances. Absent non-ratable service requirements being planned and contracted (paid) for, the sudden ramps and shut-offs can cause pipeline pressures to vary significantly from hour to hour, thereby jeopardizing reliability to all other customers taking gas from the pipeline. These challenges will increase with the use of more variable energy resources, as gas generators are called to balance these intermittent resources. Even the best forecasts of wind generation will contain forecast error, and resources dispatched to provide balancing service will require a "bandwidth" or "swing" type of fuel supply contract.

Timing Differences Between the Gas and Electric Industries

As indicated above, generators are often not committing to the appropriate amount of gas, at the right times of the day. In part, this is due to the lack of harmonization in timing between the gas and electric industries.

[6] Although outside the scope of this paper, it should be noted that commitment of these out-of-merit generators increases Net Commitment Period Compensation (uplift) and affects the accuracy of electricity prices.

On the electric side, ISO-NE commits generating units first through a financially binding Day-Ahead Market (DAM). The DAM is a forward market that operates one day prior to the delivery day, which is a standard 24-hour calendar day. The function of the DAM is to provide a mechanism for load and generators to hedge against real-time price volatility and to provide a base unit commitment schedule for the operating day.

At 10:00 a.m. on the day prior to the operating day, ISO-NE posts the hourly load forecast for the next operating day. At noon on the day prior to the operating day, the DAM bidding window is closed; all supply offers, demand bids, Increment/Decrement (virtual) offers, and external transactions that have been entered for the next operating day are fixed at this time. ISO-NE staff then has four hours to clear the DAM and post results by the standard deadline of 4:00 p.m.

The next step in ISO-NE operations is the Re-Offer period, which occurs after the DAM results have been published. The Re-Offer Period opens at 4:00 p.m. and closes at 6:00 p.m. During the Re-Offer period, generators not committed in the DAM can change their energy price offers in addition to changing their start-up and no-load costs. Generators that have been committed in the DAM can only change their energy price offers. One of the intents of the Re-Offer period is to allow updates for spot market fuel prices, which may have changed from noon to 4:00 p.m. The Re-Offer period also allows a generator not committed in the DAM to self schedule as a price-taker in the Real-Time Market.

Using the most recent energy price offers, ISO-NE next conducts the Reserve Adequacy Assessment (RAA) process. The purpose of the RAA is to ensure that sufficient capacity will be available to meet real-time energy demand, reserves and regulation requirements. The RAA process marks the final interface between DAM clearing and real-time operations. The initial RAA is published at 10:00 p.m., two hours prior to the start of the operating day, and is updated at intervals throughout the operating day, at 1:00 a.m., 5:00 a.m., 8:00 a.m., 12:00 p.m. and 5:00 p.m., with updates to real-time unit commitments as necessary to deal with unexpected events, including load forecast error, scheduling deviations in generation, and unplanned equipment (generation or transmission) outages, as well as contingency response.

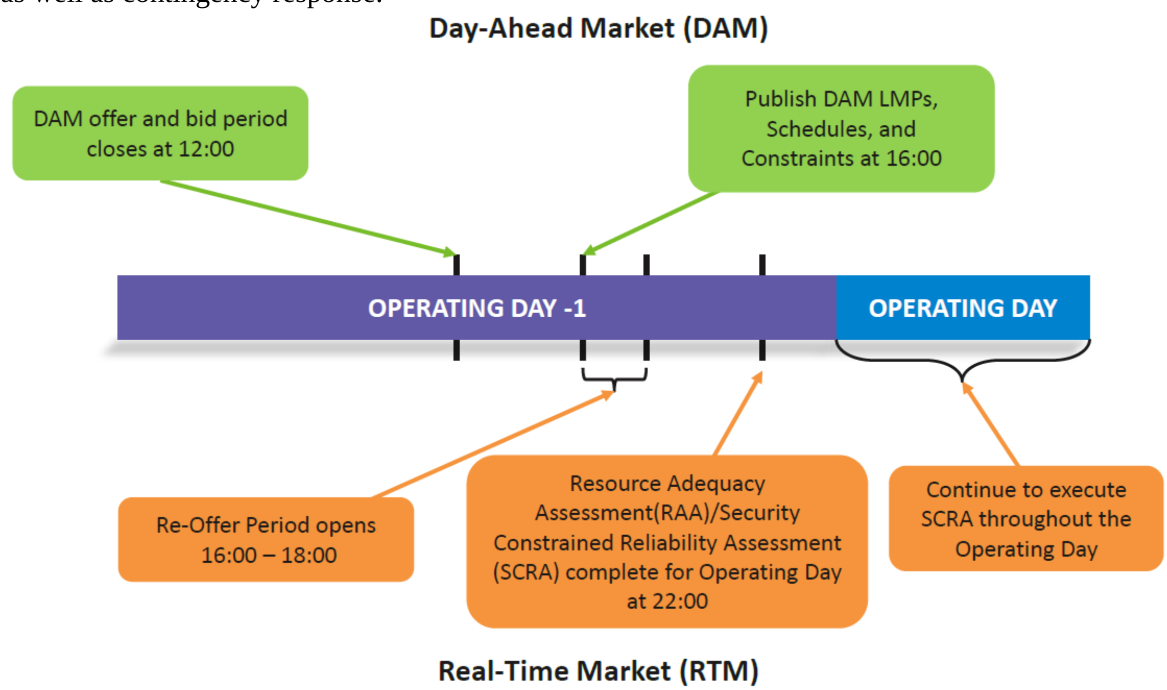


Figure 3 – Day-Ahead and Real-Time Market Timeline

The gas industry operates on a different set of time frames. As noted above, the purchase of gas is a separate transaction, generally through the brokered markets (e.g., Intercontinental Exchange) for the next gas day. The gas market is most liquid between 8:00 and 9:00 a.m. the day prior to the electric operating day.

