**THE STATE OF NEW HAMPSHIRE**
**PUBLIC UTILITIES COMMISSION**
**Docket No. IR 15-124**

# Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire

# DIRECT TESTIMONY AND EXHIBITS

**June 2, 2015**


**Richard Silkman**
**Mark Isaacson**



Anthony Buxton, Esq.
Peter W. Brown, Esq.
Counsel for the Coalition to Lower Energy Costs
c/o Preti Flaherty
57 North Main Street
Concord, NH 03302

Phone: (603) 410-1500
Email: abuxton@preti.com

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# 1 INTRODUCTION AND OVERVIEW OF TESTIMONY

**Q. Please state your names and business addresses.**

A. Richard Silkman and Mark Isaacson, Competitive Energy Services, LLC ("CES"), 148 Middle Street, Suite 500, Portland, ME 04101. We are each founding partners of CES. Dr. Silkman is the Chief Executive Officer and Mr. Isaacson is the Chairman of the Board of Directors.

**Q. Dr. Silkman, please describe your educational experience and prior work background.**

A. I received my B.A. in economics from Purdue University (with distinction) and my Ph.D. in economics from Yale University. I have served on the faculties of the State University of New York at Stony Brook (1978-1983) and the University of Southern Maine (1983-1986), where I also served as the Acting Director of the Public Policy and Management Program (1986). I was appointed by Governor McKernan to become the Director of the Maine State Planning Office (1987-1992), a cabinet level agency with broad policy and planning responsibilities, including economic development, energy, telecommunications, taxation, budgetary, land-use management and health care. In this capacity, I chaired a number of state level committees and multi-agency task forces and was on the Board of Directors of a variety of quasi-governmental agencies including the Maine Development Foundation, the Maine Science and Technology Commission and the Maine World Trade Association. I also chaired a number of Staff Advisory Committees of the National Governors' Association. I have been a member of the Board of Directors of the Council of Governors' Policy Advisors ("CGPA"), an affiliate of the National Governors Association (1988-1992), and its President (1990-1991).

I have served as a consultant on energy matters for a variety of clients across the country. My clients in the energy area have included a trade association of Maine's largest industrial consumers of energy, a Fortune 500 multi-state retail grocery company, a consortium of consumer organizations, and a variety of municipal governments and agencies. In representing these clients and others, I have negotiated special rate contracts with investor owned public utilities, have testified before the Maine, Massachusetts, New Hampshire, Vermont, California and Pennsylvania Public Utilities Commissions on matters of rate design, the justness and reasonableness of rates and electric utility industry restructuring, and have been actively involved in electric utility restructuring issues and legislation in a variety of states, including New Hampshire, where I was retained as a consultant by the New Hampshire Legislature to assist in the structuring and evaluation of a comprehensive restructuring settlement agreement with Public Service Company of New Hampshire.

Over the past decade, I have been active in the retail energy markets through Competitive Energy Services, LLC ("CES"). CES is one of the largest energy broker/consultants in the northeast, procuring energy for approximately 3,000 commercial and industrial accounts, with a total annual spend of more than $1 billion. (Additional information about CES can be found on our web site at www.competitive-energy.com.)

In addition to these activities, along with my partner, Mark Isaacson, I am a founding partner and principal in three energy ventures as noted below:

- Beaver Ridge Wind, LLC, the developer, owner and operator of a 4.5 MW wind generation project located in Freedom, Maine. This project began commercial operations on November 1, 2008. It was the second commercial grade wind generation project developed in Maine and remains the only such project in the CMP service territory. Total project costs were in excess of $12 million.

- Kennebec Valley Gas Company, LLC ("KVGC"), a company formed to develop an intra-state natural gas pipeline and to provide natural gas delivery service to customers in central Maine. KVGC received conditional authorization from the Maine Public Utilities Commission to operate as a pipeline and distribution utility within its proposed service territory and has since sold its interest in this project to Summit Natural Gas, which is proceeding with its full-scale development and began flowing gas in early 2014.
- GridSolar, LLC ("GridSolar"), a company formed to develop, manage and operate non-transmission alternatives top meet reliability requirements on electric grids and to promote the implementation of smart grid network capabilities, customer technologies and pricing structures.

**Q. Mr. Isaacson, please describe your educational experience and prior work background.**

A. I received my B.A. in history from Yale University in 1976. I received an M.B.A. with concentrations in marketing and production from the University of Chicago in 1978. From 1978 to 1980 I was employed by Bayside Enterprises, a Maine food company in the business of processing poultry, eggs, lobsters, blueberries, and squash.

In 1980, I was hired by the newly formed Miller Hydro Group to lead the development of the Worumbo Hydroelectric Project and to manage the ongoing operation of the Edwards Hydroelectric Project. Between 1980 and 1988, I managed all aspects of the licensing, financing, and construction of the 19.4 MW project in Lisbon Falls, ME. After the historic

Edwards fire in 1989, I managed the reconstruction of the Edwards Project in addition to the ongoing and highly contentious dispute over the relicensing of the Edwards Dam. In 1998, I negotiated the historic settlement of the Edwards dispute that resulted in the owners making a gift of the project to the people of Maine.

In 2000, I partnered with a former Edwards adversary, Richard Silkman, to form Competitive Energy Services, LLC (CES). CES is in the business of assisting end users of energy products in dealing with competitive markets. In the early years of the company I was active in all phases of its operation and had the primary responsibility for the management of CETX, CES' Texas affiliate. In recent years I have limited myself to overall responsibility for IT and to the development the company's more complex mathematical models.

In 2006, I partnered with Richard Silkman and Andrew Price to form Beaver Ridge Wind, LLC for the purpose of developing a 4.5 MW wind project in Freedom, ME. This project began commercial operations on November 1, 2008. It was the second commercial grade wind generation project developed in Maine and the first in the CMP service territory. Total project costs were in excess of $12 million.

In early 2009, I partnered with Richard Silkman to form Grid Solar, LLC. GridSolar is a company established in for purposes of providing a Non-Transmission Alternative solution related to matters of electric grid reliability in Maine. GridSolar was an active participant in the Maine Power Reliability Project proceedings at this Commission, which led to the historic settlement of that case and to GridSolar's role as the Smart Grid Energy Services Operator for the Boothbay Pilot Project. While I have been active in all aspects of GridSolar's work, my primary concentration has been on developing the mathematical models for grid requirements and NTA solutions.

In 2010 I partnered with Richard Silkman to form Kennebec Valley Gas Company for the purpose of bringing pipeline gas service to eleven communities in Maine's Kennebec Valley. KVGC received conditional authorization from the Maine Public Utilities Commission to operate as a pipeline and distribution utility within its proposed service territory and has since sold its interest in this project to Summit Natural Gas, which is proceeding with its full-scale development. In addition to my primary responsibility for system design and route selection, I participated in dozens, perhaps hundreds, of public meetings for the purpose of promoting and explaining this project to the public in each of the eleven communities.

**Q. Is this testimony being offered jointly?**

A. Yes. We are jointly offering this testimony on behalf of the Coalition for Lower Energy Costs ("CLEC"), which is sponsoring this testimony.

**Q. What is the purpose of your Testimony?**

A. The purpose of our Direct Testimony is to provide the Commission with a summary of the analyses we have performed to estimate the economic value to New Hampshire's electric ratepayers of incremental pipeline capacity into New England and to provide the Commission a framework for determining whether or not it is in New Hampshire's ratepayers best interests to allow New Hampshire's electric distribution companies ("EDCs") to enter into one or more long-term contracts for capacity on one or more new natural gas pipeline being proposed.

**Q. Please summarize your Direct Testimony.**

A. Our Direct Testimony includes the following points:

1. The New England region is characterized by severe natural gas pipeline constraints that prohibit inexpensive natural gas in the Marcellus region of western Pennsylvania from reaching New England to meet our region's natural gas demands during the winter months.
2. The effect of this constraint is to put upward pressure on the price of natural gas resulting in extremely high price premiums that cost New England electricity ratepayers $3 billion a year and New Hampshire ratepayers approximately $270 million a year.[1]
3. These price premiums are having a devastating impact on New Hampshire businesses, especially those businesses that are energy intensive and compete in global markets where production costs are a critical factor in determining their competitiveness, and on low-income households and small businesses.
4. The recent closure of Vermont Yankee nuclear power plant, the announcement of the Brayton Point coal generating units and the lack of natural gas production off the coast of Atlantic Canada will exacerbate the natural gas pipeline constraints resulting in even higher price impacts in the future if the pipeline constraints are not relieved.
5. The significant economic benefits of new pipeline capacity occur as a result of current energy market conditions not as a result of long-term forecasts. While there are risks that market conditions may change in the medium to longer-term, we believe it highly likely that investments in incremental pipeline capacity will pay for themselves many times over before the longer-term risks occur, if they ever occur.

[1] We have assumed that New Hampshire's electricity usage represents 8.94% of total electricity usage in NEPOOL on a dollar weighted basis. ISO-NE reported Net Energy for Load for New Hampshire as 12,370 GWhs in 2014 out of a total 138,390 GWhs in the NEPOOL Control Area. We have rounded this to 9%, since ISO-NE is forecasting slightly higher growth in New Hampshire relative to New England. 2014 Regional System Plan, ISO-NE, November 6, 2014, Table 3-1 at page 38.

6. New Hampshire should act on its own in deciding whether or not it should allow its EDCs to enter into long-term pipeline capacity contracts. It should not condition any approval on the actions of the other New England states.

## 2 REVIEW OF PRIOR STUDIES COMPLETED BY CES

**Q. Have you performed any analyses of pipeline capacity into New England and its impact on electricity rates?**

**A.** Yes, we have. In 2012 we began to become concerned about the adequacy of natural gas supply in New England during the winter when heating demands for the fuel are highest and the impact shortages would have on natural gas pricing in the region and about therefore electricity pricing. We expressed our concerns to the Industrial Energy Consumer Group ("IECG")[2] on a number of occasions, and in early 2013 the IECG retained CES to undertake a study of natural gas supply and prices in New England. During this same period, ISO-NE was beginning to focus on natural gas supply conditions and whether pipeline capacity was sufficient to meet the fuel requirements of the region's generators and therefore whether limited pipeline capacity was a threat to the reliability of the region's electric grid.

CES completed the initial phases of its study in March 2013 and issued an internal report for the IECG on April 5, 2013.[3] (We have provided a copy of this study as CES Exhibit-1.) This study showed that New England must rely on LNG or oil to meet heavy natural gas use and electric generation requirements during cold winter days. The study showed that the

[2] The Industrial Energy Consumer Group is a trade association of large industrial users of electricity in Maine, and has been an active participant in Maine, regional and national energy policy for more than 30 years. IECG is a participant in the Coalition to Lower Energy Costs.

[3] Competitive Energy Services, LLC, "Assessing Natural Gas Supply for New England for the Winter of 2013-14 and its Impact on Natural Gas prices and Electricity Prices," April 5, 2013.

fuel at the margin and therefore the fuel setting prices in the region may be unconstrained pipeline natural gas, imported LNG, propane or oil, depending on the combined heating, industrial process requirements and electricity loads in the region.[4] Historically, when the per btu prices of the four fuels – pipeline gas, LNG, propane and oil - were relatively similar, whether one or another fuel was at the margin made little difference in terms of prices consumers paid for heat or electricity. The shale gas revolution in the United States and the worldwide increase in the demand for natural gas that began in 2009 have resulted in a widening gap between the price of unconstrained pipeline gas, on the one hand, and LNG and oil, on the other.

This situation is creating discontinuities in the btu price for heating fuels and electricity in the market depending on which fuel is at the margin and therefore setting prices. Specifically, for low natural gas demands in the region when total demand is less than the throughput capacity of the region's natural gas pipelines, pipeline natural gas is the marginal fuel and prices have been and continue to be relatively close to and occasionally below those at Henry Hub.[5] However, once natural gas demands exceed the total capacity of natural gas pipelines in the region, LNG becomes the marginal fuel driving natural gas spot prices up to and beyond the world price of LNG. Further, at the highest demand levels, when there is inadequate LNG capacity, oil becomes the marginal fuel, driving prices even higher. This relationship is shown below in what is Figure 9 in the April 2013 report and here referred to as Figure 1.

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[4] There are a number of hours when pumped storage is operating at the margin. However, pumped storage is in effect natural gas, since natural gas is the fuel that provides the electricity used during the off-peak hours to pump water to where it is released to generate electricity during on-peak hours.

