Interdependency of New England’s Natural Gas and Electricity Systems: 
A Utility Perspective

April, 2013

1. Executive Summary

This paper addresses New England’s growing dependency on natural gas fired generation. Specifically, the issue that this dependency, together with emerging physical constraints in the gas pipeline infrastructure serving the region, present an increasing concern regarding the ability of the region’s gas-fired generation to continue to reliably serve electricity Customers in New England. This risk is identified, by ISO New England, as the region’s highest priority strategic risk.

In hindsight the emergence of this risk should not have been unexpected. The region’s gas pipeline system was designed and built to serve gas Local Distribution Companies (LDC) requirements under peak winter load conditions and underwritten by contracts between the LDCs and the pipelines. The risk has now been widely recognized across New England (and by the Federal Energy Regulatory Commission) and responses are being actively considered, discussed and developed. Parties to these efforts including; the electrical system operator (ISO New England), generators, pipeline operators, LDCs and electricity transmission owners. The responses being considered ranging from the short-term, (i.e. winter 2013/14) to medium-term, (e.g. changes to markets).

While worthwhile, there is accumulating evidence, from a number of sources, that the short and medium-term efforts that only seek to optimize the deployment of the region’s existing gas supplies are unlikely to be sufficient. Accordingly, this paper also suggests a number of potential long-term responses to that fundamental problem of limited gas supply. Concluding that, since it is unlikely that a single response will be able to fully address the challenges facing the region, New England’s considerations should include all of these different approaches available to it.

That is, the region’s response should ideally include both short, medium and long-term actions; such as better deployment of available gas through market changes, improved communications, information sharing and coordination, enhanced availability of alternate, or substitute, fuels within the region, together with longer-term initiatives that address the fundamental issue of enhancing the region’s ability to access reliable, 24/7, year-round gas, and hence, electricity supplies.

2. New England’s Gas Dependence

Utilities are dedicated to ensuring that their Customers have safe and reliable services. The growing interdependency between the natural gas and electricity systems in New England, together with the limitations in the gas transmission infrastructure serving the region, represents a growing risk to their ability to continue to provide those services at the high levels of reliability required.

The principal focus to date has been, correctly in our view, the impact that gas infrastructure inadequacy has on generators and hence directly on electricity supply. However, the natural gas pipelines are incurring daily operational challenges which impact pipeline system reliability which in turn impacts all pipeline services including LDC firm service. For example, natural gas pipelines in the northeast were not designed to provide the daily swings as generators are requiring today. This is the rapid ramping up and ramping down by direct-connect generators taking service on pipelines.
This results in drastic line pressure drops which in turn result in lower pressure gas deliveries to LDCs such as National Grid. When this occurs delivery pressure from the pipeline to the LDC city gate meter can be at lower than the minimum requirements resulting in LDC distribution pressure drops and potential loss of LDC gas customers. In short, the increased dependence on gas by generators taking service with interruptible services places system reliability at risk to all customers taking service on the pipeline.

Natural gas has become the dominant fuel used in electricity generation in New England. In 1990, oil and nuclear generating plant each produced ~35% of New England’s electricity with coal plants producing an additional 18%. While in 2011 (Figure 1) approximately 51% of New England’s region’s electricity was produced by gas-fired plants as compared to approximately 5% twenty years previously.

![Figure 1 – 2011 Energy Production](Ex ISO-NE – Addressing Gas Dependence, July 2012)

The development of new technologies to extract previously inaccessible gas reserves and particularly the presence of the Marcellus gas-bearing formation on New England’s doorstep have all contributed to this shift, together with the economic driver that the price of generating electricity with gas is now lower than with oil or coal-fired generation. Other factors, such as the introduction of variable renewable energy resources onto the New England system, which require greater flexibility in other generating resources to balance the system, and the possibility that the region’s older oil and coal-fired resources may opt for retirement rather than compliance with environmental regulations all contribute to the likely continuing predominance of gas-fired generation in the region’s fleet.

