Comments of John Bilda, General Manager, Norwich Public Utilities, Norwich Connecticut
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Thank you for the opportunity to offer comments from the public power sector for the Quadrennial Energy Review (QER).

The primary focus of the public power business model is to deliver a stable, reliable and reasonably priced supply of electricity to residents in our service territories over the long term, as well as meeting environmental and other public policy preferences of our communities. We hope that this perspective is consistent with the perspective that the QER Task Force is concerned with. What is needed now is a careful assessment of whether the physical infrastructure in place today, along with observable trends, will be sufficient to meet reliability objectives at an affordable cost and also consistent with the public policy goals established by our resident stakeholders. Our conclusion is that the path the region is currently moving down will not achieve the right balance between these reliability, consumer cost and public policy objectives.

The New England Governors have concluded that: ***"Securing the future of the New England economy and environment requires strategic investments in our region's energy resources and infrastructure."*** Specifically, The Governors' plan calls for ***"development of transmission infrastructure that would enable delivery of at least 1200 MW and as much as 3600 MW of clean energy into the New England electric system from no and/or low carbon emissions resources"*** as well as ***"construction of new, or expansion of existing pipelines…in the amount of firm pipeline capacity into New England of 1000 mmcf/day above 2013 levels or, 600 mmcf/day beyond what has already been announced for the AIM and CT expansion projects…"***

Public power supports the proposals for increased natural gas capacity, as we believe it represents the most promising initiative to address the region's natural gas pipeline infrastructure deficit. While there are many details to be worked out, the existing business model for financing, building and operating gas pipelines must change to accommodate the nation's paradigm shift to greater reliance on natural gas for both electric generation and home heating purposes. This shift was evident this past winter when New England's natural gas issues poured out of the region into PJM, New York, California and other regions. It also was identified clearly in multiple comments at the FERC's April 1 Technical Conference on winter 2013-14 operations, where several participants spoke of a fuel shift of historic proportions within the nation's power markets. ISO New England and the region's natural gas pipeline companies have remained focused on the idea that the only solution involves generators signing firm gas contracts, a construct that makes little sense, given the highly variable fuel supply requirements of individual electric generators. These entities refuse to recognize the need for a change in the planning process in order to adequately address the region's overall energy infrastructure needs.

With respect to new electric transmission infrastructures, public power believes that these proposals are being addressed within the existing ISO-NE transmission planning process, where issues associated with the cost allocation of public policy transmission projects have been vetted in the stakeholder process and are currently under review at the FERC in the ISO's Order 1000 compliance filing. We do have some suggestions regarding the construct of the power contracts associated with public policy transmission projects.

In general, public power agrees that substantially increasing the ability to deliver natural gas into New England holds the promise of resolving the operational and reliability problems seen over the last two years (and according to ISO-NE may only get worse in the future with unit retirements), while at the same time reducing energy market price volatility and cost to consumers. Also, adding resources whose bid prices are not tied to the price of oil or natural gas would help to further mitigate exposure to extreme price swings during periods when gas pipeline capacity is constrained. With that said, more information and important decisions regarding feasibility, implementation, property rights, financial and cost-effectiveness, cost allocation and assignment of capacity must be defined and fully evaluated. If implemented properly, this approach holds the promise of 1) providing physical infrastructure resources to meet the region's reliability needs, 2) helping to address the economic disruption caused by high and volatile market prices, and 3) helping to foster fuel diversity and environmental policy concerns in a manner consistent with state and community environmental policy and renewable development goals.

In addition, to the extent that fixed costs are allocated to publicly owned entities, we think it is imperative that we have opportunities for ownership in projects and are able to use our own sources of capital to fund at least our share of these costs. Given our ability to access capital markets at tax-exempt interest rates and the fact that in general we are not subject to state and federal income tax obligations, this approach will benefit both the publicly-owned entities and the other electric consumers in the region by reducing the overall cost and risks associated with such projects.

The current centralized market structure is based on the premise that short term hourly price signals will be sufficient to attract new investment and retain the resources needed to maintain reliability. Even the current centrally procured capacity market structure being administered by ISO-NE is limited to obtaining one year commitments from generation, demand response and import resources for a period 3+ years into the future. This mechanism is designed to procure the entire resource adequacy requirement for the New England region at a uniform price (with the possibility of limited initial five year price "lock-in" for selected new resources).