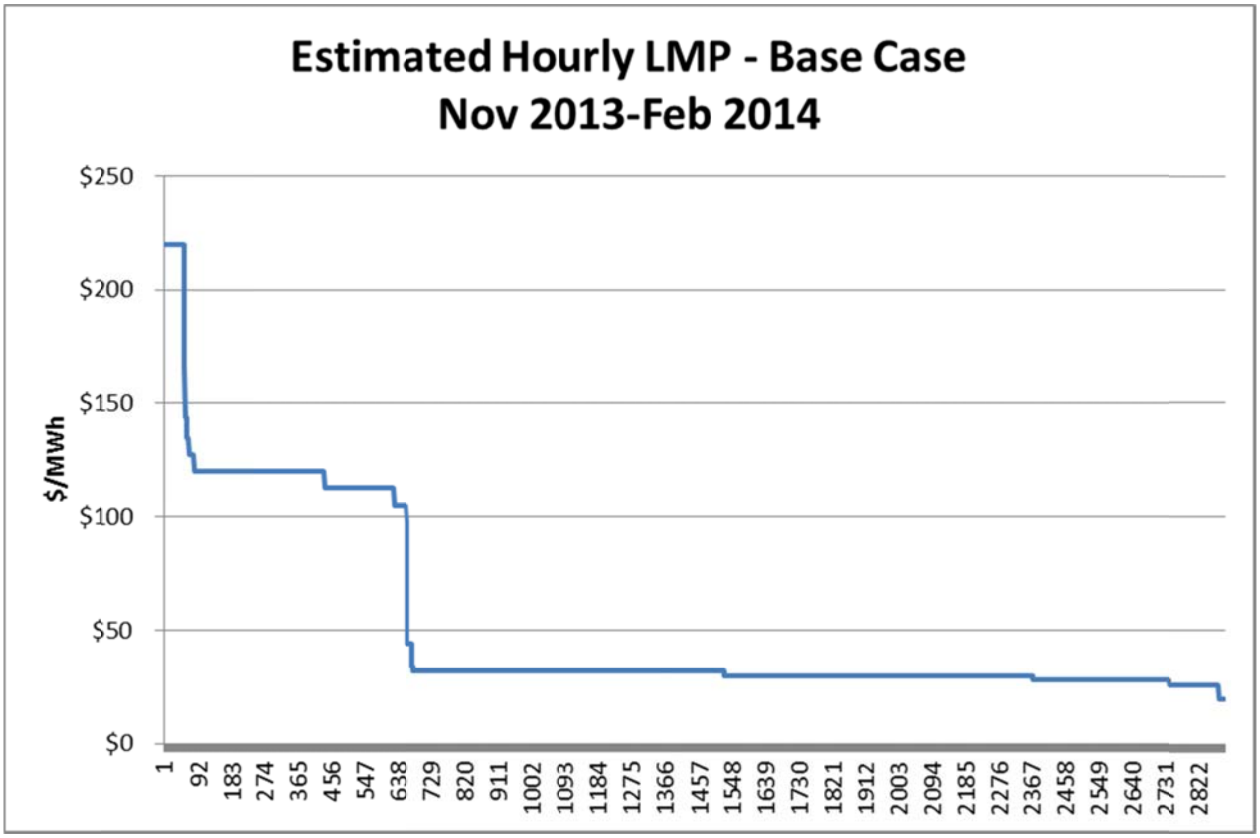
[5] This is reflected in a very low and at time negative basis price at Algonquin.

This pricing regime resulted in forward price estimates for electricity during the 2013-14 winter period of:

- $41.35 for November 2013
- $41.92 for December 2013
- $81.64 for January 2014
- $68.36 for February 2014

These price estimates were based on demand and supply conditions during 2012, which was a relatively mild winter and where LNG supplies had not yet fully adjusted to the new market conditions in New England and the world. As a result, even these high prices turned out to be well below actual prices experienced.

**Figure 1 Hourly LMP – Base Case**




**Q. Did you update you April 2013 study?**

**A.** Yes. CES updated and extended its April 2013 study and issued a report to the IECG on February 7, 2014.[6] We are providing a copy of this study as CES Exhibit-2.

**Q. Please describe the updates and extensions incorporated into the February 7, 2014 study?**

**A.** We will not repeat what is contained in the study, but rather highlight the changes in bullet form below:

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[6] Competitive Energy Services, "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices," February 7, 2014.

- Included a review and assessment of four other studies that had looked at the natural gas supply situation in New England – Concentric Energy Advisors, Inc., Black & Veatch, ICF International and Sussex Economic Advisors, LLC – at that time.
- Reduced design day volumes of natural gas for non-electrical generation from 4.4 bcf/day to 4.2 bcf/day
- Based our electricity sector model on Calendar Year 2013 conditions in New England
- Removed Vermont Yankee from the generating fleet in New England to reflect the decision to shut down the plant in 2014
- Increased the LNG price from $15/mmbtu to $18/mmbtu to reflect increases in world LNG prices
- Reduced the flow north-to-south on the Maritimes & Northeast Pipeline from 0.5 bcf/day to 0.35 bcf/day to reflect lower outputs from Sable Island, Deep Panuke and the McCully Fields and increased natural gas usage in the Maritime Provinces.
- Examined three different natural gas pipeline expansion options, which we referred to as (i) LDC Contracted option that includes a TGP expansion of 0.070 bcf/day in Connecticut plus the AIM expansion of 0.340 bcf/day proposed by Spectra Energy, (ii) Governors' Letter that included the LDC Contracted option plus an additional 0.600 bcf/day in unspecified pipeline expansion and (iii) an option for 2 bcf/day of total incremental capacity from unspecified pipeline expansions.

**Q. Please describe the results of your February 2014 study.**

**A.** We have reproduced "Figure 10: Summary of Scenario Model Results" from the February 2014 study and shown here as Figure 2. The top section of this figure shows the number of hours predicted by the model over the year that LNG, Propane and Oil are used to generate electricity sold into the wholesale market in NEPOOL under the four different pipeline scenarios with increasing amounts of capacity ranging from the Base Case with just over 3 ??? bcf/day to an incremental 2 bcf/day scenario providing a total of 5 bcf/day of pipeline capacity into New England. This table shows that as pipeline capacity increases, the number of hours during the year in which New England must rely on LNG, Propane or Oil to meet total natural gas heating and process loads plus electric generating requirements falls.

The second set of figures shows the number of hours each fuel is on the margin and therefore setting electricity prices in New England. Importantly, as pipeline capacity increases, the number of hours when each alternative fuel is at the margin declines. This decline is manifested in lower electricity prices, as shown in the third set of figures. The load weighted average annual energy price was estimated to fall from $53.43 per MWh under the Base Case to $35.22 per MWh under the incremental 2 bcf/day case. The differential in total cost across all New England ratepayers is just over $2.3 billion a year. This represents the annual value to New England electric ratepayers from an increase in natural gas pipeline capacity into New England of 2 bcf/day, assuming Brayton Point is not shut down.[7]

[7] In this testimony and in our previous studies, we restricted our focus to only the financial impacts to electric ratepayers in the NEPOOL Control Area. We have not considered the impacts to electric ratepayers in the former Maine Public Service territory or in New Brunswick and Nova Scotia. Since electric prices in New Brunswick (Keswick Node) are influenced to a great degree by prices in New England, actions that lower New England electric energy prices will benefit these consumers as well.

We have also not considered the financial benefits to natural gas consumers. This is a more difficult task because many natural gas LDCs have purchased upstream pipeline capacity for some portion of their customer loads that is moderating the steep price increases they would otherwise face. Of course, new LDCs such as Bangor Gas and Summit in Maine (and the LDCs in Atlantic Canada) have generally not acquired upstream pipeline capacity at historic rates, since there is none available. Accordingly, they and their customers (including those that transport gas) are exposed to the high winter basis and would benefit by any increases in natural gas pipeline capacity into New England.

**Figure 2 Economic Value of Incremental Pipeline Capacity**

**Summary of Scenario Analysis**

| Scenario | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,086 | 1109 | 156 | 129 |
| LDC Contracted | 3,496 | 596 | 74 | 63 |
| Governors' Letter | 4,096 | 220 | 30 | 24 |
| 2 bcf/d Option | 5,086 | 46 | 4 | 4 |

| Scenario | Hours with Fuel Type on the Margin LNG | Propane | Oil |
|---|---|---|---|
| Base Case | 953 | 27 | 129 |
| LDC Contracted | 522 | 11 | 63 |
| Governors' Letter | 190 | 6 | 24 |
| 2 bcf/d Option | 42 | 0 | 4 |

| Scenario | Annual Energy Costs ($) | Savings vs. Base Case ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|
| Base Case | $6,799,918,543 | | $53.43 |
| LDC Contracted | $5,779,346,212 | $1,020,572,331 | $45.41 |
| Governors' Letter | $4,937,899,864 | $1,862,018,679 | $38.80 |
| 2 bcf/d Option | $4,481,671,060 | $2,318,247,482 | $35.22 |

**Q. What happens to basis pricing under the different pipeline capacity scenarios?**

**A.** Average estimated monthly natural gas prices and basis differentials are shown in Figure 3 (which is reproduced from Figure 11 in the February 2014 study).

**Figure 3 Monthly Basis Differentials – Pipeline Development Scenarios**

**Estimated Average Monthly Price of Natural Gas**

| | | Scenarios | | |
|---|---|---|---|---|
| | Base Case ($/mmbtu) | LDC Contracted ($/mmbtu) | Governors' Letter ($/mmbtu) | 2 bcf/d Option ($/mmbtu) |
| Jan | $10.91 | $9.35 | $7.58 | $5.74 |
| Feb | $9.25 | $6.88 | $5.27 | $5.00 |
| Mar | $5.70 | $5.16 | $5.02 | $5.00 |
| Apr | $5.07 | $5.00 | $5.00 | $5.00 |
| May | $5.10 | $5.00 | $5.00 | $5.00 |
| Jun | $5.47 | $5.23 | $5.00 | $5.00 |
| Jul | $7.64 | $6.24 | $5.14 | $5.00 |
| Aug | $5.68 | $5.02 | $5.00 | $5.00 |
| Sep | $5.34 | $5.18 | $5.00 | $5.00 |
| Oct | $5.03 | $5.00 | $5.00 | $5.00 |
| Nov | $6.21 | $5.29 | $5.02 | $5.00 |
| Dec | $9.17 | $7.62 | $5.98 | $5.09 |
| Annual | $6.71 | $5.91 | $5.34 | $5.07 |

**Estimated Average Basis Differential**

| | | Scenarios | | |
|---|---|---|---|---|
| | Base Case ($/mmbtu) | LDC Contracted ($/mmbtu) | Governors' Letter ($/mmbtu) | 2 bcf/d Option ($/mmbtu) |
| Jan | $5.91 | $4.35 | $2.58 | $0.74 |
| Feb | $4.25 | $1.88 | $0.27 | $0.00 |
| Mar | $0.70 | $0.16 | $0.02 | $0.00 |
| Apr | $0.07 | $0.00 | $0.00 | $0.00 |
| May | $0.10 | $0.00 | $0.00 | $0.00 |
| Jun | $0.47 | $0.23 | $0.00 | $0.00 |
| Jul | $2.64 | $1.24 | $0.14 | $0.00 |
| Aug | $0.68 | $0.02 | $0.00 | $0.00 |
| Sep | $0.34 | $0.18 | $0.00 | $0.00 |
| Oct | $0.03 | $0.00 | $0.00 | $0.00 |
| Nov | $1.21 | $0.29 | $0.02 | $0.00 |
| Dec | $4.17 | $2.62 | $0.98 | $0.09 |
| Annual | $1.71 | $0.91 | $0.34 | $0.07 |

This figure shows that an incremental 2 bcf/day of natural gas pipeline capacity into New England is estimated to reduce the annual average basis differential in New England to very close to zero.[8]

[8] Our modeling at the time assumed that the unconstrained price of natural gas delivered into New England was $5.00 per mmbtu. Since performing this analysis, the prices of natural gas at Marcellus and NYMEX have fallen further. We modify this assumption is our subsequent analyses discussed later in this testimony.

# 3 MODEL REVISIONS AND UPDATES

**Q Have there been any important changes in New England since you completed your February 2014 study that impact the results of that study?**

A. Yes. One important change is the recent announcement by the owners of the Brayton Point Power Station that they will be shutting the plant in 2017.[9] New Jersey based Energy Capital Partners have notified ISO-NE that they will retire the four generating units at Brayton Point by June 1, 2017. Brayton Point has a capacity of just over 1,500 MW, approximately 1,100 MW of which are coal-fired. The shutdown of 1,100 MW of coal-fired generation will result in more reliance on natural gas-fired generation and put more stress on already constrained natural gas pipelines into the region. Our updated model takes these coal-fired units at Brayton Point out of the dispatch mix.

A second important change is more difficult to model. We noted in our February 2014 report that a fundamental shift occurred in 2013 with respect to the pricing of LNG in the New England market. As shown in Figure 4 (which reproduces Figure 12 from the February 2014 study and adds in year-to-date 2014 prices – through June 14th), Algonquin v. Tetco M3 basis price differentials in 2013 were very different from those experienced during the period 2007 through 2012. We believe that this differential represents a permanent shift in the market caused by the expiration of contracts for LNG based on historic prices and the unwillingness of LNG terminals to schedule LNG cargo deliveries without firm contracts for its resale. As a

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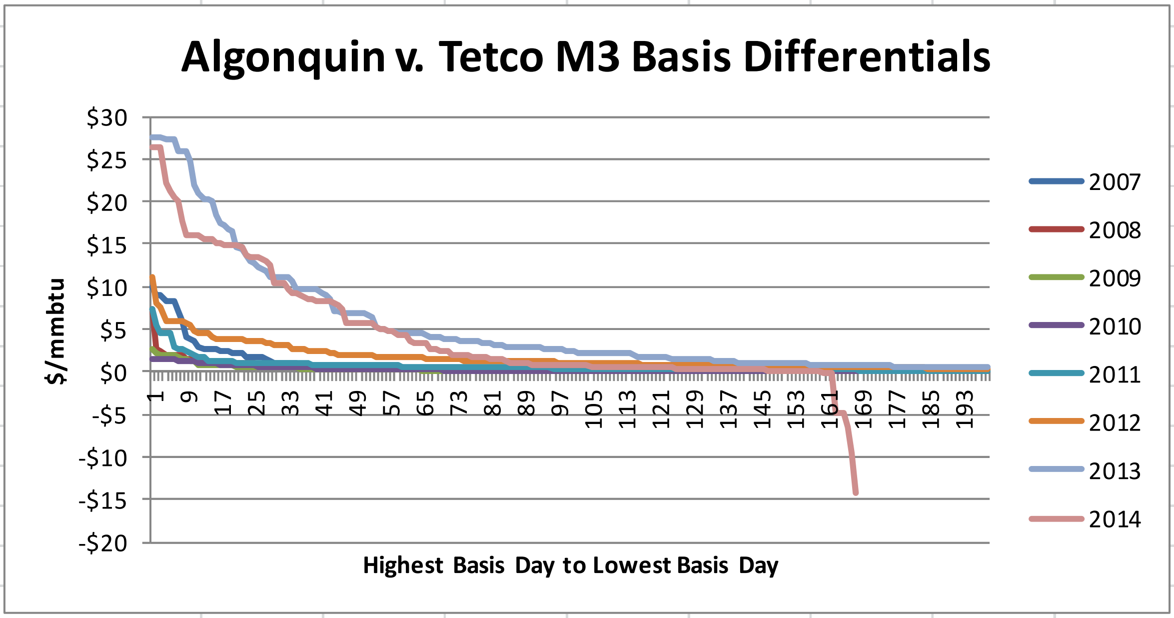
[9] http://www.providencejournal.com/breaking-news/content/20140129-after-rejecting-request-to-delay-shutdown-brayton-point-moves-to-close-coal-fired-plant-in-2017.ece

result, in 2013 we saw much higher LNG prices drive New England basis pricing higher. The graph shows that the experience in 2013 has continued into 2014.

