STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

IR 15-124

ELECTRIC DISTRIBUTION UTILITIES

Response of the Coalition to Lower Energy Costs to the Staff Request for Stakeholder Input

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The Coalition to Lower Energy Costs ("CLEC") is pleased to submit this response to the Staff Request for Stakeholder Input in this vital investigation.

CLEC is a non-profit, incorporated association of individual consumers, large energy consumers, labor unions and institutions seeking to eliminate the threat to New England's families and economy from skyrocketing natural gas and electric prices. CLEC is the only New England-wide consumer group formed to help to protect the interests of consumers in reliable, reasonably priced energy. CLEC advocates for increased renewable energy, energy efficiency, demand response and new infrastructure to give natural gas and electricity consumers access to an adequate gas supply, a cleaner energy portfolio and lower energy costs.

Some thirty[1] studies and most public officials have acknowledged that New England's energy cost crisis is caused by a lack of sufficient natural gas pipeline capacity into the region. The best available information shows clearly that it will require an additional 2.0-2.4 Bcf/day of pipeline capacity into New England from two major new or substantially new pipelines to fully solve this problem. CLEC therefore advocates here the creation of mechanisms to require New Hampshire's Electric Distribution Companies ("EDCs") to contract to purchase capacity from interstate natural gas pipelines in an amount equal to New Hampshire's pro rata share of New

[1] CLEC has provided links to the thirty-odd studies and a total of over eighty resources which directionally support the CLEC conclusion that New England lacks adequate gas pipeline capacity. CLEC has also provided links to the two studies/papers which disagree, both of which were sponsored by the New England Power Generators Association.

England electricity consumption. CLEC actively supports similar mechanisms in all New England States. These commitments will cause lower electricity costs, shutter our aged oil and coal plants and facilitate the continued growth of renewables, energy efficiency and demand response by ensuring the adequate availability of gas power plants as a "ramping" resource.

CLEC's responses will directly address Staff requests 1, 2, 3, 4, 7 and 8. Additionally, these comments will suggest decisional rules that will help to ensure that the New England states each can act independently and responsibly to reach procurement decisions that, taken together, fully solve the problem of high New England winter natural gas and electricity costs.

Executive Summary

New England businesses and consumers suffer a severe and continuing energy cost crisis, an acute social and economic disadvantage relative to consumers and businesses in regions less than a days' drive from our state borders. There is no reasonable dispute that the cause of this human suffering and economic disadvantage is the lack of sufficient natural gas pipeline capacity into the region.

The Testimony and Exhibits of Dr. Richard Silkman and Mark Isaacson of Competitive Energy Services (the "CES Testimony") included as Attachment 1 to this Response, demonstrates through modeling of the New England electricity market that 2.0 to 2.4 billion cubic feet per day (Bcf/d) of additional pipeline capacity is required to bring New England into energy cost parity with neighboring regions. This conclusion is corroborated by Synapse Energy Economics in a study requested by gas opponents and prepared for the Massachusetts Department of Energy Resources.[2] Synapse calculated the level of pipeline capacity

[2] Synapse Energy Economics, Inc., Massachusetts Low Demand Final Report (January 7, 2015) ("Low Demand Study")

insufficiency for Massachusetts alone, which represents approximately 46 percent of New England's electric load, to be between .6 and .8 Bcf/d by 2020 and between .6 and .9 Bcf/d by 2030.[3] These results, which assume "low demand," extrapolate easily to 2.0 Bcf/d being needed by New England.

It is not correct to say that the market has not provided its answer to this problem. The "market" has operated continuously throughout the period of New England's worsening energy cost crisis. We already have the market's answer. The answer has cost New England consumers and businesses billions of dollars in excess expenditures, increased the burning of oil and coal for the production of electricity, thrown thousands of New Englanders out of work, temporarily or permanently shuttered businesses, and forced families to make unacceptable choices between utility payments and other necessities. The current New England electric market is designed on principles of theoretical short term "efficiency" that ISO New England itself acknowledges cannot support the investment needed to remedy the crisis.

In addition to lowering electricity prices, increased pipeline capacity into New England will hasten the long-sought retirement of our expensive and polluting oil and coal fired power plants. Increased pipeline capacity into New England is a necessary ingredient in the transition to, and reliable integration of, a renewable and intermittent energy based portfolio. Increased pipeline capacity into New England will decrease dependence on the stubbornly pervasive use of oil for home heating. Increased pipeline capacity into New England can eliminate the current economic disadvantage of businesses seeking expansion opportunities. The benefits are immense: The obvious answer is for the states to cause the increase of natural gas pipeline capacity into New England. The market will not do this. The states must act.

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[3] *Id*. at 4.

For the states to act effectively and responsibly there must be a framework for decision that allows definitive and timely resolution, eschews strategic attempts to free-ride at the expense of others, and avoids the easy delay of continued analysis. This framework must allow New Hampshire to act independently with an appropriate level of assurance that its actions will benefit New Hampshire ratepayers regardless of the actions or inactions of other states. This framework should promote the goals and objectives of a comprehensive regional solution, but should not be dependent upon such a regional solution for its efficacy. New Hampshire cannot control the political and economic actions of other states and has an independent responsibility to its citizens to act in the public interest. This can be accomplished through the adoption of a decisional framework that incorporates the following assumptions and decisional rules.

The Commission should adopt a base year for analysis that is reasonably representative, and thus provides a degree of conservatism when calculating benefits. CLEC believes the base year for analysis should be 2013.

The Commission should base its decision on the proper level of investment in pipeline capacity on the presumption that the other New England states will adopt procurement strategies that, taken together, comprehensively solve the problem on terms that are beneficial to the region as a whole. This will result in the effective assumption of a fixed (i.e., consistent) regional capacity procurement target. This target can be established by each state conducting a region-wide average cost/average benefit analysis using consistent assumptions. The Commission should assume that the states will invest in regional pipeline capacity up to the point where the total cost of that investment over the full contract term can be recovered through ratepayer benefits from lowered electric costs over a 5-10 year payback period. This means setting the total investment in pipeline capacity at a level that will be completely paid back by ratepayer benefits within this 5-10 year window. Given that the benefits associated with these long-lived assets will extend far beyond this period, this is an extremely conservative assumption that will allow the Commission to act in confidence that intervening market or other developments will not significantly erode these benefits.

Having done all it can to effectively establish that regional capacity number, New Hampshire should procure its pro-rata share of such pipeline capacity, without regard to the actions of any other state. This strategy will assure New Hampshire ratepayers that if all other states act to procure their pro rata share, New Hampshire will have made a beneficial investment. Conversely, if other states do not act, the actual benefit received by New Hampshire ratepayers per dollar invested will only increase. This is true because there are diminishing benefits to be gained from each added increment of capacity. The effective regional procurement target is set at a point where the average benefits at that point still exceed the total costs. If less capacity is purchased by the states, the average benefit of every unit of capacity that is purchased simply increases to the region as a whole and the commercial value captured through capacity release increases. Although the region as a whole would be better off if each state bought its pro rata share, if certain states fail to act responsibly, then there may be an even greater benefit per dollar invested for those who have.

It is imperative that private parties, such as EDCs, not be allowed to set or otherwise determine the amounts of capacity to be purchased. This is a fundamentally public decision. This is particularly true where EDCs or their affiliates may own interests in pipelines, pipeline capacity or competing energy infrastructure projects, and thus may have conflicting objectives.

This decisional rule allows New Hampshire to act independently, prudently and in a socially responsible manner with assurance that its actions will lead to benefits for its ratepayers.

Further, this course of action, if followed by each state, would lead to a de facto regional solution in which every state that invested would benefit with assurance that the region as a whole would also benefit. States that act according to this rule will set the fiscal and moral example for others without burdening their ratepayers with a larger share of investment than responsible public policy would dictate under a regional solution.

CLEC believes that when this decisional framework is applied based on the best available facts and analysis, a regional investment procurement target from 2.0 to 2.4 Bcf/d of incremental capacity will be shown to be appropriate. Those who argue for "small bites" or partial solutions do not seem to do so on a well-founded risk analysis, but on a basis that serves their own, non-consumer interest. There is no rational basis for failing to fully solve the problem of gas pipeline capacity deficiency providing it is economic to do so, as that would intentionally leave in place an unjustified cost or energy tax on New Hampshire consumers. While it may be in the interest of each major pipeline to have only its project built, this is not in the interest of New England consumers. The TGP NED and Spectra/Algonquin Access Northeast projects benefit New England separately and then synergistically, and they combine to 2.2 Bcf/d in additional capacity. Spectra/Algonquin serves southern New England directly; TGP NED uniquely delivers low cost Marcellus gas in large amounts directly to the Dracut hub, where that gas can readily be delivered throughout New England. The greatest assistance to consumers, the greatest assurance of grid reliability and the greatest assistance to renewable integration all require this capacity be sourced from two major new or substantially new pipelines.