Even through these new sources of gas supply are located in close proximity, the region is still faced with issues impacting the reliability with which such fuel can be delivered. A recent study undertaken by ICF, on behalf of ISO New England’s Planning Advisory Committee, assessed the availability of natural gas pipeline capacity to serve the New England region’s demand, both gas Customers and power generation, over the next several years. ICF’s results suggest that the region’s gas pipeline capacity capability is insufficient to supply regional electric sector demand over the next decade. Almost all the pipeline capacity serving the region is contracted by LDCs to serve the firm requirement of their gas Customers, leaving a relatively small amount of non-firm capacities for other Customers such as gas-fired generators. Also the New England region has not had a major gas pipeline expansion project in many years. While the peak gas demand requirements of LDCs have grown over that period, such requirements have typically been met through usage of LNG sources to

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2 http://www.iso-ne.com/committees/comm_wkgrps/prtgpnts_comm/pac/reports/2012/gas_study_public.pdf
meet Customer requirements rather than entering into the type of long-term, firm contractual arrangements for additional capacity with pipeline operators that would underwrite further pipeline development.

Even though ICF’s analyses adopt a range of different generation forecasts, assumptions regarding nuclear or coal-fired plant outages and natural gas prices, their results reflect the following observations:

a. The region’s gas delivery system is most stressed in the winter when both generation and LDCs’ needs for fuel supplies are greatest.

b. For a ‘peak’ gas usage day, through 2020, the gas deficit is typically between 500,000 and 600,000 Dekatherms per day. (By way of comparison, the Algonquin gas pipeline currently delivers ~1,100,000 Dekatherms per day into New England.)

c. This is equivalent to 2,100MW to 2,500MW of generating capacity being unavailable.

Recent operational experience tends to reinforce ICF’s conclusion. In February 2013 ISO New England issued a “Winter Operations Summary: January – February 2013” this report concludes that the ISO has immediate and growing concerns about the availability and flexibility of generating resources particularly natural gas and oil-fired resources to reliably serve the daily, round-the-clock demands of electricity consumers in New England.

3. New England’s highest priority strategic risk

The ISO has been aware of the risk of natural gas dependency for some time and identifies it as the highest priority strategic risk for the region. Stating that gas dependency risk is escalating rapidly and current fuel arrangements for generators, including the "structural inflexibility" of fuel delivery systems, is leading to "likely unsustainable operating conditions". ISO New England goes on to say the risk is not isolated to extreme cold weather events or even to the winter and that challenges are showing up in operations on an ongoing year round basis. ISO New England concludes that these challenges; “will threaten the reliability of power systems for the six-state region if not addressed in a timely manner”.

The region has initiated a number of actions to address this risk, these are intended to; i) provide for a better understanding of the nature and scale of the problem, ii) to identify (and implement) actions in the short and medium term to mitigate its effects, and iii) consider longer-term solutions that are able to address the limitations of the gas delivery systems into the region.

4. New England’s Options

There is no single ‘silver-bullet’ solution to the challenge of the region’s increasing dependency on natural gas. Rather it is an issue that will require a range of responses across a number of areas and timescales. It is likely that these will require consideration of changes in the design and the timing of the operation of the region’s gas and electricity markets and of revisions to current policies on communications and information sharing between gas and electricity entities. The implementation of any such changes will also likely be across different timescales, some may be readily accessible but a number, (e.g. changes to the operations of markets) will require comprehensive stakeholder and regulatory approvals processes to be successfully concluded prior to their adoption.

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3 ICF’s study considered four electricity / gas demand forecasts. A50/50, (i.e. probability of electric load (and thus gas demand) exceeding forecast is 50%), a 90/10 (the Reference Gas Demand Forecast) and two further scenarios where there are additional outages of large nuclear or coal-fired plant at either high or low natural gas prices. The ‘peak’ gas usage used here refers to the Reference Gas Demand Forecast.
However, while worthwhile, based on the accumulating evidence from a number of sources, it is not clear that such ‘optimizations’ will alone be sufficient to address the region’s underlying issue of the adequacy of natural gas supply into the region via existing gas pipeline infrastructure.

The following sections identify some of the short and medium-term responses that are either being discussed or are actively being developed, many under the auspices and leadership of ISO New England, together with some suggestions on potential longer-term approaches to the challenges of the limitations in New England’s gas delivery infrastructure that we believe are worthy of the region’s consideration.

5. Short and Medium-Term Responses

3.1 – Improved Information Sharing and Communications – ISO New England together with regional stakeholders is seeking agreement to changes in information policies that would allow the wider sharing of information both on generators’ fuel status and supply obligations and also of gas availability from pipelines. Agreement to such changes would enable ISO New England to make more accurate determinations both of an individual generator’s, and the wider region’s, ability to meet its electricity supply obligations. Such changes, together with improved communication and coordination of the scheduling of planned maintenance, would provide ISO New England, as regional electricity System Operator, with an enhanced understanding of the limitations that gas-fired generators may be operating under and improved ability to dispatch the electrical system to mitigate those constraints.