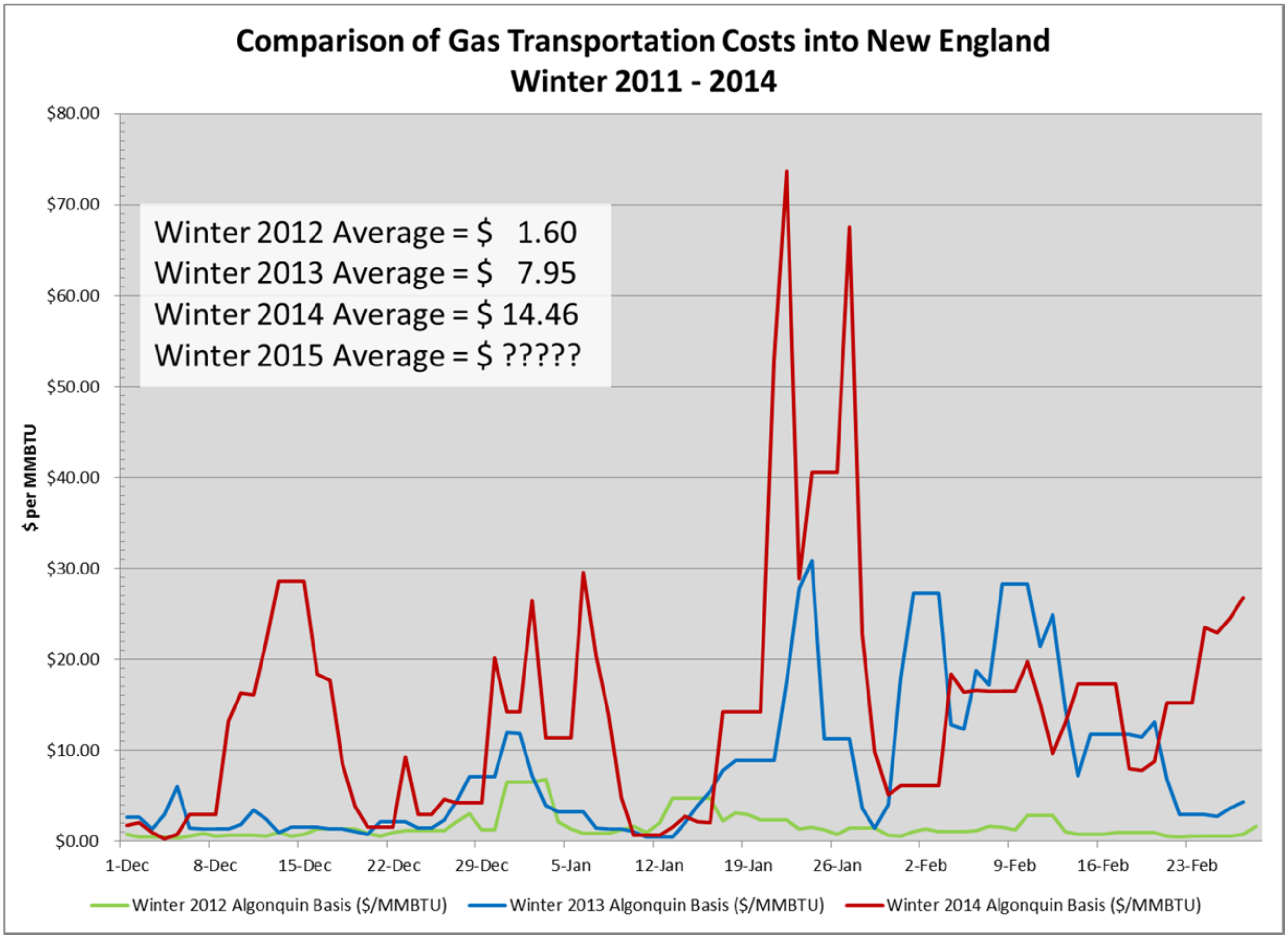
Many in our sector have come to believe that the very near term nature of the focus on system operations, settlement administration and the market biases routinely exhibited by ISO-NE and some other stakeholders has inevitably led us to the situation we currently face. These problems with the wholesale market design have contributed to and exacerbated the impact of infrastructure constraints on electric consumers. In addressing the gas supply problems, the first step should be a much larger discussion about the implications and potential benefits in balancing reliability, consumer cost and public policy objectives in long-term resource procurement. Specifically, there may well be value in separating the longer term resource procurement process from the near term system operations, as well as market rule and tariff administration functions currently being performed by ISO-NE.

