Liberty Utilities

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 14-380

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
D/B/A LIBERTY UTILITIES

Approval of Tennessee Gas Pipeline, LLC Precedent Agreement

REBUTTAL TESTIMONY
OF
FRANCISCO C. DAFONTE

June 4, 2014

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francisco C. DaFonte. My business address is 15 Buttrick Road, Londonderry, New Hampshire 03053. My current position is that of Vice President, Energy Procurement for Liberty Utilities (EnergyNorth Natural Gas) Corp. ("EnergyNorth or the "Company").

Q. Are you the same Francisco C. DaFonte that submitted Direct Testimony in this proceeding on December 31, 2014?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to discuss the Company's Precedent Agreement ("PA") with the Northeast Energy Direct ("NED") Project in response to the direct testimonies of (i) Ms. Melissa Whitten who filed testimony on behalf of the Staff of the New Hampshire Public Utilities Commission ("Staff"); (ii) Dr. Pradip K. Chattopadhyay, who filed testimony on behalf of the New Hampshire Office of Consumer Advocate ("OCA"); and (iii) Mr. John A. Rosenkranz, who filed testimony on behalf of the Pipeline Awareness Network for the Northeast, Inc., ("PLAN" and collectively with the Staff and OCA witnesses the "Intervening Witnesses"). Prior to presenting my response to the testimony of each witness, I provide certain, necessary context regarding the size, location, and design of the EnergyNorth system and how those aspects make it necessary for EnergyNorth to remain opportunistic when acquiring new pipeline capacity. This context is provided in response to certain criticisms of the EnergyNorth procurement philosophy by all three Intervening Witnesses. Finally, I discuss why it is important for EnergyNorth to preserve options in its gas supply portfolio as the U.S. market continues to evolve.

Q. Please summarize your response to Staff Witness Ms. Whitten.

A. Ms. Whitten's concerns are related to the EnergyNorth demand forecast, certain out-of-model adjustments for the reverse migration of capacity-exempt customers and the expected demand of iNATGAS, the process used to evaluate alternatives to the NED Project, and the planning horizon utilized to establish the quantity outlined in the NED PA. Ms. Whitten's concerns are based on her misunderstanding of the process relied upon by EnergyNorth in developing the demand forecast presented in this proceeding. For example, Ms. Whitten criticizes the Company for failing to use the demand forecasting process utilized in the Company's most recently filed Integrated Resource Plan ("IRP") in November 2013. However, the Company's demand forecast used to decide the quantity listed in the NED PA is nearly identical to the process used in its most recent IRP filing and which was approved by the New Hampshire Public Utilities Commission (the "Commission") on February 9, 2015 in Order No. 25,762.[1] In that order, the Commission noted, "Liberty plainly took a careful approach to examining its demand- and supply-side planning forecasting needs…"[2]

[1] NH PUC Order No. 25,762 in Docket DG 13-31, Order Finding Integrated Resource Plan Adequate, Feb 9, 2015.
[2] *Ibid*., at 5.

To formulate the instant demand forecast, EnergyNorth relied upon the same demand forecasting econometric model from the IRP for forecasting annual demand over the entire 24-year period. That model was updated to reflect an additional year of billings and the most recent Moody's© economic forecast information that underlies the demand forecast model. EnergyNorth used the annual growth factor from the annual demand forecast in developing the 24-year design day forecast.[3]

While Ms. Whitten acknowledges that the Company's comparison of three new capacity options (i.e., NED, C2C, and Atlantic Bridge) is appropriate, she criticizes the Company for failing to consider lower volumes on the NED Project. Ms. Whitten's criticism fails to recognize the significant opportunity the NED Project provides to EnergyNorth's customers from a system reliability, gas supply diversity, and price stability perspective.

In addition, Ms. Whitten fails to acknowledge the commercial realities involved in any negotiation. By joining with other local distribution companies ("LDCs") to form a consortium, EnergyNorth was able to leverage the volumes of other, larger LDCs. However, as in any negotiation, there were necessary points of give and take between the counterparties. As a result, the NED PA should be considered in its entirety (i.e., as an integrated package), which represents the best overall deal negotiated by the broad LDC Consortium. Any change to one component of that package will affect the overall deal and the willingness of the participants to accept any revised deal or package. In other

[3] As noted in the testimony of Company Witness William Clark, EnergyNorth has experienced greater than historical customer growth since the acquisition from National Grid. Nonetheless, EnergyNorth's forecast of customer growth in this docket included some of the historical lower growth experienced by National Grid, resulting in somewhat conservative growth assumptions.

words, the terms of the NED PA before the Commission cannot be changed unilaterally by EnergyNorth. Any change would require a renegotiation of the agreement that may or may not be acceptable to all parties, potentially putting the project itself at risk.

Finally, with regard to her criticism of the Company's planning horizon, Ms. Whitten fails to recognize the limited frequency with which a project like NED is proposed and how it would better position EnergyNorth for the long-term. In other words, failing to obtain the NED capacity precludes the Company from exercising certain existing portfolio options and more importantly forecloses other future options.

Q. Please summarize your response to Dr. Chattopadhyay's direct testimony.

A. Dr. Chattopadhyay's criticisms are related to what he entitles the optimization of the EnergyNorth resource portfolio from an economic standpoint. Dr. Chattopadhyay's conclusions are based on his analysis of certain Sendout® runs which Dr. Chattopadhyay requested the Company perform. By focusing only on selected outputs from the Sendout® model runs, Dr. Chattopadhyay's conclusions do not consider the market and operational realities such as:

- Regional supply issues,
- Regional price differences,
- Pipeline and LDC constraints, and
- Physical operations.

In addition, Dr. Chattopadhyay's analysis fails to consider the various benefits of the NED Project, which include:

- Improved reliability,
- Increased access to the largest natural gas basin in North America, and
- A reduction in price volatility.

Q. Please summarize your response to Mr. Rosenkranz's direct testimony.

A. Mr. Rosenkranz's testimony attempts to present a rationale as to why alternative pipeline projects are better transportation alternatives and why the Company can rely on short-term market area purchases to support its design day needs. His testimony is based on the faulty assumption that natural gas is and will remain available in the market area, specifically Dracut, in similar quantities as have been experienced in previous years. That assumption is notwithstanding the fact that despite the current levels of supply available at Dracut, EnergyNorth still experienced historically high basis differentials in recent winters.[4] Mr. Rosenkranz's analysis fails to account for:

1. Decreasing production at two off-shore production facilities in Atlantic Canada, namely Sable Island and Deep Panuke;
2. Increasing demand in Atlantic Canada that further limits the quantity of natural gas to be shipped into the U.S. Northeast; and

[4] A basis differential or "basis" is the difference between natural gas prices in two locations. It is often used to demonstrate the value of transportation capacity between two locations since theoretically the prices would equalize net of transportation costs if sufficient capacity existed to transport natural gas supply between the two locations.

3. Pricing trends as a result of new transportation capacity from the Marcellus production basin to Wright, NY.

Mr. Rosenkranz's analysis fails to account for major changes in the North American natural gas markets. The rise of Marcellus and Utica natural gas production is fundamentally altering the natural gas market in the U.S. Access to these cost effective resources is crucial to ensure the relative competitiveness of EnergyNorth compared to Southern New England. In contrast, production from offshore Nova Scotia is swiftly declining and expected to be largely exhausted by the time NED enters service. Given these trends, Mr. Rosenkranz's approach would leave EnergyNorth exposed to the rapid price fluctuations that have resulted from natural gas transportation constraints throughout New England and Atlantic Canada.

Finally, Mr. Rosenkranz fails to recognize the reliability enhancement provided by the NED Project and namely the second interconnection that is offered by NED.

Q. Do you have any other responses to the direct testimonies of the Intervening Witnesses?

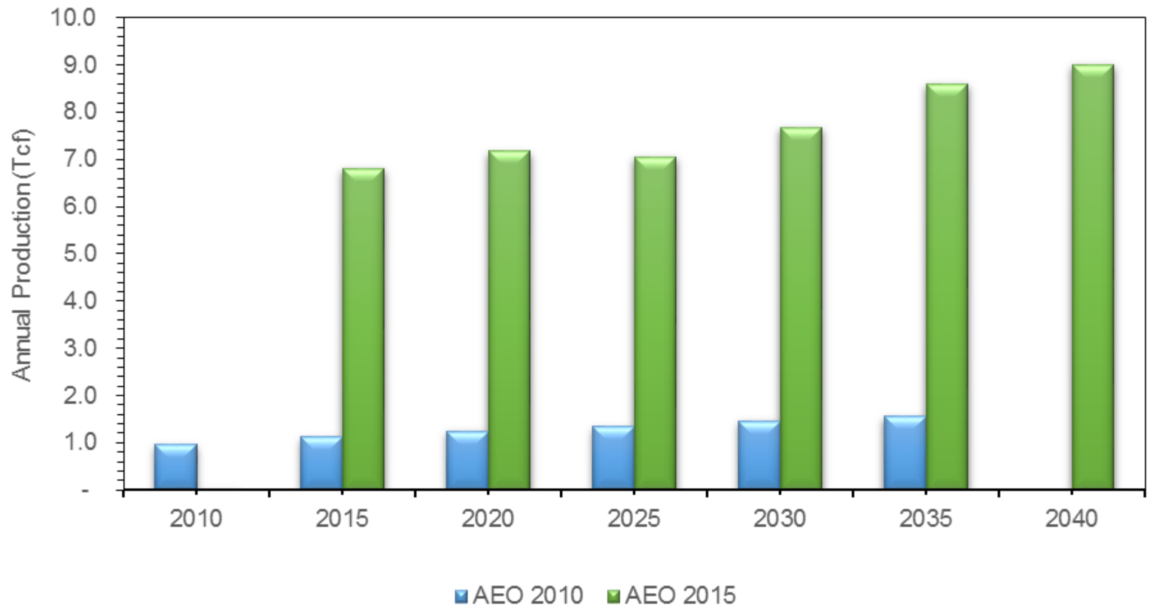
A. Yes, I do. All of the Intervening Witnesses have failed to recognize the current uncertainty in the natural gas market and the need to maintain, or, if possible, expand the available options in the face of that uncertainty. The changes in natural gas flows and availability alter the operations of the natural gas market.

