**STATE OF NEW HAMPSHIRE**
**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Approval of Tennessee Gas Pipeline, LLC Precedent Agreement

Docket No. DG 14-380

# TESTIMONY OF JOHN A. ROSENKRANZ ON BEHALF OF PIPE LINE AWARENESS NETWORK FOR THE NORTHEAST, INC.

**May 8, 2015**

**REDACTED VERSION**

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## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, position, and business address.**

A. My name is John A. Rosenkranz. I am Principal with North Side Energy, LLC. My business address is 56 Washington Drive, Acton, MA 01720.

**Q. Please describe your professional background and experience.**

A. I have more than 25 years of experience in the areas of natural gas supply planning, fuel management for electricity generation, gas utility regulation, and pipeline and storage project management. I have worked as a consultant to natural gas distribution companies, helping to evaluate gas supply options and document these decisions. I have negotiated and managed long-term gas supply and transportation contracts, and have done market and rate analysis for interstate pipeline and underground storage projects. I have been a witness in gas procurement and rate proceedings before the Federal Energy Regulatory Commission, the Maine Public Utilities Commission, the Arizona Corporation Commission, and the Ontario Energy Board. I have been a witness in electric generation siting cases in Wisconsin and Minnesota. I received a BA degree in economics from George Washington University, and completed all course and examination requirements for a doctorate in economics at Northwestern University. My resume is attached as Exhibit JAR-16.

**Q. Have you previously testified before the New Hampshire Public Utilities Commission?**

A. No, I have not.

**Q. On whose behalf are you submitting testimony in this proceeding?**

A. I am testifying on behalf of the Pipe Line Awareness Network for the Northeast, Inc. (“PLAN”).

**Q. What is the purpose of your testimony in this matter?**

A. EnergyNorth has entered into a Precedent Agreement with Tennessee Gas Pipeline, LLC (“Tennessee”) for new firm natural gas transportation service that would utilize expansion capacity created by the proposed Northeast Energy Direct Market Path project

("NED"). The purpose of my testimony is to consider whether the proposed service is needed, and to examine the process EnergyNorth used to evaluate alternatives, taking into account supply reliability objectives and the costs that would be paid by EnergyNorth customers.

**Q. Please summarize your testimony.**

A. EnergyNorth's proposal to modify and expand its gas transportation services from Tennessee by contracting for 115,000 Dth/day of capacity on the NED expansion project should not be approved. The first part of the EnergyNorth proposal, which would convert 50,000 Dth/day of existing Tennessee short-haul transportation service from Dracut, MA to long-haul transportation service from Wright, NY, is not in the interests of EnergyNorth customers because the additional fixed transportation costs are likely to be significantly greater than the gas commodity cost savings. The second part of the EnergyNorth proposal, to contract for 65,000 Dth/day of incremental firm transportation service from Wright, is not reasonable because it would add more than twice the quantity of firm gas supply resources that are needed to meet projected growth in requirements over a ten-year planning horizon. In addition, EnergyNorth's proposal is incomplete because it fails to address the risk that EnergyNorth will need to contract for additional firm transportation service upstream of Wright because gas supplies at Wright will be inadequate. Finally, EnergyNorth does not adequately assess alternatives. In particular, EnergyNorth appears to have understated the costs and overstated the savings under the NED alternative.

**Q. Please discuss how your testimony is organized.**

A. Section II describes EnergyNorth's proposal. Section III considers whether converting 50,000 Dth/day of existing Tennessee transportation service from short-haul service to long-haul service is likely to increase or decrease EnergyNorth customers' gas costs. Section IV addresses EnergyNorth's proposal to contract for 65,000 Dth/day of additional firm transportation service to meet projected growth in customer requirements. Finally, Section V discusses EnergyNorth's analysis of the NED project and other pipeline alternatives.