**Figure 4** **Algonquin v Tetco M3 Basis Differentials – 2007 - 2014**




| Premium Level ($/mmbtu) | Number of Days During Year with Premium | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
| >$10 | 0 | 0 | 0 | 0 | 0 | 1 | 34 |
| $5 to $10 | 8 | 1 | 0 | 0 | 2 | 9 | 21 |
| $2 to $5 | 14 | 7 | 5 | 0 | 9 | 38 | 59 |
| $1 to $2 | 12 | 16 | 6 | 13 | 12 | 64 | 39 |
| $0 to $1 | 331 | 342 | 354 | 352 | 342 | 254 | 212 |
| Totals | 365 | 366 | 365 | 365 | 365 | 366 | 365 |

Notes: 2014 is from 1/1/2014 through 6/14/2014
2014 negative values occurred during cold snap that created constraints flowing west to east out of Marcellus

**Q Did you make any other modifications to your model?**

A. Yes. In our February 2014 report we looked at three different pipeline scenarios, as described earlier. In our updated study we have looked at pipeline capacity expansions in a less specific but more granular manner. Instead of identifying specific pipeline expansion scenarios, we have modeled generic expansions in increments of 0.20 bcf/day. We have done this to enable the Commission to match the incremental benefits of discrete pipeline capacity additions with the costs of those additions as revealed through a Request for Proposals process that we anticipate the Commission or the EDCs in New Hampshire will undertake if given the appropriate authorizations.

**Q. Did you adjust the time period of your analysis to include any days in 2014 or is the model still based on Calendar Year 2013 energy market and weather conditions?**

A. We did not adjust the time period; we have continued to model Calendar Year 2013. We gave some thought to adjusting the period to include the 2013-2014 winter, but decided not to for the following reason: The winter of 2014 was an historically colder than normal winter, which pushed natural gas and electricity usage to higher than normal levels. In contrast, the winter of 2013 was a fairly typical winter for the northeast and more indicative of weather conditions in this region of the country. Further, by 2013 most, if not all, of the legacy gas LDC LNG contracts had expired, so all of the LNG imported into the region from overseas was priced at world market prices.

**Q. ISO-NE implemented a Winter Reliability Program this past winter, but this program was not in effect during the January – March 2013 period of your model period. Are you concerned that this has impacted your analysis?**

A. No. As shown in Figure 4, the basis differential between Tetco-M3 and Algonquin in 2014 (year-to-date) has been very similar to the experience in 2013. This suggests that the

Winter Reliability Program had some impact on moderating this basis differential. This program, however, cost New England electric ratepayers approximately $75 million, which is not included in our analysis. Further, in our model we capped the prices for LNG and oil at $18 per mmbtu and $22 per mmbtu, respectively. This cap is the result that the Winter Reliability Program is intended to create, by ensuring that there is adequate oil inventory available in enough generating plants in the region to keep the lights on. The effect of this would be to cap the price of pipeline natural gas and LNG at the $22 level.

# 4 UPDATED MODEL RESULTS – STEP 1

**Q. Before discussing the estimated value of additional natural gas pipeline capacity into New England, please describe how the shutdown of the Brayton Point generating station impacts spot prices and fuel use in New England.**

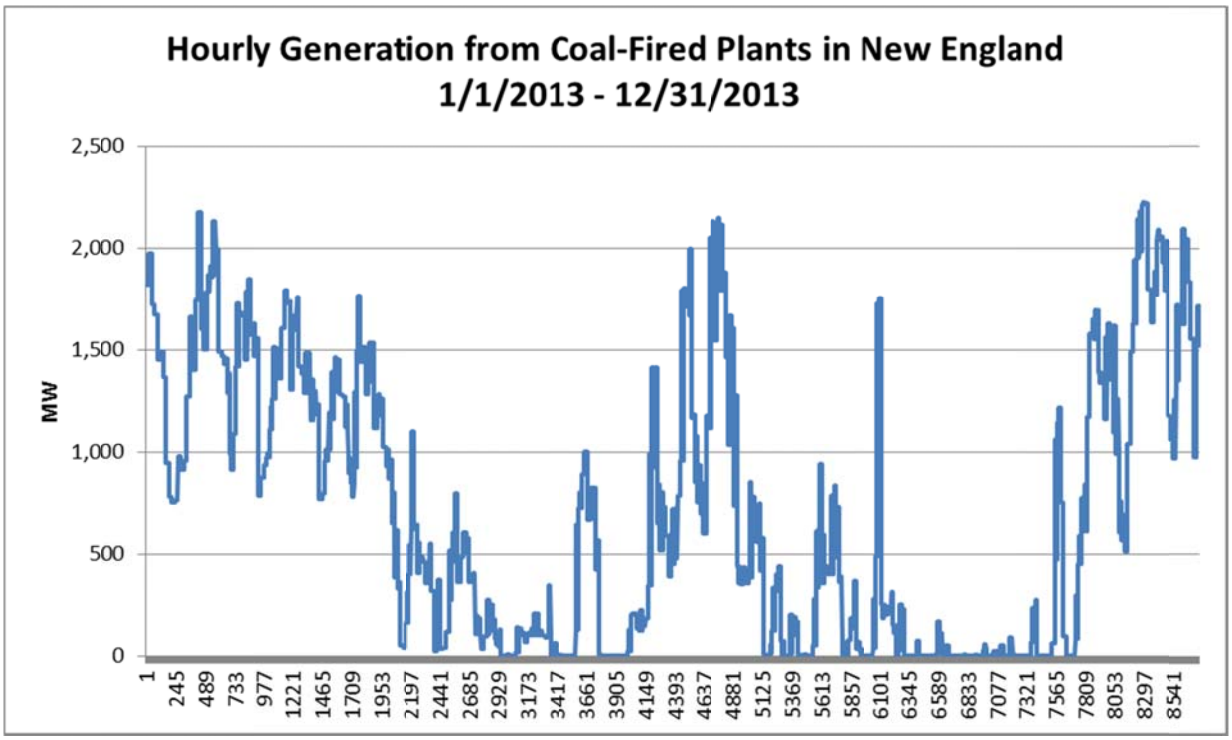
A. The Brayton Point generating plant consists of four generating units, three of which are coal-fired and have a combined winter capacity of approximately 1,100 MW. The fourth unit is a dual-fuel (natural gas/oil) unit with a winter capacity of approximately 400 MW. The plant is one of five coal-fired generating plants in New England that have a combined total winter capacity rating of 2,205 MW.[10]

Figure 5 shows the amount of coal-fired generation operating each hour in New England during 2013, as reported by ISO-NE. (Note – this includes Brayton Point.) This figure shows that coal units are not operating in a baseload manner, but in fact, are providing energy when load levels in the region are at their highest in the summer and when natural gas prices are high in the winter. ISO-NE does not provide enough detail to determine which of the coal units were

[10] ISO-NE, CELT Report, May 16, 2014. Available on-line at http://www.iso-ne.com/trans/celt/report/index.html.

operating during the hours shown in the figure. We have assumed for our modeling purposes that the first 1,100 MW of coal generation during any hour is from the Brayton Point plant and have replaced this generation with an equivalent amount of natural-gas fired generation in our dispatch model. Assuming that the replacement natural gas generation operates at a heat rate of 10,000 btu/kWh, this new generation will add an additional 0.26 bcf/day of demand for natural gas during the winter months.

**Figure 5 Hourly Generation from Coal-Fired Plants in New England –2013**




Replacing Brayton Point with natural gas-fired generation increases the demand for natural gas during those hours when Brayton Point would otherwise be generating electricity. This shifts the natural gas requirements curve upward, and in a more pronounced way when natural gas requirements are already high in the winter. In our modeling, the upward shift increases the number of hours when LNG is required to meet natural gas demands from 1,102 hours when Brayton Point is operating to 1,502 hours when Brayton Point is shutdown. If we assume that the average marginal heat rates of Brayton Point and the replacement natural gas-fired generation are both 10,000 btu/kWh during such hours and that total ISO-NE load is 20,000 MWs, we estimate the incremental cost to New England's electricity users, assuming an LNG price of $18/mmbtu and a coal price of $5/mmbtu, to be roughly $2.6 million an hour. When this is multiplied by the 393 incremental hours when LNG is required, the total cost to New England electricity consumers is a staggering $1.02 billion a year.

**Q. Please describe the results of your updated modeling.**

A. Except as noted in the prior section, the model is the same model used in our February 2014 report. The Base Case assumes that natural gas flows into New England on the Algonquin, Tennessee, Iroquois and PNGTS pipelines are at their respective capacities, while flows from the Sable Island, Deep Panuke and McCully Fields in Atlantic Canada on the Maritimes & Northeast Pipeline are set at 0.035 bcf/day. This level of flow is well below that pipeline's capacity and is constrained by the production of the natural gas fields. We assume further that LNG availability out of Canaport can increase flows on the Maritime & Northeast pipeline up to 0.860 bcf/day, that send out from the Distrigas facility in Everett can reach 0.70 bcf/day and that the LDCs can draw upon up to 1.40 bcf/day from their own LNG storage facilities located throughout the region. This total capacity is more than adequate to meet the region's natural gas design day requirements, assuming there is adequate LNG supply.

Figure 6 shows the model results for the Base Case compared to the Base Case modeled in the February 2014 report. The graph shows the shift in the natural gas requirements curve resulting from the shutdown of Brayton Point and lower flows on the M&N pipeline against pipeline capacity (the horizontal line). Under this new Base Case, with no additional pipeline capacity beyond what currently exists, New England electricity consumers can expect to spend approximately $7.95 billion a year at an average annual price of $62.44/MWh.

**Figure 6 Effect of Brayton Point Shutdown on Natural Gas Demands**

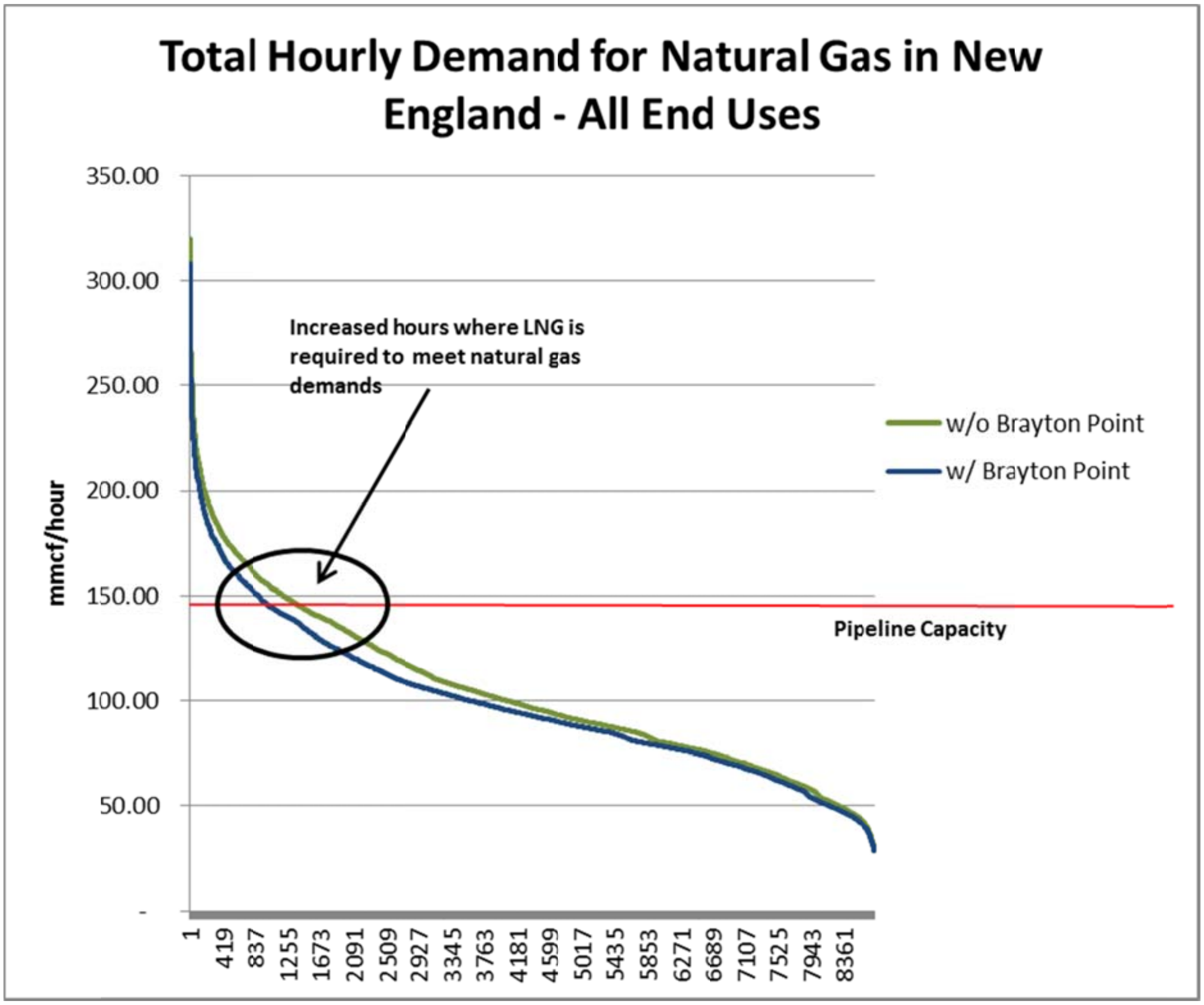



Figure 7 shows how the total and average costs of electricity fall with each incremental 0.20 bcf/day of natural gas pipeline capacity into New England. The effect of this incremental capacity results in a shift upward of the pipeline capacity line in the graph in Figure 6. With each incremental shift upward, the intersection of that horizontal line with the natural gas requirements curve shifts to the left resulting in fewer hours when LNG must be called upon and therefore increased savings to electricity consumers.