Beginning in 2008, new sources of natural gas supply began to fundamentally shift the natural gas market. Prior to 2008, natural gas supply planning followed a fairly predictable pattern in which natural gas in New England was sourced from traditional production basins in the Gulf of Mexico and Western Canada. Additional supplies were available via LNG imports in eastern Massachusetts and offshore production facilities near Nova Scotia.

By 2006 and through 2008, the natural gas market began to change as natural gas supplies became increasingly constrained. At that time, industry analysts and market participants became increasingly concerned that the continent may soon experience a shortfall of cost effective natural gas and would be forced to turn to imported LNG to meet demand. Numerous LNG import facilities were proposed around the continent, but by 2008 few of those facilities were actually constructed.

Following 2008, abundant low cost natural gas from the Marcellus and Utica production basins have largely collapsed natural gas prices outside of New England. As shown in Figure 1 below, the forecast for production from the Marcellus and Utica basins has increased substantially since 2010. Specifically, the 2015 forecast reflects a 477% increase over the 2010 forecast in 2020 and a 450% increase by 2035.

Figure 1: EIA Natural Gas Production Forecast (2010 & 2015)[5]



Despite the substantial production in nearby states, natural gas prices in New England have remained elevated and exhibited unprecedented volatility that has been nearly universally attributed to transportation constraints into the New England region.

The Commission has recognized the effects of supply constrains during periods of high demand by stating:

> "[d]uring recent winters, significant constraints on natural gas resources have emerged in New England, despite abundant natural gas commodity production in the Mid-Atlantic States and elsewhere. These constraints have led to extreme price volatility in gas markets in the winter months in our region …"[6]

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5 U.S. EIA 2010 & 2015 Annual Energy Outlook.

6 The State of New Hampshire Public Utilities Commission, *Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire, IR 15-124, Order of Notice,* at 2.

The effects of the supply constraints are clear and have a substantial impact on New Hampshire customers. In light of these market changes, EnergyNorth and its customers must preserve flexibility and optionality as new natural gas infrastructure is constructed, new production basins are developed and new interconnections are proposed.

II. COMMERCIAL CONSIDERATIONS OF NATURAL GAS PIPELINE DEVELOPMENT

Q. Why is it necessary to discuss the commercial implications associated with new natural gas pipeline development?

A. As discussed throughout my rebuttal testimony, each of the intervening witnesses, to varying degrees, have failed to consider how natural gas pipeline infrastructure is developed, how certain physical attributes of the EnergyNorth system impact the Company's ability to obtain incremental natural gas capacity, and how the NED Project is consistent with EnergyNorth's previously approved IRP.[7]

Q. What considerations impact the development of new natural gas pipelines in the United States?

A. The development and construction of large-scale natural gas projects requires the investment of hundreds of millions or billions of dollars. In order to move forward with a new project, natural gas transmission owners and operators seek to establish long-term contracts with shippers that assure recovery of the construction, financing, and operating

[7] EnergyNorth Natural Gas, Inc. Integrated Resource Plan (November 1, 2013- October 31, 2018), Docket DG 13-313, at 12.

costs of the new pipeline. These customers, often referred to as anchor shippers, receive substantial benefits which may include:

1. Reduced rates that are below, and in some cases substantially below, the recourse, or cost of service based rate,
2. Most Favored Nation status, such that if any other party negotiates benefits or pricing better than the anchor shipper, the anchor shipper will receive the same benefit, and
3. First rights of refusal on expansion or renewal capacity.

[redacted] In exchange for bestowing these benefits and rights on anchor shippers, the natural gas pipeline developer receives an assurance that its investment will be recovered over the course of the contract. Natural gas transmission owners and operators seldom undertake new construction without this assurance of cost recovery.

As noted above, anchor shippers typically negotiate a variety of terms and often bargain for rates that are below the cost of service based rates. These negotiations occur in the context of a single integrated package whereby costs and other terms typically cannot be viewed separately. That is to say, changing a term, condition, or price element will often lead to renegotiating the entire package or deal. In this way, it is not possible to fully isolate the value or cost of each component of the agreement or to suggest that an anchor shipper, or in this case, the LDC Consortium, could meaningfully reduce the maximum daily quantity levels without experiencing a resultant increase in the price per Dth or a removal of other beneficial terms and conditions such as the construction of citygate stations or laterals.

Additionally, the interstate natural gas transportation system lacks a reliability planning body similar to the regional Independent System Operators that determine if power generation capacity is permitted to retire and when new transmission lines are required. It is incumbent on each LDC to adequately subscribe to natural gas transmission projects to support construction of sufficient capacity to serve their customers. Absent commitments from potential shippers, pipeline developers generally do not move forward with projects. As a result, it is crucial for firm shippers such as EnergyNorth to subscribe to new projects that meet the needs of its customers. Otherwise, sufficient natural gas capacity will not be developed to serve EnergyNorth's customers.

Q. How do you respond to Staff Witness Whitten's statements that anchor shipper status burdens customers rather than benefits customers?

A. Overall, Ms. Whitten's statements are incorrect and counter to the notion of anchor shipper status. Ms. Whitten's statements are based on the concept of reserve capacity.[8] That is to say, Ms. Whitten's argument is based on the premise that capacity above the current design day requirement has a negative effect on customers. While I agree there is an incremental upfront cost associated with reserve capacity, I disagree that it has a negative effect on customers.

[8] Whitten Direct Testimony, at 18.

Foremost, anchor shipper status on the NED Project has allowed EnergyNorth to negotiate a demand charge that is more than [redacted] less than the expected recourse rate of the NED Project.[9] Stated differently, the recourse rate on NED would increase the demand charge by more than [redacted].

Table 1: Comparison of NED Recourse & Negotiated Rates[10]

[redacted]

As illustrated by Table 1, the discount negotiated by the LDC Consortium as part of the overall package, results in an annual savings to EnergyNorth customers of over [redacted] million. That discount is expected to save EnergyNorth's customers in excess of [redacted] million over the term of the NED PA.

Secondly, Ms. Whitten ignores the fact that EnergyNorth customers will also receive secure firm transportation services for a period of twenty years at an essentially capped price. This commitment ensures that sufficient transportation capacity is available to sustain existing customer demand and to support future growth within current and future service territories of EnergyNorth.

9 *See* DaFonte Direct Testimony, at 20.
10 *See* DaFonte Direct Testimony, at 17, 22.

Lastly, anchor shipper status, and the associated [redacted] rights, will permit EnergyNorth's customers to benefit from any [redacted] that are negotiated by other shippers. This ensures that EnergyNorth not only receives the benefits of anchor shipper status, but has positioned itself to receive a [redacted], if offered to another shipper in the future. In essence, the NED PA assures EnergyNorth of achieving the [redacted] while continued reliance on market area purchases leaves the customers of EnergyNorth exposed the marginal cost of supply at Dracut.

Q. What are the effects of the commercial considerations of developing a new natural gas pipeline on EnergyNorth and its customers?

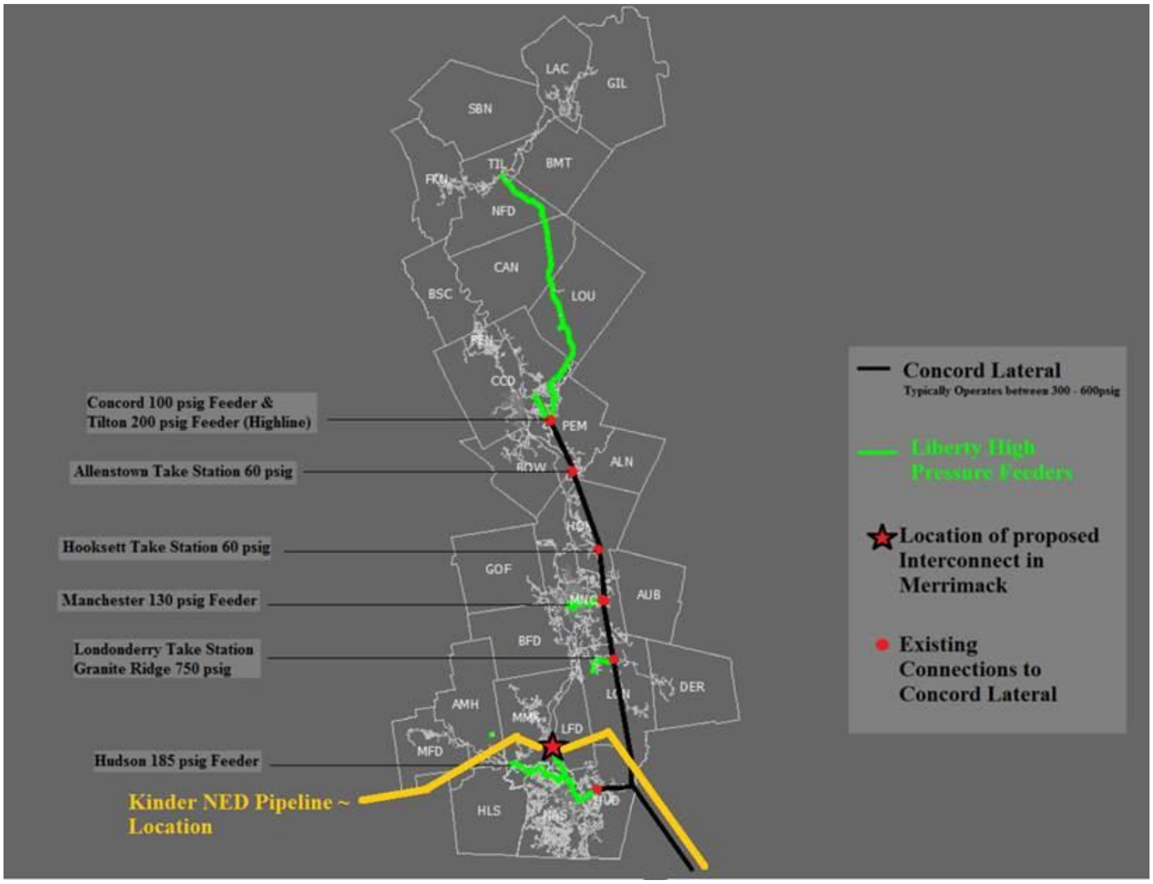
A. As a small, approximately 90,000 customer natural gas LDC, EnergyNorth faces additional challenges in obtaining sufficient pipeline capacity to support its existing and new customers. Most importantly, the size of EnergyNorth and its demand quantities are insufficient to support pipeline construction unilaterally. Since the large cost of pipeline construction would be spread across a relatively low volume, the project would be uneconomic to pursue. By way of example, EnergyNorth represents approximately 25% of the LDC Consortium volumes, and without this volume it is unlikely that the NED Project would be built. The same is true if other members of the LDC Consortium were to meaningfully reduce their commitment. Therefore, EnergyNorth must opportunistically plan its capacity purchases to coincide with the needs and demands of surrounding LDCs to create a project of sufficient size and economies such that all the LDC customers will benefit from the a project that gets built.