## II. ENERGYNORTH'S PROPOSAL

**Q. Please describe the EnergyNorth proposal.**

A. The EnergyNorth proposal has two parts. First, EnergyNorth proposes to move the receipt point for 50,000 Dth/day of existing Tennessee transportation service from Dracut, MA to Wright, NY. Dracut, MA is the interconnection between the Tennessee system and the Joint Facilities pipeline that is shared by Maritimes & Northeast Pipeline ("M&N") and the Portland Natural Gas Transmission System ("PNGTS"). Dracut is also the starting point for the Tennessee Concord Lateral, which extends north into New Hampshire. All of EnergyNorth's pipeline-delivered gas supplies are received at Tennessee gate stations on the Concord Lateral. EnergyNorth currently holds two firm transportation contracts with a Dracut receipt point that have a combined contract quantity of 50,000 Dth/day.

Wright, NY is an interconnection between Tennessee and the Iroquois Gas Transmission System ("IGTS"), and would be the terminus of the proposed Constitution Pipeline. Having firm transportation from Wright would allow EnergyNorth to replace gas purchased in the New England market area with gas purchased at a location closer to the Marcellus and Utica gas producing areas in Pennsylvania and West Virginia.

Under the terms of EnergyNorth's precedent agreement with Tennessee, the additional fixed demand cost for this receipt point change would be [redacted] million per year for 20 years. This is the annual demand cost for the new firm transportation service from Wright, [redacted].

Second, EnergyNorth proposes to add 65,000 Dth/day of Tennessee transportation service from Wright to a new delivery meter in West Nashua. The fixed demand cost for this incremental service would be [redacted] million per year for 20 years. In total, the proposed Tennessee agreement would cause EnergyNorth's total transportation demand costs to more than [redacted], from $23.3 million per year to [redacted] million per year.

EnergyNorth's existing and proposed gas supply resource portfolios are shown in Table 1. EnergyNorth currently holds "long-haul" transportation services that provide access to gas supply points outside of New England, and "short-haul" transportation services that provide access to gas supply points within the New England market. EnergyNorth seeks to convert all of its existing short-haul transportation service to long-haul service, and add 65,000 Dth/day of additional long-haul transportation, beginning with the 2017-18 planning year.[1]

**TABLE 1: EnergyNorth Design Day Resources (Dth)**

| | Existing 2014-15 | Proposed 2017-18 |
|---|---|---|
| Transportation – Long-Haul | 29,718 | 155,718 |
| Transportation – Short-Haul | 50,000 | 0 |
| Off-System Storage Services | 28,115 | 28,115 |
| On-System LNG | 12,600 | 12,600 |
| On-System Propane | 34,600 | 34,600 |
| Total | 155,033 | 220,033 |

## III. PROPOSED SHORT-HAUL CONTRACT CONVERSION

**Q. How does EnergyNorth use its short-haul transportation service from Dracut today?**

A. EnergyNorth utilizes the transportation service from Dracut mainly for winter supply. Figure 1, which overlays the design day capacities of each gas supply resource from Table 1 on EnergyNorth's load curve for 2014-15, illustrates how the Dracut-based supply is dispatched during the year.[2] These market-area purchases are made on relatively cold days, after EnergyNorth dispatches its gas supplies tied to long-haul transportation services and underground gas storage services, but before dispatching on-system LNG and propane peaking resources for system supply.