3.2 – Align the timing of regional electricity and gas markets – At present the timing of the region’s gas and electricity markets do not align. Currently generators have to make a fuel commitment before knowing if their supply offer has been accepted. Adoption of a proposal, put forward by ISO New England, which envisages the adjustment of the timing of the Day Ahead Market such that generating schedules are made available earlier to allow generators to commit to the purchase of the appropriate amount of gas to meet their accepted supply offer. Such a change would increase the certainty, both for the generator and ISO New England, that an accepted offer to supply can and will be fulfilled.

3.3 – Allow generators more flexibility in revising their electricity market offers – The constrained supply of natural gas into New England is giving rise to increased volatility in gas prices. This volatility together with the current market design, which only allows market participants to revise their offers into the electricity Day Ahead Market for a limited period, and not during the actual operating day the offer refers to, means that generators may be dispatched against offers that are below their production cost, thus incentivizing them not to generate.

While each of these individual proposals, and others that are being proposed and discussed, will require individual scrutiny and careful consideration, in our view they represent changes that could enhance the region’s ability to respond to some of the issues around its increasing dependence on natural gas. Although, since typically they seek to optimize usage of existing regional gas supplies, rather than expanding that supply, they do not address the region’s underlying issue of fuel supply inadequacy.

6. Long-Term Responses

From a utility perspective any long-term solutions to the challenges faced by the region needs to meet a number of criteria:

a. Maintain gas and electric system reliability – Utilities must continue to be able to provide a safe and reliable service to their Customers.
b. **Minimize Customer bill impacts** – The bill-impacts to Customers must be minimized consistent with continued safe and reliable service.

c. **Appropriate allocation of costs** – Costs, and risks, associated with the chosen solution(s) must be appropriately allocated together with an appropriate risk / reward balance.

The areas addressed in the following suggestions for potential responses to the longer-term issue of gas pipeline infrastructure adequacy are ones that, we believe, merit consideration. At the present stage of regional discussions none of these responses are developed to the stage of an off-the-shelf solution, there is also a degree of overlap between the proposals, (e.g. effective market incentives for physical or contractual fuel security would mitigate a specific requirement for dual fuel capability). Some, (e.g. regional tariff based funding of gas pipeline development) would also represent significant departures from the current regulatory model, but all include elements that should be part of the regional discussion.

**Enhanced capacity supplier incentives / penalties**

This is an option which is already being discussed in the context of ISO New England’s Strategic Planning Initiative.

It is proposed to modify the region’s electricity Forward Capacity Market (FCM) to establish a pay-for-performance approach such that each market participant’s revenue is dependent on its actual performance during periods when the region’s electrical system is stressed. The structuring of the incentives in the FCM would be such that revenues would be transferred from “under-performing” resources, (i.e. those not able to meet their obligations to supply) to “over-performing” resources, (i.e. those able to meet and, if called upon, to exceed their supply obligations). The structuring, and scaling, of payments in this manner providing strong incentives for resources to ensure that they can both perform as needed and to seek to access the benefits of being able to “over-perform” as necessary.

In terms of fuel-supply this would provide an incentive for all capacity suppliers, including gas-fired generators, to reduce their financial risks by improving the certainty of their fuel supply and is likely to stimulate a range of responses, (e.g. firm or more flexible gas-supply contractual arrangements, dual-fuel supplies etc.) albeit that suppliers may incur additional costs to provide such enhanced certainty. Such risks and costs will likely be reflected in their future FCM bids.

While there are likely additional costs associated with this market-based type of approach it also encourages suppliers to adopt the most efficient and cost effective solutions corresponding to their own facilities and circumstances.

**Require dual-fuel capability**

Absent the establishment of appropriate market based mechanism to incentivize enhanced certainty of access to fuel supplies, an alternative approach is to directly establish a requirement that all new / existing generation be dual-fuel capable. The costs of establishing and maintaining such a capability being borne by the region either in the form of a tariff based payment or reflected in the offered prices for supply.

Also, given that recent fuel surveys indicate that oil-fired generators themselves are only maintaining their oil tanks one third full, in recognition of the small proportion of time they are called upon to

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generate, such a dual-fuel capability requirement would also likely require a corresponding obligation that generators maintain on-site storage of some agreed period of alternate fuel supply. Once again the costs associated with a maintaining such quantities of fuel, which will potentially be unused, would be borne by the region.