Figure 7 provides our then estimates of the declining marginal value of each incremental 0.20 bcf/day of incremental pipeline capacity. For example, the first 0.2 bcf/day of capacity results in $690 million in reduced electricity costs in the region; the second 0.2 bcf/day results in $590 million and so on. We have modeled up to an additional 2.4 bcf/day, the last 0.20 bcf/day of which would add very little value to the region – approximately $31 million a year. The cumulative impact of an additional 2 bcf/d is over $3 billion, with Brayton Point shut down.

**Figure 7 Summary – Economic Value**

**Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers**

| Pipeline Capacity | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,086 | 1502 | 233 | 183 |
| + 0.2 bcf/d Capacity | 3,286 | 1147 | 168 | 138 |
| + 0.4 bcf/d Capacity | 3,486 | 858 | 127 | 95 |
| + 0.6 bcf/d Capacity | 3,686 | 641 | 86 | 68 |
| + 0.8 bcf/d Capacity | 3,886 | 456 | 64 | 50 |
| + 1.0 bcf/d Capacity | 4,086 | 336 | 48 | 39 |
| + 1.2 bcf/d Capacity | 4,286 | 242 | 37 | 33 |
| + 1.4 bcf/d Capacity | 4,486 | 174 | 31 | 27 |
| + 1.6 bcf/d Capacity | 4,686 | 133 | 25 | 15 |
| + 1.8 bcf/d Capacity | 4,886 | 93 | 13 | 11 |
| + 2.0 bcf/d Capacity | 5,086 | 66 | 10 | 6 |
| + 2.2 bcf/d Capacity | 5,286 | 49 | 6 | 6 |
| + 2.4 bcf/d Capacity | 5,486 | 39 | 6 | 4 |

| Pipeline Capacity | Annual Energy Costs ($) | Incremental Savings ($) | Cumulative Savings ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|---|
| Base Case | $7,945,735,821 | | | $62.44 |
| + 0.2 bcf/d Capacity | $7,255,844,755 | $689,891,066 | $689,891,066 | $57.02 |
| + 0.4 bcf/d Capacity | $6,664,449,979 | $591,394,776 | $1,281,285,842 | $52.37 |
| + 0.6 bcf/d Capacity | $6,196,962,991 | $467,486,988 | $1,748,772,830 | $48.70 |
| + 0.8 bcf/d Capacity | $5,779,395,509 | $417,567,482 | $2,166,340,312 | $45.41 |
| + 1.0 bcf/d Capacity | $5,495,438,821 | $283,956,688 | $2,450,297,000 | $43.18 |
| + 1.2 bcf/d Capacity | $5,263,210,225 | $232,228,596 | $2,682,525,596 | $41.36 |
| + 1.4 bcf/d Capacity | $5,087,525,805 | $175,684,420 | $2,858,210,016 | $39.98 |
| + 1.6 bcf/d Capacity | $4,977,290,940 | $110,234,865 | $2,968,444,881 | $39.11 |
| + 1.8 bcf/d Capacity | $4,865,818,772 | $111,472,168 | $3,079,917,049 | $38.24 |
| + 2.0 bcf/d Capacity | $4,787,981,865 | $77,836,907 | $3,157,753,956 | $37.62 |
| + 2.2 bcf/d Capacity | $4,737,078,172 | $50,903,693 | $3,208,657,649 | $37.22 |
| + 2.4 bcf/d Capacity | $4,705,966,963 | $31,111,208 | $3,239,768,858 | $36.98 |

## 4.1 Discussion of Model Assumptions

**Q. Please describe the key assumptions that you have made in developing and running your model and discuss whether you believe them to be "conservative" or "aggressive" with respect to the model's estimates of the economic value of incremental natural gas pipeline to New England's electricity consumers.**

A. Our February 2014 report included a discussion of some of the assumptions in our model and what impact these assumptions have on the estimated economic value of incremental pipeline capacity. We have incorporated some of that discussion in this section and expanded it to include a broader set of assumptions, an indication of whether each assumption is conservative or aggressive and an accompanying discussion of each assumption.

1. Analysis Period – Calendar Year 2013

Our period of analysis is for Calendar Year 2013. Temperatures and weather conditions during 2013 were close to "normal" for New England, certainly closer to normal than the relatively warmer 2011-12 and the relatively colder 2013-2014 winters. We believe that this assumption is neither conservative nor aggressive. One important point that needs to be emphasized is that any period of analysis must reflect the absence of long-term legacy LNG contracts that provided LNG supply from overseas to New England's natural gas LDCs at contract prices that are different from world market prices. These legacy contracts are the primary reason why the basis differential curves in Figure 4 through 2012 are relatively moderate compared to those for 2013 and 2014.

2. Design Day LDC Usage Set to 4.2 bcf/day

There is general agreement among those who have examined natural gas conditions in New England that total annual LDC demand for natural gas is in the range of 430 bcf. While annual demand for natural gas is important, it is not what is driving capacity shortage situations and very high price spikes in New England. These are the result of peak demands, driven by cold weather and usage levels approaching Design Day demands on LDC systems. There is less agreement among Black & Veatch, Concentric Advisors and ICF about what Design Day demands for the New England region are, as shown below in Figure 8:

**Figure 8 New England LDC Design Day Demands**

| Consultant/Study | Design Day (bcf/day) |
|---|---|
| ICF International | 4.2 |
| Concentric Advisors | 3.5 |
| Black & Veatch | 3.0 |

Each of these values appears to have been developed using different methodologies and different sources. ICF used as a proxy 1% of total annual volumes to measure Design Day loads; Concentric Advisors based their estimate on the aggregate of the Design Day loads for most of the LDCs in the region gleaned from their Integrated Resource Plans; while Black & Veatch developed its Design Day volumes based on historical records that Black & Veatch says show a 2.56 multiplier for Design Day conditions compared to average winter conditions.

Our own work that we performed to specify design capacities for our proposed pipeline system to serve Kennebec Valley Gas Company[11] customers in central Maine resulted in a system-wide Design Day volume equal to approximately 1% of annual projected volumes, leading us to support the ICF estimate.[12] We have used a Design Day volume equal to 4.2 bcf/d

[11] Kennebec Valley Gas Company was sold to Summit Natural Gas of Maine, which began flowing gas to its largest industrial users in early 2014 and is continuing to build-out the distribution pipeline infrastructure to serve commercial and residential customers in Central Maine. Summit Natural Gas has also initiated an expansion into the Portland suburbs of Falmouth, Cumberland and Yarmouth, and expects to begin flowing gas this winter.

[12] In addition, Sussex Economic Advisors, LLC, who was retained by the Maine Public Utilities Commission to assist in modeling the price impacts of additional pipeline development in New England, indicated during a telephone conversation that they believed Design Day volumes to be in the 4.2 bcf/d range.

in our modeling. While this figure is on the high end of the range, we believe that it is neither too aggressive nor conservative, especially in combination with our assumption of zero load growth discussed below.

3. LDC load growth

There is general agreement that demand for natural gas for heating and process purposes is likely to grow over the next decade throughout New England as a result of new natural gas expansions (e.g., Summit Natural Gas of Maine) and fuel-conversions where natural gas infrastructure already exists to serve customers (e.g., Connecticut's policy to increase residential and commercial natural gas penetration rates by 50% by 2020[13]). There is less agreement, however, regarding the amount by which LDC demands are likely to grow and whether that growth will be in Design Day volumes or overall annual usage. Concentric Advisors projected average demand growth rates of 0.5% in Design Day volumes for the region through 2020 or an increase of about 0.150 to 0.250 bcf/d.[14] ICF International projected a much higher Design Day average annual growth rate of 1.4% over the same period and an average growth rate of 1.2% for annual LDC demands. This latter growth rate results in an estimated total region-wide demand of 468 bcf by 2020. Finally, Black & Veatch projected average growth in natural gas demand of 1.6% per year New England (except Connecticut), with Connecticut's goal of increasing natural gas penetration by 50% through 2020, resulting in a

[13] For example, Connecticut Natural Gas recently announced it has begun construction on a 10 mile expansion project in East Hampton, CT to serve nine schools and municipal buildings, reach major businesses and more than 400 residential and commercial customers.

[14] We have adopted the convention of reporting natural gas volumes in billions of cubic feet (bcf) rather than mmbtu, since this has been the standard unit of reference when discussing pipeline capacities. For our purposes, we have assumed that 1 bcf = 1,000,000 mmbtu.

higher growth rate in that state.[15] We have not included any LDC load growth in our model, an assumption that we believe is conservative, especially given that it will be a few years before any new pipeline capacity can be brought on line.

4. Flows south out of Canada on the Maritimes & Northeast pipeline

We have modeled natural gas flows (excluding injections of regasified LNG out of the Canaport facility) from Atlantic Canada south into the United States on the Maritimes & Northeast pipeline at 0.35 bcf/day. This gas includes production from Sable Island and Deep Panuke as well as limited production from the McCully Field in New Brunswick, and is net of natural gas demands in Nova Scotia and New Brunswick. This is a very conservative estimate, especially for future flows beyond 2019. Based on published production estimates, expected output from these three facilities will fall over the next five years, with production at Sable Island falling from 0.18 bcf/day to below 0.10 bcf/day, production at Deep Panuke falling from 0.30 bcf/day to 0.10 bcf/day and production from the McCully Field remaining relative flat at 0.010 bcf/day. During this same period, natural gas usage in Nova Scotia and New Brunswick is expected to increase from approximately 0.20 bcf/day to 0.25 bcf/day during the winter months, and higher on peak cold weather days.[16] At these levels, we can expect very little natural gas from these three fields to flow south into New England during the winter months.

We do believe, however, that eventually there will be shale gas developed in New Brunswick in amounts that could, under the right circumstances, replace the flows from the other sources. This gas remains speculative at best at this time, and its development is being

[15] Black & Veatch state that they anticipate natural gas demand growth of 0.360 bcf/d from 2014 through 2029, but it is unclear whether this includes growth from electricity generation as well as LDC demand.

[16] "The Future of Natural Gas Supply for Nova Scotia," ICF Consulting Canada, Inc., March 28, 2013.

slowed by resistance to hydraulic fracking in the Province.[17] Therefore, while we expect that by 2020 all of the natural gas flows from Canada south into New England on the Maritimes & Northeast pipeline will be LNG sourced through the Canaport facility, we are using the much more conservative 0.35 bcf/day of Canadian natural gas in our base case for modeling purposes.

5. Ramping capacity of generating units

Our model does not include any operating constraints on various generating units. Specifically, we do not consider minimum run times or ramping requirements for fossil units. This means that we are underestimating the demand for natural gas somewhat, since we are using average heat rates for all operating hours. It also means that we are underestimating the number of hours that oil/steam units with long ramp times operate. Accordingly, this is a conservative assumption.

6. Generation Plant shutdowns

As noted earlier in our testimony, our model incorporates the recent shutdown of Vermont Yankee in 2014 and the announced shutdown of Brayton Point in 2017. ISO-NE has identified that up to 8,300 MW of non-gas-fired generation is "at risk" for retirement by 2020. These are 28 older oil and coal units.[18] The shutdown of an oil plant has no impact in our model, as oil generation is the last type of unit called upon, and we have assumed that there is always enough

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[17] The most recent election in New Brunswick was, among other things, a referendum on fracking natural gas in the Province. The party opposed to fracking prevailed, which will delay even further any potential New Brunswick natural gas exports into New England.

[18] "Infrastructure Needs: electricity – Natural Gas Interdependencies," Gordon van Welie, ISO-NE, U.S. Department of Energy Quadrennial Energy Review, April 2014. Available on line at http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2014/van_welie_interdependencies_4-21-14.pdf.

oil generation, either in the form of oil steam or dual fueled gas turbines, to meet electricity loads during the winter should there not be enough other units available.

Coal unit shutdowns, however, are a different matter, as we have shown earlier in our discussion of the impact of shutting Brayton Point. Based on the 2014 ISO-NE CELT Report, there are just over 1,000 MW of coal-fired generating capacity, not including Brayton Point, in New England. These units no longer provide much energy, but they do remain very important during the winter period. If all of these units were to shutdown, the impact would be to increase the demand for natural gas on during the winter, resulting in additional hours where LNG or oil ~~is required~~would substitute for natural gas to meet electric loads. Accordingly, our assumption that there will be no further coal plant shutdowns is a conservative one.

7. New Generation Plants

We have assumed that there will be no additional renewable generation (or other must-run, zero-bid resources) beyond those in the generation mix in 2013. This is an aggressive assumption, as we know there is significant solar PV generation that has come on-line this year and will continue to expand over the next five years. In addition, we expect to see more land-based wind generation in the region.

This generation, however, has limited impact on the overall demand for natural gas, since its energy output is only a fraction of its installed capacity. Nevertheless, we did model the impacts of an additional 1,000 MW of solar PV and 1,000 MW of land-based wind, which we discuss further in Section 7.

8. Electric Load

We have assumed that there will be no electricity load growth in New England, and in particular no load growth during the winter months when natural gas pipeline capacity is constrained. We view this assumption as neither conservative nor aggressive; however, we do note a recent uptick in the demand for heat-pumps as an alternative to heating residential space with oil, some of which is being aided by state or utility funding. We note that these heat pumps operate at the their lowest efficiency on the coldest days and that increased reliance on heat pumps could increase energy usage on those days when natural gas supply constraints are most critical.

# 5 UPDATED MODEL RESULTS – STEP 2

**Q. Have you made any further updates to your modeling since those discussed in the previous section?**

A. Yes. The specific updates are:

1. We have reduced the north-to-south flows on the Maritime & Northeast Pipeline out of Canada to zero. This is consistent with the estimated production volumes from Deep Panuke and Sable Island relative to combined New Brunswick and Nova Scotia natural gas demands.[19]
2. We have increased pipeline capacity into New England by 0.40 bcf/d to reflect the increased certainty that Spectra's AIM project and Tennessee's Connecticut expansion project will come on-line over the next two years.