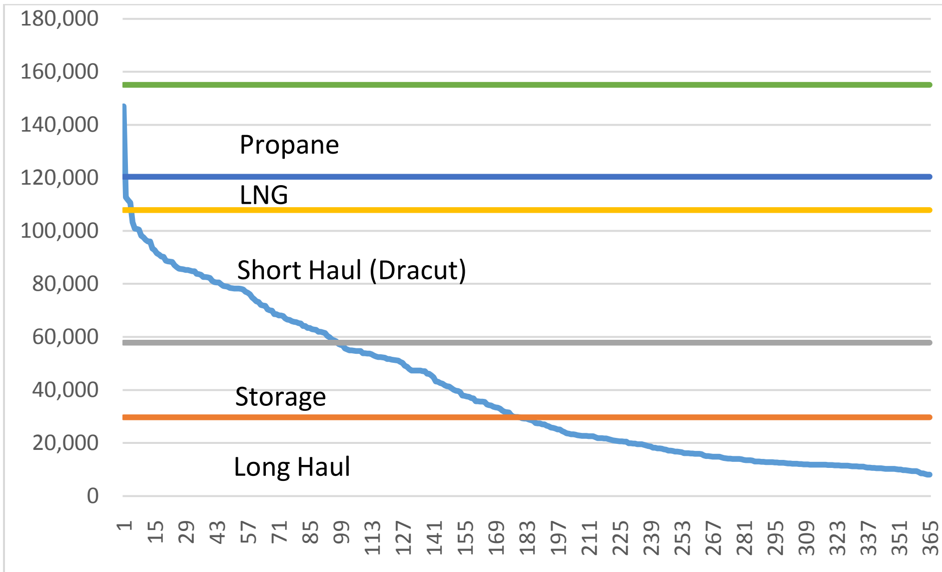
EnergyNorth typically enters into both winter season baseload and swing contracts for firm gas supply delivered at Dracut. This gas is typically priced at a New England market price, such as the Tennessee Zone 6-200 leg index. During the 2014-15 winter

[1] The gas supply planning year extends from November 1 through October 31.

[2] *See* attached Exhibit JAR-1, Petitioner's Response to Data Request Staff 2-2. The load curve was developed from the daily requirements forecasts, referenced at Attachment Staff 2-2(c) therein.

season EnergyNorth bought 2.46 Bcf of gas under transactions that were backed by its short-haul firm transportation contracts from Dracut.[3]

**Figure 1: Projected 2014-15 Requirements with Actual Design Day Resources (Dth/day)**




**Q. Why does EnergyNorth propose to change the receipt point on its existing contracts from Dracut to Wright?**

A. EnergyNorth's proposal to contract for additional transportation capacity to shift the receipt point for existing Tennessee transportation service from Dracut to Wright is based on concerns about the future availability of gas at Dracut and recent increases in New England gas prices. With respect to supply, EnergyNorth points to declines in the quantities of gas from offshore Nova Scotia gas production that will be available for export and uncertainty about LNG imports at Canaport.[4] However, it appears that the latter concern is not related to changes in the physical deliverability from the Canaport LNG vaporization and storage facilities, but to uncertainty about price of LNG supplies.

In terms of price, EnergyNorth observes that Dracut has been one of the highest priced purchase points in the country in recent years.[5] However, this concern is not specific to Dracut, since prices at different locations within the New England market are closely

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[3] *See* attached Exhibit JAR-2, Petitioner's Responses to Data Requests PLAN 2-2, 2-3, and 2-4.

[4] *See* attached Exhibit JAR-3, Petitioner's Response to Data Request PLAN 1-8(a).

[5] DaFonte Testimony, Bates p. 25.

related. Dracut supply is generally priced off of the Tennessee Zone 6-200 leg index, and the Algonquin Citygates index typically trades at a slight premium to both the Tennessee Zone 6-200 leg index and the Dracut price.[6]

**Q. Do you agree with EnergyNorth's concerns about gas supplies at Dracut?**

A. Not entirely. There is no question that the gas market at Dracut has changed since the Joint Facilities pipeline began full operations in 2000. In the early 2000s production from the Sable Offshore Energy Project ("SOEP") was approximately 500,000 Dth/day and the market for gas upstream of the M&N end point at Dracut was very limited. Since the early 2000s the production rate from the SOEP fields has declined, and there is now an established market for natural gas in Nova Scotia and New Brunswick. At the same time, new supply sources have been attached to the M&N system (Canaport in 2009 and the Deep Panuke field in 2013), and winter season deliveries from TransCanada PipeLines ("TCPL") into PNGTS have increased. As shown in Figure 2, the total winter season gas receipts into M&N and PNGTS that are deliverable to Dracut have remained fairly level over the last nine years.[7] When all of the current and future sources of gas deliverable to Dracut are considered, it is reasonable to expect that firm gas supplies will continue to be available at Dracut during the winter season at some price.