Next, a generator must nominate (request) pipeline capacity to transport natural gas from one specified location to another over the gas day. Submitted nominations are confirmed and scheduled by the pipelines based on priority of service, available pipeline capacity and ability to maintain pressure within prescribed limits for reliable operation along the designated contract path.

Much like the electric industry, timelines are critical in coordinating natural gas flow from injection and storage to the end use customers. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour gas day from 10:00 a.m. to 10:00 a.m. Eastern Standard Time. Nominations fall into three categories: Timely, Evening, and Intra-day. The timing of each nomination is detailed in Figure 4 below.

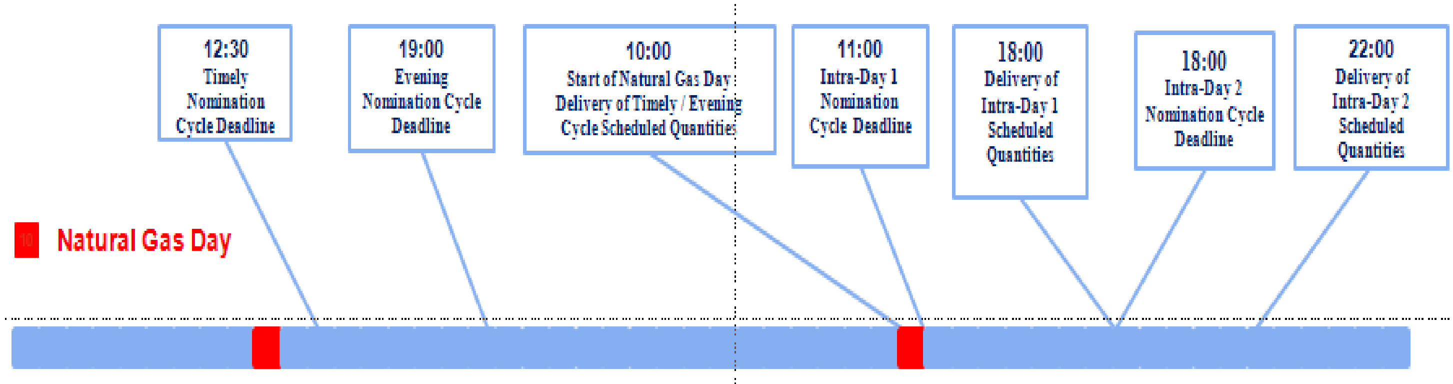


Figure 4 – Natural Gas Day and Nomination Timeline

Timely nominations give the strongest assurance to shippers that they will receive the nominated amounts of pipeline capacity throughout the next gas day, as long as they do not exceed the scheduled contract quantities. Under industry standards, firm customers that do not nominate their full entitlements during the Timely cycle effectively free up capacity for other shippers that have a lower pipeline service priority.

During the Evening nomination cycle (which occurs from 12:31 p.m. to 7:00 p.m.), “bumping” can occur. Bumping is the process by which a shipper with a higher priority can force its nomination to take precedence over a lower priority shipper’s nomination.

As the gas day progresses, the two remaining gas scheduling periods, Intra-Day 1 and Intra-Day 2, become windows of last resort with respect to nominating additional fuel as a result of a revised dispatch order from ISO-NE. In addition, gas trading does not typically take place over weekends and holidays, meaning generators must plan days in advance of weekends and holidays.

The disparate schedules used by the gas and electricity markets pose challenges for gas-fired generators. In New England, ISO-NE’s DAM closes at noon, with the results not posted until 4:00 p.m. – well after gas-fired generators must submit their initial gas demands (at or before 12:30 p.m. for the Timely cycle nomination deadline). In other words, to be assured gas delivery, generators must purchase and schedule gas before they know that they have been scheduled to generate electricity. Conversely, when the pipelines indicate that their systems will have constraints the next day, ISO-NE will not know which generators have a DAM obligation until 4:00 p.m.

The RAA determinations are published at 10:00 p.m. (after the Evening gas nomination deadline of 7 p.m.). This can result in a situation where the resource is committed to generate, but is unable to procure the fuel in subsequent nomination periods. As result, the generator is unavailable, leaving ISO-NE little time to re-commit the replacement energy to reliably operate the system. As discussed below, the long lead-times required by non-gas generators exacerbate the reliability challenges.

Moreover, for each electric operating day, gas-fired generators must manage fuel procurement and scheduling spanning two gas days. For hours ending 11:00 a.m. through midnight, they can either purchase and nominate by the Timely cycle deadline the projected amount of natural gas they expect to use, or wait for ISO-NE's DAM results and then nominate their respective gas demands by the Evening cycle (7:00 p.m.), when there is a higher risk of not being able to schedule gas. For hours ending 1:00 a.m. through 10:00 a.m., they must rely on the Intra-Day nomination cycles from the previous gas day to schedule their fuel requirements in the overnight hours. There is an even greater risk of not being able to schedule the gas within the Intra-Day cycles. A comparison of the gas and electric days is shown in Figure 5, below.