[19] This flow figure does not include any flows of LNG from the Canaport facility in Saint John.

3. We have increased peak day LDC natural gas demands from 4.2 bcf/d to 4.5 bcf/d to account for new or expanded natural gas loads in the region.
4. We have reduced the prices of non-pipeline natural gas fuels to reflect recent changes in energy markets[20] as follows:
    a. Oil - $22/mmbtu to $17/mmbtu[21]
    b. LNG - $18/mmbtu to $14/mmbtu
    c. Propane - $19/mmbtu to $16/mmbtu

We have made no further adjustments in our basic model for potential coal and/or oil generating unit shutdowns or delistings in New England nor for any increased renewable generating capacity, including, for example, new purchases from Canada. We have also made no further adjustments for weather variations or load growth, as we believe the 2013 calendar year represents a reasonable representation of expected future weather and electric load conditions in New England.

**Q. Please describe the results based on the above set of revised assumptions.**

[20] We have made this adjustment to our estimates of the economic benefits to New Hampshire of additional pipeline capacity and to address the argument that the recent fall in oil prices has eliminated any need for additional pipeline capacity into News England. Since it will take 2 to 4 years to develop new pipeline capacity, the relevant fuel prices are those that will exist in 2018 and beyond. As of December 2014, Bloomberg was reporting NYMEX forward crude oil contracts for 2018 at $90/barrel. These have since fallen to around $70 per barrel. We are unaware of any market-based price indexes for forward LNG contracts other than those that are oil-based. As we note later in the testimony in Figure 10, the TETCO M3 price for the past 12 months has been $3.25 per mmbtu, which is well below the $5.00 per mmbtu figure we have used in our modeling as the zero New England basis price. Since it is the difference between this zero basis price and the price of oil or LNG that generates value to New England ratepayers, we view the fuel price parameters in this model as reasonable.

[21] It is important to note that the cost of oil reflects not just the cost of the fuel, but the costs of the ISO-NE Winter Reliability Program. In 2014, ISO-NE reported that the Program cost approximately $60 million and resulted in the generation of about 2 million MWhs. At an average heat rate of 10,000 btu/kWh, this equates to a surcharge of approximately $3 per mmbtu.

A. The net effect of these additional changes on the economic value of incremental pipeline capacity into New England is relatively minor as they tend, in the aggregate, to offset each other. We present the results of the model in Figure 9.

With a baseline of 3.136 bcf/d of pipeline capacity into New England, total annual energy costs for electricity are just below $7.7 billion, since LNG will be required to meet natural gas demands for just over 2,100 hours a year. In this base case, the average annual load weighted energy clearing price is estimated to be $60.38/MWh.

An incremental 200 mmcf/d of natural gas pipeline capacity into the region reduces the number of hours when LNG is called upon by 400 hours. This lowers the load weighted average energy clearing price to $56.55, resulting in total annual savings of just less than $500 million to electric ratepayers across New England. Further pipeline capacity increases result in additional incremental savings, although at a decreasing rate, until at 2.4 bcf/d of incremental pipeline capacity, there are only about 50 hours where LNG or a higher priced fuel is setting the clearing price, and total savings to New England's electric ratepayers are $3 billion a year.[22]

[22] As in our prior modeling efforts, we have not attempted to estimate the value of additional pipeline capacity to natural gas LDC customers or industrial process loads. This value will depend upon the amount of existing firm capacity holdings the LDCs and industrial customers hold and the contractual terms of such holdings.

**Figure 9 Summary – Economic Value**

**Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers**

| Pipeline Capacity | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,136 | 2113 | 374 | 296 |
| + 0.2 bcf/d Capacity | 3,336 | 1723 | 267 | 217 |
| + 0.4 bcf/d Capacity | 3,536 | 1316 | 198 | 158 |
| + 0.6 bcf/d Capacity | 3,736 | 993 | 144 | 120 |
| + 0.8 bcf/d Capacity | 3,936 | 750 | 104 | 78 |
| + 1.0 bcf/d Capacity | 4,136 | 550 | 71 | 56 |
| + 1.2 bcf/d Capacity | 4,336 | 391 | 53 | 46 |
| + 1.4 bcf/d Capacity | 4,536 | 288 | 41 | 35 |
| + 1.6 bcf/d Capacity | 4,736 | 206 | 34 | 28 |
| + 1.8 bcf/d Capacity | 4,936 | 152 | 27 | 22 |
| + 2.0 bcf/d Capacity | 5,136 | 111 | 17 | 12 |
| + 2.2 bcf/d Capacity | 5,336 | 74 | 11 | 9 |
| + 2.4 bcf/d Capacity | 5,536 | 54 | 7 | 6 |

| Pipeline Capacity | Annual Energy Costs ($) | Incremental Savings ($) | Cumulative Savings ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|---|
| Base Case | $7,683,828,621 | | | $60.38 |
| + 0.2 bcf/d Capacity | $7,196,238,670 | $487,589,951 | $487,589,951 | $56.55 |
| + 0.4 bcf/d Capacity | $6,662,968,905 | $533,269,765 | $1,020,859,716 | $52.36 |
| + 0.6 bcf/d Capacity | $6,215,782,492 | $447,186,412 | $1,468,046,128 | $48.84 |
| + 0.8 bcf/d Capacity | $5,862,015,565 | $353,766,927 | $1,821,813,055 | $46.06 |
| + 1.0 bcf/d Capacity | $5,556,608,801 | $305,406,764 | $2,127,219,819 | $43.66 |
| + 1.2 bcf/d Capacity | $5,302,503,435 | $254,105,366 | $2,381,325,185 | $41.67 |
| + 1.4 bcf/d Capacity | $5,129,825,208 | $172,678,227 | $2,554,003,412 | $40.31 |
| + 1.6 bcf/d Capacity | $4,986,336,567 | $143,488,641 | $2,697,492,053 | $39.18 |
| + 1.8 bcf/d Capacity | $4,887,791,007 | $98,545,560 | $2,796,037,613 | $38.41 |
| + 2.0 bcf/d Capacity | $4,809,857,588 | $77,933,420 | $2,873,971,033 | $37.80 |
| + 2.2 bcf/d Capacity | $4,737,106,541 | $72,751,047 | $2,946,722,080 | $37.22 |
| + 2.4 bcf/d Capacity | $4,696,129,285 | $40,977,255 | $2,987,699,335 | $36.90 |

## 6 NOT ALL PIPELINES ARE CREATED EQUAL

**Q. Do all increases in pipeline capacity into New England provide the same benefits to electricity ratepayers throughout New England?**

A. We have not attempted to model gas flows throughout the region under different natural gas pipeline expansion scenarios. The key questions are (1) whether or not increased natural gas flows are able to move throughout the region to serve natural gas-fired generating plants thereby enabling such plants to run on pipeline natural gas and (2) whether or not the electricity generating by such plants can move freely in an unconstrained manner across the NEPOOL Control Area.

With respect to the second matter, we expect that the more than $10 billion of new transmission expansion already constructed or scheduled to be constructed over the next few years will have the effect of reducing, if not eliminating, energy congestion throughout the region, especially during winter periods of relatively high electricity demands. This means that as long as enough pipeline natural gas is flowing to some natural gas-fired generators to meet total electric loads, clearing prices will reflect the market price of such pipeline gas and not the prices of either imported LNG or oil.

Whether or not natural gas is able to flow as freely as electricity throughout the New England region will depend on pipeline configuration and capacities, gas flows and the ability of gas to flow in both directions on the major pipelines into the region. We have not seen any evidence to the contrary that most of the region's natural gas-fired power plants located in southern New England could not be served by expanding either Spectra's Algonquin pipeline or by developing Kinder Morgan's Northeast Direct pipeline and backhauling gas on Algonquin to the Tennessee Gas pipeline.[23]

What does seem clear is that incremental gas flows into the region must be able to flow from south-to-north on the Maritimes & Northeast pipeline for such gas to serve natural gas-fired power plants in New Hampshire and Maine. It appears that this will be possible either as a result of Spectra's Atlantic Bridge project or the Northeast Direct project, with some additional work at its point of interconnection with the Maritimes & Northeast pipeline in Dracut, Massachusetts.

**Q. Are there any other differences among pipeline capacity expansion proposals that the Commission should consider?**

A. Yes. We believe it is important to the Commission to consider the "point of receipt" of natural gas on each pipeline proposal, as the price of natural gas may be very different depending on where each pipeline proposal interconnects to the rest of the natural gas pipeline network in the U.S.

**Q. Please explain.**

A. Our early modeling estimates the value of incremental pipeline capacity relative to a point of receipt of natural gas in New York and priced at the TETCO M3 liquidity point. For purposes of these analyses, we have assumed an annual average price for natural gas of $5.00 per mmbtu at this liquidity point. This represents a NYMEX price of $4.25 and a TETCO M3 basis differential of $0.75. This assumption is appropriate for any new pipelines, pipeline expansions or pipeline upgrades that receive natural gas upstream of New England at a

[23] Even in the heavily litigated Maine proceeding where such an argument was offered, the argument was not substantiated.

point governed by the TETCO M3 price. We understand that this applies, for example, to Spectra's AIM project.

It does not apply, however, to new pipelines or pipeline expansions or upgrades that receive natural gas upstream at points outside the TETCO M3 region. These would include the PNGTS Continent-to-Coast expansion (C2C) and the Kinder Morgan Northeast Direct (NED) projects.[24]

This is an important issue that needs to be carefully considered by the Commission and factored into its evaluation of each pipeline proposal it receives. This is because the pricing at various liquidity points in the northeast can be very different. Figure 10 shows the average spot market price of natural gas ($/mmbtu) at the various liquidity points over the past year for the 12 month period December 1, 2013 through November 30, 2014.[25] These values are prices for natural gas received at each of these liquidity points.

[24] It also includes the Tennessee CT expansion, which has as its effective point of origination, receipt of natural gas at Wright, NY. We discuss the proposed major Spectra expansion later in this section.

[25] These values represent the simple averages, assuming a constant volume each day. Since the price differentials tend to be higher during periods of higher gas demand, we would expect that load weighted differentials would be somewhat higher than those shown. The source of this information is Bloomberg.

**Figure 10 Average Spot Price for Natural Gas at Various Liquidity Points in the Northeast for the last 12 Months ($/mmbtu)**

| Liquidity Point | Symbol | Average Price per mmbtu from 5/27/14 – 5/26/15 |
|---|---|---|
| | | |
| Henry Hub – NYMEX | NGUSHHUB | $3.491 |
| | | |
| TGP Z4 Marcellus | NGNETE4M | $1.737 |
| Millenium EP | NGCEMLNE | $2.027 |
| TETCO M3 | NGCGNYNY | $3.252 |
| DAWN | NGCAPARK | $3.842 |
| Transco Z6 (NY) | NGNETRNZ | $4.239 |
| | | |

Since what matters to New Hampshire customers, and indeed all natural gas and electricity ratepayers throughout New England, is the delivered price of natural gas, it is critical that the Commission evaluate the delivered price of natural gas that can be expected from each of the pipeline proposals it receives. To illustrate the significance of this, we have developed three generic scenarios that we believe to be reasonably representative of proposals from Kinder Morgan (NED), PNGTS (C2C) and Spectra (Access Northeast) with respect to an estimated price of natural gas at the point of receipt and point of delivery for each of the proposals.

- Kinder Morgan (NED) – assuming the point of receipt is Wright, NY, the price of natural gas at this receipt point will be equal to the TGP Z4 Marcellus price of $1.737/mmbtu (from Figure 10) plus the tariff rate on NED from the Marcellus Region to Wright, NY, which we assume to be $0.75/mmbtu. The price at the point of delivery into New England will be the price at the point of receipt (Wright, NY) plus the rate Kinder Morgan will offer for delivery on NED to Dracut.
- PNGTS (C2C) – assuming the point of receipt is the intersection of PNGTS with the TransCanada Pipeline (TCPL) in Quebec, the price of natural gas at this receipt point

will be equal to the Dawn price of $3.842 (from Figure 10) plus the tariff rate on TCPL to PNGTS, and the price at the point of delivery will be the price at the point of receipt plus the rate PNGTS will offer for delivery to Maritimes and Northeast. Alternatively, PNGTS has indicated it can backhaul natural gas from the Marcellus region using the Constitution Pipeline to the Iroquois Pipeline into Canada and then to the TCPL Pipeline to PNGTS. In this case, the price of natural gas at the receipt point will be the Marcellus price of $1.737 (from Figure 10) plus the tariffs on Constitution, Iroquois and TCPL, which we estimate to be $0.75, $0.22 and $0.43, respectively, ($1.40 in total). The price at the point of delivery into New England will be this price at the point of receipt plus the rate that PNGTS will offer for delivery to New England.[26]

- Spectra – assuming the point of receipt is the TETCO M3 liquidity point, the price of natural gas at this receipt point will be equal to the TETCO M3 price of $3.252 per mmbtu (from Figure 10). The price at the point of delivery into New England will be the price at the point of receipt plus the rate Spectra will offer for delivery to New England on its proposed Access Northeast expansion project.

These prices are summarized in Figure 11 in tabular form. Figure 11 illustrates the advantage Kinder Morgan's pipeline proposal offers through its extension directly back to the Marcellus region and its ability to provide relatively inexpensive natural gas at the point of receipt in Wright, NY. Assuming that the values for "x" and "z" in Figure 11 are similar, the Kinder Morgan pipeline proposal provides an additional $0.77/mmbtu in value relative to the Spectra option for delivery to New England. Further, since the Kinder Morgan pipeline

[26] The source for these tariff prices for Iroquois and TCPL are from PNGTS Update, Maine Natural Gas Conference, October 9, 2014. We have assumed the price from Marcellus to Wright is equivalent for both the NED and PNGTS pipeline proposals at $0.75/mmbtu.

proposal does not have to backhaul gas through Canada, it may provide a lower cost source of access to Marcellus gas than the PNGTS pipeline proposal, depending on the value of "x" and what finally happens with tariffs on TCPL after the upgrades to that system.