Appendix - Natural Gas Infrastructure Impacts on Wholesale Electric Costs

New England is particularly vulnerable because of its reliance on natural gas for both home heating and power generation. In addition, operating coal and nuclear plants are planning on shutting down. Some renewable resources are coming online, but they do not provide the kind of direct control needed to ensure the lights stay on **and** that homes stay warm in severe weather conditions like those we've experienced in the past few years.

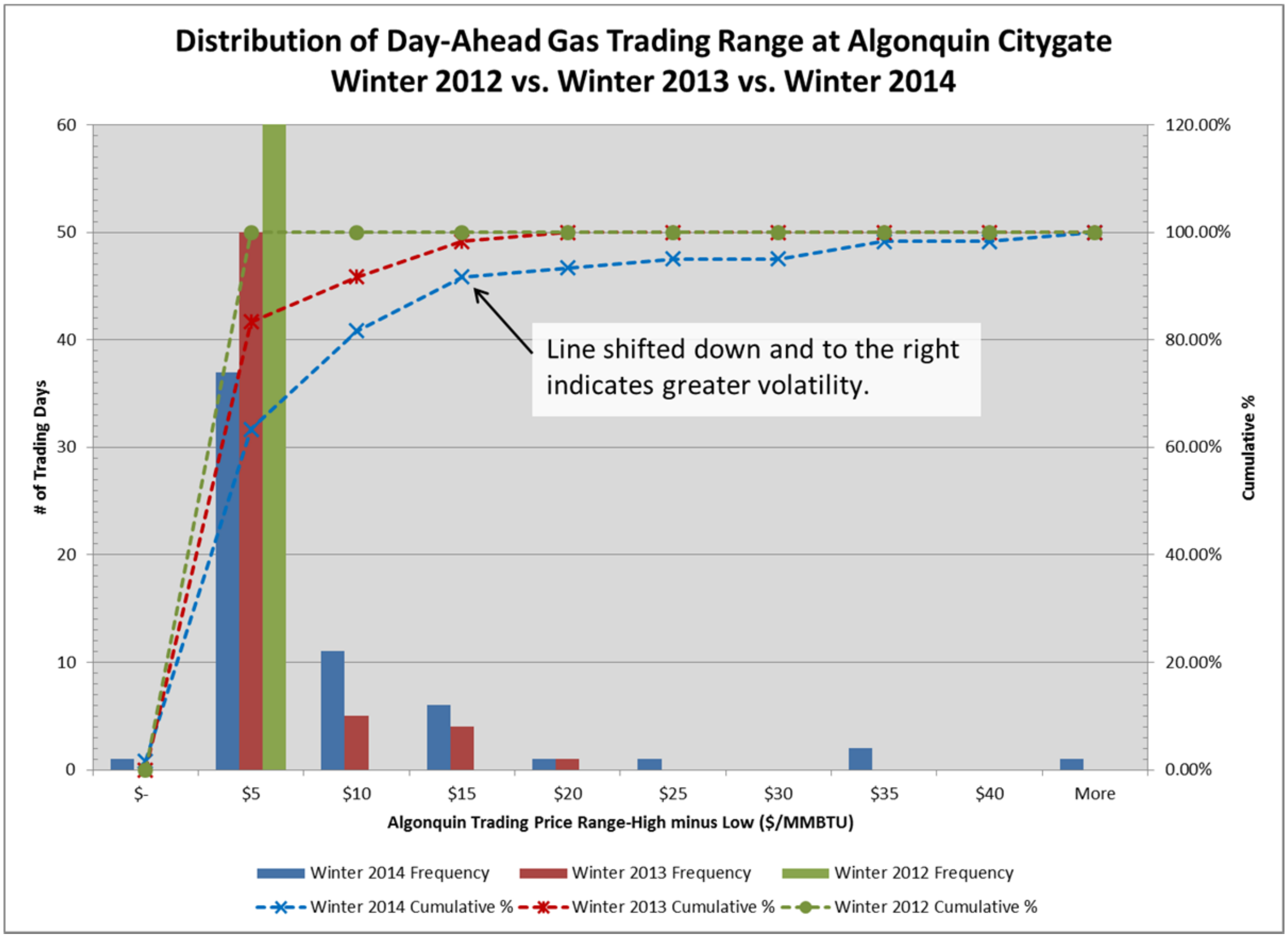
Over the last three winters, we have seen a steady increase in the cost of natural gas delivered into New England as well as a tremendous increase in both the day-to-day volatility and in the intra-day volatility. For the most part, this trend appears to be driven by the cost of gas transportation into the region. Figure 1 below compares the difference between the price at the Algonquin Citygate and Henry Hub for the period from December 1 through February 28 for the last three winters (winter 2011-2012, winter 2012-2013 and winter 2013-2014 periods), respectively. Gas transportation costs during the winter months increased from $ 1.60 per MMBTU in winter 2011-2012 to $7.95 per MMBTU in winter 2012-2013 and $ 14.46 per MMBTU in winter 2013-2014. Perhaps even more disconcerting, the difference between the maximum and minimum daily gas transportation cost within each period increased from $ 6.39 per MMBTU in winter 2011-2012 to $ 73.46 per MMBTU in winter 2013-2014.