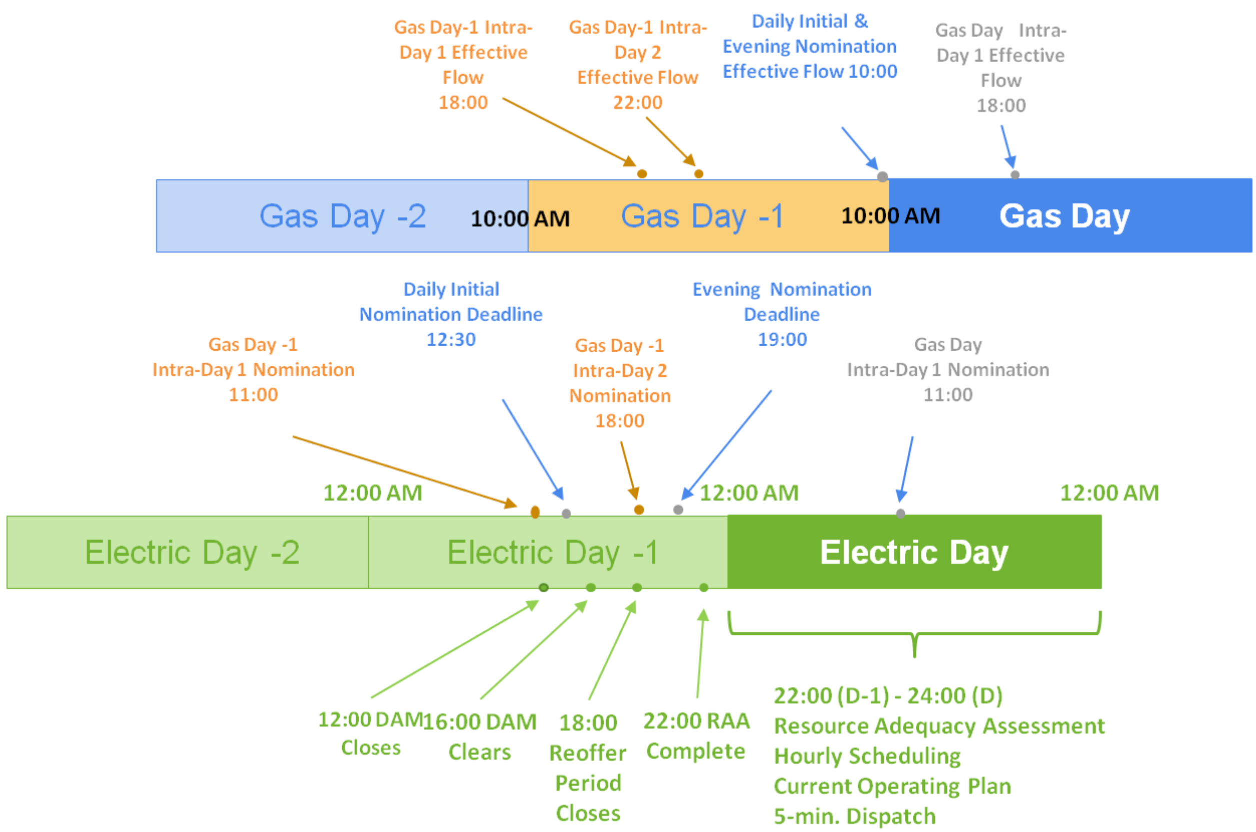


Figure 5 – Comparison of Natural Gas and Electric Days

A recent contingency on July 6 illustrates the challenges of the disparate gas and electric days. During the morning load ramp, ISO-NE was informed that two major pipelines in New England would be restricting generators. As this was the end of the July 5 gas day, the generators were unable to secure gas. A related factor, as described in the discussion of generator commitments that do not match nominations, was the generators' over-drawing earlier in the July 5 gas day. In sum, fourteen generating resources, totaling 3,800 MW, faced reductions of approximately 2,100 MW. Of the 2,100 MW of reductions, approximately 780 MW had cleared in the DAM and were unavailable for real-time operation, while an additional 620 MW from resources committed in the initial RAA were unavailable for real-time operation. The remaining 700 MW were from market participants with offline resources who were alerting the ISO that they did not have gas to operate and those resources were unavailable and out of service.

Gas Supply Disruption

In the fall of 2005, the Gulf of Mexico was hit by two back-to-back hurricanes (Katrina and Rita). Almost 100% of both oil and natural gas production within the Gulf, both offshore and onshore, was shut-in. Despite the efforts by regional energy industries, access to a portion of the nation's energy supplies was crippled and slow to return to normal. Some production never made it back. While New England was spared the major impacts of the reduced fuel supply given the exceptionally mild winter, the storms did highlight our vulnerability in the event of a major gas supply disruption.

In November 2007, ISO-NE experienced reliability issues as a result of a temporary interruption to natural gas production at the Sable Offshore Energy Project, which is located approximately 200 km southeast of Halifax, Nova Scotia, above the deepwater oil and gas wells in the Scotian Shelf. The natural gas sector supply contingency significantly diminished natural gas injections into the Maritimes & Northeast pipeline and eventually caused several gas-fired electric power stations in Maine to go off-line due to the loss of fuel supply. As generators were reliant on this just-in-time fuel delivery system, Maine experienced electric capacity deficiencies. The loss of generation due to this fuel supply shortage came with no notice to ISO-NE.