**Figure 11 Price at Point of Delivery for Various Generic Pipeline Proposals**

| | Kinder Morgan (NED) | PNGTS (C2C) (DAWN) | PNGTS (C2C) (Marcellus) | Spectra |
|---|---|---|---|---|
| | | | | |
| Price at Upstream Liquidity Point if Upstream of Point of Receipt | $1.737 | $3.842 | $1.737 | N/A |
| Tariff to Point of Receipt | $0.75 (1) | $0.89 (2) | $1.40 (3) | N/A |
| Price at Point of Receipt | $2.487 | $4.732 | $3.137 | $3.252 |
| Tariff to Point of Delivery | "x" | $0.60 (4) | $0.60 (4) | "z" |
| Price at Point of Delivery | $2.487 + "x" | $5.332 | $3.737 | $3.252 + "z" |

Notes to Figure 3:

(1) CES does not know what specific tariff that Kinder Morgan plans to offer shippers to move gas from the Marcellus region to Wright, NY on its NED. CES is using the $0.75/mmbtu for illustration purposes.
(2) PNGTS Update, Maine Natural Gas Conference, October 9, 2014
(3) This is the sum of the Constitution, Iroquois and TGP tariffs
(4) PNGTS Update, NGA Market Forum, May 1, 2014
"x" This is the rate for the Kinder Morgan NED pipeline proposal
"z" This is the rate for Spectra's Access Northeast pipeline proposal

The above figures and calculations represent conditions as they existed over the last 365 days, from May 27, 2014 through May 27, 2015. In the future, we can expect to see additional pipelines being built to move Marcellus gas to the south and west. This will increase the price in Marcellus, reducing the difference between it and the price at Henry Hub, all other things being equal.[27] Similarly, if there are additional pipelines constructed to move gas from Marcellus into the New York (TETCO M3) market, the TETCO M3 price will fall, which will reduce the delivered price of on Spectra's Access Northeast pipeline proposal. Alternatively, the Access Northeast pipeline may be in a position to take delivery of gas at Millennium EP, which offers a more attractive price that the TETCO M3 receipt point. This issue needs to be clarified by Spectra, including whether there are any additional costs incurred depending on the point of receipt of gas into the Access Northeast pipeline.

Over time we expect these factors will tend to reduce, though not eliminate, the point of receipt price differentials between the Kinder Morgan pipeline proposal (the price at Wright), the PNGTS pipeline proposal (the price at TCPL) and the Spectra pipeline proposal(s) (the price at TETCO M3). In any case, it is critical for the Commission to understand the price differentials at the point of origin of the gas into the proposed pipelines serving New England and to factor this information into its ultimate decision.

Assuming the capacity of the Kinder Morgan proposed pipeline is less than 1.2 bcf/d, throughput on the Kinder Morgan proposed pipeline will be less than the combined electric and non-electric market demand for natural gas in New England on most days of the year.[28] As a result, depending on prices at other points of origin, pipeline flows on this line may not represent marginal flows into the New England market, and these flows may not set clearing prices in that market.[29] Therefore, to the extent there is a delivered cost advantage of the

[27] However, it is not likely that "all other things will be equal," as increased pipeline availability is likely to increase drilling and production at Marcellus.

[28] If we assume that all of this gas is used for electric generation and none for either space heat or industrial processes, at an average heart rate of 8,500 btu/kWh, this flow represents approximately 120,000 MWhs a day. This is approximately 33% of the average daily MWh load in New England.

[29] It is useful to think of this delivered cost advantage as an "economic rent" that flows to the holder of the firm capacity. The economic rent exists because the tariffed price for such capacity is based on costs and not economic value.

Kinder Morgan proposed pipeline relative to other routes, that advantage will redound to the benefit of the holder(s) of firm capacity on that pipeline, while the gas price reduction in the market will be equal to that for other routes.

As we discuss further in the next section, if New Hampshire EDCs holds firm capacity on this or any pipeline that represents a relatively small percent of the daily natural gas flows into New England and that pipeline has a delivered cost advantage relative to other pipelines, New Hampshire ratepayers should be able to capture this delivered cost advantage as its value is flowed back to these ratepayers by the EDCs.

# 7 IDENTIFYING AND ASSESSING THE RISKS OF LONG-TERM GAS PIPELINE CAPACITY PURCHASES

**Q. You have identified the benefits to New England and New Hampshire from increasing natural gas pipeline capacity. Are there risks to New England and New Hampshire businesses and residents associated with such activity?**

A. Yes, there are risks related to every investment. The fundamental question facing any entity including the Commission in assessing the risk or any long term investment or transaction is, whether it is a sound investment – that is, whether it is likely that the benefits to be derived in the future will more than offset the commitment of scarce resources today. We discuss below a number of events that could prevent the benefits of this pipeline investment being realized and the likelihood of these events occurring. Because this analysis deals with projections far out into the future, the likely time horizon for both the pipeline investment and the return on that investment in comparison to other things that might happen is critical. We anticipate that the pipeline investment will be made in 2017-18 and the payback will begin in 2019. Depending on the ultimate cost to build out the pipeline capacity, payback could be completed in as little as three years.[30] The probability of most of the possible risks delineated below occurring prior to 2022 is very small.

**Q. Since additional pipeline capacity provides New England access to less expensive natural gas, is there a risk that the current low price of natural gas from the Marcellus region will not continue into the future?**

A. The primary benefit to be derived from pipeline expansion is the price spread between natural gas as fuel for electric generation and other fuels which might be used for the same purpose within acceptable environmental constraints. In New England these acceptable fuels are limited to oil, LNG, and propane. We do not believe that expansion of coal generation would be acceptable or that biomass expansion is feasible at the necessary scale. Further, we do not believe that the region will accept a new nuclear plant.

The basic commodity risk is that prices per btu will equilibrate between pipeline gas brought into the region from the Marcellus fields and one of the other three acceptable fossil fuels. Equilibration can result from a collapse in the prices of oil, LNG, or propane or by a rise in the unconstrained or basis free price of pipeline gas. A collapse in the price of liquid fuels can result from a significant decline in demand or a significant increase in supply at current production costs.[31] Because these liquids fuels are traded world-wide in enormous volumes, a very long and extremely deep depression recession would be required for a sustained price collapse. We note that the great recession of the past few years had very little impact on the

[30] We have seen reported prices of $3 billion for the Spectra Access northeast expansion and $4 billion for the Kinder Morgan Northeast Direct pipeline.

[31] As noted previously, we have lowered the prices of oil, LNG and propane from our original modeling to reflect lower long-term price forecasts for each commodity.

price of liquid fuels, and in the case of LNG was more than offset by increased Japanese and other national demands following the Fukishima nuclear disaster.

Certainly there is considerable incentive for entities to get into or expand the export of North American gas. In the very long term this is likely to happen, but the price that exporters can pay for U.S. domestic natural gas must always be less than the world price for LNG minus the amortized cost of the liquefaction plant and the cost of added pipeline capacity to bring gas to the plant. Gas liquefaction plants have very significant economies of scale, the larger the plant the lower the price per btu. However, there are few places in the U.S. that have both adequate coastal geography and sufficient pipeline capacity back to abundant and low cost natural gas fields to support more than a small amount of LNG export, and a small amount of LNG export will not cause North American gas to equilibrate to world prices. This is evident in the long-term forward prices for natural gas traded on NYMEX, where nominal prices remain below $6.00 per mmbtu as far out as November 2026. At a $6.00/mmbtu NYMEX price, the economic benefits from expanded natural gas pipeline capacity are fully 80% of those we have estimated in the prior section of our testimony.

Even in the extreme case where LNG liquefaction proceeds at such scale to support major exports of U.S. natural gas supply, the cost of converting natural gas to LNG and shipping it to overseas markets will preserve a price differential of approximately $5/mmbtu.[32] This would still leave approximately 40% of our estimated economic value related to pipeline capacity expansion, thereby increasing the expected simple payback period on the investment

[32] Perhaps the best overall study of the world LNG market was done recently by Leonardo Maugeri at the Harvard Kennedy School. He cites Cheniere's calculation of Sabine Pass LNG train 1 delivery costs to different regions as ranging from $4.50 per mmbtu to Europe to $6.50 per mmbtu to Asia, with $3.50 of these amounts being the cost of liquefaction. "Falling Short: A Reality Check for Global LNG Exports," Leonardo Maugeri, Harvard Kennedy School, Belfer Center for Science and International Affairs, December 2014. We have provided this study as Exhibit 3 to our testimony.

from less than three years to less than five years. Since it would take more than a decade to develop the infrastructure necessary for this scenario to play itself out, if it did occur, it would occur well beyond the point at which the increased pipeline capacity had paid for itself.

The flip side of the risk of major U.S. exports of LNG is the scenario where non-North American natural gas supply increases to such an extent that the demand for LNG falls and with it the price of LNG. This would require a confluence of a number of low probability events. First, other countries with the potential for significant shale gas would have to adopt U.S. gas fracking technology and develop the technical expertise to support its wide-scale deployment. While we may see some of this occurring over the next decade in places such as China and Poland, the current trend is much the opposite as political opposition in places such as France, Germany and even neighboring New Brunswick represents a major obstacle for moving forward.

Second, even if countries were able to overcome the technology gap and political opposition to fracking, the opportunity for cheaper gas would most certainly lead to rapid expansions of domestic natural gas use, as it has in the U.S. Countries such as China would be in a position to swap out cleaner natural gas for coal as a fuel for generating electricity, which would exert upward pressure on natural gas prices and in turn worldwide prices for LNG until much of the fuel substitution had run its course. This could take decades – certainly well beyond the timeframe necessary for the benefits of expanded pipeline capacity in New England to far surpass the costs of the pipeline capacity.

One example of just how difficult it is to affect major structural change in an industry characterized by significant capital investment is in transforming all or part of the U.S. transportations sector from gasoline to natural gas. There have been a number of suggestions and a few implementations[33] for conversion of U.S. transportation from liquid fuels to LNG or CNG. While there is a significant fuel price advantage in making this conversion, there are also very significant infrastructure barriers to be overcome. One current implementation example on the long haul corridor between Las Vegas and Los Angeles, while not unique, is also not representative of the investment required to undertake large scale conversion. The Las Vegas to Los Angeles route is accomplished with only three refueling stations and a limited number of trucks dedicated to a single route. Even a U.S. conversion at scale would place only modest downward pressure on liquid fuel prices because the U.S. is only a fraction of global demand. While such a conversion would put upward pressure on natural gas prices, the potential squeeze is not open ended because the market would respond by bringing more natural gas to market in response to higher prices. In short, we do not believe that transportation conversion will equalize U.S. natural gas and liquid fuel prices in the foreseeable future.

**Q. Is there a risk that alternative generating sources will expand significantly in New England thus reducing the need for increased natural gas pipeline capacity?**

A. The economic value of increased natural gas pipeline capacity derives primarily from reducing the fuel input price to electric generating facilities during the winter months and especially on the coldest days. Because fossil fuel generation is on the margin during these periods and throughout most of the year in New England, the price of fuel drives not just the price paid to the fossil fuel fired generators, but to the entire market. If additional non-fossil fuel generation such as hydro from Hydro Quebec, biomass plants, new nuclear generation or in-region wind or solar PV were added to the generation mix, the hours when fossil fuels are on

[33] See for example Clean Energy - http://www.cleanenergyfuels.com/about-clean-energy-natural-gas-fueling/index.html.

the margin would be reduced. This, in turn, would reduce the benefit to our region's electricity consumers from expansion of natural gas pipeline capacity into New England.

We have modeled a few representative scenarios showing the impact of adding 1,000 MW of new generating capacity of different types on the value of incremental natural gas pipeline capacity. The results are shown in Figure 12.

The columns in Figure 12 show the annual cost of electricity in New England for each of five scenarios, including the Base Case, assuming additional 0.20 bcf/day increments in natural gas pipeline capacity into the region. These costs are only the energy costs and do not include any capital costs associated with the development of the additional generation or pipeline capacity. The Base Case repeats the results shown earlier in Figure 7, where the incremental value of each additional 0.20 bcf/day of pipeline capacity is shown.[34]

**Figure 12 Energy Costs to New England Electricity Consumers Under of Various Alternatives to Pipeline Expansion ($ per Calendar year)**

| Added MCF/day | Base Case | New Wind | New Solar | Baseload HQ | New Nuclear |
|---|---|---|---|---|---|
| 0 | $ 7,945,735,821 | $ 7,408,949,256 | $ 7,478,762,711 | $ 6,595,822,070 | $ 6,682,181,613 |
| 200 | $ 7,255,844,755 | | | | |
| 400 | $ 6,664,449,979 | | | | |
| 600 | $ 6,196,962,991 | | | | |
| 800 | $ 5,779,395,509 | | | | |
| 1000 | $ 5,495,438,821 | | | | |
| 1200 | $ 5,263,210,225 | | | | |
| 1400 | $ 5,087,525,805 | | | | |
| 1600 | $ 4,977,290,940 | | | | |
| 1800 | $ 4,865,818,772 | | | | |
| 2000 | $ 4,787,981,865 | | | | |
| 2200 | $ 4,737,078,172 | | | | |
| 2400 | $ 4,705,966,963 | | | | |

[34] This analysis is from our February 2014 report. It has not been updated.

As might be expected, the addition of either 1,000 MW of new wind generation or 1,000 MW of new solar PV provides only small incremental energy savings and only a fraction of the benefits that can be realized through expansion of natural gas pipeline capacity. Each provides less incremental savings than the first 0.20 bcf/day of incremental natural gas pipeline capacity. This is because each of these two types of generation is intermittent and produces a relatively low amount of energy for each installed MW of capacity. Incremental HQ hydro (which we assume operates at essentially a 100% capacity factor) and nuclear generation provide the equivalent benefits to New England electricity consumers of an incremental 0.40 bcf/day of natural gas pipeline expansion, i.e., a benefit roughly equivalent to that provided by the AIM expansion and the TGP Connecticut expansion combined or about half of the capacity of the Maritimes & Northeast pipeline that has been lost to New England due to falling production in gas fields off the coast of Nova Scotia.