1. **Identification of the Root Cause of the High Winter Wholesale and/or Retail Electricity Prices**

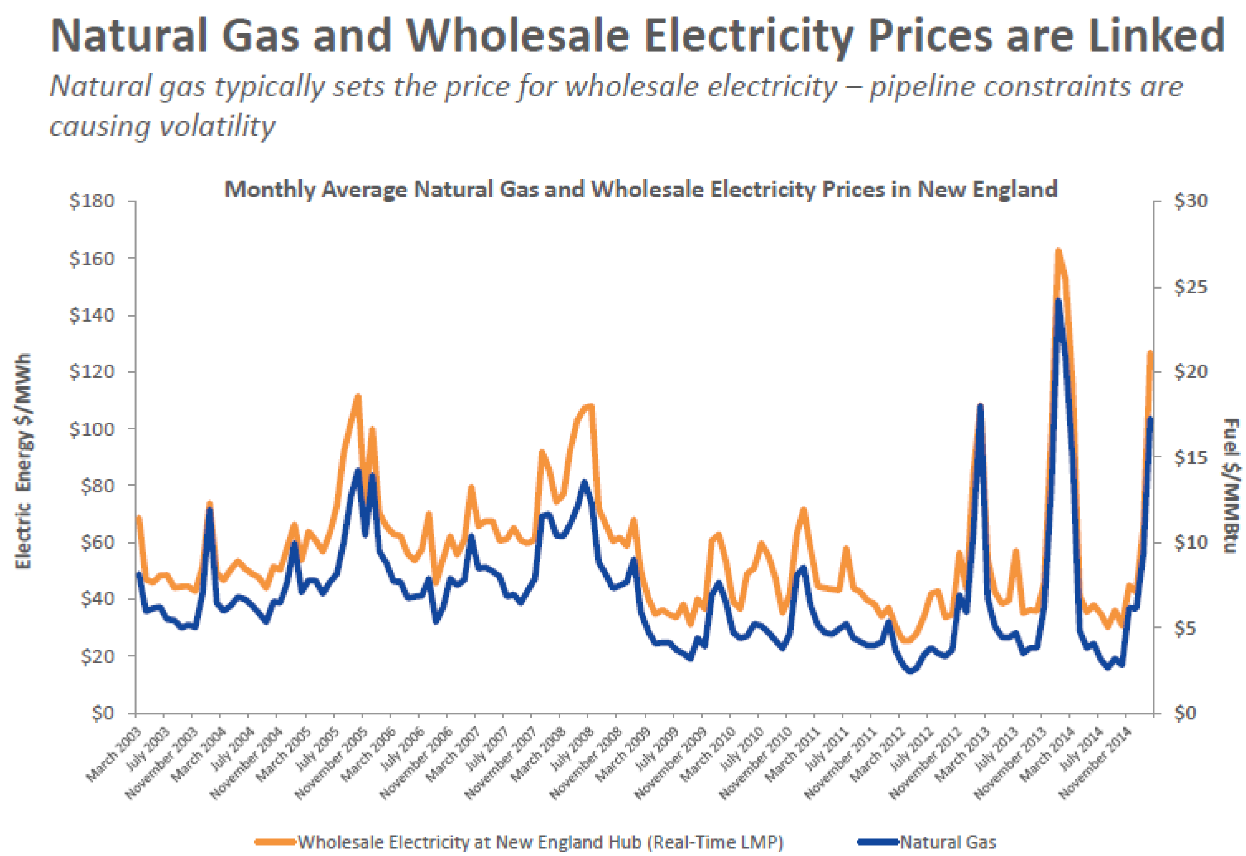
The root cause of high winter electricity prices in New Hampshire and New England is the divergence in prices per Btu between oil and LNG, on the one hand, and domestic pipeline natural gas, on the other, *combined with* the lack of adequate natural gas pipeline capacity into the region. This conclusion has been reached repeatedly by state and federal policymakers and is supported by numerous credible studies. In response to item 8, below, we provide a list of more than thirty of these studies, with web links. In addition, we provide attached the CES Testimony, which presents detailed analysis specific to New Hampshire.

Few, if any, New England social problems have been so exhaustively studied, and with the studies reaching such consistent conclusions. Not only is it highly improbable that all of these studies from multiple independent experts are wrong; there are no credible studies showing how New England's energy cost crisis can be similarly solved by other means.

In its February 2015 Status Report to the Federal Energy Regulatory Commission ("FERC"), ISO New England stated: "high natural gas prices drove wholesale electricity prices to record levels in the past two winters (2012-2013 and 2013-2014)."[4] In early 2015, the Low Demand Study prepared for the Massachusetts Department of Energy Resources stated that "[i]nsufficient natural gas capacity for the electric sector has contributed to high wholesale gas prices to generators and thus high electricity prices."[5]

The close correlation between the price of natural gas and electricity in New England is well documented, as demonstrated by this slide prepared by ISO New England: [6]

[4] *Re ISO New England Inc., Fuel Assurance Status Report of ISO New England Inc*., Docket No. AD13-7-000, AD14-8-000 (February 18, 2015).
[5] Synapse Energy Economics, Inc., Massachusetts Low Demand Final Report (January 7, 2015) ("Low Demand Study") at 2.
[6] ISO NE, Managing the Dramatic Transformation of NE's Resource Mix, slide 4 (March 24, 2015).

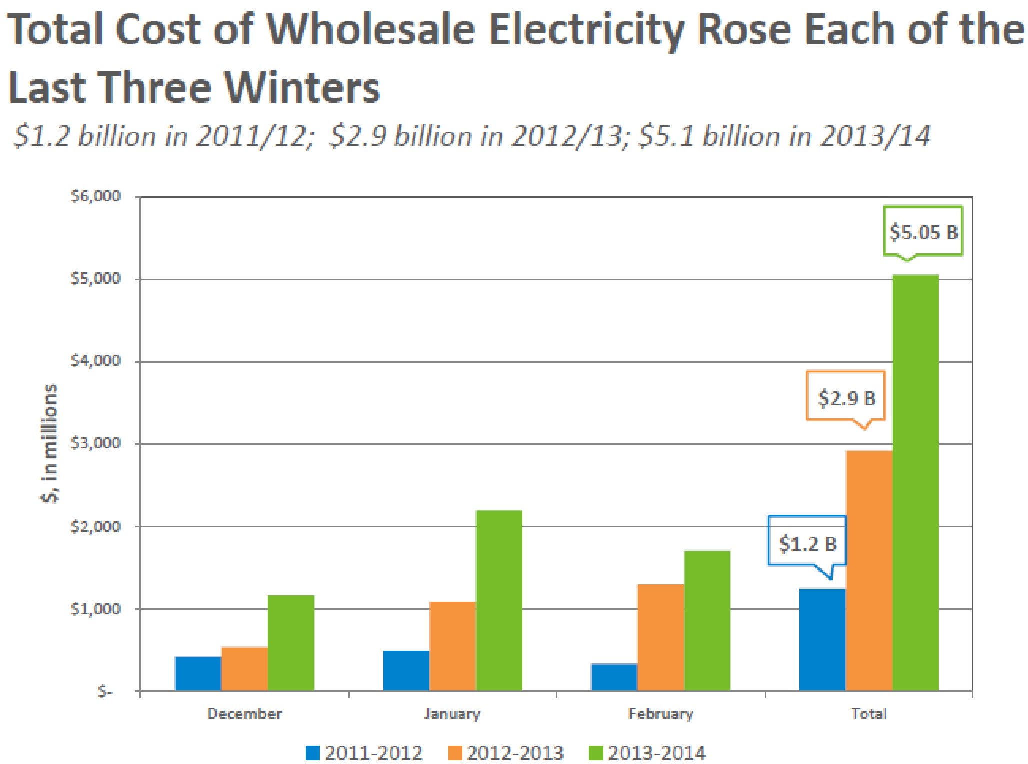


This Commission, in comments submitted to the Federal Energy Regulatory Commission ("FERC") on March 20, 2015, concurred with the conclusion that the problem of very high prices and extreme price volatility is caused by insufficient pipeline capacity into New England.[7] These comments are replete with concerns about the lack of new pipeline infrastructure and the effects that this lack of capacity has on wholesale electricity prices.

CLEC shares the views expressed by ISO New England, Synapse Energy Economics, the Commission itself in its 2015 comments, the CES Testimony and the unanimous conclusions of the numerous other studies and authorities cited herein: substantially increased gas pipeline capacity is the right and only solution.

[7] *Comments of the New Hampshire Public Utilities Commission, before the Federal Energy Regulatory Commission*, Docket Nos. AD13-7-000 and AD14-8-000 (March 20, 2015).

Not only is the root cause of these cost increases without serious doubt, the magnitude of the cost increases to electric ratepayers in New England have been dramatic and economically debilitating. ISO New England estimated the following impacts during the winters of 2011-12, 2012-13 and 2013-14, respectively: [8]



The CES Testimony estimates the effect of this constraint on electric ratepayers in New England to be approximately $3.0 billion per year. Given New Hampshire's electricity consumption proportional to the region's consumption is approximately 9 percent, the cost to New Hampshire's consumers approximates $270 million per year.