Figure 1



Not only has this upsurge in natural gas price volatility affected day-to-day prices, it has also manifested itself in prices within the gas trading day. Based upon data reported by the Intercontinental Exchange (ICE) trading platform, on the day-ahead market trading days between December 1, 2011 and February 28, 2012, the average daily trading range (equal to the difference between the reported high price and the reported low price for the day) was $ 0.54 per MMBTU, with a maximum daily trading range of $ 2.60 per MMBTU. For winter 2012-2013, the average daily trading range was $ 2.95 per MMBTU with a maximum daily value of $ 19.00 per MMBTU. For winter 2013-2014, the average daily trading range was $ 6.86 per MMBTU with a maximum daily range of $60.00 per MMBTU. During the most recent winter, the daily trading range exceeded $5 per MMBTU on over 36% of the trading days. In 2011-2012 there were no days where the daily trading range exceeded $5 per MMBTU. This significantly increases risks to resource owners needing to submit day-ahead resource bids in time to meet the ISO bidding requirements. Figure 2 below plots the distribution of these daily trading ranges over the last three winter seasons and exhibiting this dramatic increase in intra-day price volatility.

Figure 2



In addition to having long term firm load obligations, many public power systems are also responsible for submitting offers for their generation resources. We believe that this puts us in a unique position to evaluate the challenges and implications that this price volatility has on entities on both sides of the market. Increasing the supply of natural gas into the New England region will certainly help mitigate some of the concerns evidenced by the experiences outlined above.

In addition, it is important to keep in mind that asset owner behavior is also influenced by market conditions. During winter 2013-2014, the cost of natural gas delivered at the Algonquin Citygate, expressed on a $ per MMBTU basis, was more expensive than the price of Ultra-Low Sulfur Diesel (ULSD) on 30 days during the period. During winter 2012-2013 the Algonquin Citygate gas price was more expensive than the ULSD price on 10 days (with 5 of these days occurring during and immediately after Winter Storm Nemo.) As a result of this apparent price inversion, based on information provided by the ISO COO, resource owners increased oil inventories by 1.79 million BBL during the month of February 2014. Note that at this point ISO has not provided similar data to update this analysis as of the end of March. This shows, however, that resource owners will respond to market signals out of self-interest when circumstances warrant. Despite seeing such dramatic changes in underlying market conditions, this past winter's oil procurement program "was instrumental in maintaining reliable system operations." (*ISO-NE Cold Weather Operations Report at April 1, 2014 FERC Technical Conference.)* Given planned unit retirements, we would support consideration of a similar program for next winter.