Based upon recent history, we believe that it is more likely that New England will have less rather than more nuclear capacity over the next 20 years, which will exacerbate the pipeline constraints not relieve them. While there is considerable support within the region for additional HQ generation and the attendant transmission expansion, we note that there is also considerable opposition, e.g., the Northern Pass Project. Further, we share other energy market analysts' concerns that new HQ generation will be more costly to develop and transmit to the New England market than existing generation and is likely to cost more per MWh than the cost of incremental natural gas-fired generation, when the costs of transmission upgrades are included. Also, we note that New England's primary need for non-fossil-fuel generation is during the winter months, which is when electricity demands and prices in Canada are at their highest.[35]

**Q. This past winter was an abnormally cold winter. With global warming, is there a risk that New England winters will become less severe, thus reducing the demand for natural gas which will alleviate the pipeline constraint?**

A. As we have stressed earlier in our testimony, our model and results are based on the "normal" winter of 2013, rather than the colder more extreme winter of 2014. To the extent that New England winters trend warmer over time due to climate change, the value of incremental pipeline capacity will fall, all other things being equal, because there will be fewer hours when LNG, propane or oil are on the margin in the electricity market. However, even the most dire predictions of global warming place the time scale over which significant temperature increases will occur in the decades, which is far longer than the payback period for any natural gas pipeline capacity expansion under discussion.

**Q. Please summarize your conclusion about the risks of investments in new natural gas pipeline capacity into New England.**

[35] Black & Veatch expressed some concern over whether Canadian hydro would be available when most needed in New England in the winter and in light of a tightening demand-supply balance in Canada. "The fact that the Canadian market which is to be the source of the energy is a winter peaking market may limit the energy imports offered to New England during the winter months when gas infrastructure is most constrained …" Black & Veatch, 2013 at page 36. There is recent evidence that the Black & Veatch concern is very real as HQ has indicated that it does not have existing generating capacity to sell to New England during winter months. For example, HQ has stated , "We do have surplus energy to meet Quebecers' needs. But surpluses are rare in winter, when we must often purchase power to meet those needs. In order to meet peak winter demand, Hydro-Québec purchases power from neighboring systems at times. Energy exchanges between Hydro-Québec and its neighboring systems are common practice. In turn, neighboring U.S. systems can rely on our power deliveries to the meet their summer peak consumption needs." http://www.hydroquebec.com/residential/save-energy/understanding-and-taking-action/winter-consumption/

A. The central feature of any investment in new natural gas pipeline capacity into New England that distinguishes it from many other investments that have been made in the electric utility industry is the immediate and substantial dollar value of the benefits such investment will provide the region's electricity consumers. Our analysis places this benefit at just under $3 billion a year for investments in an incremental 2 bcf/day of pipeline capacity. This estimate is not based on twenty or thirty year forecasts of energy market conditions that are inherently volatile and difficult by their very nature to forecast, such as the 30 year oil price forecasts that provided the foundation for investments in nuclear plants such as Seabrook and Shoreham or on excessively high forecasts of peak load growth that underwrote the $1.6 billion Maine Power Reliability Program and billions of dollars of transmission throughout the region. Rather, the estimated benefits are based on current market conditions, and before any of the potential risk factors will come into play, the investment will have paid for itself many times over.

# 8 A PROPOSED DECISION RULE FOR THE COMMISSION AND EDCs

**Q. Please explain whether a purchase of firm capacity on an new natural gas pipeline by the Commission or by New Hampshire's EDCs provide a "hedge value" to New Hampshire's electric ratepayers.**

A. There has been considerable confusion in other proceedings and in the public discussion regarding the concept of "hedge value" and how the so-called hedge value of a pipeline option should be calculated. We believe that much of this confusion derives from the use of the term "hedge value."

A fundamental characteristic of a hedge is that it has no economic value at the time of its purchase – the price of the hedge will reflect the value today of the expected future value of a product, commodity or service when it is used. Thus, one may enter into a future contract for natural gas today, for example a one-year strip at Henry Hub, and the price of that contract will be equal to what the market expects the value of that contract to be in the future when it is exercised.[36]

What a hedge does provide is insurance against the risk that actual prices in the future will be significantly different from what those future prices are expected to be today. Changes in market conditions between the time a hedge is purchased and when it is exercised will be incorporated in the value of the hedge over this period, as the price of the hedge conforms to changing expectations about future prices at the time the hedge is exercised. Expectations that market conditions will push future prices higher will turn the value of the hedge positive; while expectations that market conditions will push future prices lower will turn the value of the hedge negative. Of course, if there are no changes in the market or if any changes in the market offset each other, the economic value of the hedge will remain equal to zero.

A natural gas pipeline is not a hedge as this term is generally used in economic and financial theory and practice. Rather, it is an investment that costs money to build and will yield an anticipated return over its useful life. A pipeline provides no certainty against changes in the actual prices of natural gas compared, for example, to what the market today has determined to be the expected future prices of natural gas. Instead, what a pipeline does is change the physical point at which natural gas is received for delivery to one or more end-use customers. Accordingly, the better term to describe the product or service a pipeline provides

[36] Throughout this discussion, we assume that there are no transaction costs associated with the purchase of a hedge.

is, to borrow a term of art from the electricity market, a "firm transmission right" or "FTR." A holder of firm capacity in a natural gas pipeline is entitled to purchase natural gas in the market at the origination of the pipeline for delivery to such holder for use in the market at the termination point of the pipeline (or at any intervening point along the pipeline's route.) Critically, however, the opportunity to resell (through capacity release) this right into the market creates a stream of revenues that can be used to benefit New Hampshire ratepayers that is in addition to the savings from reduced electricity prices resulting from a decrease in the basis differential.

Understanding a natural gas pipeline as an FTR helps emphasize a few very important points:

1. The value of firm pipeline capacity derives from different market conditions at the origination and termination of the pipeline and not from changes in either market in the future relative to expectations today about those future market conditions; that is, a pipeline's economic value derives from spatial and not temporal conditions in markets.
2. A pipeline, in and of itself, acts to reduce differences in market conditions across space. Assuming all other factors impacting market prices do not change, a pipeline will result in price increases in the originating market and prices decreases in the terminating market, as the "excess" supply in the originating market is transferred through the pipeline to the termination market where there is "insufficient" supply.[37]
3. A purchaser that holds firm pipeline capacity is able to move its point of receipt of natural gas from its point of end-use (e.g., a specific factory, office building or

[37] An economist would say that a pipeline, by moving natural gas from the market at its origin to the market at its termination, shifts the supply curve at its origin to the left and the supply curve at its termination to the right.

collections of residences) to the point of origination of the pipeline, which is upstream of the point of end use, and therefore closer to the source of natural gas.

Thus far, the discussion has viewed the pipeline from the perspective of the user of that natural gas. It is important to note, however, that a pipeline can also provide FTRs to a source of natural gas, e.g., a natural gas well or storage facility, at the origination of the pipeline. A natural gas well owner may hold firm capacity on a gas pipeline that entitles it to sell its natural gas into the market at the termination of the pipeline. This is stated in point number 4 below:

4. Where the holder of firm pipeline capacity is a supplier of natural gas, it is able to move its point of delivery of natural gas from its source to the point of termination of the pipeline, which is downstream of the point of its source.

Whether the holder of firm pipeline capacity is the end-user or the source of gas, the economic consequences are the same. The pipeline eliminates the geographic distances between the sources of the gas at the pipeline’s point of origin and the end-users of the gas at the pipeline’s point of termination. However, a seller and a public entity buyer have very different objectives regarding investment in additional pipeline by other entities. The seller opposes such investment because it reduces the price at the downstream end of the pipe and hence the margin he can achieve on his gas in storage or well. A public entity such as the State of New Hampshire welcomes such investment because it lowers the cost of gas at the point of receipt and is multiplied through its impact on the electric clearing price.

We now turn our attention to developing a framework for estimating the economic value of a specific holding of firm capacity on a pipeline. To do this, we focus on a firm pipeline capacity block of 200 mmcf/d on a pipeline that originates in the TETCO M3 (New York State) market and terminates in the AGT/TZ-6 market (New England). (We choose these points to align with the results of our modeling and analysis presented in our direct testimony in earlier sections of our testimony.) We further assume for illustration purposes that the 200 mmcf/d block of firm pipeline capacity is the only additional natural gas pipeline capacity into New England. Finally, if we assume an average heat rate of 8,500 btu/kWh in a natural gas fired generator[38] and an annual capacity factor of 100% for that generator(s).[39] Based on these assumptions, the 200 mmcf/d flow is equivalent to 73 million mmbtu/year of natural gas (at a heat content of 1,000 btu/cubic foot of natural gas) that will generate 8.6 million MWhs of generation and support roughly 1,000 MW of generation capacity.

Figure 9 estimates the savings to New England electric ratepayers from the first 200 mmcf/d of incremental pipeline capacity to be $488 million a year. This occurs as a result of a fall in the average annual energy price from $60.38 to $56.55 per MWh resulting from the increase in supply of pipeline natural gas into the New England market.[40] Since New Hampshire electric ratepayers represent approximately 9% of the total energy use in New England, the savings to New Hampshire electric ratepayers is roughly $44 million a year. The $488 million and $44 million represent the annual value to all New England and to just New Hampshire electric ratepayers, respectively, of a 200 mmcf/d firm pipeline capacity entitlement

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[38] This is an approximation of the load weighted average heat rate in New England.

[39] This assumes that if the natural gas is not used by any one specific generator, it will be used by another generator.

[40] The actual savings that result are sensitive to the cost of liquid fuels that must substitute for natural gas during those hours when the pipeline capacity into the region is constrained.

on a pipeline that originates in the TETCO M3 region and terminates in the AGT/TZ-6 region, assuming this is the only incremental capacity available. These annual values can be compared to the costs of the capacity to determine whether or not New Hampshire (and indeed the rest of the New England states) should secure through a long-term firm pipeline capacity contract the additional 200 mmcf/d.

The market value of this firm pipeline capacity to any generator or group of generators, however, is much lower. To see this, we ask what the 1,000 MW natural gas-fired generator(s) noted above would be willing to pay for this firm capacity or FTR. The ability of this generator(s) to take delivery of its gas supply in the TETCO M3 region means that it is able to generate electricity for $36.90/MWh[41] (the generator purchases gas at the TETCO M3 price and converts it at the same heat rate of 8500 btu/kWh)[42], which it can then sell into the New England market for $56.55/MWh. Since the generator is able to generate 8.6 million MWhs/year, the value of the firm capacity or FTR to generators is equal to just under $170 million per year.[43] This is the amount that natural gas-fired generator(s) would be willing to pay for the 200 mmcf/d of firm pipeline capacity, assuming this was the only incremental capacity developed. This is considerably less than the total value of $488 million to all New England electric ratepayers. Since no individual generator or set of generators is able to capture the gains resulting from the impact additional natural gas pipeline firm capacity has on energy

[41] We note that in a static environment the new capacity will also increase gas price at the source. We ignore these impacts here because they are likely to be small and will be offset at least in part by additional gas wells brought on stream to meet increased demand – production is not actually static.

[42] We use the figure from the last row of Figure 9 of the CES analysis as an approximation of the condition under which there is no longer any basis differential between TETCO M3 and AGT/TZ6 pricing.

[43] This is calculated as 8.6 million MWhs x (the generation cost difference of $56.55 – $36.90).

clearing prices, the value of such capacity to ratepayers will always be greater than the value to any individual generator.[44]

Now, let's assume for purely hypothetical purposes that this additional pipeline capacity costs $200 million a year. If the Commission or the EDCs were to purchase this incremental capacity and then resell it (through capacity release) into the secondary market to one or more electricity generators, the Commission or the EDCs would in effect be paying $200 million for something that has a market value of $170 million – a difference of $30 million. It would recover this $30 million from New Hampshire electric ratepayers. While these electric ratepayers would face a $30 million surcharge, their electric bills would fall by $44 million, leaving them $14 million better off.

This analysis points out an important issue. Should the Commission or the EDCs elect to enter into a contract for firm pipeline capacity, the value of that firm capacity to one or more natural gas-fired generators in the secondary market will be considerably lower than the value to all electric ratepayers that is used to evaluate the economic benefits of the pipeline in the first instance.

One additional footnote to this analysis should be added and that is that the market value of firm pipeline capacity on a pipeline proposal that provides a delivery cost advantage relative to a pipeline proposal that takes receipt of natural gas at TETCO M3 will be higher than what has been described above. For example, using the figures in the prior section, if the price at the point of receipt for the Kinder Morgan proposed pipeline is $1.70/mmbtu less than the price at

[44] There was some question as to whether the benefits estimated by CES should be adjusted for potentially higher capacity costs to offset lost revenues in the energy market. We do not believe this is necessary, since the market clearing price for capacity is expected to be driven by natural gas-fired generation and since gas fired generators simply pass through gas prices, there should be no change in the profitability of these generators as a result of changes in gas prices and thus no need for additional capacity payments. Indeed it is likely that the economics tend in the opposite direction. As additional pipeline and gas generation is added to the system the hours of oil generation will decline, the hours of gas generation will increase, the value captured from the energy market by gas generators will increase and the need for capacity payments should decline.

TETCO M3, a generator that holds firm capacity on that pipeline will be able to reduce its generation costs from the zero-basis price of $36.90/MWh to approximately $25/MWh. This increases the value of the firm capacity to this or other generators from $172 million to $271 million a year. This is significantly higher, though still well below the $488 million value the additional pipeline capacity is worth to all New England ratepayers. Accordingly, under a long term capacity contract in the example above New Hampshire would be paying $200 million for an investment that has a market value of $270 million in addition to the $44 million in electric savings New Hampshire electric ratepayers receive each year.