On a per kWh basis, these price increases have thus far translated into the following wholesale and retail supply rates:

[8] ISO New England, State of the Grid presentation, slides 21, 28 (January 21, 2015).

Table 1: Wholesale Market Costs and Residential Retail Power Supply Rates [(a)]

	Wholesale Market Costs (¢/kWh)	Effective Date of Residential Retail Power Supply Rates	Residential Retail Power Supply Rates[(b)] (¢/kWh)
January – December 2012	4.82 – 5.10	January 1, 2013	7.19 – 9.08
January – December 2013	6.75 – 7.23	January 1, 2014	6.81 – 9.56
January – December 2014	7.53 – 8.27	January 1, 2015	7.56 – 15.56

(a) The analysis is based on a hypothetical residential consumer that uses 750 kWh/month. The values indicate a range of lowest to highest costs among the states.

(b) The range of residential retail power supply rates includes the states that have unbundled retail electricity markets. Vermont has not unbundled its retail electricity market, and therefore its rates are not included as part of this analysis.

Prices during the winter of 2014-15 were again high, with Locational Marginal Prices in the ISO New England markets approximately equal to those experienced in 2012-13.[9] Indeed, despite fortuitous weather and world market conditions related to oil and LNG and an expansion of the Winter Reliability Program,[10] New England endured the third highest monthly average wholesale electricity prices in its history in February of 2015, while relying on oil and coal to produce over 26 percent of its electricity.[11]

These price increases have put the region at a severe economic disadvantage relative to neighboring regions of the country, with many businesses laying off workers for extended periods or even ceasing operations altogether.[12] Without decisive action to address this crisis,

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[9] ISO New England, Monthly LMP Indices spreadsheet, available at http://www.iso-ne.com/transform/csv/monthlylmpindex?year=2015.

[10] ISO NE, ISO Newswire – Updates: "New England power system performed well through winter 2014/2015" (4.7.15).

[11] ISO NE, ISO Newswire – Updates: "Monthly wholesale electricity prices and demand in New England," February 2015.

[12] See, e.g., "Natural gas price spike forces Gorham mill layoffs," Manchester Union Leader (January 4, 2014); "Some Maine mills forced to idle lines as price of power soars," Portland Press Herald (December 19, 2013); "Price Spike Dooms Maine Paper Mill's Gas Conversion Plans," MPBN.net (February 7, 2014); "Verso mill in Bucksport to close by year's end, 570 employees to lose jobs, Bangor Daily News (October 1, 2014)("the mill's rising costs, especially for natural gas, were major factors in the decision to close the mill.")

continued high prices threaten the region's ability to attract and retain manufacturing and other business. Individual consumers have also suffered, with delinquency rates for payment of electric bills soaring,[13] and those consumers able to make their payments forced to do so at the expense of other necessities.

Some have argued that "the market" will solve the crisis. However, there is no mechanism within the current ISO New England market rules to compensate generators for making long-term pipeline commitments and thus many generators have inadequate access to capital to fund such an obligation. This is evidenced by the historical failure of generators to arrange long term fuel commitments.[14] Further, ISO New England itself concedes that its "Pay for Performance" program will "not address the concern the New England States have over price volatility or higher emissions."[15] In vertically integrated electric systems, the incumbent utility has a public service obligation to make long-term fuel supply arrangements. In New England, no entity has a similar responsibility.[16]

In short, there is no serious doubt that the much higher prices of oil and LNG in combination with the lack of adequate natural gas pipeline capacity is the root cause of high winter electricity prices in New Hampshire and New England.

[13] Connecticut Consumer Counsel, presentation and remarks at the Northeast Forum on Regional Energy Solutions (April 23, 2015), available at www.ct.gov/occ/lib/occ/governor_panel_remarks.pdf. (Payment in arrears among non-low income consumers in Connecticut have quadrupled since 2012.)

[14] Peter Bradford, former Commissioner of the Nuclear Regulatory Commission and Chair of the Maine and New York commissions, testified that a belief that the "market" will solve the problem of high energy costs in the future after failure to do so for many years is, in a word, "eccentric." Maine PUC Docket No. 2014-00071, Hearing Transcript, July 17, 2014, at pp. 117-18.

[15] Gordon van Welie, *Challenges Facing the New England Power System: Gas-Electric Interdependency: The Realities of Keeping the Lights On*, Washington Press Club (March 26, 2015) at 21, available at http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf.

[16] Vermont's utilities are vertically integrated, however they do not rely on natural gas, having elected instead to enter a long-term contract with Hydro Quebec to replace their entitlements in the shuttered Vermont Yankee nuclear facility.

2. **<u>How the preferred solution results in lower wholesale and/or retail electricity prices for New Hampshire consumers. For example, if the preferred solution requires one or more New Hampshire EDCs to purchase firm pipeline capacity, explain in detail how that purchase translates into lower Load Marginal Prices (LMPs) for wholesale electricity customers and eventually lower electric energy rates for retail customers. Identify all steps in the process and specify all assumptions</u>**.

A. <u>The Preferred Solution, Lowering Wholesale and Retail Electricity Prices</u>.

CLEC's preferred solution, requiring New Hampshire's EDCs to contract to purchase capacity from interstate natural gas pipelines into New England, will cause lower wholesale and electricity prices by enabling efficient gas generators throughout New England to access low-cost gas from the Marcellus region during periods that otherwise would experience pipeline constraints. Increased natural gas supply will also enhance reliability and facilitate the growth of renewable resources in New England's generation mix.

The CES Testimony explains in detail how the purchase of pipeline capacity translates into lower Locational Marginal Prices for wholesale electricity customers and eventually lower electric energy rates for retail customers, including all steps in the process and all assumptions. Figure 1, included in CLEC's response to item 4, below, provides a summary of reduction in Locational Marginal Price by increment of additional pipeline capacity constructed.

Natural gas pipeline infrastructure provides a public benefit far in excess of any market value that can be captured by generation suppliers in the market.[17] History and common sense show that 1) the displacement of environmentally disfavored oil and coal generation has been and can be facilitated by increased natural gas generation, 2) the market will not provide the needed infrastructure to support expansion or even reliable operation of existing gas generation,

[17] See CES Testimony at pages 55 and 56 discussing the disparity in market value to generators and value to ratepayers in terms of lower prices of additional pipeline capacity.

and 3) this failure has burdened and will continue to burden the region with unacceptable energy costs until and unless timely action is taken.

B. **Framing the Analysis to Determine How Much Capacity should be Purchased and Determining Benefits.**

CLEC recommends that the Commission frame its analysis with baseline data, measurement protocols, and other assumptions that are congruent with the overall goals cited by the states for redressing the regional economic disadvantages created by the lack of natural gas infrastructure. We believe this is best achieved by framing the analysis as follows.

(i) Base Year for Data.

CLEC recommends that the Commission adopt as a baseline data year for analysis the year 2013. Other recent years like 2012 and 2014 each have anomalous characteristics that depart substantially from recent trends, and reasonable expectations of the future. As discussed more fully in the testimony of CES in Attachment 1 to this filing:

> 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.[18]

If parties adopt different base year data sets, there can be no meaningful comparisons of cost benefit analysis because the results will be apples to oranges. Using 2013 as a base for all analysis, parties are free to present various sensitivities to illustrate ranges of temperature, load or other variations they think are relevant or worth considering. But without an agreed upon base year for analysis, sensitivity analyses are analytically dubious.[19]

[18] CES Testimony at p. 26 lines 14-23

[19] The Commission in its comments to the FERC, has used year 2011-2012 for comparison purposes to show the increase in prices in subsequent years. Our analysis of the year 2013 assesses the suitability of the year 2013 as a baseline year based on a number of factors noted above.

(ii) Fixed or Consistent Regional and State Procurement Assumptions.

The Commission analysis should adopt a procurement assumption that assumes the region, taken as a whole, will invest in sufficient capacity to solve the region's problem in a comprehensive fashion. CLEC believes, based on the analyses of CES, Synapse and others, that a comprehensive solution requires additional pipeline capacity of at least 2 Bcf/d and that such capacity must be sourced from two pipelines. We believe these analyses, based on an average cost/benefit measurement protocol (described below) yields this, or some greater amount of capacity, as appropriate on a regional basis. In response to the Staff's question 4 below, we describe the mechanics for determining what this fixed amount should be based on the relationship between average cost and average benefit. In this section, however, we focus on the need to determine a fixed regional procurement assumption (whatever that level turns out to be) as a necessary method for avoiding 'paralysis by analysis' and the potentially endless do-loop of speculation on other parties' actions or motives that thus far may have contributed to the gas pipeline deadlock for the region. As long as each state's decision remains contingent on continuous re-evaluation based on the decision that 'might' be made by every other state, no resolution will be possible.