Pipelines are able to operate with a temporary supply disruption, provided the gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure along an interstate gas pipeline could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses. For instance, the Algonquin pipeline currently supports some 7,300 MW of summer capability and over 7,900 MW of winter capability, with over 3,800 MW having gas as a single fuel source. Local fuel inventory for gas generators (e.g. the capability to switch to oil or liquefied natural gas) will provide gas generators with a backup fuel option. Until the gas system issues have been fully addressed, the region will be reliant on non-gas generators (such as oil and coal units), or dual fuel gas units,[7] to mitigate this risk.

Pipeline Maintenance

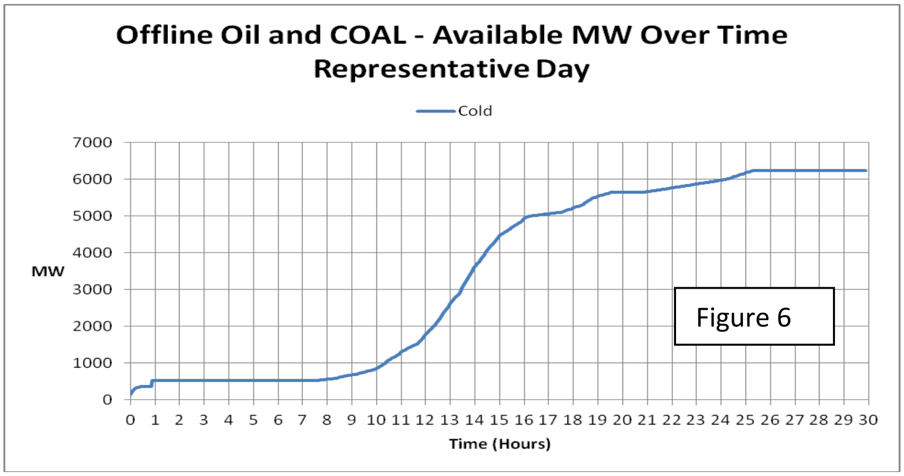
On occasion, gas-fired generators become unavailable due to pipeline inspections and maintenance. Pipeline outages tend to occur during the pipelines' off-peak season (summer) – which coincides with the peak season of the electric system. While pipeline maintenance outages are to be expected, issues have occurred both due to the timing of planned pipeline maintenance relative to high electric load conditions as well as short notice of pipeline outages.

During the week beginning June 6, 2011, several gas pipelines experienced issues related to the high electrical load coupled with pipeline maintenance, resulting in the imposition of restrictions on generators. A year later, during the week of June 4, 2012, ISO-NE was made aware of a pipeline inspection that could cause a capability reduction of the Algonquin pipeline, with effects ranging from immediate reductions of up to 65% capability to no reduction at all. In order to prepare for anticipated restrictions and potential interruptions of fuel supply to New England generators, ISO-NE committed 650 MW of non-gas-fired additional capacity to provide greater fuel diversity.

[7] Dual fuel units have the infrastructure to allow a gas generator to switch to oil.

On June 29, 2012, as a heat wave approached, both gas pipelines from the west, Algonquin and Tennessee, were restricted due to ongoing maintenance. Due to the uncertainty of gas units being able to obtain additional gas or off-line units being able to get intra-day gas, operators committed a number of long-lead time oil and coal units. Spikes in gas prices highlighted that, even if gas were available, generators were not able to change their electricity offers to reflect increased gas costs.

Fortunately, in the examples above, ISO-NE had time to commit off-line oil- and coal-fired units, many of which require a significant amount of lead time to synchronize to the grid. As shown in Figure 6, there are approximately 6,000 MW of off-line coal and oil available to ISO-NE, of which only 500 MW is able to synchronize within 8 hours from a cold status.



When ISO-NE has insufficient notice of service interruptions, the system operator must take steps to ensure that either sufficient replacement production capacity with fuel has been committed to be on-line or sufficient quick start generation with on-site fuel or no-notice fuel delivery is available off-line. The confluence of short notice of gas service interruptions and the long lead-times required by many non-gas generators to get on-line drives the electric system into emergency actions more quickly, potentially to the point of shedding firm load. This risk will be exacerbated if the non-gas units utilized today for fuel diversity retire for environmental and economic reasons. Ideally, as these older, less flexible units retire, there should be sufficient incentives in the wholesale markets to attract investment in flexible units that have secure fuel supplies and can be called on for dispatch within the operating day.

Section 4: Proposed Solutions

The preceding discussion highlights the vulnerability of the regional power system to dependence on gas-fired generation that does not have sufficient incentives to perform. The region has traditionally had a reasonably diverse mix of generation; however, a combination of economic and environmental pressures is making it likely that a significant portion of the oil and coal fleet will retire in the coming years. This increases the risk that ISO-NE will not be able to compensate for uncertain energy production from gas-fired generators, particularly under stressed electrical or gas system conditions. Furthermore, even if the oil and coal units were to remain on the system, the start times of these units is so long that they are of little use to address reliability issues that occur with short notice within the operating day.

System operators depend on an energy management system to commit and dispatch the power system – which automatically dispatches the generation based on the relative economics and the ***stated operational characteristics of the generators, and assumes that all the generators either have, or can secure, the fuel needed to meet their real-time performance obligations.*** It is clear that this assumption is no longer valid and, therefore, ISO-NE must take the necessary steps to address this reliability risk. In addition, the fact that this assumption is not valid for all generation creates a series of economic distortions in the markets, as discussed below.