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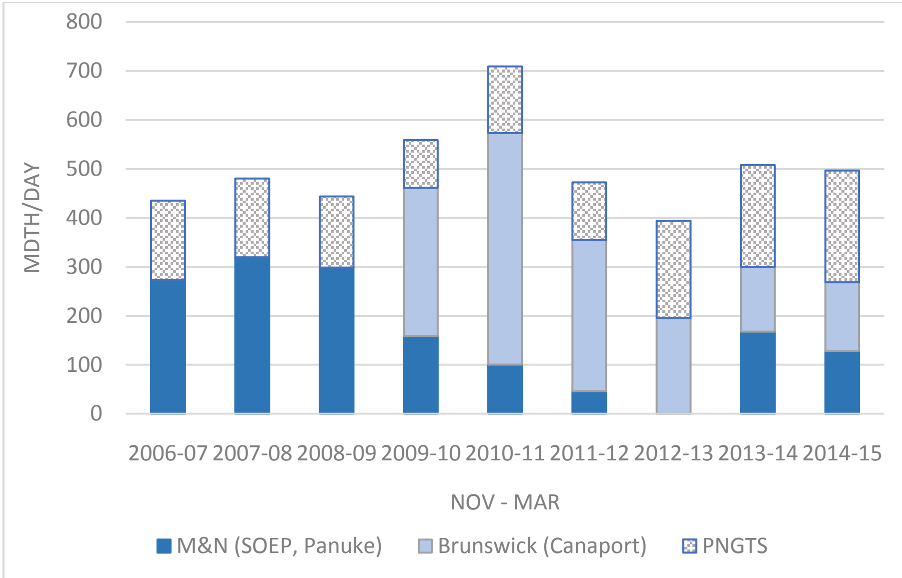
[6] *See* attached Exhibit JAR-3, Petitioner's Response to Data Request PLAN 1-8.

[7] This information is taken from the M&N and PNGTS Operationally Available Capacity reports.

**Figure 2: M&N and PNGTS Winter Season Receipts**




**Q. How much of the firm transportation capacity into Dracut is controlled by LDCs?**

A. A review of pipeline Index of Customer reports shows that most of the firm pipeline capacity into Dracut is held by marketers, not LDCs. PNGTS controls approximately 210,000 Dth/day of capacity into Dracut. The gas transported on PNGTS includes both Canadian and U.S. gas production, as well as winter season withdrawals from underground storage fields in Michigan and Ontario. LDCs currently hold 80,600 Dth/day of firm transportation on PNGTS during the winter season.[8] Much of the remaining capacity is held by gas marketing companies, such as DTE Energy Trading, and is available to make sales of gas at Dracut, and other points on the PNGTS system.

M&N has the capacity to receive up to 833,000 Dth/day at the international border, and can deliver up to 440,000 Dth/day into Tennessee at Dracut. All of the mainline capacity on the U.S. portion of the M&N system is held by gas producers and marketers.

**Q. Did EnergyNorth consider how pipeline projects proposed by Algonquin and PNGTS would affect the supply and pricing of natural gas at Dracut?**

A. There is no indication that EnergyNorth considered that other gas infrastructure projects would increase the quantities of gas that are deliverable to Dracut and expand the supply

[8] The LDCs with long-term firm transportation contracts on PNGTS are Bay State Gas (45,500 Dth/day), Northern Utilities (34,100 Dth/day) and EnergyNorth (1,000 Dth/day).

of gas into the New England market, which would effect prices. The Algonquin Incremental Market ("AIM") project, which was approved by the Federal Energy Regulatory Commission ("FERC") in March 2015, is expected to add over 300,000 Dth/day of pipeline capacity into New England from New Jersey and New York in 2016. Algonquin Gas Transmission does not have facilities at Dracut, but M&N connects with the Algonquin HubLine pipeline at Beverly, MA. Additional pipeline capacity into eastern Massachusetts that is created by the AIM project is likely to displace existing M&N deliveries at Beverly, which could allow gas supplies that are currently delivered by M&N at Beverly to be redirected to Dracut.