It is also anticipated that consideration would need to be given to air quality issues. While it’s likely the anticipated level of operations may be consistent with present permit limits the acceptability of a strategy premised on enhanced use of oil-fired generation would need to be considered.

A final consideration is that most generators do not have direct access to oil pipelines or major storage facilities and as such are dependent on tanker or barge based replenishment. Concerns have been expressed that with the decline in oil-fired generation, the necessary infrastructure and support services for refill are not as effective as previously, (e.g. assuming a representative heat rate it takes ~20 large road oil tankers, each of ~9,000 gallons capacity, per day to support 130MW of generation6).

**Increase regional LNG storage**

At present gas LDCs in New England employ discrete LNG storage facilities located across the region to manage peak Customer demands on their systems. These facilities are supported via a truck-based replenishment strategy based on the Distrigas of Massachusetts terminal in Boston. While there can be the potential for limited releases of gas to support generation, these facilities are sized to meet the requirements of the LDCs themselves and the pace of replenishment is such that significant diversion of gas to third parties would impact the ability of LDCs to serve the needs of their own Customers.

The options around increased LNG storage to consistently support generation would require either the construction of new regional liquefaction, storage and vaporization facilities or accessing any spare capacity there may be at the existing facilities at Distrigas, Boston (or potentially at Canaport, New Brunswick).

Investigations undertaken by the Analysis Group7, on behalf of ISO New England, addressed a generic LNG storage facility, roughly equivalent in size (~60,000 cubic meters) to existing peak-shaving facilities elsewhere. Such a generic regional facility (based on three recently sited facilities of roughly equal storage capacity) would be sufficient to support 540MW of generation capacity for approximately 14 days of operation. The liquefaction capability being sufficient to replace 1 days usage in 14 days, or more than 190 days to fully refill the tank after discharge. Their analysis concluding; “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.”

The initial costs of the recent facilities studied ranged from approximately $1,850 to $2,450 per cubic meter of storage, implying $129M for a hypothetical regional facility. Thus, while such a regional facility may not fully address the gas adequacy issues facing the region it should be considered as one possible element of a wider response.

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Both this response and the previous proposal requiring dual-fuel capability would be ‘standalone’ in the sense that they do not seek to increase the delivery of additional gas supplies into the region, but both are also limited by the quantities of fuel/LNG able to be stored and the fact that such resources can typically be depleted much more quickly than they can be replenished.

**Enhanced electricity transmission links**

The physical bottleneck in the delivery of natural gas into New England is in the limitations of the existing gas pipeline infrastructure serving the region. The constraint on its expansion lying in the implications of its regulatory model, (i.e. the need that Customers enter into long-term capacity contracts to underwrite investment and the inability of Customers to take on such contracts).

Given that the principal use of such infrastructure would be to deliver additional gas for electricity generation. If the regulatory model for gas pipelines does not facilitate the development of such gas infrastructure, an alternative is to deliver the electricity directly into the region via infrastructure, (i.e. electricity transmission) that can be developed under a more flexible regulatory model.

The development of electricity transmission within New England has already provided significant benefits, by effectively eliminating congestion within the region’s electricity system. Similarly enhanced interregional transmission interconnections would provide access to generation capacity in neighboring regions. Also, given that electricity transmission is fuel-agnostic, such enhancements would potentially also be able to address wider policy goals, (e.g. fuel diversity, renewable requirements, etc.)

Such an electricity transmission development may not be required, or justifiable, against existing criteria of reliability or economic benefit. However, in its recent Order 1000 the Federal Energy Regulatory Commission accepted that Public Policy, including state legislation, is a legitimate driver of electricity transmission planning. This raises the possibility that if the New England states decided to enact appropriate legislation the necessary regional transmission could be planned, developed and funded through regional mechanisms that are already being developed.

Further, Order 1000 also provides for interregional transmission planning and thus a framework for working with our neighboring regions on such an initiative.

**Regional counterparties for firm pipeline capacity**

The position of the natural gas pipeline owners and operators is that while they are ready to make the necessary investments to enhance the ability of their assets to transport additional gas into New England, such investments need to be underwritten by long-term, (e.g. 10-15 years) capacity contracts. It is the inability of some gas-fired generators to take on the risks associated with such long term contractual commitments, when they have limited certainty that they will require such transport capacity, which is inhibiting the construction of the additional pipeline capacity to serve the region.