To address the challenges created by gas dependence, ISO-NE believes that the region must take action in three areas: creation of sufficient incentives to cause generators to perform in accordance with operating characteristics; enhancements to the flexibility of existing markets; and facilitation of improved information flows among generators, ISO-NE and the gas pipelines.

Creating Performance Incentives

As the reliability issues described in Section 3 make evident, while ISO-NE commits and dispatches the system in accordance with generators' offers and stated operational characteristics, generators currently do not have sufficient market incentives to make the necessary firm fuel arrangements, by procuring firm gas delivery services, using stored liquefied natural gas, or, for oil- and dual-fuel generators, maintaining adequate levels of oil inventory.

All of these options have a cost that must be recovered through the offer the generator makes to the wholesale market. Currently, generators that make firm fuel arrangements do not receive value for those arrangements, as prices are often set by the generators with the least secure fuel supplies, and non-performance penalties are relatively weak. In order to compensate for the resulting reliability risk, ISO-NE often has to proactively dispatch uneconomic generators (such as coal and oil generators), thus impacting market efficiency and creating additional "uplift" costs that are unanticipated by market participants and cannot be hedged.

As discussed below, ISO-NE believes that incentives to acquire firm fuel can be created, in the long-term, through changes to the Forward Capacity Market (FCM) and the Forward Reserve Market (FRM). In the short-term, we believe the region must engage in supplemental procurement of resources with firm fuel supplies.

These long- and short-term efforts should increase generators' incentives to perform, leading them to procure firm gas commitments. These commitments, in turn, may have the additional benefit of triggering gas pipeline expansion, and the related opportunity to influence the design of the pipelines and the services offered to include no-notice type services, such that generators may meet their performance obligations without threat of fuel interruption, and bandwidth or swing type contracts, to permit generators to take their gas outside of the $1/24^{th}$ structure currently assumed by the gas pipelines. Alternatively, gas generators could choose to pursue other options more suitable to them, such as investing in dual fuel capability.

FCM/FRM

The existing FCM rules include little incentive for capacity market resources to invest in the capability to operate at capacity under all fuel supply conditions (e.g., through firm gas contracts, dual fuel capability, or fuel storage arrangements). There are no enhanced payments related to product differentiation based on firmness of energy production, and there are effectively no penalties for failure to operate according to capacity supply obligations.[8]

ISO-NE's proposal for long-term FCM redesign is described in a white paper that was released to stakeholders in May.[9] It proposes three categories of change to the FCM, staggered over time. The first set of changes involves the improved definition of the core capacity product, performance

[8] The capacity market penalty for unavailability is currently capped at the unit's capacity. The probability that a penalty is imposed is effectively zero, given that the trigger for these penalties is a "shortage event," which rarely occurs. Penalties may occur if a capacity resource offers, as required, in the DAM and Real-Time market, clears in DAM and does not deliver in Real-Time – but only if the Real-Time price exceeds the DAM price.

[9] See the FCM paper at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_whitepaper_final_may_11_2012.pdf.

incentives, and consequences for failure to perform. These changes would include market incentives that are sufficient to encourage and sustain adequate levels of firm fuel supply (and inventory, where appropriate) over the long-term, along with penalties for failure to perform when dispatched, so that generators that are unavailable or that fail to follow dispatch orders due to a lack of fuel are subject to penalties sufficient to encourage adequate fuel supply. Similarly, FRM product definitions could require reserve resources to invest in and maintain the ability to reliably deliver power under all fuel supply conditions.

The second set of FCM changes identified in the white paper includes definition of system operational needs (such as resource flexibility) and translation of these needs into additional product specifications for the FCM, with appropriate delivery incentives and consequences. For example, FCM product specifications could be modified to make some portion of the capacity subject to having firm service or back-up fuel capability. Resources would be required to submit additional operating information, and there would be additional constraints within the auction instead of the current single category for total resource capability. Regarding reserve products, ISO-NE and stakeholders must consider whether to continue procuring these products through the FRM or in the FCM, based in part on the price signals and timing issues.

Finally, ISO-NE proposes the specification of system locational requirements and market constructs to induce locational responses. These changes are intended to facilitate the procurement of "market resource alternatives," which are supply and demand side resources that could substitute for the development of transmission to meet identified reliability needs. In addition to changes to FCM, changes will also be required to coordinate with ISO-NE's planning processes. ISO-NE has released an additional paper on this topic.[10]

All of these changes will require auditing mechanisms to validate performance, including possibly a "deliverability test" or other means for ISO-NE to verify that the generator has scheduling rights to sufficient gas infrastructure to deliver gas on seasonal peak days, or has sufficient on-site storage of back-up fuel capability. ISO-NE may also need to routinely confirm the viability of dual-fuel capabilities.

Supplemental Procurement

As noted above, ISO-NE intends to address the issue of fuel security in the FCM performance obligations. However, it is unlikely that this can be implemented before Forward Capacity Auction 9, which purchases resources for capacity year 2018/19. In the interim, ISO-NE has proposed for discussion with stakeholders a supplemental procurement to assure appropriate levels of firm fuel capability for the existing gas and oil fleet. This temporary procurement mechanism would ensure, at a minimum, that sufficient generators maintain an adequate level of local liquid fuel inventory (e.g., oil or liquefied natural gas), or access to no-notice, variable take, firm gas supply. This procurement could also specify other characteristics that are supplemental to today's FCM product definition, in a specific quantity. For example, ISO-NE might specify start-time, availability, and dispatch flexibility.