M&N is also able to receive gas from Algonquin at Beverly, but at present this gas must come from one of the offshore LNG receiving facilities that are connected to the offshore HubLine pipeline in Massachusetts Bay. However, by adding compression at Weymouth, MA, the proposed Algonquin Atlantic Bridge project would allow physical delivery of gas into M&N from the Algonquin mainline, which would create an additional source of gas supply deliverable at Dracut.

Finally, PNGTS does not propose to increase capacity on the Joint Facilities as part of its "C2C" expansion, but by expanding receipt capacity from TCPL this project could increase the supply of gas available at Dracut by allowing PNGTS to deliver more gas into M&N and the Joint Facilities pipeline at Westbrook, ME.

**Q. Please discuss the outlook for natural gas prices in the New England market.**

A. Over the last three years, winter season gas prices in New England have been high, both in absolute terms and relative to other U.S. markets. For forecasting purposes, natural gas prices are often considered in two parts. The first part is the Henry Hub or "NYMEX" price, which is a benchmark for price trends that affect the overall North American market. The second part of the gas price is the difference from the Henry Hub price, called the "basis", which reflects conditions specific to the local market. Henry Hub prices have been relatively stable in recent years, but the New England basis from the Henry Hub has been more volatile. Table 2 shows the basis for the New England market price, as measured by the Algonquin Citygates price index, starting with the 2008-09 year (November through October). The winter and summer basis numbers were relatively steady from through 2011-12, but the winter basis increased sharply within the last three years, with extremely high prices during the winter of 2013-14.

**TABLE 2: New England Market Price Basis vs. Henry Hub ($/Dth)**[9]

| | Winter | Summer | Annual |
|---|---|---|---|
| 2008-09 | [redacted] | [redacted] | [redacted] |
| 2009-10 | [redacted] | [redacted] | [redacted] |
| 2010-11 | [redacted] | [redacted] | [redacted] |
| 2011-12 | [redacted] | [redacted] | [redacted] |
| 2012-13 | [redacted] | [redacted] | [redacted] |
| 2013-14 | [redacted] | [redacted] | [redacted] |

Actual prices for the 2014-15 winter were not as high as the previous year, and forward price quotes for future years indicate that the extreme prices seen during the 2013-14 winter season are not expected to be the norm.[10] As shown on Table 3, the forward basis quotes for the peak months of December, January and February for 2017-18 are nearly two-thirds lower than the actual average basis for the same months in the winter of 2013-14. While there is no guarantee that regional price relationships will return to pre-2012 levels, it is also unlikely that the experience of the last three years, with extremely high prices in New England relative to other nearby markets, will persist for another 15 or 20 years. Projects to expand pipeline capacity into New England and increase deliverability from LNG storage and peaking facilities within the region are expected to narrow the difference between New England prices and prices in New York and New Jersey.

9 *See* attached Exhibit JAR-5, Petitioner's CONFIDENTIAL Response to Data Request PLAN 1-3, for source data.

10 *See* attached Exhibit JAR-7, Petitioner's Response To Data Request OCA 1-9 (and particularly, the referenced Attachment OCA 1-9 therein, which provides New England market area gas prices for the 2014-15 winter).

**TABLE 3: New England Market Price Basis for the Peak Winter Months ($/Dth)[11]**

| | | DEC | JAN | FEB | Average |
|---|---|---|---|---|---|
| Actual | 2013-14 | 9.55 | 16.94 | 21.00 | 15.86 |
| Actual | 2014-15 | 9.75 | 8.48 | 7.46 | 8.56 |
| Forward | 2015-16 | 6.99 | 9.86 | 9.59 | 8.81 |
| Forward | 2016-17 | 3.85 | 7.99 | 7.71 | 6.52 |
| Forward | 2017-18 | 3.24 | 7.27 | 6.62 | 5.71 |