New Hampshire cannot compel other states to adopt specific public policy goals and objectives. The states must guard against perpetuating the same dynamic that has kept the market from resolving this issue. No generator will invest in pipeline capacity because, if it does, its competitors will underprice it in the market and it will have bought a general benefit for ratepayers at its own expense. This dynamic can be perpetuated indefinitely. Likewise, if each state holds out, hoping some other state will invest first, or in anticipation of a regionally binding agreement, the prospects for any state taking action are substantially diminished.

By contrast, adopting a fixed regional capacity target that fully solves the problem and assuming that each state will act responsibly within its means and political processes to procure its 'fair share' of incremental capacity, will allow New Hampshire, and the other states to act prudently yet independently to secure the benefits its ratepayers' need. Adopting the average cost/benefit measurement protocol discussed (iii) below, New Hampshire can assure itself that New Hampshire will invest at a beneficial margin for its ratepayers and, to the extent other states do not, the benefits of New Hampshire's investment to its ratepayers will only increase. This is because cutting off total regional investment at the point where the average benefit matches or exceeds by some specified margin the average cost (as discussed in response to question 4) generates conservative state by state investment caps. Because there are decreasing *incremental* benefits as the total capacity purchased increases, if other states do not invest in their share, there will be a higher average benefit associated with any amount purchased by New Hampshire.[20] Further, as less capacity is purchased, the commercial value of the asset in the capacity release market increases; the greater the remaining scarcity, the greater this value becomes.[21] Alternatively, if other states do step up and invest proportionately, New Hampshire's investment will still yield benefits to its ratepayers. NH may lose a portion of the capacity release value as the scarcity is relieved, but it will gain more by sharing in a larger regional energy price reduction.

[20] One way to think about this is to note that each individual generator would most certainly be willing to invest in a long-term capacity contract with a pipeline if it could be certain that it and it alone was able to act in such a way – so that its capacity would represent 100% of the incremental capacity available to the New England market.

[21] The EDCs will not use this capacity themselves but will release it to the market in some way. The greater the scarcity of capacity the higher the remaining basis differential, which means that a generator able to use that capacity to access cheaper fuel at the source (avoiding the basis differential) will see greater and greater profits in the energy market and so will pay more to acquire the capacity in the release market. This dynamic is thoroughly discussed in CES testimony at pages 51-57.

CLEC recognizes that, if other states do not invest, there may be a perception of a free rider issue. Even though New Hampshire ratepayers would still benefit from investment by New Hampshire, other states who do not invest will also benefit. Again, this is a dynamic that cannot be definitively resolved within the necessary time frame given the disparate political and legislative frameworks of the six states.[22] This is not to discourage the states from working vigorously towards a regional understanding if one is possible. But holding individual state procurement decisions hostage to either a uniform or a unified process runs a substantial risk of allowing the least common denominator to prevail by default. New Hampshire should decide what is best for New Hampshire ratepayers under assumptions that do not depend for their validity on the actions of others. The fixed regional capacity target suggested herein, along with the average cost benefit calculation methodology described in the next section, provide the tools to achieve this.

For these reasons, CLEC recommends that New Hampshire adopt a fixed capacity procurement target based on New Hampshire's pro rata share of an amount of incremental capacity needed to comprehensively resolve the region's gas pipeline infrastructure deficiencies for the reasonably foreseeable future. We recommend that pro rata share be established by comparing New Hampshire's annual load as a proportion of New England load. By using the regional average cost benefit analysis outlined below, New Hampshire can ensure that if it purchases its load ratio share of such capacity, its ratepayers will receive benefits equal to or greater than the investment made, regardless of whether any other New England state purchases capacity.

[22] As discussed in the CES testimony, acting strategically to secure a free ride in this instance is also a morally dubious course for a public entity to adopt in situations where it clearly expects its citizens will receive a needed public benefit from an investment that "does not impinge upon the entity's philosophical belief or its physical well being." See, pages 63-67.

(iii) Average Cost/Benefit Measurement Protocol.

As the analyses of CES and others show, there are diminishing (though still positive) incremental ratepayer benefits to each additional increment of investment in pipeline capacity. This is because the greatest price spikes are associated with the most highly constrained hours and, as these hours diminish in number and severity, additional investment, though still beneficial, provides less benefit per incremental dollar spent.[23] As a result, the exact same dollar investment in pipeline infrastructure can be attributed very different cost benefit values depending upon the incremental 'order' in which it is considered. The "first" .5 Bcf/d of capacity is incrementally more valuable than the "second" .5 Bcf/d, even though both are beneficial to the region and, if considered as being made simultaneously rather than sequentially, would both yield an identical positive average benefit per dollar invested. For investments in long-term infrastructure such as pipelines, and in the context of a regional solution to be achieved by relatively contemporaneous[24] investments by multiple parties, assigning "positions" to various tranches for the purpose of incremental analysis is highly arbitrary. For example, if New Hampshire were to be the only state to invest in additional pipeline capacity and were only to procure a small amount, the benefit of that investment would be substantial because it would have the effect of eliminating constraints or reducing constraints in the most constrained hours. However, that value would be "achieved" only at the expense of leaving the economic disadvantage of the region as a whole, including New Hampshire, largely intact. On the other hand, if New Hampshire were to evaluate this same investment on an incremental value basis assuming several other states or actors *had already purchased* significant amounts of capacity

[23] See Testimony of Silkman and Isaacson, Maine Public Utilities Commission Docket No. 2014-00071 (July 11, 2014) at 25-27. Please note that during subsequent pipeline development phases, when compression is added rather than pipe, capacity expansions are incrementally less expensive.
[24] *I.e.*, within a time frame of two or three years.

(i.e. provided New Hampshire with a "free ride"), it would conclude that the identical amount of investment had a much lower benefit cost value (even though still positive). Absent the ability to control the actions of other parties, speculation as to which of these two incremental values should be used is fruitless. Further, the mistaken use of this analysis is inconsistent with the cost to consumers of actual pipeline capacity, which is determined on an average cost basis by FERC.

Relying on an incremental or marginal cost measurement protocol to evaluate benefits creates a dynamic problem analogous to that created by the current market paradigm for generators, but in reverse. Each state investor will now want to be "the first" to invest, but only if no other party "would have" invested, because with the assumed investment by each subsequent party, the incremental value of its own investment "decreases." Likewise, if each state assumes that it is the last to invest, then the value of its investment looks, at least by this mistaken analysis, to be diminished compared to the investments made by others. Once again, there is no principled way to avoid this dynamic absent a binding regional agreement, which is unlikely to be practical given the time frame within which action must be taken.[25] Notably, if a regional agreement could be reached, its allocation of costs and benefits would rely upon the average cost methodology, as states' consumers would share equally in costs and benefits on a per kilowatt hour basis.

As a matter of technical and economic realism, New Hampshire cannot act alone even if it wished to. Neither the Northeast Energy Direct nor the Spectra project could ever be built based solely on New Hampshire's pro rata share of a 2 Bcf/d regional target. If New Hampshire invests and these projects go forward, it will be on a scale well in excess of New Hampshire's

[25] Even if precedent Agreements were signed today, needed expansion could not be complete until the end of 2018, at the earliest. In the interim Ratepayers will continue to suffer unnecessary harm in the range of $2-3 billion per year, a huge opportunity cost loss to the region.

pro rata share. Thus, looking at incremental values and cost on the very low end of the investment scale is unrealistic. New Hampshire's example and investment may well be critical to moving these projects forward, but a far more realistic example of the shifting value of such investment is provided on page 58 of the CES testimony where an increment of capacity moving procurement from 1.4 to 1.6 Bcf/d is considered. This is a scale that might support either Spectra or NED or both and thus offers a more realistic point of potential reference. At the level of investment that would actually get these projects built, the benefit to New Hampshire ratepayers in terms of lower energy costs alone is consistently positive. Thus if New Hampshire were to commit to its pro rata share on either of these projects, the eventual expansion would either be at a level that assured benefits or it simply would not happen.

The effect of evaluating costs and benefits on an average basis under the assumption that the region as a whole will invest in a target amount of capacity protects New Hampshire ratepayers by assuring that they are not burdened with more than their "fair share" of any solution and if other states refuse to act, the benefit/cost ratio of their own investment will only increase.

3. Whether the Preferred Solution is Part of a Regional Solution to Reduce Wholesale Electricity Prices. If so, Describe the Regional Solution and Specify all Approvals Needed to Ensure Such Solution Moves Forward

The best way for six states with differing political, legislative processes and laws to come to a comprehensive solution is for each state to act responsibly within its capabilities under the assumption that other states will act accordingly. This is a de facto regional solution, not unlike the Regional Greenhouse Gas Initiative.[26] The framework we set out here does not depend on

[26] See, Regional Greenhouse Gas Initiative website, *available at* http://www.rggi.org/. ("The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland,

action by any other state, assures New Hampshire ratepayers will receive benefit regardless of the actions of any other state, and would encourage by fact and moral example the development of a comprehensive regional solution. Thus, the course outlined herein is compatible with development of a regional solution, and would likely even lend encouragement to one, but is not dependent for its efficacy on any such regional solution.