The payments associated with this procurement would be paired with performance penalties for failure to meet these required operating characteristics. Issues to be discussed with stakeholders include the structure of the procurement, which could be an annual auction or Request for Proposals, the qualification process, and an auditing or validation mechanism. ISO-NE intends that this procurement mechanism will expire when the FCM changes are effective.

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[10] See the paper at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/mra_discussion_paper_06132012_vtransmit.pdf.

Improving the Flexibility of Energy Markets

To facilitate generators' ability to procure fuel, the markets must allow generators to modify their offers to recover their costs of acquiring fuel intra-day, and the timing of the electricity market must better align with the gas markets to facilitate reliable electric operations.

Hourly Offers and Intra-day Reoffers

Currently, resources can only submit one energy market offer for each hour of the electric operating day and cannot change their energy market offer after 6 p.m. on the day prior to the electric operating day. This constrains generators in two ways. First, generators cannot reflect price differences over the two gas days that span a single electric operating day. Second, generators cannot reflect changes in fuel prices within the electric operating day in their energy market offers.

Given these limitations on bidding behavior, when the cost of producing electricity (given real-time gas market prices) exceeds the real-time electricity prices, resources fueled by natural gas may choose not to generate energy by redeclaring their operating limits or using Limited Energy Generation (LEG) rules to remove all or part of their energy production capability from dispatch. This was the case during the June 29 heat wave and the January 2004 cold snap discussed above. In those instances, generators that had access to fuel made the economically rational decision to forego producing electricity, as the costs of doing so exceeded electricity prices.

The hourly offers and intra-day reoffers solution aims to change the status quo, such that resources are able to reflect changes to costs in the energy market closer to the hour of operation. Accordingly, resources that must buy intra-day gas will be able to reflect their true costs, and generators that might not be able to get gas in real-time and want to switch to oil will have the ability to reflect the cost of switching.

By providing generators the ability to better reflect their costs to produce electricity in real-time, ISO-NE believes generators will be more likely to respond when called to come on-line or increase production in real-time. These changes will also reduce the likelihood that electricity market prices fail to reflect fuel prices, and may also facilitate the use of more expensive northern gas and alleviate the pressures on the pipelines from the west.

Timing of the Day-Ahead Electricity Market

As noted above, the timing differences between the gas and electricity sectors may be contributing to the increasing incidence of gas-fired resources informing ISO-NE that they do not have sufficient fuel to meet their generation commitments. To alleviate this problem and give system operators more notice of unavailability, so that long-lead time replacement generation can be secured and reliability maintained, ISO-NE proposes to move the timing of the DAM so that generating schedules are published before the Timely nomination deadline for gas, and before the primary gas trading period (i.e., before 10:00 a.m.). ISO-NE would also move the timing of the reoffer period and the initial RAA prior to the Timely nomination deadline for gas.

The timing adjustment will also benefit the pipeline operators, who need to know fuel scheduling requirements, including any potential intra-day short notice or short duration withdrawals that may impact pressures and the reliability of their system. Making the electric reliability determinations at 10:00 p.m., based on the current DAM process timelines, is too late for the pipelines to modify their operating plan for the next day and essentially under-utilizes the capacity of the pipeline system.

A timing change will also facilitate gas-fired generators' ability to secure gas. The existing timing differences require gas-fired generators to manage fuel procurement and scheduling over two gas operating days for each electric operating day. Moreover, given that DAM results are not posted until 4:00 p.m. and the Timely cycle nomination for gas delivery ends at 12:30 p.m., generators have the choice to either secure gas before they know they have been scheduled to generate or take their chances with later gas nomination cycles. This problem is more difficult for generators that are scheduled as part of the RAA, the results of which are published at 10:00 p.m., well after the Evening gas nomination deadline of 7 p.m. These resources are committed to generate, but may be unable to procure fuel in the Intra-Day nomination periods.

ISO-NE recognizes that moving the market timelines is not without risk. In particular, advancing the DAM timeline creates more price risk that must be factored into offers and the reference prices used for market monitoring and mitigation. The advanced timing may also increase the uncertainty in load forecasts used to inform the bidding process, particularly for demand response and renewable resources, although preliminary analysis indicates load forecast differences due to the earlier timing may be small. These and other issues must be considered in detail with stakeholders.

Table 7 below shows a comparison of the gas and electric days after the DAM and RAA have been moved. In this example, the DAM clears in the evening two days before the operating day. While ISO-NE intends to propose this formulation to stakeholders as a straw proposal, ISO-NE notes that there may be other time frames that could achieve its goals. Table 7 is included merely for illustration.