The size of EnergyNorth is the reason that the New England LDCs including Berkshire Gas Company ("Berkshire"), Columbia Gas of Massachusetts ("CMA"), Connecticut Natural Gas Corporation, Southern Connecticut Gas Corporation, the City of Westfield Gas & Electric, and National Grid coordinated their negotiations of the Precedent Agreements with the NED Project (collectively the "LDC Consortium").[11] By doing so, the LDC Consortium was able to leverage its combined capacity requirements to support a project that meets the needs of all parties. The trade-off for such an approach is a commitment from the LDCs for a collective volume, and therefore, a commitment from each for their individual volume. In order to change the terms and conditions in the NED PA, EnergyNorth would be forced to unilaterally renegotiate the agreement without the direct benefit of the combined purchasing power of the LDC Consortium.

Further, the EnergyNorth service area is served off a single lateral. Figure 2 shows the location of the EnergyNorth system in relation to the interstate natural gas system.

[11] Kinder Morgan, *Kinder Morgan Confirms Anchor Shippers for Northeast Energy Direct Project,* March 5, 2015.

Figure 2: Map of EnergyNorth System



As shown on Figure 2 all of EnergyNorth's natural gas is currently delivered off of the Concord Lateral which connects to the Tennessee Gas Pipeline ("TGP") mainline system near Dracut, MA.

As a result, EnergyNorth is solely reliant on the operation of this lateral for natural gas deliveries. Any project to provide EnergyNorth with incremental transmission capacity must either expand the Concord Lateral while incurring costs unique to EnergyNorth, or construct a new interconnection to EnergyNorth's system via greenfield construction.

Projects, such as NED, that rely on a route that permits a new interconnection independent of the needs of EnergyNorth present relatively unique value propositions. Specifically, the costs associated with certain facilities that only benefit EnergyNorth are aggregated into the total project cost. Thus, the package agreement provided to EnergyNorth includes these benefits that are unique to this project, and the costs of which are spread across all of the billing determinants.

Q. Have other natural gas distribution companies experienced operational or expansion challenges or limitations as a result of a lack of new natural gas transportation capacity?

A. Yes, they have. Other LDC systems that were unable to leverage previous opportunities such as NED are currently facing moratoriums on new customer connections. These LDC systems are all served off of a single lateral that permits only one connection to the interstate pipeline system. For example, the towns of Amherst, Hadley, and Hatfield, Massachusetts, which are served by Berkshire Gas Company[12] ("Berkshire Gas") off of the North Hampton Lateral of the TGP system, recently saw 3-year moratoriums imposed on new residential and commercial natural gas connections due to a lack of natural gas capacity.[13] In response, the Hadley Building Commissioner has stated that such a moratorium will stop development in the area.[14] Specifically, the Hadley Building Commission cites that the large chain stores and restaurants are able to afford acquiring

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12 As of 2013, Berkshire Gas Company serves approximately 42,000 customers in western Massachusetts. Source: SNL Financial, LLC.

13 The Berkshire Gas moratorium includes not only new service connections, but expansions of new existing service connections for additional usage.

14 MassLive, *Berkshire Gas imposes Hampshire County hookup moratorium blocking projects in Amherst, Hadley while calling for Kinder Morgan pipeline*, March 20, 2015.

propane tanks, but locally-owned business will be prevented from opening due to the added cost.[15] Other new service moratoriums have also been imposed by Berkshire Gas in the Massachusetts communities of Greenfield, Deerfield, Montague, Whatley and Sunderland.[16] The Berkshire Gas moratoriums follow more than a decade of incremental improvements to increase capacity on the Northampton Lateral.[17] However, Berkshire Gas is no longer capable of unilaterally increasing capacity on the Northampton Lateral. Berkshire Gas now must wait until the timing of new projects such as NED to restart its conversion and growth efforts. As a result, certain customers will not have the option to convert to natural gas, resulting in greater energy costs for those customers.

Similarly, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts[18] ("CMA"), imposed a new service moratorium in Northampton and Easthampton in late 2014 due to a lack of capacity on the Northampton Lateral.[19]

Both Berkshire Gas and CMA have executed precedent agreements for the NED Project in order to relieve the constraints that have led to the aforementioned moratoriums.[20] In that regard, both companies have stated that lifting of new service moratoriums is dependent on construction of the NED Project. In other words, absent the NED Project,

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15 *Ibid.*
16 *Ibid.*
17 *Ibid.*
18 CMA serves approximately 300,000 customers in central and southeastern Massachusetts. Source: SNL Financial, LLC.
19 Holyoke Gas & Electric, a municipally owned utility in Holyoke, MA, is also served off of the Northampton Lateral and could face moratoriums in three to five years absent new capacity.
20 http://news.kindermorgan.com/press-release/all/kinder-morgan-confirms-anchor-shippers-northeast-energy-direct-project, *Kinder Morgan Confirms Anchor Shippers for Northeast Energy Direct Project,* March 5, 2015.

customers of Berkshire Gas and CMA will be precluded from exercising the option to convert to natural gas.

Q. Please reiterate EnergyNorth's resource planning objectives.

A. As noted in the approved 2013 EnergyNorth IRP, EnergyNorth pursues a best-cost resource portfolio that considers the reliability of the supply and transportation resources while seeking to achieve the lowest possible customer cost.[21] EnergyNorth's resource planning objectives are summarized as follows:

- Maintain portfolio reliability (which includes enhancing diversity across pipelines and supply basins);
- Reduce portfolio costs;
- Provide flexibility; and
- Acquire viable resources.[22]

These objectives are informed by the pipeline development process and recognize that long-term incremental capacity often cannot be acquired in the short-term or in the exact quantity desired.

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21 EnergyNorth Natural Gas, Inc. Integrated Resource Plan (November 1, 2013- October 31, 2018), Docket DG 13-313, at 12.

22 DaFonte Direct Testimony, at 27.

Q. Has the contract for capacity on the NED Project remained consistent with those objectives?

A. Yes, it has. The NED Project will enhance the reliability of the EnergyNorth gas supply portfolio, while increasing overall price stability. Specifically, the NED Project allows EnergyNorth to replace 50,000 Dth per day of Dracut capacity with a contract from Wright, NY. As such, the Company will increase its access to the robust Marcellus and Utica basins, and reduce its exposure to the declining offshore Nova Scotia supplies and the uncertainty of imported LNG deliveries.

As demonstrated in my direct testimony and the remainder of rebuttal testimony, the NED Project is a package of benefits and obligations negotiated by the LDC Consortium. As such, EnergyNorth will reduce its exposure to a declining supply basin and volatile pricing, and will increases its access to a growing domestic gas supply. In addition, there are certain infrastructure upgrades for EnergyNorth that are part of the overall package offered by the NED Project. Finally, and of utmost importance, the NED Project will further preserve or enable numerous gas supply options for EnergyNorth and its customers going forward.

III. RESPONSE TO STAFF WITNESS WHITTEN

Q. Please summarize the primary concerns contained within the testimony submitted by Staff Witness Whitten.

A. Ms. Whitten's principal contentions relate to the methodology utilized by EnergyNorth to forecast its design day[23], the demand assumed for capacity-exempt customers returning to EnergyNorth's sales service system, the time horizon of EnergyNorth's demand forecast, and EnergyNorth's Sendout® modeling that compared the NED Project to the Atlantic Bridge and Continent to Coast ("C2C") projects.[24] Much of Ms. Whitten's criticism of the Company's forecasted design day relates to her interpretation of the 2013 EnergyNorth IRP.[25]

Q. How do you respond to Ms. Whitten's criticisms of EnergyNorth's demand forecasting methodology?

A. First, I note that Ms. Whitten has acknowledged that EnergyNorth has demonstrated a need for incremental capacity[26] and that EnergyNorth has presented a "credible argument" that the NED Project is the most cost effective option amongst the three projects that were available at the time of the Company's decision.[27] Ms. Whitten's criticisms are largely based on a misunderstanding of the forecasting process used by EnergyNorth. Ms. Whitten's understanding of the forecast methodology appears to be based on her understanding of the manner in which EnergyNorth extended the 5-year

23 Whitten Direct Testimony, at 11.
24 *Ibid.*, at 38.
25 *Ibid.*, at 29.
26 *Ibid.*, at 6.
27 *Ibid.*, at 10.

2013 IRP design day forecast for the 24-year period to enable a comparison with the current 24-year forecast. The current forecast, however, is the result of a 24-year econometric modeling process that relies on updated billing and Moody's® economic forecast information to forecast annual demand. For clarity, this is the same process used for the NED analysis, but updated for more recent information. [28] EnergyNorth then applied the annual growth factor from the new annual demand forecast to a statistically derived design day demand model in order to forecast the design day demand over the 24-year period.