The coordinated regional approach guided by the New England States Committee on Electricity over the past years unfortunately did not result in a consensus of the six New England States to create a mechanism to expand pipeline capacity into New England. Consequently, individual state commissions have undertaken to address the issue, including this Commission, the Maine Public Utilities Commission and the Massachusetts Department of Public Utilities.[27] Connecticut and Rhode Island apparently will open proceedings to examine these issues as well. The results of the Maine proceeding have not been determined, but both Maine's statutes and the apparent direction of the Maine proceeding indicate compatibility with CLEC's suggested approach. Thus, at this writing it would appear that five New England states comprising about 95% of New England's electric load are headed in compatible directions.

Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce power sector CO2 emissions.

RGGI is composed of <u>individual</u> CO2 Budget Trading Programs in each participating state. Through independent regulations, based on the RGGI Model Rule (2013) and the Summary of RGGI Model Rule Changes, each state's CO2 Budget Trading Program limits emissions of CO2 from electric power plants, issues CO2 allowances and <u>establishes participation in regional CO2 allowance auctions</u>. …

Regulated power plants can use a CO2 allowance issued by any participating state to demonstrate compliance with an <u>individual state program</u>. <u>In this manner, the state programs, in aggregate, function as a single regional compliance market for CO2 emissions</u>." (emphasis added)).

[27] The Maine Public Utilities Commission is in the midst of proceedings on these issues prompted by the enactment of legislation requiring the Maine Commission to determine whether Maine should enter into a contract supporting pipeline expansion. Docket No. 2014-00071, Re: Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A M.R.S. § 1901.

4. **<u>For the Pipeline-Based Solutions, Specify the Firm Pipeline Capacity in Dth/day to be Purchased by Each EDC, the Associated Annual Cost and the Contract Term, Identify the Pipeline Project to which the Estimated Annual Cost Relates, Provide the Estimated Benefit-Cost Ratio for Such a Project and the Projected Reduction in Wholesale and/or Retail Electricity Prices.</u>**

A. Payback Analysis.

CLEC does not have access to actual cost information regarding particular pipeline projects. We can, however, lay out the means by which benefit-cost ratios can be derived and reductions in wholesale electric costs can be estimated. Further, we can provide examples at assumed capacity prices or rates.

First, the fixed regional incremental capacity target amount, described in the decisional framework above, can be determined using Figure 1 provided by CES.[28]

[28] CES Testimony at Figure 9.

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers				
	Pipeline Capacity	Hours of Generation by Fuel Type		
Pipeline Capacity	bcf/d	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

	Annual Energy Costs	Incremental Savings	Cumulative Savings	Load Weighted Avg. Energy Price
Pipeline Capacity	($)	($)	($)	($/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

Figure 1

Using this information one can compare the cumulative savings to ratepayers from reduced electric charges at any level of investment with the total incremental capacity. Dividing the former by the latter, yields an average benefit per Bcf/d value at each level of investment.[29] This should then be compared to the total cost of purchasing pipeline at each level based on offers provided by the pipelines. The Commission should obtain actual information by soliciting offers from pipelines as part of this proceeding. CLEC would then suggest that the regional target for incremental procurement be established at the level of investment where the cost of the total investment in pipeline equals the total benefits to be received by ratepayers over 5 to 10 year pay-back period. This means that the projected savings to ratepayers must meet or exceed the total cost of the project within a five to ten year window from commencement of commercial operations. This is consistent with the analysis by CES that has determined that market developments that could seriously impair the value of an investment in pipeline are highly unlikely to occur within such a time frame.[30]

This is a conservative estimate of benefits given that (1) the average benefit per dollar invested only increases as less is purchased and (2) many of the benefits associated with additional pipeline capacity cannot be captured adequately in terms of lower electricity costs, and thus come on top of the benefits established through this method.[31] It is reasonable to assume that, regardless of the "order" in which investments are made, the region as a whole will not continue to invest beyond the point where average costs exceed average benefits. CLEC believes

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[29] CES and others have provided studies which bracket a reasonable and conservative range of expected benefits to be achieved through varying levels of pipeline capacity investment. These benefits should be compared to the cost proposed for various increments of new pipeline capacity to determine where the cost and benefit curves intersect, such that total benefits equal total costs. Some reasonable margin for benefits to exceed costs could be included, although the states should be aware that not all of the benefits in terms of economic development and environmental improvement can be captured simply by comparing the costs to the savings to be achieved through lower electricity rates.

[30] See CES testimony pages 43-51 Identifying and Assessing the Risks of Long Term Gas Pipeline Capacity Purchases.

[31] For example, additional capacity will benefit the region's and New Hampshire's natural gas customers by lowering the average cost of natural gas to these customers. New Hampshire's Liberty Utilities has estimated that elimination of gas pipeline bottlenecks would allow a forty percent reduction in the cost of home heating.

that, given the multiple environmental, economic and reliability benefits beyond what can be captured in the CES model resulting from simple reductions in energy prices, it would be reasonable for the region to continue to invest until the total benefit over the selected payback period equals the total cost of the investment. In this way, New Hampshire can move forward with assurance that its investment will yield benefits for its ratepayers and the region as a whole. If each state were to procure its load ratio share of this capacity, each state would be making an investment whose benefits exceeded its costs. In the event that some state does not procure its pro rata share of such capacity, the average benefits achieved for each dollar invested by those who have invested simply goes up, although the total benefit to New England consumers falls when compared to what would have occurred had each state done its share. Thus, while for environmental, social and broad economic development reasons it would be better if every state purchased its pro rata share, the benefit *per* dollar invested will only increase due to this failure to act by some portion of the states. This is true even though their failure to act will reduce overall benefits to the region compared to what could have been achieved if all states had invested up to their pro rata share.

It is true that states not investing their fair share would still enjoy the benefits of the investment made by the others. But New Hampshire ratepayers would still have made their own investments on terms that were favorable to them as compared to not having made them. Given the economic and environmental challenges facing the region and the need for prompt action, these measurement and analytic protocols are reasonable and prudent.

Figure 2, below, demonstrates how this payback analysis would work. For simplicity, we have assumed that the cost of a pipeline reservation would be $1.50 per Dth per day. At this amount, the full cost of commitments totaling 2.0 Bcf/day would be $1,095,000,000 per year, and the full twenty year cost would be approximately $22 billion. Taking the annual savings from 2.0 Bcf/day of additional capacity from Figure 1, above, we see that the cumulative savings from such additional capacity would exceed the cost in approximately eight years:

Sample Breakeven Analysis

Year	Reservation Cost*	Saving**	Cumulative Savings	
1	1,095,000,000	2,873,971,033	2,873,971,033	
2	1,095,000,000	2,873,971,033	5,747,942,066	
3	1,095,000,000	2,873,971,033	8,621,913,099	
4	1,095,000,000	2,873,971,033	11,495,884,132	
5	1,095,000,000	2,873,971,033	14,369,855,165	
6	1,095,000,000	2,873,971,033	17,243,826,198	
7	1,095,000,000	2,873,971,033	20,117,797,231	
8	1,095,000,000	2,873,971,033	22,991,768,264	Breakeven
9	1,095,000,000	2,873,971,033	25,865,739,297	
10	1,095,000,000	2,873,971,033	28,739,710,330	
11	1,095,000,000	2,873,971,033	31,613,681,363	
12	1,095,000,000	2,873,971,033	34,487,652,396	
13	1,095,000,000	2,873,971,033	37,361,623,429	
14	1,095,000,000	2,873,971,033	40,235,594,462	
15	1,095,000,000	2,873,971,033	43,109,565,495	
16	1,095,000,000	2,873,971,033	45,983,536,528	
17	1,095,000,000	2,873,971,033	48,857,507,561	
18	1,095,000,000	2,873,971,033	51,731,478,594	
19	1,095,000,000	2,873,971,033	54,605,449,627	
20	1,095,000,000	2,873,971,033	57,479,420,660	
	21,900,000,000			
* - 2 Bcf/day at $1.50/Dth/day = $1.50 x 2,000,000 x 365				
** - CES Estimate of Cumulative Savings from 2.0 Bcf/day				

Figure 2

B. Payback Period vs. Contract Period.

The benefit/cost ratio needs to be calculated over a reasonable time period. Although these assets are long lived and will continue to provide benefits far into the future, general economic and other trends become less and less certain as they are projected further into the future. Even though there will be benefits from utilization of the same infrastructure for the entire useful life of the projects, quantification of those benefits becomes more speculative the further one extends the analysis. We have recommended that the Commission adopt the CES recommendation of a 5-10 year analysis, a relatively short period of time. Given the extended useful life of these projects, CLEC believes that this is an extremely conservative payback schedule, and one which assures that the margin of benefits to be garnered by ratepayers is substantial.