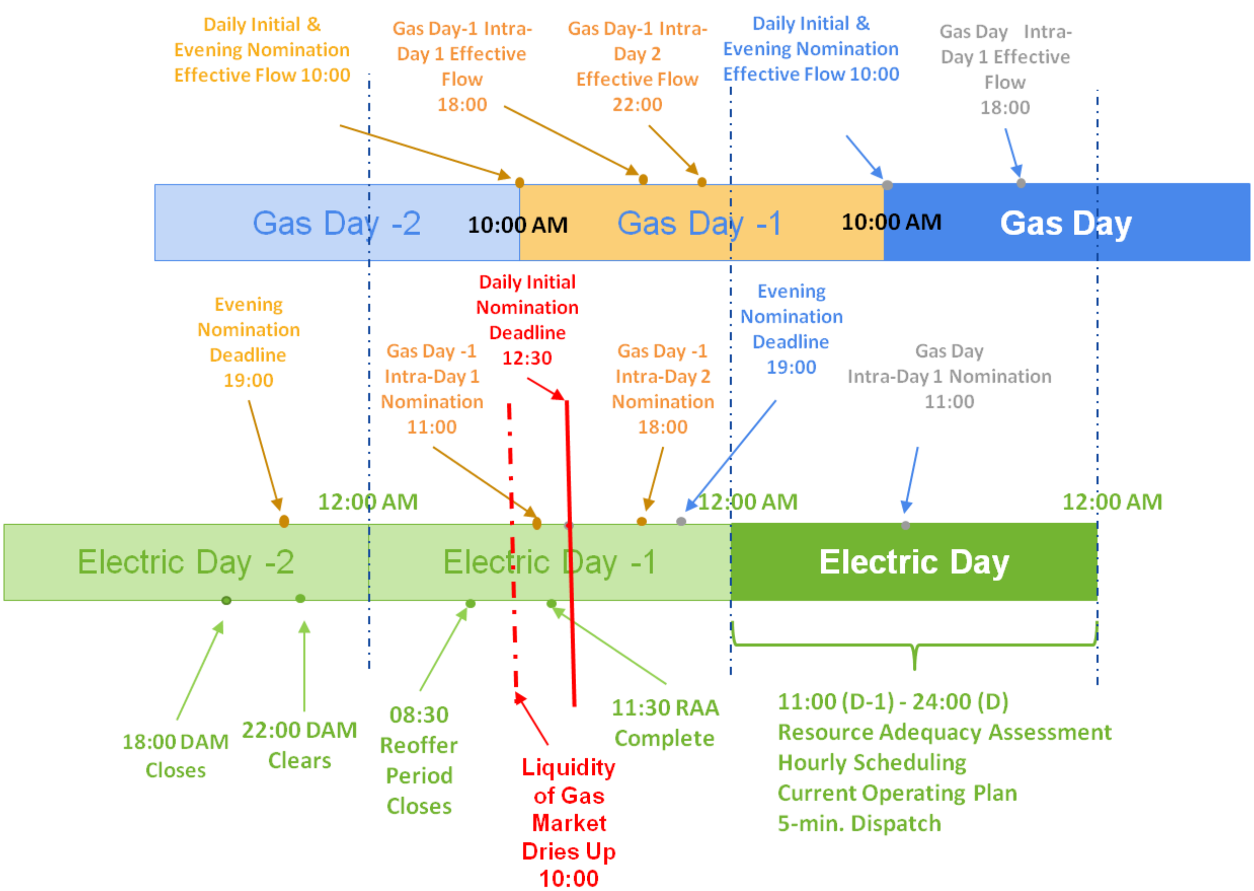

Figure 7 – Comparison of Natural Gas and Electric Days After DAM Timing Change

Information Enhancements

As indicated above, the worst stresses on the electric system occur when ISO-NE has short notice of generator unavailability due to inability to secure fuel, or of supply disruptions or pipeline maintenance. These stresses are exacerbated by the long lead-times required by many of the non-gas fired generators in New England (see Figure 6, above). To facilitate better information flow, ISO-NE proposes to require more information from generators and to continue ISO-NE's current coordination efforts with the gas pipelines.

Regarding information from generators, ISO-NE is considering enhancements to the required offer information submitted by generators. Specifically, as part of the offer process, ISO-NE would require generators to provide information on fuel schedules and any differences between cleared amounts (and/or commitments) and scheduled fuel supply. Generators would have a continuing obligation to proactively inform ISO-NE of any condition that would prevent them from meeting their DAM or RAA commitment schedules or that would otherwise restrict their ability to follow dispatch instructions. This information, in combination with information from the pipelines, would improve the system operator's ability to assess the likelihood that generators will fail to accurately follow dispatch requests.

ISO-NE also needs better information from the pipelines regarding their operations. While gas-electric coordination has greatly improved in recent years, largely due to the active communication between ISO-NE and the pipeline operators and the establishment of a Coordination Committee composed of the Northeast electric system operators, gas pipelines, liquefied natural gas storage operators and LDCs, ISO-NE needs better information about scheduled outages on natural gas pipelines.

Conversely, pipeline and storage operators as well as LDCs with gas generation in their distribution system need improved information about the potential impacts on their operations from planned or unplanned generation or transmission outages, expected changes in electricity demand, and expected changes in renewable generation. Outages on the electric transmission system can impact gas flow and pressure on gas pipelines due to dispatch of gas generation that does not have a nomination.

Finally, gas and electric operators also need to discuss real-time operating information so that they can work together to re-dispatch to maintain the reliability of both systems. To achieve this end, ISO-NE must address information policy constraints that prevent it from informing pipelines of actual generator commitments.

Section 5: Continuing Efforts

While there is no longer any uncertainty about the existence of reliability problems as a direct result of gas dependence, the solutions continue to evolve. As set forth herein, ISO-NE intends to pursue, through the stakeholder process, long-term changes to FCM, supplemental procurement, hourly re-offers, changes to the timing of the DAM, and improved information flows.