Q. Did EnergyNorth provide any additional updates to its demand forecasts in this proceeding?

A. Yes, it did. EnergyNorth updated its demand forecast in its response to Staff Information Request Staff Tech-23 (Attachment FCD-1 hereto) which is replicated in Table 2 below. In that updated forecast, EnergyNorth reflected its expectations for new customer acquisitions in its Keene division and new expansion opportunities. Based on the updated forecast, EnergyNorth's reserve capacity is expected to be exhausted seventeen years after NED enters service.

[28] EnergyNorth Natural Gas, Inc. Integrated Resource Plan (November 1, 2013- October 31, 2018), Docket DG 13-313.

Table 2: EnergyNorth Updated Design Day Demand and Resources[29]

Year	Original Design Day Demand Forecast	Updated Design Day Demand Forecast	Design Day Resources w/NED Capacity	Surplus/ Deficit
2014/15	146,968	148,547	155,033	6,486
2019/20	167,773	172,732	220,033	47,301
2024/25	182,421	191,001	220,033	29,032
2029/30	194,851	204,046	220,033	15,987
2034/35	209,190	219,093	220,033	940
2034/36	212,101	222,148	220,033	(2,115)
2036/37	214,790	224,970	220,033	(4,937)
2037/38	217,519	227,834	220,033	(7,801)

EnergyNorth's response in Staff Data Request Staff Tech-23 further demonstrates that should EnergyNorth retire its propane air facilities, then EnergyNorth's reserve capacity would be exhausted in five years or less following the completion of NED. See Table 3 below.

Table 3: Design Day Capacity Surplus/Deficit[30]

Year	Original Design Day Demand Forecast	Updated Design Day Demand Forecast	Design Day Resources w/NED Capacity, w/o Propane	Surplus/ Deficit
2014/15	146,968	148,547	155,033	6,486
2018/19	164,526	167,926	155,033	(12,893)
2023/24	179,790	188,240	185,433	(2,807)
2028/29	192,341	201,412	185,433	(15,979)
2033/34	206,238	215,995	185,433	(30,562)
2037/38	217,519	227,834	185,433	(42,401)

As a result, EnergyNorth would either require additional resources; or would need to limit or eliminate new customer growth approximately 5 years after the in-service date of the NED project.

29 Staff Data Request Staff Tech-23, data shown for each five year period.
30 *Ibid.*

Q. Why did EnergyNorth not include new customer acquisitions from the Keene Division it its original demand forecast?

A. EnergyNorth previously did not include these customer acquisitions in its demand forecast as part of the original demand forecast because it had not yet completed the acquisition of the EnergyNorth Keene Division.[31] The information was included in subsequent analyses as it reflects customer growth potential enabled by the NED capacity contracted by EnergyNorth. In general, new customer additions provide incremental volume that allows EnergyNorth to spread its fixed costs over more billing determinants; thus lowering costs for all customers.

Q. What is a capacity-exempt customer?

A. Capacity-exempt customers are customers that were never assigned (i.e., were exempted from) a "slice" of EnergyNorth's capacity and supply resources. Therefore, these customers do not rely on the Company's capacity portfolio, nor do they receive the benefits of the Company's resources.

Recently, capacity-exempt customers have begun returning to EnergyNorth's sales service due to the same natural gas transportation capacity constraints recognized by the Commission and experienced by the Company. Those constraints are making it more difficult for capacity-exempt customers to secure their own natural gas transportation into the region. These customers are electing to become sales customers, which requires

[31] Closing of the acquisition of the EnergyNorth Keene Division (formerly known New Hampshire Gas Corporation) was announced on January 2, 2015.

EnergyNorth to plan for their load, even if they return to transportation service in the future, including contracting for pipeline capacity. To date, the Company's transportation customers have not expressed any concerns with its decision to contract for the NED pipeline capacity, which will be released to them at the negotiated rate in the PA and which will comprise approximately 67% of allocated pipeline capacity.

Q. What is Ms. Whitten's criticism related to the capacity-exempt customers?

A. In her direct testimony, Ms. Whitten notes that she is concerned that reverse migration of capacity-exempt customers is being captured in the Company's IRP forecast and in the subsequent out-of-model adjustment that is included in the current design day forecast.[32] This concern is not well placed. EnergyNorth's out-of-model adjustment does not include additional capacity-exempt customers returning to the system. Despite the fact that EnergyNorth has not modeled growth in the number of returning capacity-exempt customers, the Company has continued to see reverse migration within this customer classes, including three additional capacity-exempt customers that recently returned to EnergyNorth's sales service. Capacity-exempt customers have determined that continued reliance on market area supply is not in the economic interest of their respective businesses and have decided that signing up for long-term capacity (these customers will always maintain a "slice" of the EnergyNorth portfolio including NED capacity should it be approved) with EnergyNorth is both cost-effective and reliable. The updated list of returning capacity-exempt customers and their peak-day usage is provided in Table 4 below.

[32] Whitten Direct Testimony, at 35.

Table 4: Returning Capacity-exempt Customers (as of June 1, 2015)

Name	Peak Day Usage (Dth)
WEBSTER VALVE	[redacted]
MILFORD SCHOOL DISTRICT	[redacted]
BALES ELEMENTARY SCHOOL	[redacted]
WINNESQUAM BOATS LLC	[redacted]
OSRAM SYLVANIA	[redacted]
LA CARRETA RESTAURANT	[redacted]
BLUE SEAL FEEDS-PLANT	[redacted]
UNION LEADER	[redacted]
LIFE IS GOOD WHOLESALE	[redacted]
LIFE IS GOOD WHOLESALE	[redacted]
INDIAN HEAD REALTY TRUST	[redacted]
HITCHINER MFG CO	[redacted]
HITCHINER MFG CO INC	[redacted]
ST GOBAIN PERFM PLASTICS	[redacted]
NASHUA CORP	[redacted]
RED OAK PROPERTY MGNT	[redacted]
MARKET BASKET	[redacted]
CHOMERICS DIVISION-PARKER	[redacted]
OXFORD HEALTH PLAN	[redacted]
	[redacted]

The peak day usage in Table 4 is the most current design day capacity-exempt out-of-model adjustment for which EnergyNorth must plan. EnergyNorth expects that the number of capacity-exempt customers returning to the system will increase as long as the natural gas transportation constraints remain in New England. The Company's expectation is based on the need for these customers to secure natural gas supply and the current concerns regarding gas supply availability and market area pricing.[33]

[33] EnergyNorth believes that if the NED PA is rejected by the Commission and the NED Project is not completed, it is likely that additional capacity-exempt customers will quickly return to EnergyNorth's sales service due to an affirmation of continued transportation capacity constraints. The estimated peak day usage for the Company's 58 (69 meters) remaining capacity-exempt customers is approximately 14,000 Dth.

Q. Did Ms. Whitten provide similar criticisms of the Company's iNATGAS demand forecast?

A. Yes, she did. Ms. Whitten criticizes the Company for not basing its iNATGAS forecast on an econometric forecast of iNATGAS projected operations and demand.[34] Ms. Whitten's criticism fails to consider that (i) iNATGAS is a new type of natural gas sales customer for which there is limited available information to support a sales forecast and (ii) the Company is obligated to plan for the highest reasonable customer demand under the design day criteria.[35]

With regard to the former consideration, it is important to recognize that iNATGAS represents essentially a new business segment for EnergyNorth and New Hampshire. As described in more detail in Mr. Clark's Rebuttal Testimony, iNATGAS is expected to provide Compressed Natural Gas ("CNG") as an open access tolling facility and fuel for their own commercial/industrial customers that are unable to directly connect to natural gas LDCs. Due to the relative new business model presented by iNATGAS, EnergyNorth does not have adequate planning information to support a detailed econometric model to predict the long-term supply needs of the facility.

On the latter consideration, the design day criterion inherently requires EnergyNorth to plan for a customer's design day consumption. Therefore, the Company relied on the

[34] Whitten Direct Testimony, at 34.

[35] It is also important to recognize that iNATGAS is only obligated to remain on the EnergyNorth system for one year. However, given the trend in the reverse migration of capacity-exempt customers and the firm supply requirements of iNATGAS, it is unlikely they would forego EnergyNorth's supply and/or capacity until such time as new capacity, such as the NED Project, is built into the region.

design capacity of the iNATGAS facility, taking into account the need to ramp up the iNATGAS operations over a reasonable period of time.

Q. How does EnergyNorth respond to Ms. Whitten's criticism of EnergyNorth's Sendout© modeling?

A. In her criticism of EnergyNorth's Sendout© modeling, Ms. Whitten acknowledges that EnergyNorth's modeling of the three greenfield pipeline projects each at 115,000 Dth of capacity is appropriate. Ms. Whitten, however, criticizes the Company for failing to consider unconstrained capacity portfolios that permit: (i) contracting for a lower maximum daily quantity, (ii) retaining portions of EnergyNorth's capacity at Dracut, (iii) procuring seasonal citygate supply, or (iv) retiring EnergyNorth's propane facilities.[36]

Such an approach is not well-founded given that EnergyNorth has previously identified a need for 115,000 Dth per day and limits to the available supplies at Dracut or the citygate. I discuss the reasons why continued purchases at Dracut are not in the interest of customers later in my testimony. Due to that determination, EnergyNorth was left with two alternatives that would each require expansion of the existing Concord Lateral to accommodate the incremental capacity (65,000 Dth per day or greater if the EnergyNorth propane facilities are retired), resulting in a higher cost. As shown in Table 5 below, the cost of the alternative projects become uncompetitive once the cost of expanding the Concord Lateral is reflected in the analysis.

[36] Whitten Direct Testimony, at 10.