Adopting a conservative payback period as a benefit/cost screen should not be confused, however, with false assertions or assumptions that the benefits derived from these projects will in fact cease after 5-10 years. Some gas opponents advance the misconception that long lived pipeline assets will become "stranded" either operationally, financially or both, as the power portfolio in New England changes over time. On the financial side, the claim is that, under a typical 20-year capacity commitment, ratepayers may still be "paying" for these assets long after they are no longer needed to suppress the basis differential because, as time passes, our total energy needs (total kWh production by fuel type) must move away from reliance on natural gas to renewable sources. Therefore, some argue, the fact that consumers may still be "servicing the debt" for pipeline capacity in these out years means consumers have been burdened with "stranded" or "uneconomic" costs. These arguments are incorrect both financially and operationally. Financially, they rest upon semantics rather than sound economics; operationally, they fail to account for the benefits of flexible operations that only natural gas infrastructure can enable that will be needed to support all future progress towards a more renewable based generation portfolio in New England.

The financial argument that these assets will become "stranded costs" in the future confuses two concepts. The first is the total economic cost benefit of any transaction. The second is the temporal matching of the benefit stream with the financing term. Under the framework for decision outlined here, ratepayers will receive benefits (in terms of lower rates for power) within the first 5-10 years of project operations that exceed the *total* costs to be extracted from them over the full financing term of any pipeline expansion. Benefits will continue to accrue even after this point, but no additional costs are incurred, because the total cost under a fixed financing contract will not increase. After the 5-10 year window the investment is already "economic" and not financially "stranded." In fact, under reasonable interest assumptions and absent a period of sustained deflation, the total benefit that accrues to ratepayers is likely increased the further the financing period is extended.

The second fallacy is based on a misunderstanding of the operational role of expanded pipeline capacity in the future. There is no reasonable expectation that expanded pipeline capacity into the region will not continue to be used, useful and, in fact, an essential element in meeting climate and economic goals for the foreseeable future. Those who argue that increased "dependence" on natural gas is inconsistent with climate goals fail to recognize the operational distinction between capacity and total MMbtu throughput and the essential future role of gas as a swing or ramping resource to enable reliable operations as a larger and larger percentage of New England energy is supplied by intermittent and renewable resources. The expansion of natural gas pipeline infrastructure into New England is critical to the integration of renewable generation resources into the New England grid. Further, the need for increased pipeline capacity to support this ramping function is wholly consistent with a diminished role for gas in the production of energy as more renewables are integrated. The instantaneous demands for gas generators to ramp to full output and back, potentially several times a day and in a variety of locations, to respond to contingencies and provide ancillary service support can only be accommodated through robust capacity and compression services available at little or no notice. These instantaneous demands imply a shift from base-load operations (energy) to reliability based (capacity dependent) services that make intense but shorter demands for output (less energy) but still require the full range of output (capacity) to be available for dispatch. These issues are discussed more comprehensively in response to the Staff's reliability inquiry.

7. Whether the Preferred Solution Will Enhance Reliability of the Electric Power System in New Hampshire and the Region. If so, Explain How the Preferred Solution Enhances Reliability.

A. Increasing Pipeline Capacity into New England will Enhance Electrical Reliability in New Hampshire and the Region

There is little question that increasing natural gas pipeline capacity into the New England region would enhance electric reliability for New Hampshire and the entire New England region. As ISO New England and its executives have recognized, "New England has a serious and growing reliability problem due to gas pipeline constraints, a growing resource performance problem, retirements of non-gas generation, and a growing need to balance an increasing amount of intermittent renewable energy."[32]

During the 2012-13 winter period, ISO New England recognized significant reliability threats to the region's electric grid resulting from the inadequacy of existing natural gas pipeline infrastructure. For instance, in its 2013 Regional System Plan, ISO New England described the lack of adequate gas infrastructure as "causing persistent reliability concerns."[33]

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[32] ISO NE, "Prepared Statement for Gordon van Welie" (U.S. Department of Energy -- Quadrennial Energy Review Meeting), page 7 (April, 21, 2014).
[33] ISO New England, *Regional System Plan* (November 7, 2013) at p. 126.

As a result of its electric reliability concerns, for the 2013-14 winter period ISO New England implemented a Winter Reliability Program.[34] This program adopted extraordinary measures to ensure that various generators would have adequate fuel supply to operate during periods of natural gas shortages.[35]

Despite adopting these extraordinary measures, the reliable operation of the New England grid was again threatened during the 2013-14 winter period. Following the 2013-14 winter period, ISO New England CEO Gordon van Welie told the U.S. Department of Energy that "New England has a serious and growing reliability problem due to gas pipeline constraints, a growing resource performance problem, retirements of non-gas generation, and a growing need to balance an increasing amount of intermittent renewable energy."[36]

In its 2014 Regional System Plan,[37] ISO New England described the experience during the 2013-14 winter period as follows:

> With virtually all the natural gas- and oil-fired generators operating with limited fuel inventories and constrained energy-production capabilities, the *reliable operation of the grid proved challenging for the ISO*. During the coldest days, the ISO carried gas-fired units as reserves, *but the increased dispatches to provide these reserves further stressed the gas pipelines for covering non-gas-fired contingencies*.[38]

Because of its experience during 2013-14, ISO New England adopted an even more aggressive winter reliability program, for the 2014-15 winter period,[39] and has revised its long term capacity market rules to implement Performance Incentives ("PI") to improve unit availability. Even with these measures, ISO New England has informed regional stakeholders that "power system reliability will continue to be threatened until the region invests in sufficient

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[34] *ISO New England Inc.*, 144 FERC 61,204 (2013).
[35] *Id*.
[36] ISO NE, "Prepared Statement for Gordon van Welie" at the U.S. Department of Energy -- Quadrennial Energy Review Meeting (April 21, 2014).
[37] ISO New England, Inc., *Regional System Plan* (November 6, 2014).
[38] *Id.* at p. 132 (emphasis supplied).
[39] ISO New England Inc., Docket No. ER14-2401-000, Winter 2014-15 Reliability Program (Part 1 of 2) (July 11, 2014) at 4-6.

infrastructure to either resolve the pipeline constraints, or sufficiently offset the need for natural gas through investment in other fuels or energy sources."[40] Other measures are simply inadequate.

The threats to system reliability faced in 2012-13 and 2013-14 do not reflect the shutdowns of the 604 MW Vermont Yankee nuclear generating facility, the 342 MW Norwalk Harbor Station oil-fired facility or the 1,535 MW Brayton Point coal fired generating facility.[41] In addition, ISO New England has identified up to 6,000 MW of additional non-gas-fired generation that is "at risk" for retirement by 2020, consisting of 28 older oil and coal units.[42] These retirements seem likely given both the age of the units and the U.S. Environmental Protection Agency's Clean Power Plan, announced June 2, 2014, as well as other public policy initiatives intended to reduce reliance on coal and oil fired generation in New England, including the Regional Greenhouse Gas Initiative.

ISO New England states that the majority of the replacement resources are likely to be natural-gas-fired units.[43] For comparison, today there are approximately 11,000 MW of winter capacity resources in New England that are fired only by gas and approximately 7,000 MW of gas/oil dual fueled resources,[44] supplying about half of the electricity consumed annually in New England.[45] If, as ISO New England anticipates, the majority of the 8,300 MW+ of retiring electric generating capacity is replaced by natural gas fired capacity, the demand for natural gas to serve electric generating units would increase by up to 5,000 MW over the next five years.

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[40] ISO New England, Press Release-2014-2015 Winter Outlook-Sufficient Power Supplies Expected, but Natural Gas Pipeline Constraints an Ongoing Concern (November 20, 2014).
[41] ISO New England, Inc., *2014 Regional Electricity Outlook*, at pp. 15.
[42] *Id.* at pp. 14-15.
[43] *Id*. at p. 15.
[44] ISO New England, Inc., ISO New England, Inc., CELT Report – 2014-2023 Forecast Report of Capacity, Energy, Loads and Transmission (May 1, 2014, revised May 16, 2014)(the "2014 CELT Report") at 2.3.2, 2.3.3 and 2.3.4.
[45] ISO New England, Inc., *2014 Regional Electricity Outlook* at p. 13.

The reliability challenges faced by ISO New England in recent winters also do not reflect the fact that production from both the Deep Panuke and Sable Island gas fields is slowing. In recent years, these fields have combined to produce at a rate of approximately .35 Bcf/d during the winter period. Based on published production estimates, expected output from both fields' facilities will fall over the next five years, with production at Sable Island falling from .180 Bcf/d to below .1 Bcf/d, and production at Deep Panuke falling from .3 to .1 Bcf/d. During this same period, natural gas usage in Nova Scotia and New Brunswick is expected to increase from .2 to .25 Bcf/d during the winter months, so much if not all eastern Canadian gas will be consumed in Eastern Canada. Recent announcements even suggest that the Sable Island field may be shut down even sooner.[46] Thus, in the near future, exports from the Maritimes provinces can reasonably be anticipated to be at least .33 Bcf/d lower than recent winters.

Finally, the recent electric reliability challenges resulting from inadequate gas pipeline capacity do not yet reflect increased LDC customer demand for natural gas. The price and other favorable characteristics of natural gas, as well as public policy initiatives in some New England states, is driving consumers to switch from oil to natural gas for domestic heating.[47] Many commercial and industrial consumers are also seeking to replace oil with natural gas where possible.