**Q. How does your analysis change if New Hampshire is not the first and only entity to purchase firm capacity on a new natural gas pipeline?**

A. This is where the discussion becomes most interesting, but also where we believe most of the discussion to date has been seriously misguided. Consider the situation in which the Commission or a New Hampshire EDC is not the first purchaser of incremental capacity, but a later purchase of such capacity, that the purchase is equal to 200 mmcf/d and further, for ease of exposition and without limiting the generality, that the 200 mmcf/d that represents the capacity incremental to an already contracted for 1.4 bcf/d; that is, this purchase brings the total incremental capacity from 1.4 bcf/d to 1.6 bcf/d. CES has estimated the incremental savings to New England’s electric ratepayers associated with this 200 mmcf/d increase in pipeline capacity to be approximately $143 million a year, with New Hampshire’s 9% equal to just under $13 million. Were the Commission to seek to maximize benefits to New Hampshire, it would compare this incremental benefit to the marginal costs of developing the associated incremental capacity.

**Q. Is this the correct comparison?**

A. While this comparison is theoretically correct, it should not be performed, because firm pipeline capacity is not priced under FERC's regulatory regime on a marginal cost basis. Rather, it is priced on the basis of average costs, reflecting total revenue requirements and total annual throughput. This is a serious matter that cannot be overlooked by the Commission. While economic theory directs further investments in, or purchases of, incremental pipeline capacity to the point where the marginal benefits from such investments or purchases equal the marginal costs of such capacity, the FERC pricing regime renders such a decision rule inappropriate. Instead, the Commission must look to some other metric, since it would make no sense to compare the marginal benefits of incremental pipeline capacity to the average costs of providing the full (and not the incremental) amount of pipeline capacity.

If the Commission were to compare average costs to marginal benefits, it may be led to significantly overinvest or underinvest in new pipeline capacity, depending on the relationship between both average and marginal benefits and costs. Accordingly, the appropriate methodology is to compare the average costs (FERC tariffed rates) to the average benefits provided by the pipeline capacity. This ensures that the Commission will never expand capacity to the point beyond which total net benefits turn negative.

Applying this result to the case described above where the New Hampshire purchase of incremental capacity contributes to increasing total new capacity to 1.6 bcf/d results in a total New England wide benefit of approximately $2.7 billion a year. As shown in Figure 9, this total benefit is achieved through a reduction in the load weighted average energy price in New England falling from $60.38 to $39.18 per MWh. New Hampshire's 9% share of this total benefit is $243 million a year.

As in the discussion in the prior section, the market value of the 200 mmcf/d is much lower than the value of that capacity to all New England and New Hampshire electric ratepayers. By purchasing the 200 mmcf/d capacity from the Commission or a New Hampshire EDC, one or more natural gas-fired generators will be able to secure gas supply in the TETCO M3 market at an effective electricity generation cost of $36.90, but would be able to sell that power at only $39.18. This differential results in a market value of only $20 million a year, well below the $2.7 billion and $240 million annual values of the full 1.6bcf/d capacity to all New England and New Hampshire electric ratepayers, respectively. Accordingly, the total benefit to New Hampshire electric ratepayers of 1.6 bcf/d of new pipeline capacity into New England is $262 million a year.

If the Commission applies a conservative decision rule that any natural gas pipeline capacity purchase must pay for itself within 5 to 10 years, it should approve a pipeline capacity contract for 200 mmcf/d if the cost to construct its 200 mmcf/d entitlement to firm capacity is less than $1.31 billion for the 5 year payback period or $2.62 billion for the 10 year payback period.[45] If we assume that the total cost to construct 2 bcf/d of new pipeline capacity is $7 billion (see footnote 29, above), then the cost for the 0.2 bcf/d is $700 million and the simple payback period is 2.7 years.

An alternative way to look at this is to ask how long it would take for the benefits received by New Hampshire electric ratepayers to exceed the total 20-year costs of a firm capacity entitlement. For illustration purposes, if the per mmbtu tariff rate on a pipeline proposal is $1.50 for a 20 year period, the annual cost of this capacity will be $1.50 x 365 x 200,000 mmbtu/d = $109.5 million and the total cost over this 20 year term will be $2.19

[45] This is computed as ($242 million plus $20 million) x either 5 years or 10 years.

billion. Assuming the contract is for pipeline capacity with an origination point in the TETCO M3 region and the purchase represents an increase in total capacity from 1.4 to 1.6 bcf/d, the market value of this entitlement through resale in the secondary market is approximately $20 million a year, resulting in a total annual benefit to New Hampshire's ratepayers of $242 million plus $20 million = $262 million.[46] This means that the full cost of the 20 year contract, including interest, O&M and return to equity, of $2.19 billion will be paid for in full through savings to New Hampshire's electric ratepayers in 8.3 years.

Finally, we have provided in Figure 13 the same calculations for each 200 mmcf/d tranche of additional pipeline capacity from 0.2 bcf/d to 2.4 bcf/d as described above, assuming that New Hampshire's firm capacity entitlement is 200 mmcf/d and has an origination point in the TETCO M3 region. Column [2] of Figure 3 shows that the economic value to New Hampshire electric ratepayers of additional pipeline capacity increases as more capacity is added. However, column [3] shows that the market value of New Hampshire's 200 mmcf/d firm capacity entitlement falls as the total amount of such capacity increases, reflecting the fact that the value of incremental pipeline capacity faces diminishing returns. The net effect of these is shown in column [4]. Given the total 20 year cost of the firm capacity entitlement of $2.19 billion (see column [5]), the number of years it takes for the annual benefits to New Hampshire's electric ratepayers to cover in full the costs of the 20 year capacity entitlement contract falls from 10.3 to 8.1 years as the total amount of additional pipeline capacity increases from 0.2 bcf/d to 2.4 bcf/d of capacity.

[46] We have treated the market value of the firm capacity entitlement as a benefit to New Hampshire in this calculation and not as an offset to the cost. This subjects the market value benefit to the same uncertainty assumed for the economic value benefit as reflected in the 5 to 10 year payback period criterion we are recommending.

**Figure 13 Years to Payback the Total Costs of a 20 Year Pipeline Capacity Entitlement of 200 mmcf/d Assuming Increasing Amounts of Additional Pipeline Capacity is Constructed into New England**

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Market Value | Total Value | NH Cost | Yrs to Payback |
| | Economic Value of Capacity | | to NH | to NH | of Firm Capacity | Total Cost of |
| | to New England | to NH | of Entitlement | of Entitlement | Entitlement | firm Capacity |
| Pipeline Capacity | ($million) | ($million) | ($million) | ($million) | ($million) | Entitlement |
| | [1] | [2] | [3] | [4] | [5] | [6] |
| | (1) | [1] x 9.0% | (2) | [2]+[3] | (3) | [5]/[4] |
| Base Case | | | | | | |
| + 0.2 bcf/d Capacity | $488 | $44 | $169 | $213 | $2,190 | 10.3 |
| + 0.4 bcf/d Capacity | $1,021 | $92 | $133 | $225 | $2,190 | 9.7 |
| + 0.6 bcf/d Capacity | $1,468 | $132 | $103 | $235 | $2,190 | 9.3 |
| + 0.8 bcf/d Capacity | $1,822 | $164 | $79 | $243 | $2,190 | 9.0 |
| + 1.0 bcf/d Capacity | $2,127 | $191 | $58 | $250 | $2,190 | 8.8 |
| + 1.2 bcf/d Capacity | $2,381 | $214 | $41 | $255 | $2,190 | 8.6 |
| + 1.4 bcf/d Capacity | $2,554 | $230 | $29 | $259 | $2,190 | 8.5 |
| + 1.6 bcf/d Capacity | $2,697 | $243 | $20 | $262 | $2,190 | 8.3 |
| + 1.8 bcf/d Capacity | $2,796 | $252 | $13 | $265 | $2,190 | 8.3 |
| + 2.0 bcf/d Capacity | $2,874 | $259 | $8 | $266 | $2,190 | 8.2 |
| + 2.2 bcf/d Capacity | $2,947 | $265 | $3 | $268 | $2,190 | 8.2 |
| + 2.4 bcf/d Capacity | $2,988 | $269 | $0 | $269 | $2,190 | 8.1 |
| | | | | | | |
| Pipeline Tariff - TETCO M3/Wright to Dracut ($/mmbtu) | | | | $1.50 | | |
| New Hampshire Share of New England Electric Load | | | | 9.0% | | |
| Term of Firm Pipeline Commitment (years) | | | | 20 | | |
| | | | | | | |
| Notes: | | | | | | |
| (1) - Source is Figure 9 | | | | | | |
| (2) - 8.6 million MWhs x (Difference in Energy Clearing Price from Figure 11) | | | | | | |
| (3) - Computed as $1.50/mmbtu x 200,000 mmbtu/d x 365 d/year x 20 years | | | | | | |

**Q. You included the value received by New Hampshire ratepayers of the first 1.4 bcf/d of capacity in the calculations evaluating whether to purchase an incremental 0.2 bcf/d. Won't New Hampshire ratepayers receive the value of the 1.4 bcf/d regardless of whether the Commission approves the incremental 0.2 bcf/d?**

A. New Hampshire ratepayers may or may not receive the benefits, depending on whether one or more other states in the region support in one form or another the expansion of natural gas pipeline capacity. The question is really one of whether or not it is possible or appropriate for New Hampshire ratepayers to "free-ride" on the purchases made by other states and/or the region's natural gas LDCs.

**Q. Please explain what you mean.**

A. Our analysis shows that the benefits of incremental pipeline capacity accrue to all New England ratepayers regardless of how or by whom the incremental pipeline capacity is funded and regardless of where in the New England region the ratepayers reside. Incremental pipeline capacity in any and all forms lowers natural gas prices in New England, and since the market clearing price for electricity is determined region-wide, the lower natural gas prices result in lower electricity prices across the entire region. This situation creates the possibility that certain ratepayers may receive benefits but not contribute to the costs required to achieve the benefits – a condition that is frequently referred to as free-ridership.

**Q. Are situations in which free-riders can exist unique?**

A. No, they are not. A couple of instances that we all deal with on a daily basis are, for example, the decision to contribute to New Hampshire Public Television or Radio and to have ourselves and our children vaccinated against contagious diseases. In each instance, the presence of a limited number of free-riders will not impact the ability of those who share in the costs of receiving benefits; however, if free-ridership becomes large, the benefits will disappear for all, not just those who do not contribute, and all parties will be worse off.

**Q. Is free-ridership ever an appropriate course of action?**

A. Yes, it can be an acceptable course of action, but only in very limited circumstances, none of which apply in this case. We believe that any exercise of free-ridership as a strategy to obtain the benefits of the actions of others without contributing to their costs is shameful when the sole reason for not participating in sharing the costs is the conscious strategy of reaping the benefits while avoiding the costs. On the other hand, free-ridership may be excusable where an entity is financially unable to contribute to the costs, is physically unable to take the actions necessary to avoid being a free-rider, is philosophically opposed to participating in the actions that provide benefits or is an accidental and infrequent beneficiary of the benefits.

**Q. Please provide examples of these exceptions.**

A. We may give the indigent a pass on not making contributions to public television, even though they watch it; we certainly would exempt children from vaccinations where their health would be at serious risk due to an allergic reaction to the vaccine, even though they receive the benefits of near ubiquitous vaccinations (the so-called "herd effect"); we are likely to exempt religious workers from taking certain actions where taking such actions violates their fundamental religious beliefs, even though those actions provide widespread societal benefits; and we are inclined to accept an infrequent tourist from California's reception of New Hampshire Public Radio's programming, even though that person does not make voluntary contributions to support the broadcasts.[47]

These, and other similar examples, are distinctly different from those instances where an entity consciously decides not to contribute to support a good or service for which it fully intends to receive regular benefits, even though it has the financial wherewithal to make the

[47] We would most certainly view the actions of the Californian as fair if he or she contributed to California public radio.

contribution and contributing does not impinge upon either the entities philosophical belief or its physical well-being. This type of willful free-ridership may be viewed by the entity pursuing this course of action as “strategic”, but under any standard of reasonable behavior it is shameful. It is especially shameful when the entity acting “strategically” is a governmental body, which, itself, is ultimately dependent upon the collective – that is, non-strategic – actions of all of its citizens.

**Q. Based on this, what decision criteria do you recommend the Commission to follow?**

A. We recommend that the Commission evaluate the total benefits New Hampshire electric ratepayers receive from the development of new natural gas pipeline capacity into New England, where the total benefits are those benefits that derive from such incremental pipeline capacity financed directly by the Commission or by New Hampshire’s EDCs plus the benefits derived from incremental natural gas pipeline capacity financed by the other states and utilities in New England. The Commission should then evaluate whether the total benefits so calculated exceed the direct costs of the capacity entitlement to New Hampshire’s electric ratepayers over a period of 5 to 10 years. If this condition is satisfied, the New Hampshire Commission should either make the purchase itself or permit its electric distribution companies to enter into such commitments, roughly in proportion to the amount of load each serves, relative to total load in New England.

**Q. You have not recommended that New Hampshire condition its purchase on the decisions of the other New England states to make similar purchases. Why not?**

A. This condition is a form of protection against free-ridership. Just as we have recommended that New Hampshire not pursue a course of free-ridership that would enable it to potentially benefit from the actions of the other New England states, we do not believe that New Hampshire should worry about other states pursuing a free-ridership course of behavior. Our concern is that a set of mutually established conditions might stall actions that would otherwise lead to the development of incremental pipeline capacity sooner, and therefore cost New England's electric ratepayers billions of dollars a year in foregone opportunity. We have no doubt that some may call us naïve or even foolish for recommending this course of action. However, our experience is that the New England states have a long history of cooperative actions on just this sort of matter, where there may have been potentially individual benefits to some states from free-riding on the actions of the others, but where they did not choose to pursue this course of action.

# 9 CONCLUSION

**Q. Does this conclude your Direct Testimony?**

A. Yes.

# 10 EXHIBITS

| | |
|---|---|
| Exhibit CES-1 | "Assessing Natural Gas Supply for New England for the Winter of 2013-14 and Its Impact on Natural Gas Prices and Electricity Prices," April 5, 2013 |
| Exhibit CES-2 | "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices," February 7, 2014. |
| Exhibit CES-3 | "Falling Short: A Reality Check for Global LNG Exports," Leonardo Maugeri, Harvard Kennedy School, Belfer Center for Science and International Affairs, December 2014. |