Table 5: Alternative Project Cost Comparison[37]

[redacted]

As illustrated by the table, the NED capacity cost, even assuming the highest level of construction cost over-runs, is competitive with the per unit cost of Atlantic Bridge and C2C even before considering the cost of expanding the Concord Lateral. Once the Concord Lateral cost is included, the NED Project is clearly the most economic option. Further, neither of the two alternatives provides a secondary feed into the west end of the Company's distribution system or provides opportunities for the Company to expand natural gas service to its Keene Division and surrounding communities.

Q. Did Ms. Whitten criticize the Company's choice of 20-year planning horizon for the NED Project?

A. Yes, she did. Ms. Whitten contends EnergyNorth's use of a 20-year planning horizon for the NED Project results in reserve capacity that is too large.[38] However, the Company's reserve capacity, and thus planning horizon, is shortened once consideration is given to the Keene and new service territory expansion opportunities and the possibility of retiring the aging propane plants. As shown previously in Table 3, once the addition of the Keene load and other new service territory load and the retirement of the propane

[37] DaFonte Direct Testimony, at 31-32.
[38] Whitten Direct Testimony, at 27.

facilities are considered in the analysis, EnergyNorth's planning horizon is reduced to less than five years.

Additionally, Ms. Whitten's criticism is counter to her response to Company Data Request 1-9 (Attachment FCD-2 hereto) in which she provides a document from the *Regulatory Assistance Project*.[39] That document includes a survey of industry planning horizons which span from 10 to 20 years.[40] Although, she chose to criticize the EnergyNorth planning horizon for the NED Project, it is within the reasonable range specified by this industry document. In that response, Ms. Whitten also notes that three other utilities in the Pacific Northwest utilize a 20-year planning criterion.[41]

IV. RESPONSE TO OCA WITNESS DR. CHATTOPADHYAY

Q. What are Dr. Chattopadhyay's primary criticisms of the Company's NED PA?

A. Dr. Chattopadhyay's principal contentions are that EnergyNorth's Sendout© modeling did not consider portfolios with less than 50,000 Dth of capacity from Dracut to the EnergyNorth citygate, and that the EnergyNorth forecast period should be 5 or 10 years rather than the term of the NED PA.[42]

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39 Company Data Request 1-9, Attachment 1-9a. Ms. Whitten also noted that two other utilities in Massachusetts have sought approval for 20-year contracts with NED. Source: Whitten Direct Testimony, at 45.

40 *Best Practices in Electric Utility Integrated Resource Planning*, June 2013, at 6, Table 1.

41 Company Data Request 1-9.

42 Chattopadhyay Direct Testimony, at 9.

Q. How does EnergyNorth respond to Dr. Chattopadhyay's contentions?

A. Dr. Chattopadhyay's contention that the Sendout© modeling should consider portfolios with less than 50,000 Dth of NED capacity from Dracut to the EnergyNorth citygate is essentially a strategy to minimize demand charges without regard to non-cost factors. This strategy fails to consider (i) the lack of supply availability at Dracut due to declining natural gas production at the off-shore Nova Scotia facilities and the uncertainty regarding deliveries from the LNG import terminals, (ii) the natural gas price volatility associated with the Dracut pricing point, and (iii) the overall deal structure and package negotiated by EnergyNorth as a participant in the LDC Consortium.

Q. Please describe EnergyNorth's concerns with regard to natural gas supply availability at Dracut.

A. Purchases at the Dracut point represent market area transactions for natural gas to supply EnergyNorth's customers. Put another way, in order for natural gas to be available at Dracut, natural gas must be first produced in another location and transported via ship and/or pipeline to Dracut. Generally, EnergyNorth or another entity will have been required to incur transportation charges to move the natural gas to Dracut. This may result from natural gas producers that have chosen to move natural gas from the production area to the market area at their expense, natural gas marketers that may elect to move natural gas supplies to Dracut due to higher prices and available natural gas capacity, or LNG supplies shipped to LNG facilities in Massachusetts and New

Brunswick.[43] Given the increase in demand from the power generation segment, the increase in Marcellus production, and the lack of new pipeline infrastructure, the supply constraints from west to east have increased. As a result, under peak conditions, transportation constraints from New York into New England severely limit the amount of natural gas that can be transported from west (i.e., outsides of New England) to east (i.e., into New England). As detailed later in my testimony, in recent years, that lack of supply at Dracut has translated to exceedingly high prices, and at times created a concern that natural gas will be unavailable to purchase within the market area.

This is further exacerbated by the high correlation in weather experienced across New England. In other words, when one LDC in New England is experiencing design day conditions, the surrounding LDCs are similarly experiencing design day or near design day conditions. Moreover, the electric generation and capacity-exempt market segments are also experiencing winter peaks coincident with LDCs.

Dr. Chattopadhyay's analysis of the Sendout® model runs that he requested the Company produce on his behalf does not reflect this very real concern regarding the availability of natural gas within the market area. When questioned about this concern in Liberty Data Request 1-2 (Attachment FCD-3 hereto), Dr. Chattopadhyay noted that he did not conduct any independent analysis and simply relied on the results of the Sendout® models runs for which he specified the conditions to EnergyNorth. Dr. Chattopadhyay then

[43] LNG would also incur additional pipeline demand charges to move the natural gas from the LNG import terminals to Dracut since no LNG facility directly interconnects at Dracut.

asserted that the deficiency was the result of the Company's failure to speculate on his intended assumptions for this analysis.[44] Nonetheless, Dr. Chattopadhyay's recommendations are based on these faulty assumptions and do not reflect any limitations on the natural gas available at Dracut or the cost of that gas during peak days. In essence, his recommendations are based on a "hope and prayer" planning philosophy which assumes that affordable natural gas supplies will be available at Dracut during extreme winter conditions.

Q. Why does EnergyNorth believe that a 20-year capacity commitment to the NED Project is appropriate?

A. EnergyNorth's 20-year commitment to the NED Project provides the Company with sufficient capacity to meet its design day for the long-term while permitting the Company to review, evaluate and implement other options including: (i) retirement of the propane facilities, (ii) reviewing other capacity options when contracts are up for renewal or (iii) evaluating further asset optimization strategies to maximize the value of any unused capacity.

Dr. Chattopadhyay's contention that the EnergyNorth forecast period should be 5 or 10 years rather than the 20-year term of NED PA is based on the notion that additional capacity can be procured at will. Dr. Chattopadhyay's contention fails to recognize the commercial realities of pipeline development that were discussed in Section II above. Specifically, EnergyNorth is limited in its ability to access incremental capacity and must

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44 *Ibid.*

plan its purchases to coincide with the demands of other proximate LDCs to maximize benefits at the most economical cost. Using a shorter planning term effectively forces the Company into a position whereby it must hope that new capacity will be developed in a timeframe that supports EnergyNorth's planning horizon. EnergyNorth does not believe such a planning strategy represents prudent utility management.

V. RESPONSE TO PLAN WITNESS ROSENKRANZ

Q. Has EnergyNorth identified any overarching considerations related to Mr. Rosenkranz's testimony?

A. Yes, it has. It is important to note that Mr. Rosenkranz is testifying on behalf of an organization whose stated purpose is to stop the development of the NED Project on behalf of affected landowners. As noted on the PLAN website, "PLAN-NE is working at the state and federal levels to stop Kinder Morgan's Northeast Energy Direct Project."[45] Thus, PLAN's participation in this proceeding is not premised on ensuring just and reasonable rates, but instead is part of a larger objective of preventing the development of new interstate pipeline capacity in New York, Massachusetts, and New Hampshire. Mr. Rosenkranz's testimony should be considered in that proper context.

Q. Please summarize Mr. Rosenkranz's principal contentions in this proceeding.

A. Mr. Rosenkranz's primary arguments in this proceeding include:

[45] https://plan4ne.wordpress.com/, accessed May 20, 2015.

- The potential cost savings from moving the receipt point of 50,000 Dth/day from Dracut, MA to Wright, NY are subsumed by the increased demand charges associated with the change;[46]
- Other new pipeline options that will bring incremental transmission capacity to southern New England, coupled with LNG imports, and deliveries from Atlantic Canada could potentially provide natural gas to Dracut;[47]
- New pipeline capacity development proposals are relatively common in New England;[48] and
- EnergyNorth's planning horizon should be reduced.[49]

Q. How does EnergyNorth respond to Mr. Rosenkranz's contention that sufficient volumes of natural gas will be available at Dracut to support the Company's purchases at this receipt point?

A. Mr. Rosenkranz argues that sufficient natural gas will be available at Dracut due to:

- LNG imports from the Canaport and the Distrigas facility in Everett, MA;
- Production in Atlantic Canada from Sable Offshore Energy Project ("SOEP") and the Deep Panuke offshore production facility; and
- New pipeline capacity that could potentially provide additional natural gas to Dracut through further infrastructure upgrades.[50]

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46 Rosenkranz Direct Testimony, at 4.
47 *Ibid.*
48 *Ibid.*
49 *Ibid.*, at 19.
50 Rosenkranz Direct Testimony, at 9-10.

This analysis fails to consider the pricing dynamics that are required to support importing LNG to New England, and several recent announcements related to both off-shore production projects in Atlantic Canada.

Q. Please describe the pricing dynamics related to LNG imports in New England.

A. The decision to import LNG is based on the relative price of natural gas in the target market as compared to other global markets. LNG imports are only supported by the expectation of high prices in New England that exceed expected prices in Europe and Asia. For example, the Company has experienced LNG prices in the [redacted] per Dth range over the past two winters. As such, EnergyNorth would only be able to rely on LNG to the extent it expects continued high prices.