Many of these factors were examined by ICF International in its November, 2014 report to ISO New England,[48] ICF sought to quantify New England's natural gas supply capabilities (contracted pipeline capacity, peak shaving capabilities, and LNG import facilities) and

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[46] See, e.g, Halifax Herald Business, "Sable's end point disputed" (August 19, 2014), available at http://thechronicleherald.ca/business/1230615-sable-s-end-point-disputed.

[47] See, e.g., CES Testimony at 29; "Natural gas companies plan major expansion in CT," Newstimes.com (June 17, 2013)(Three Connecticut gas utilities have filed "expansion plans to provide gas heating to 280,000 new customers in the next decade").

[48] ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II* (November 20, 2014).

projections for growth in peak day gas loads for the region's LDCs, and compare these values to ISO New England's projections for power sector peak day gas consumption for the purpose of assessing the adequacy of New England gas supplies to meet the growth in peak day gas loads.[49] ICF concluded that "[b]ased on projected gas supplies, LDC demands, and electric generator gas demands, there is a *high probability that the electric sector will have a gas supply deficit on 24 to 34 days per winter by 2019/20*."[50]

Given the current and projected magnitude of the deficit in pipeline capacity serving New England, and its threat to the reliability of the New England, the development of additional pipeline capacity is essential to maintaining the reliability of the New England grid.

B. No Other Option Can Adequately Address the Reliability Problem

Some have suggested that other options could address New England's reliability problem, but no alternative solution addresses the reliability problem as effectively as expanded pipeline capacity.

ISO New England itself has focused on increasing the amount of dual fuel capacity in the region as a potential solution, particularly in the near term when gas supply is insufficient to meet winter peak demand. However, ISO New England also concedes that dual fuel units are not as fully reliable. For instance, in its 2014 Regional System Plan, ISO New England stated that "the natural gas units with dual-fuel capability have not always been effective or timely in switching to using oil."[51] Dual fuel units also face the potential for curtailment in order to meet emissions limitations and many may not be able maintain dual fuel operation in the long term due to environmental regulations and policies:[52]

[49] *Id*. at p. 6.
[50] *Id*. at p. 5 (emphasis supplied).
[51] ISO New England, 2014 Regional System Plan at pp. 5-6.
[52] ISO New England, 2015 Regional Electricity Plan at p 31..

> In some cases, state regulations restrict the number of hours that dual-fuel units can burn oil. And over time, the Regional Greenhouse Gas Initiative's cap and trade program for carbon dioxide emissions could make oil and coal less economic fuels.

Finally, "many oil and dual-fuel generators burned through their supplies and experienced difficulty in securing additional oil inventories."[53]

Reliance on LNG to meet peak demand also presents potential reliability problems. ISO New England had stated that "LNG supplies, while beneficial, have been subject to competition from growing worldwide demand."[54] Further, during February, 2014, "LNG deliveries became intermittent when one LNG import terminal ran out of fuel and another terminal was unable to dock and unload cargoes because of poor weather conditions."[55]

Finally, new and existing Canadian imports are not well suited to address New England's reliability issue. ISO New England has stated that "[i]mported Canadian hydropower is limited during very cold weather (because Québec is a winter-peaking system)."[56] This is not just a theoretical limitation, as demonstrated by an event this past winter:[57]

> System operators implemented Operating Procedure 4, Actions during a Capacity Deficiency once during the winter because of an event originating outside New England. On December 4, 2014, Hydro Québec experienced outages on two of its major transmission lines and had to significantly cut electricity exports to New England and other neighboring areas. The ISO brought additional generation online to maintain grid reliability in New England and also to provide support to our northern neighbors as they worked to restore their system to normal operations. OP-4 was implemented at 4:15 p.m. and was cancelled at 8:45 p.m.

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[53] ISO New England, Press Release, "Oil inventory key in maintaining reliability through colder weather during winter 2013-2014" (April 4, 2014)
[54] ISO New England, 2014 Regional System Plan at pp. 5-6.
[55] ISO New England, Press Release, New England power system performed well through winter 2014-2015 (April 7, 2015)
[56] ISO New England, Managing the Reliability of the Electric Grid While the Power Industry Undergoes Rapid Transformation (September 19, 2014)
[57] ISO New England, Press Release, "New England power system performed well through winter 2014-2015," (April 7, 2015)

Thus, expanding natural gas pipeline capacity is the preferred mechanism for addressing New England's reliability issues.

C. No Specific Pipeline Project Provides any Advantage with respect to Addressing Reliability Concerns; Both Major Projects are Necessary

CLEC supports the construction of a minimum of 2 Bcf/d of additional capacity carried over 2 pipelines, Tennessee Gas Pipeline's Northeast Energy Direct project and Spectra's Access Northeast project, as the preferred solution to New England energy cost crisis and reliability problems, as well as to facilitate greater integration of renewables into the electric grid. Two pipelines enhance reliability by providing invaluable diversity of supply and by ensuring that all gas fired generators in New England have fair access to gas supply. From the perspective of consumers, it would be a tragedy to choose one project over the other and, as a result, to have only one project constructed.

For example, Spectra has actively promoted its ability to serve a significant number of gas-fired units as evidencing the superiority of its Access Northeast Project over other pipeline proposals. A careful review of ISO New England's CELT Report,[58] however, suggests that the Access Northeast Project has no meaningful advantage, particularly with respect to grid reliability.

Specifically, Spectra has claimed to exclusively serve 21 natural gas-fired generating units on its Algonquin pipeline system.[59] The units that it has identified represent approximately 7,300 MW of capacity.[60] However, review of the 2014 CELT Report demonstrates that 12 of the 21 units are dual fuel units capable of burning residual fuel oil, distillate or kerosene.[61] These

[58] 2014 CELT Report.
[59] Spectra Proposal For an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission (December 5, 2014).
[60] 2014 CELT Report at 2.3.2, 2.3.3 and 2.3.4.
[61] *Id*.

units constitute approximately 3,500 MW of capacity and would have been available to provide service during critical reliability hours regardless of the availability of gas supply. Critically, the 3,800 MW of gas-only capacity served by the Algonquin system constitutes only 34% of the gas-only generating capacity in New England.

Spectra has also touted its ability to provide increased flow from Algonquin system to the Maritimes & Northeast Pipeline System.[62] To the extent that Spectra Energy is suggesting that its Access Northeast and Atlantic Bridge projects have the sole ability to provide combined service with Maritimes & Northeast, such an implication is at best misleading and at worst a misrepresentation of FERC's open access requirements.

Maritimes & Northeast Pipeline provides service subject to the jurisdiction of FERC and subject to FERC's open access policies and the Natural Gas Act's prohibition of undue discrimination and preference in providing transportation service. Both the PNGTS and the Tennessee Gas Pipeline systems interconnect with the Maritimes & Northeast system. If additional flows to generators located on the Maritimes & Northeast system are required, such service must be offered to deliveries off of any interconnecting pipeline. Maritimes & Northeast must offer available service to Maine and New Hampshire shippers regardless of whether such gas originates from the Algonquin system, the PNGTS system, or the TGP system.

The existing TGP system in Massachusetts also feeds huge volumes of gas into the Algonquin system to serve generators located on that system. Because of its strategic delivery point at the Dracut, Massachusetts TGP's Northeast Energy Direct project will also be capable of feeding additional gas into the existing Algonquin system, as well as the Maritime & Northeast Pipeline system, to serve generators located on those systems. This is possible because, if the

[62] Spectra Proposal For an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission (December 5, 2014).

predominant direction of flows on the Algonquin system is west to east, it is possible to inject gas from a point on the eastern end of the Algonquin system to serve generators on the Algonquin system from east to west. Further, TGP's Northeast Energy Direct project delivers to Dracut at significantly higher pressures and thus develops a large bi-directional loop throughout the entire Northeast pipeline network. Thus, it will be able to take advantage of existing pipeline capacity to serve virtually all of the 66% of gas-only generation capacity in New England not served by Algonquin, plus a significant portion of the 34% that is served by Algonquin.

Finally, the location of future generation is critical. ISO New England has identified the "Central Massachusetts Hub," as a strategic location for new generating facilities to replace older coal and oil units being retired.[63] ISO New England described the hub as "a central trading location in energy market where no significant energy congestion is expected."[64]

This electric transmission hub parallels the existing Tennessee Gas Pipeline transmission line along the southern Massachusetts border with Connecticut and Rhode Island and the proposed Northeast Energy Direct Project parallels the northern edge of the hub. Indeed, the Northeast Energy Direct Project will be collocated in part with the 345 kV electric transmission system that forms the Northern edge of the hub, including locations in New Hampshire. This collocation will permit strategic location of new generation. Critically, construction in this region will permit generating resources necessary for reliable operation of the electric grid to be developed without the need for costly electric transmission system upgrades.