From a regional perspective one way to address this conundrum may be for the region itself to establish counterparties to the necessary contractual arrangements. Such counterparties could be existing entities, (e.g. regional or state entities, the ISO or LDCs) or some special purpose vehicle established, by the region, for this specific need. The particular contractual obligations taken on by a counterparty could be determined based its nature, (e.g. a central regional counterparty could take on full regional responsibility while an LDC may only act on behalf of generators who are already (or become) Customers on their distribution system.

Such counterparties would enter into the necessary long-term capacity contracts with pipelines to underwrite necessary pipeline investment on behalf of the region. Subsequently releasing such
capacity to generators, or others, who require such capacity in the short-term. Any differential between costs incurred under the long-term contractual arrangements and the revenues arising from short-term releases being credited-to or recovered-from regional electricity Customers.

In any such scenario, certainty of cost recovery would be a critical element to counterparty participation together with an appropriate risk / reward balance. Given the likely scale and term of the contractual obligations involved such certainty might require both regulatory and legislative action in any state that decided to participate.

**Natural gas producers as counterparties for firm pipeline capacity**

Similarly to the previous option this option envisages a third party, in this case the gas producers themselves, entering into the long-term capacity contracts identified by the pipeline owners as being a necessary pre-requisite to underwrite the investment necessary for the expansion of capacity.

In this case such capacity contracts would not be funded directly the region, although regional Customers would still ultimately bear the costs. Rather the contracts would be entered into as a commercial proposition by the producers. From their perspective they would be taking on the cost and risk of the long-term gas transport contracts (if they are unable to sell their gas) but are gaining access to potential Customers that would otherwise be inaccessible. Producers would be able to offer a product that included both gas supply and transport.

Assuming that producers would consider entering into such arrangements, a particular issue in the value of such an approach to the region may be that any producer decision to underwrite any additional amount of pipeline infrastructure into the region would be based on commercial criteria rather than regional gas adequacy considerations.

**Regional tariff based funding of pipeline construction**

The regulatory model applied to the funding of gas transmission is significantly different to that applied to electricity transmission. The former is underwritten by the asset investor entering into contractual arrangements with the user of the facility thus funding the investment and providing an allowed return, whereas investment and returns on electricity transmission are funded, in New England at least, through a tariff based mechanism supported by the electricity Customers across the region.

A more radical alternative to facilitate the construction of additional pipeline infrastructure to serve New England would be the adoption of a model closer to that of electricity transmission. Pipeline owners, or others, would fund and construct necessary additional pipeline capacity into the region and would in return receive associated operating costs and a FERC approved ROE on their investment, funded through a regional tariff supported by regional electricity load. The additional infrastructure developed under such a model would make additional supplies of gas available to the region’s generators.

Adoption of such an approach would represent a significant departure from the current regulatory paradigm for the development of natural gas pipelines and give rise to a number of issues. For example, how would the need for a specific pipeline to be developed under this alternate model be determined and confirmed, given that there is no independent planning entity for gas transmission. Similarly where would the responsibilities for the development, and administration, of the necessary tariff mechanisms lie?

While the challenges associated with the development of such an alternate regulatory model are not inconsiderable. Likely giving rise to comparability and level playing-field issues between assets.
developed via the different models, together with questions of who experiences the benefits of such assets, (e.g. is it exclusively electricity Customers?). It is worth noting that in the context of electricity transmission such a model has been extremely successful in New England to the benefit of both the markets and Customers alike. There may well be lessons from that electricity experience that could be beneficial in considering the region’s gas transmission issues.

7. **Conclusions**

There is no single response that will be able to fully address all of the challenges arising from the region’s growing dependency on natural gas-fired generation.

The short and medium-term responses currently being developed, while valuable, do not necessarily address the underlying issue of the structural inadequacy of the natural gas delivery systems into the region.

The overall strategy and policies adopted by the region should seek to take full advantage of all the short, medium and long-term responses available to New England to mitigate this risk by;

a. Optimizing the deployment of existing gas supplies available to the region, (e.g. by adjustments to market timing),

b. Enhancing the resilience of the region’s gas and electricity systems and markets during periods when they are stressed, (e.g. through better communication, information sharing between ISO New England, generators and pipeline operators),

c. Seeking to deploy alternative, or substitute, fuels to mitigate limitations on the availability of pipeline delivered natural gas, (e.g. by seeking to expand dual fuel capabilities and by the local storage and delivery on natural gas),

d. Enhancing the ability to access electricity supplies from neighboring regions through new or expanded electricity transmission interconnections, and

e. Seeking to expand the capabilities for the delivery of natural gas into New England.
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