Moreover, there are ultimately two LNG suppliers consistently providing LNG into the New England market (GDF SUEZ, Repsol). Similar to Mr. Rosenkranz's concerns related to the fact that two shippers control 100% of the transportation capacity along the recently approved Constitution Pipeline that connects Marcellus to Wright, this market concentration could leave EnergyNorth with limited negotiating leverage. The market for natural gas supply at Wright contrasts with the New England LNG market given that several other projects have been proposed to bring additional natural gas to Wright. Moreover, existing capacity on TGP and the Iroquois Gas Transmission System ("Iroquois") that connects Wright to Waddington can be used to obtain natural gas supply. Additionally, the NED Project will enable EnergyNorth with the option to contract for direct access to the Marcellus and Utica basins. Absent the NED capacity, this option does not exist.

In addition, unlike interstate transmission capacity, LNG availability is limited to the available cargoes delivered to the import facility. To the extent LNG exists in the storage tank, it can be relied on to meet short-term needs. Absent high prices to incent cargo delivery in New England, LNG cannot support prolonged periods of high demand.[51] The high prices required to attract LNG cargoes will increase the basis between New England and markets such as Wright, further enhancing the cost effectiveness of the NED capacity.

The reliability of LNG may further be challenged by the source of supply. According to the International Gas Union ("IGU"), LNG is currently exported by 17 countries, many of which are currently facing political instability that may jeopardize the availability of LNG cargoes from those counties.[52] For example, the IGU noted supply-side constraints in the Atlantic Basin including in Nigeria where exporters were subject to a tax-related blockade by the Nigerian government and pipeline sabotage.[53] Other examples cited by the IGU include a reduction in Egyptian exports as feedstocks were rerouted for domestic

[51] The International Gas Union noted that in 2013 the Japanese average LNG price was $15.30 per mmBtu and the German benchmark averaged between $11.50 and $12.00 per mmBtu. The publication further noted that these prices reflected a premium to Henry Hub of approximately $7 and $10 per mmBtu for the German and Japanese benchmarks respectively. See International Gas Union, *World LNG Report – 2014 Edition*, at 6 and $14.

[52] International Gas Union, *World LNG Report – 2014 Edition*, at 8.

[53] *Ibid.*

consumption and Norwegian exports faced technical constraints.[54] Similarly, Yemen was a large source of LNG exports, including the delivery of the equivalent of 59.1 Bcf to the GDF Everett, MA LNG import terminal in 2014. Nonetheless, LNG exports from Yemen have been halted due to the recent political instability in that country.[55] Although LNG is likely to be available from alternative countries, the constraints to supply are likely to push up LNG prices further. These international issues should be contrasted to the Marcellus and Utica production basins which will respond to domestic price, political, and regulatory dynamics.

Q. Does EnergyNorth disagree with Mr. Rosenkranz's analysis of other potential supply into Dracut?

A. Yes. In support of his assertion that sufficient supply will be available at Dracut, Mr. Rosenkranz cites Deep Panuke as a new source of supply. Mr. Rosenkranz's assertion ignores several recent announcements related to this facility. First, Encana, the owner of Deep Panuke, recently announced that it was decreasing its proved reserves for Deep Panuke by more than 50% and its daily production was approximately half of original expectations.[56] Figure 3 illustrates actual Deep Panuke production volumes since operations commenced in late 2013.

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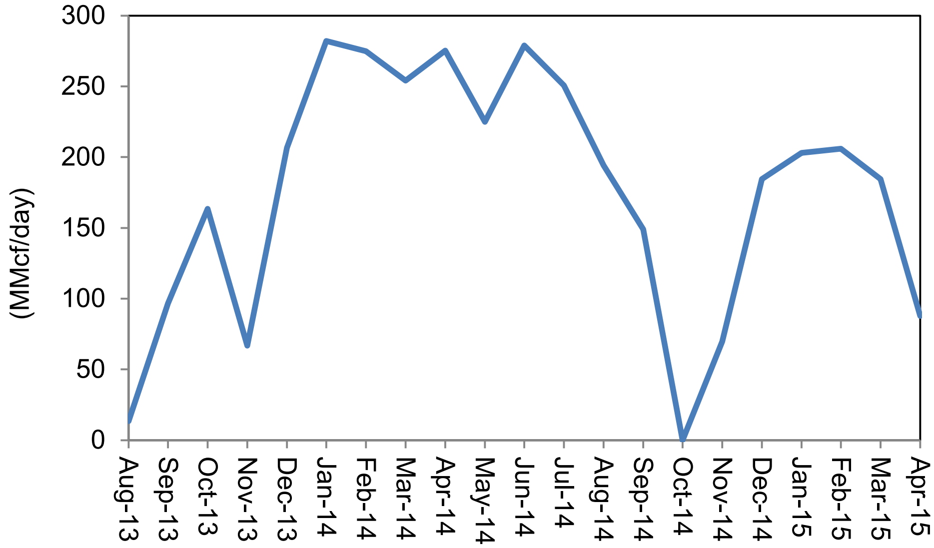
[54] *Ibid.*
[55] Platts Gas Daily, April 20, 2015 edition. Pg. 5.
[56] Natural Gas Intelligence, "Deep Panuke NatGas Reserves Halved by Encana," February 26, 2015.

Figure 3: Deep Panuke Daily Production[57]



As shown above, Deep Panuke actual production volume has been far below its initial expectations of 300 MMcf per day. In addition, the variability of production would impact the reliability of contracts for natural gas supplies from Deep Panuke.

It should be noted that in order to preserve the cost effectiveness of its investment, Encana is now limiting Deep Panuke production to the winter period. In the winter of 2013/14, Encana announced it received an average price of more than $19 per Dth for its production.[58] These prices were during the winter period in which Mr. Rosenkranz notes that the basis between Wright and New England was nearly $9.30, and which would have more than offset the demand charges for the NED capacity. Once consideration of capacity mitigation revenues is considered, the value of NED capacity relative to market purchases would only increase.

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[57] http://www.cnsopb.ns.ca/offshore-activity/offshore-projects/deep-panuke. Accessed May 28, 2015.
[58] Natural Gas Intelligence, "Deep Panuke Nat Gas Reserves Halved by Encana," Feb. 26, 2015.

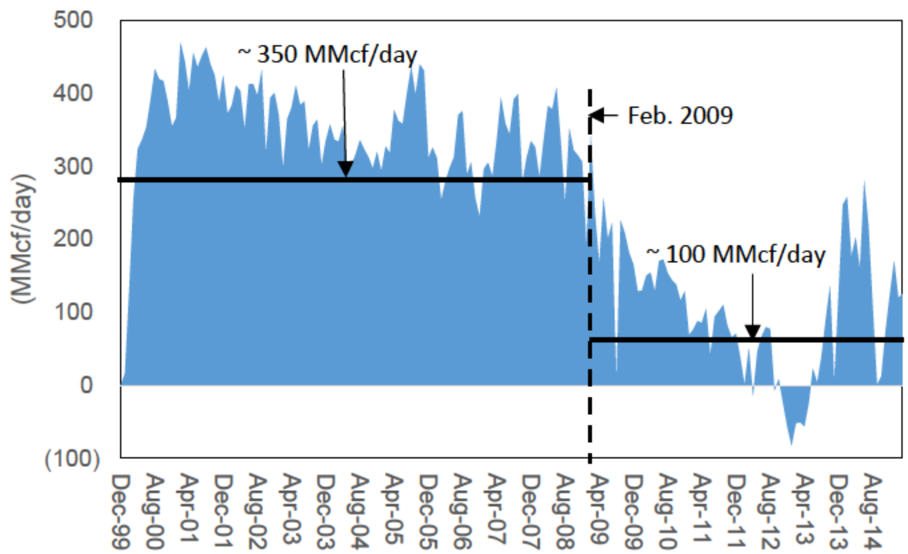
In addition to the reduction of supply from Atlantic Canada, demand within the Atlantic Canada provinces is increasing. ICF Consulting, a consulting firm that specializes in modeling North American natural gas markets, recently noted the following in a March 2013 report prepared for the Nova Scotia Department of Energy:

> "there is a strong argument for Maritimes Canada consumers to contract for firm pipeline capacity on one of the proposed pipeline expansions into New England that would allow shippers to buy gas at one of the Marcellus basin hubs to an interconnection with M&NP. This would ensure a reliable source of gas as well as avoid the price volatility in New England."[59]

The reduction in deliveries from Atlantic Canada can best be seen in Figure 4 below which illustrates imports at Baileyville, Maine.

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

Figure 4: Average Daily Imports at Baileyville, ME[60]



As shown above, imports into Baileyville averaged approximately 350 MMcf per day between December 1999 and February 2009. Since 2009, the daily average has been approximately 100 MMcf per day or approximately 70 percent less than the prior average. This period also showed the first exports from the U.S. into Canada through Baileyville. Overall, the uncertain production of Deep Panuke and unknown duration of supply result in significant concerns regarding the reliability of natural gas production to meet winter heating requirements.

Q. Is Mr. Rosenkranz correct in asserting that new natural gas pipeline development proposals are common in New England?

A. No, Mr. Rosenkranz's assertion is incorrect. Mr. Rosenkranz's assertion is based on a table in his direct testimony that purports to represent pipeline expansion projects in New

60 National Energy Board of Canada, Natural Gas Exports - Monthly Summary by Port - Volume (Mcf) and Natural Gas Imports - Monthly Summary by Port - Volume (Mcf).

England over the last 10 years.[61] This table includes three projects that have been placed in service and four development projects that are proposed in New England, including the NED Project.[62]

Mr. Rosenkranz fails to understand that none of the projects that he notes are currently in-service represent new greenfield capacity with delivery to the EnergyNorth system. In fact, there have been no new greenfield pipelines constructed in New England since the completion of the Maritimes and Northeast Pipeline in 1999 or nearly 20 years prior to the anticipated in-service date for the NED Project.

In response to Liberty Data Request 1-8 (Attachment FCD-4 hereto), Mr. Rosenkanz provided project costs for five of the projects listed in his direct testimony. Table 6 below summarizes those costs by project and provides a comparison of the anticipated NED Project costs.

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61 Direct Testimony of John A Rosenkranz, at 20, Table 8.
62 *Ibid.*

Table 6: Comparison of Recent and Proposed Pipeline Expansion Project Costs with the Anticipated NED Project Costs.