ISO New England estimates that approximately 8,300 MW of nuclear, coal and oil unit retirements will need to be substantially replaced, and that the majority of the replacement

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[63] ISO New England, Inc., *ISO New England's Strategic Transmission Analysis* (June 14, 2013) at slide 9.
[64] *Id*.

resources are likely to be natural-gas-fired units.[65] ISO New England envisions a significant portion this generation to be located at the hub or to be seamlessly interconnected with it. In considering the reliability benefits offered by pipeline expansion, CLEC urges the Commission to consider the benefits not just of existing generation, but new generation required to maintain grid reliability in New England in the face of recent and likely further retirements.

Finally, it is imperative that private parties, such as EDCs, not be allowed to set or otherwise determine the amounts of capacity to be purchased. This is a fundamentally public decision. This is particularly true where EDCs or their affiliates may own interests in pipelines, pipeline capacity or competing energy infrastructure projects, and thus may have conflicting objectives.

To be clear, CLEC is not suggesting that construction of the Access Northeast project would not enhance reliability. Rather, to address fully the reliability concerns posed by inadequate pipeline infrastructure, it would be inappropriate to rely on Access Northeast alone. As with the problem of price, reliability can only be fully addressed with two pipelines and 2 Bcf/d of new capacity. Half-measures or "small bites" will simply perpetuate the status quo.

D. Additional Pipeline Capacity is Critical to Reliable Integration of Renewables into the New England Grid.

Expansion of the natural gas pipeline infrastructure into New England is critical to the integration of renewable generation resources into the New England grid at the level necessary to achieve public policy goals.

California has faced a similar challenge. In responding to operational concerns created by that state's push towards greater reliance on intermittent and renewable resources, the

[65] *2014 Regional Electricity Outlook*, at p. 15.

California ISO identified a laundry list of operational characteristics required of resources to assure reliable grid operations:

> **Green grid reliability requires flexible resource capabilities**
>
> To reliably operate in these conditions, the ISO requires flexible resources defined by their operating capabilities. These characteristics include the ability to perform the following functions:
>
> • sustain upward or downward ramp;
> • respond for a defined period of time;
> • change ramp directions quickly;
> • store energy or modify use;
> • react quickly and meet expected operating levels;
> • start with short notice from a zero or low-electricity operating level;
> • start and stop multiple times per day; and
> • accurately forecast operating capability.[66]

With the exception of the "storage" function, this is almost a complete operational capability list for a gas generator *provided* that generator has access to sufficient gas pipeline capacity and compression to draw up to its full demand when called upon to ramp. Unlike electricity which travels at the speed of light, gas travels at approximately 30 miles an hour when properly pressurized. Gas generators have the desirable feature of being able to ramp quickly in response to changes in demand or fluctuations in the output of other generation, but such ramping requires immediate access to volumes of gas (i.e., capacity) at sustainable pressures. Even if the generator is seldom used (because, for environmental reasons the region chooses to get most of its *energy* from renewables), the capacity needed for it to effectively serve such a ramping function requires facilities to be sized to serve the generator's maximum potential draw (capacity) on demand in response to fluctuations in (for example) solar output. Moreover, for reliability and other reasons such as voltage support, stability and transmission contingencies, a variety of generators will each need to have this capability at multiple electrical locations, even if it is never anticipated that they will all run simultaneously. Each such generator at each location

[66] California ISO, *Fast Facts: What the Duck Curve Tells us About Managing a Green Grid*, available at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

must be able to draw at maximum capacity and sustainable pressures, even if only for a short period, in order to effectively serve a reliable ramping function. This means that even if the capacity on the pipes is no longer utilized for baseload or intermediate generation operations, in order to serve as a ramping resource, generation will need access to at least the same, or greater, instantaneous capacity in order to operate reliably and permit the transition to a more renewable based resource mix.

ISO New England agrees: "Developers are proposing over 5,000 megawatts (MW) of natural gas-fired resources and over 3,000 MW of wind resources (nameplate capacity). New England's electric grid will remain heavily dependent on natural gas and will see a growing level of renewable energy – requiring a flexible fleet to balance the variability of those renewable resources."[67]

ISO New England continued: "As more renewable energy connects to the grid, and as the region loses conventional non-gas fired generation, the need increases for responsive resources that are not operationally constrained by fuel infrastructure limitations."[68] ISO-NE concluded that the region will need "[a] responsive fleet of generation (with adequate fuel infrastructure) and demand-side resources, to balance variable renewables."[69]

Critically, even though ramping functions require access to greater capacity, this is entirely consistent with the percentage of total *energy* being produced by burning natural gas declining over time as more total energy is supplied by renewables. Those who argue that building pipeline infrastructure "dooms" New England to burn greater volumes of gas willfully ignore this dynamic, as well as the demonstrated environmental harm of perpetuating existing

[67] ISO New England, "Final Comments on U.S. DOE's Quadrennial Energy Review," page 2 (10.10.14).
[68] ISO New England, "Managing the Reliability of the Electric Grid While the Power Industry Undergoes Rapid Transformation – Massachusetts Restructuring Roundtable" (September 19, 2014) at slide 17.
[69] *Id*. at slide 23.

reliance on coal and oil. Nor can these parties explain how reliable grid operations can be maintained without such resources as we move towards greater penetration of renewables. In fact, the lack of ramping resources will very quickly set a technological upper bound on renewable and intermittent resource integration that will fall well short of the region's aspirations absent the addition of resources with these capabilities and the pipeline capacity to support them.[70]

There are no other realistic and environmentally sound options for such swing operations. Nuclear simply cannot be ramped. Coal and oil can be, but are less flexible than the current vintage of combined cycle gas-fired generation and far less desirable environmentally. They further suffer from the reliability issue associated with fuel delivery discussed above. Demand response cannot be called on repeatedly in the course of each operating day in the volumes needed without inducing consumer fatigue. Demand Response also is best used as a peak shaving, rather than ramping resource. Energy efficiency is not a ramping resource. It may lower the overall load curve over time but offers no system response, ramping, voltage or frequency control capabilities, all of which gas generation provides and all of which are essential to reliably operating a 'green grid.' New England has no significant undeveloped hydro resources; Canadian hydro cannot now provide winter reliability. Storage options at this scale are not yet economically feasible and could not be developed to scale on time to meet current climate targets. Further, even if feasible in the future, large scale storage will involve substantial

[70] ISO New England, "Final Comments on U.S. DOE's Quadrennial Energy Review" (October 10, 2014) at page 2. "Developers are proposing over 5,000 megawatts (MW) of natural gas-fired resources and over 3,000 MW of wind resources (nameplate capacity). New England's electric grid will remain heavily dependent on natural gas and will see a growing level of renewable energy – requiring a flexible fleet to balance the variability of those renewable resources."

capital costs that may simply duplicate the capabilities of the pipeline capacity that needs to be developed currently.[71]

The arguments against "dependence" on natural gas are based on the false assumption that increased capacity is only valuable if gas is intended to serve a baseload generation function. This is an incorrect and dangerously short-sighted argument. Expanded pipeline capacity into New England is an essential component in creating the infrastructure needed to support the reliable integration of and a transition to a renewable and intermittent resource based energy mix.

8. <u>Provide All Studies that Support the Claimed (i) Benefit-Cost Ratio(s); (ii) Reduction in Wholesale and/or Retail Electricity Prices and (iii) Reliability Enhancement</u>

In response to this request, CLEC has listed numerous studies and references with open links to the content of these studies and references. This form of presenting the information called for by this request was authorized by staff counsel. CLEC has attached the full and complete Direct Testimony and Exhibits of Richard Silkman and Mark Isaacson, dated June 2, 2015 (the "CES Testimony").

(i) See response to Staff Request 4, above.

(ii) <u>Reduction in Wholesale and/or Retail Electricity Prices</u>

1. Competitive Energy Services; Direct Testimony and Exhibit June 2, 2015, appended in full under subsection (iv). See pp. 32-35.
2. EIA, Short-Term Energy Outlook Supplement: "*Constraints in New England likely to affect regional energy prices this winter*" (1.18.13) http://www.eia.gov/forecasts/steo/special/pdf/2013_sp_01.pdf

[71] *Id*. at page 3: "The natural gas pipeline constraints are particularly acute during cold weather. During the winter months, the firm capacity taken by LDCs severely limits the natural gas supply available to power generators and reduces their output to minimal levels. … These natural gas resources are particularly important because they are fast-ramping resources that can balance an increasingly variable resource profile in New England (which I discuss below) and fill shortages left by older, less efficient resources that are at times unable to operate. In addition, these circumstances will only worsen in upcoming summers as the gas pipelines remove facilities from service for maintenance and, more significantly, for the already planned expansion outages that are supported by LDC contracts."

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Conclusion

CLEC commends the Commission and its Staff for their efforts in this vital matter. Prompt, prudent and public minded action is a necessity for NH consumers and the region as a whole. CLEC respectfully urges the adoption of the recommendations herein as the best means of meeting that objective.

Respectfully submitted, this 2nd day of June, 2015

/s/ Peter W. Brown

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