Given the mounting reliability issues, ISO-NE hopes to begin the stakeholder process regarding the identified solutions immediately. Specifically, ISO-NE has established implementation targets for the proposed solutions, as follows: information improvements by winter 2012; changes in the timing of DAM alignment in the first quarter of 2013; supplemental procurement by summer 2013; and hourly reoffers in 2014. Other changes remain possible, including changes to the Limited Energy Generation rules.

Additional solutions may stem from work with the broader industry and the North American Energy Standards Board. For example, the gas industry serving New England may want to consider implementing products to better serve electricity generators, including the no-notice, bandwidth and swing products referenced above. The electricity markets may need corresponding changes to create incentives for generators to purchase these products.

A change in the gas day may also be warranted. Figure 8 below shows the differences in timing between the gas and electric industries, as well as the hourly concentration of gas generator starts during the year. As shown, the electric morning load increase begins at approximately 3:00 a.m. The majority of daily generator starts occurs in this time period; most of these generators are those with the flexibility to cycle, which at this time is the gas fleet.

Ideally, a standard gas day would accommodate the morning load pickup and the ensuing electric peak period in a single operating day. A closer synchronizing of the gas and electric energy operating days would facilitate generators' purchase of gas in concert with their daily electric commitment; currently, if generators buy gas ahead of time, it generally only matches their DAM commitment so that they are not forced to sell any unused portion at a loss. This causes problems if conditions in real-time are materially different than the DAM schedule.

Advancing the electric DAM and RAA timelines to precede the gas Timely nomination deadline will allow generators to purchase gas to meet day-ahead and supplemental reliability commitments, enhancing system reliability. Moving the gas day start time from 10:00 a.m. to no later than 4:00 a.m. would allow generators to procure and schedule fuel for their entire daily commitment.

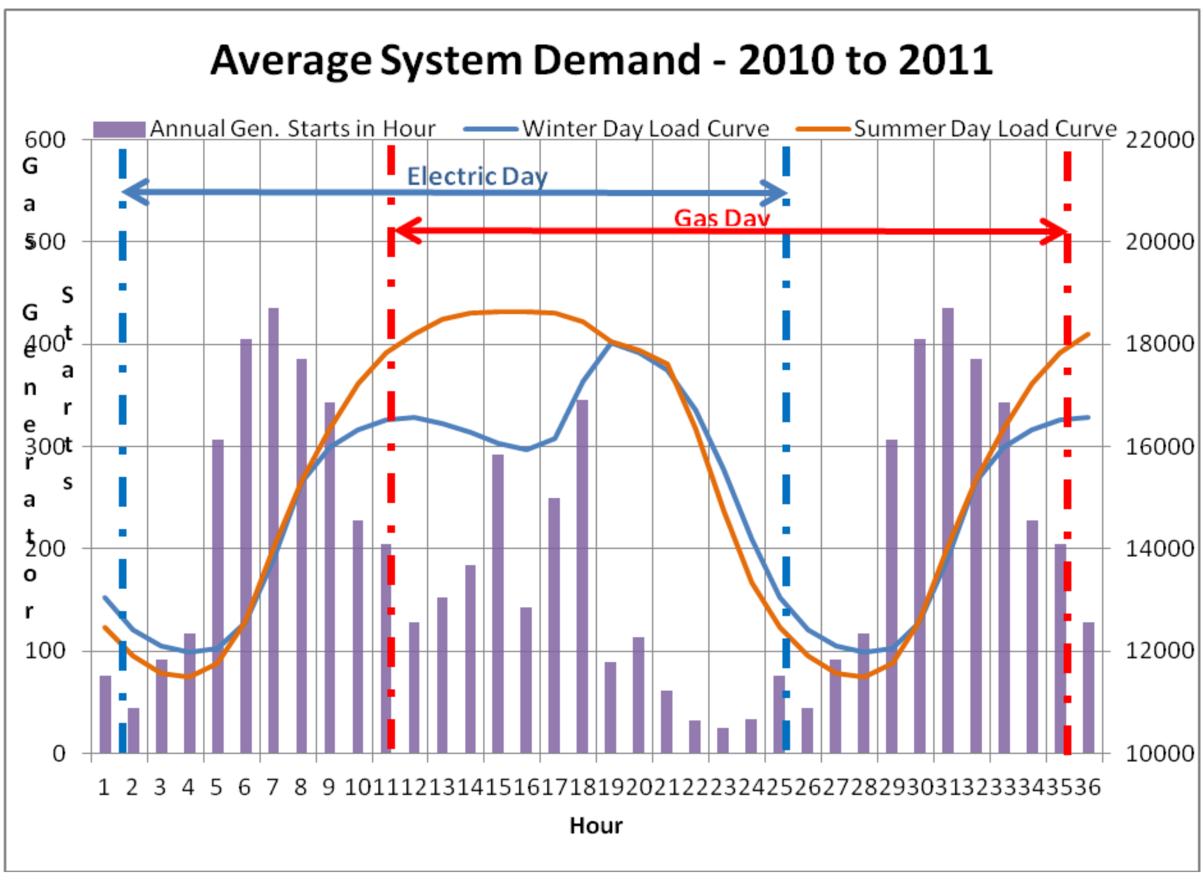

Figure 8 – Gas Day vs. Electric Day

ISO-NE looks forward to discussing these issues with stakeholders and the electric and gas industries at large. We recognize that these changes will require a significant amount of time and effort from the region, but we believe that they are necessary to ensure the reliability of the bulk power system and the competitiveness of the market structure that the region has adopted.