[redacted]

Putting aside that Mr. Rosenkranz comingles negotiated rates and recourse rates in the comparison and does not disclose the vintage year dollars for each cost estimate, summing these rates with the anticipated cost of expanding the Concord Lateral to deliver the incremental capacity to the EnergyNorth system results in costs that nearly uniformly exceed the demand charges for the NED Project. Given that many of these project estimates are likely from historical periods, once adjusted for inflation, the cost of these projects would increase further.

Q. Please describe Mr. Rosenkranz's analysis of the potential cost savings to EnergyNorth as a result of switching from market area purchases at Dracut to production area purchases at Wright.

A. To analyze the potential cost-savings from shifting 50,000 Dth per day of transportation capacity from receipt points at Dracut, Massachusetts to Wright, New York, Mr. Rosenkranz considers the historical pricing relationships between Dracut and Wright with the incremental cost of transportation between Wright and Dracut.[63] Mr. Rosenkranz then relies on forward market prices for the Algonquin City Gates and Iroquois Zone 1 to suggest that the forward price curves do not indicate a continuation of the historical pricing relationships.

Q. Does Mr. Rosenkranz's analysis adequately consider the price savings of converting 50,000 Dth per day of EnergyNorth's existing TGP capacity to receipt points at Wright?

A. No, it does not. Mr. Rosenkranz's analysis fails to capture the price differences of natural gas purchased near the production area relative to purchases at Dracut during periods of high demand, the so-called peaks and superpeaks. Superpeaks represent design day or near design day conditions. Recent history has shown that during these periods of high demand, natural gas prices in the New England region, and particularly at Dracut, have increased substantially as a result of pipeline constraints into the region.

An example of the effect of peak and superpeak pricing is captured in Mr. Rosenkranz's analysis of historical pricing differentials. In that analysis, Mr. Rosenkranz notes that in the 2013/14 and 2014/15 winters, there were significant average price differences.[64] For example, Mr. Rosenkranz notes that the price of natural gas in New England was $9.30 per Dth higher than the winter average pricing for Wright, NY. If the new NED capacity

[63] Rosenkranz Direct Testimony, at 5-12. Mr. Rosenkranz relies on pricing at Waddington, NY as a proxy for Wright, NY. Mr. Rosenkranz states that he selected Waddington because there was not a separate pricing index for Wright, NY.

[64] Rosenkranz Direct Testimony, at 12.

was used at a 100 percent load factor for the five winter months, this would have resulted in savings to EnergyNorth customers of approximately $20 million.[65]

Further, the basis differentials between these points experienced several superpeaks due to extreme winter demand. For example, between November 2011 and May 2015, the basis between Dracut and Waddington was greater than $10 per Dth on 26 days and on two of those days exceeded $20 per Dth.

Table 7: Dracut to Waddington Basis Frequency (Nov. 2011 – May 2015)[66]

Dracut-Waddington Basis Days w/	# of Days
>$20 Basis	2
>$10 Basis	26
>$5 Basis	106

Since the superpeak periods represent the periods of greatest demand, these are also the periods during which EnergyNorth would purchase the highest volume of natural gas. On these 26 days of superpeaks (i.e., basis of greater than $10 per Dth), the cost savings related to the conversion of market area purchases at Dracut to production area purchases at Wright would have created $20 million of cost savings for EnergyNorth's customers.[67] This further amplifies the cost savings associated with obtaining firm transportation capacity closer to the production area, and clearly demonstrates the value of obtaining capacity with receipt points closer to the Marcellus production area.

65 Calculated as the product of 50,000 Dth per day, an average basis of $9.30 per Dth, and 90 winter days subtracted from the annual incremental demand charges associated with the NED capacity.

66 Source: SNL Financial, LLC.

67 As Mr. Rosenkranz notes, EnergyNorth may later consider contracting for additional capacity directly into the Marcellus supply basins. Using the Leidy pricing point for the same period results in 127 days in which the basis between Dracut and Leidy exceeded $10 and 53 of those days exceeded $20. The basis on these days would have generated more than $125 million in savings for EnergyNorth customers.

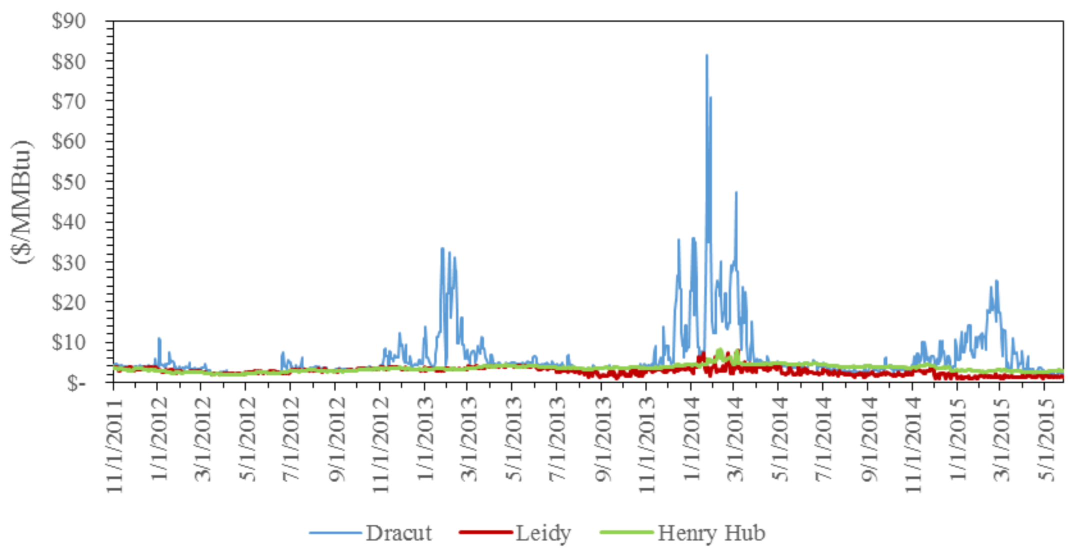
A simple breakeven analysis of the NED Project can be used to demonstrate the conditions under which the NED Project would be cost effective. This analysis is based on the actual volumes purchased and prices paid by EnergyNorth at Dracut or the EnergyNorth citygate in 2013/14 and 2014/15. As shown in Table 8 below, this analysis demonstrates that the NED capacity would have been cost effective at an average natural gas price at Wright of almost $12.50 per Dth in 2013/14 and almost $6.00 per Dth in 2014/15.

Table 8: NED Production Area Purchases Breakeven Price

[redacted]

Neither of these calculations account for capacity mitigation revenues which would only increase the breakeven price by reducing the net cost of the NED capacity. Even so, the large spike in basis to the New England market can quickly overwhelm the breakeven prices. As shown in Figure 5 below, the Dracut price in each of the last three winters has experienced large price increases that exceeded historical expectations.

Figure 5: Dracut, Leidy, Henry Hub Pricing (2011 to 2015)[68]



As shown above, despite the supply constraints and exceedingly high prices in New England, the rest of the country has enjoyed the benefit of relatively stable and low cost natural gas priced off the Henry Hub and other points such as Leidy within the Marcellus production basin.

VI. PRESERVING AND ENABLING OPTIONALITY AND OPERATIONAL FLEXIBILITY

Q. Are there additional considerations that were noted in your direct testimony that relate to the direct testimony of the Intervening Witnesses?

A. Yes. There are two considerations that are not adequately considered by the Intervening Witnesses. First, the NED Project allows EnergyNorth to preserve numerous options and

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68 Source: SNL Financial, LLC.

enables other options. Second, the NED Project presents EnergyNorth with additional operational flexibility.

Q. Please describe the options that are either preserved or enabled by the NED Project.

A. There at least five options that EnergyNorth has identified as being preserved or enabled by the NED Project including the following:

1. The option to mothball or retire EnergyNorth's three propane air facilities depending on customer demand and cost effectiveness following the completion of the NED Project;
2. The option to construct a new gate station to enable conversion of the Company's Keene division to natural gas service;
3. The option to provide service to new communities that currently have no access or limited access to affordable and clean natural gas service.
4. The option to consider what other capacity contracts are renewed or allowed to expire during the term of the PA depending on customer demand and cost effectiveness; and
5. The option to consider future transportation capacity options to further extend its receipt points directly into the Marcellus production area.

Q. How does the NED Project preserve or enable the option to retire EnergyNorth's four propane air facilities?

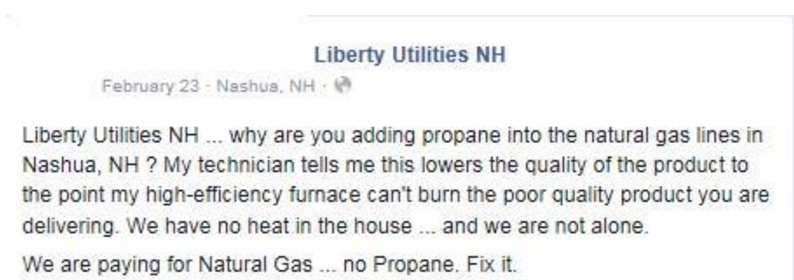
A. The NED Project preserves EnergyNorth's option to either retire or further invest in these facilities by providing alternative capacity to serve customer demand. As noted in my direct testimony, these facilities are approximately 50 years old and the ability to operate the facilities is based on continued investment in maintenance. Staff Witness Whitten has noted that the retirement of these facilities would mitigate a portion of the reserve capacity created by the NED PA. This point was supported by EnergyNorth's response to Staff Data Request Staff Tech-23 (Attachment FCD-1) that demonstrated with potential new customer additions and the retirement of the propane facilities, all of the reserve capacity created by the NED Project would be exhausted within five years of the NED Project entering service. Should EnergyNorth receive approval to proceed with the NED PA, EnergyNorth will be in a position to consider the cost effectiveness of continuing to invest in all or a portion of these facilities in light of the customer demand that exists after the NED Project enters service.

While EnergyNorth is not in a position to commit to retiring the facilities today, the NED Project allows the Company to gather additional information related to customer demand, natural gas prices, and natural gas availability before making a final decision related to the facilities. In light of the uncertainty as to how the market will develop, obtaining additional information and market intelligence can only be deemed prudent.

Q. Why is the Company not in a position to commit to retiring the facilities today?

A. EnergyNorth requires the capacity of the propane facilities to meet its current design day until the NED PA is approved by this Commission and the NED Project enters service. The propane facilities also provide valuable leverage in the Company's negotiations with natural gas pipeline developers.

Nonetheless, EnergyNorth recognizes that given the age of the facilities, the propane plants are not a viable long-term solution. In addition, from a system operations perspective, the Company has received multiple complaints from customers with new high-efficiency heating equipment as a result of EnergyNorth's use of the propane facilities. These complaints are generally attributable to the limited tolerance of more modern equipment to varying natural gas heating values, and at times has led to "no heat" calls by the customers. As an example, the Company received the following compliant from a customer via Facebook in February 2015:



Additionally, the Company has received reports from HVAC contractors that service accounts near to one of EnergyNorth's propane facilities which indicated they had received numerous customer calls due to noise from their high efficiency boilers, including certain customers that were uncomfortable remaining in their homes while this was occurring. One of the HVAC contractors noted that it was "selling more and more" of the high efficiency boilers due to rebates that incent their installation.

Due to the age of the facilities and the long-term incompatibility with high efficiency heating equipment, the Company would consider a commitment to retire the propane facilities following completing of the NED Project assuming the NED PA is approved. Such a decision would be made in the context of a future IRP proceeding.

Q. How does the NED Project preserve or enable the option to consider converting EnergyNorth's Keene Division to natural gas service and expanding to nearby communities?

A. The Company's approximately 1,250 Keene Division customers are currently served exclusively by propane. The most recent route for the NED Project will bring it within 10 miles of the Keene Division, allowing the Company to consider constructing a gate station and converting the existing customer base to natural gas service. This decision will be based on the cost effectiveness of such a proposal at the time it is considered. Absent the NED Project or another project that follows a similar route, the cost of constructing a lateral or main to connect the Keene division to natural gas service will likely remain uneconomic. The testimony of Company witness William Clark further discusses EnergyNorth's growth plans in Keene and the expansion opportunities in the surrounding region.

Q. Please describe how the NED Project preserves or enables the option to consider other transportation capacity options in the future?

A. Because EnergyNorth will have reserve capacity following completion of the NED Project, EnergyNorth will be able to consider its other capacity positions as they come up for renewal. These decisions can be made more proximate to the time when the existing contracts expire and with additional information related to the level of customer demand.

EnergyNorth will similarly retain the option to enter into asset optimization arrangements that will reduce the cost of any reserve capacity that exists in each year.

Based on the current demand forecast presented in the Company's response to Staff Request Staff Tech-23, EnergyNorth anticipates that it will require all of its existing capacity options. Nonetheless, the NED Project will provide EnergyNorth with the ability to consider such options in light of future demand.

Q. Please describe why the NED Project permits the Company to consider extending its receipt points directly into the Marcellus production area and why this could be beneficial to EnergyNorth's customers.

A. The NED Project provides EnergyNorth with transportation capacity from Wright, New York to the Company's service area. As noted by PLAN Witness Mr. Rosenkranz in his testimony before the Ontario Energy Board in January 2015, there are at least three natural gas transmission projects designed to bring between 1.33 and 1.73 Bcf per day from Marcellus to Wright by November 2018.[69] That expansion capacity is in addition to existing capacity which totals approximately 1.0 Bcf per day. EnergyNorth expects Wright to demonstrate sufficient liquidity to supply its customer demand based on construction of a portion of these projects. However, EnergyNorth could elect to contract for capacity on any of the three proposed projects in order to purchase natural gas closer to the well-head in the Marcellus production area.

Such a decision to contract for additional capacity would permit EnergyNorth to purchase gas via some of the lowest cost and least volatile pricing indices in the U.S., (e.g., Tennessee Zone 4 300 Leg Pool, or Leidy) and gain access to existing underground storage facilities. The fact that the Company could go from purchasing supplies at the highest prices in the country to the lowest prices as a result of the NED Project cannot be understated. As shown earlier in Figure 5, these pricing indices have traded at a discount to Henry Hub and New England due to the abundance of natural gas in the Marcellus region. In addition, these indices have not demonstrated the volatility seen in New England natural gas prices in recent years.

Q. How does the NED Project enhance EnergyNorth's operational flexibility?

A. The NED Project provides a unique feature that is not matched by any other capacity option available to the Company, i.e., a second connection to the interstate natural gas

[69] Ontario Energy Board, Docket EB-2014-0261, *Union Gas 2016 Dawn-Parkway Expansion: Capacity Turnback Issues*, Testimony of John A. Rosenkranz prepared for the Canadian Manufacturers & Exporters, Federation of Rental-housing Providers of Ontario, and the Ontario Greenhouse Vegetable Growers, at 6-7. In this docket, Mr. Rosenkranz recommended the OEB condition its approval of certain expansion projects due to increased production in the Marcellus basin and the increased likelihood that U.S. LDCs would turnback capacity and replace it with capacity from Marcellus to New England.

transmission network. That second connection is via a new gate station [redacted]. This new interconnection will permit the Company to inject gas near to its most densely populated region and lower its withdrawals from the Concord Lateral in Southern New Hampshire. This will ultimately make available additional natural gas resources to serve customers in the northern portion of EnergyNorth's service territory. That flexibility makes EnergyNorth less vulnerable to curtailments or operational constraints on the existing Tennessee Gas Pipeline and the Concord Lateral.[70] In addition, customer fuel choices have been enabled.

Q. Why is it important for EnergyNorth, the Intervening Witnesses and the Commission to consider availability of these options in the context of the NED Project?

A. The natural gas market has experienced overall uncertainty in the availability and price of supply for the nation as whole. For example, just six to seven years ago, market analysts were increasingly concerned that the U.S. would exhaust its supply of competitively priced natural gas and would begin importing LNG. More recently, the market is facing more uncertainty within particular markets that are downstream of natural gas transmission constraints. As discussed above, this uncertainty has manifested itself in New England as periods of extraordinarily high prices and emergent concerns related to sourcing sufficient quantities of natural gas during extreme weather events.

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70 TGP experiences numerous curtailments over the course of the winter which can be minimized or completely avoided by a new high pressure pipeline feeding the terminus of the TGP system with abundant natural gas supplies.

Maintaining and preserving options in the face of market uncertainty is fundamental to developing a procurement strategy that allows the Company to respond to that uncertainty.[71] Each of the above options allows the Company to select the capacity resources that permit it to respond best to changes in its demand forecast, natural gas prices in particular supply basins, or new pipeline constraints. The NED Project permits EnergyNorth to obtain this flexibility in a cost-effective manner.

Absent the availability of these options, the Company will be forced to rely on its existing supply portfolio and hope that either increased customer demand does not materialize or pray that other capacity resources are offered into the market to serve design day demand. Should that customer demand materialize and other capacity options not materialize, EnergyNorth could be forced into a position akin to the moratoriums recently issued by Berkshire Gas and CMA.

VII. CONCLUSIONS

Q. Please summarize your conclusions related to the Intervening Witnesses

A. To prepare the present filing EnergyNorth has relied on a design day forecast methodology that is identical to the forecast methodology that was used in the EnergyNorth's most recently approved Least Cost Integrated Resource Plan. That forecast methodology has demonstrated a need for new transportation capacity including 65,000 Dth per day of incremental capacity. Once the Company accounts for its potential

[71] See for example, McKenzie Quarterly, S*trategy under uncertainty*, June 2000 "…choices of strategic posture are not carved in stone and underscores the value of maintaining strategic flexibility under uncertainty. The best companies supplement their shaping bets with options that allow them to change course quickly if necessary."

customer growth in its Keene Division and other surrounding communities, and for the potential retirement of its propane plans, the new capacity is exhausted in just 5 years.

In addition, the Company's analysis and Sendout® modeling has demonstrated a need to replace 50,000 Dth of capacity used for market area purchases at Dracut with transportation capacity to effectuate purchases nearer to production basins such as the fast growing Marcellus and Utica basins. This will provide the Company with access to more reliable natural gas supplies at cost-effective prices.

Only three pipeline projects provided the Company with the necessary incremental capacity and the ability to access natural gas supplies outside of the market area (i.e., Dracut). Of those projects, the NED Project clearly provided the most cost effective option for EnergyNorth and our customers.

The NED Project also presents several benefits to EnergyNorth in that it has allowed the Company to leverage the benefits of the LDC Consortium's combined volumes to negotiate a rate that is substantially below the expected recourse rate which will provide a unique benefit to EnergyNorth in the form of a second high pressure interconnection to the interstate transmission system. That second interconnection will enhance EnergyNorth's reliability in the long-term, and is a benefit of the NED Project not provided by the other alternatives (i.e., Atlantic Bridge and C2C).

The NED Project will enable numerous options for EnergyNorth and its customers including: (i) the opportunity to retire EnergyNorth's three propane facilities depending on customer demand, (ii) the opportunity to construct a new gate station to enable conversion of the Company's Keene Division to natural gas service, (iii) the opportunity to provide natural gas service to new communities that do not currently have access to affordable and clean natural gas, (iv) the opportunity to consider what other capacity contracts should be renewed or allowed to expire, and (v) the opportunity to consider future transportation capacity options to further extend its receipt points directly into the Marcellus production area. Each of these options provide EnergyNorth with the opportunity to deliver additional savings to its customers. Absent the NED Project, many of these options will be foreclosed for the foreseeable future and customers will remain susceptible to higher market area prices and increasing supply reliability concerns.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.