**Q. Does EnergyNorth provide evidence to show that contracting for long-haul pipeline capacity would reduce costs for consumers?**

A. No, EnergyNorth does not provide any analysis to show that extending the transportation path for its existing 50,000 Dth/day of transportation service back to Wright, NY would be expected to benefit consumers. The modeling cases that EnergyNorth presents in its application are all based on 115,000 Dth/day of firm transportation service from either Wright or Ramapo, NY, with no market area gas purchases. EnergyNorth's application does not include any scenarios in which EnergyNorth retains its existing 50,000 Dth/day of transportation service from Dracut and continues to purchase firm winter season gas supplies at market area prices. It appears that the EnergyNorth simply assumes that any pipeline transportation service that creates access to lower-cost gas supply will result in lower total costs.

**Q. What are likely to be the cost consequences of replacing short-haul transportation service from Dracut with long-haul transportation service from Wright?**

A. The proposed receipt point shift is likely to cause EnergyNorth customers' gas costs to be higher, not lower. Just because market-area gas prices in New England are high relative to prices at upstream locations that are closer gas production does not necessarily mean that all market-area purchases should be eliminated from a distributor's supply portfolio, as EnergyNorth has proposed. There is a trade-off between higher transportation costs and lower gas commodity costs. The optimum mix of supply-area and market-area

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11 *See* attached Exhibit JAR-4, Petitioner's Response to Data Request PLAN 3-2 (and particularly, the referenced Attachment PLAN 3-2(b) therein) for the source data.

purchases depends on (1) the gas price difference between the two markets; (2) the fixed and variable transportation costs; and (3) the quantities of gas that will be purchased and delivered relative to the transportation capacity. The relationship between actual utilization and maximum capacity defines the "load factor".

When a large portion of the transportation cost is a fixed cost, load factor is particularly important. For example, if the fixed transportation cost is $1.00/Dth and the transportation capacity is used at maximum throughout the year (i.e. at 100% load factor), adding transportation capacity reduces total costs if the average savings in gas commodity costs is at least $1.00/Dth. However, if the capacity is only used the equivalent of 30 days per year (i.e. at load factor of 8.2%), the average commodity cost savings would need to be $12.17/Dth in order to break even.[12]

In this case we know that the difference in fixed transportation costs between EnergyNorth's existing Tennessee service from Dracut and the proposed service from Wright is [redacted] million per year. The existing transportation service from Dracut has an average of fixed cost $0.304/Dth, which for 50,000 Dth/day of capacity translates to an annual cost of $5.548 million. The proposed fixed rate for 50,000 Dth/day of incremental transportation service from Wright is [redacted] million per year. As discussed above, we also know that market area purchases backed by Tennessee transportation service from Dracut are required mainly for winter season supply, so that this supply source is used at a relatively low load factor over the year. The missing input to the analysis is the future relationship between New England gas prices and prices at Wright.

**Q. How is natural gas priced at Wright, NY today?**

Wright, NY is not a major gas trading point, so there is not a separate price index published for Wright. Pricing information for IGTS Zone 1, which includes Wright, shows that there is a close relationship between gas prices at Wright and prices at Waddington, which is the New York-Ontario border point where IGTS receives gas from TCPL. Wright typically trades at a small premium to Waddington because Wright is

[12] This simple example assumes no variable transportation costs and no remarketing of surplus off-peak capacity.

located downstream, so for purposes of comparing prices in New England and Wright it is reasonable to use the Waddington price as a proxy. Table 4 shows the relationship between winter and summer season prices in New England and Waddington over the last six years, using the AGT citygates index as the benchmark for the New England market.

**TABLE 4: Waddington Gas Price vs. Henry Hub and New England Market ($/Dth)[13]**

| | Waddington Price vs. Henry Hub | | | New England Price vs. Waddington | | |
|---|---|---|---|---|---|---|
| | Winter | Summer | Annual | Winter | Summer | Annual |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 2008-09 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2009-10 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2010-11 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2011-12 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2012-13 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 2013-14 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**Q. Did you quantify the cost impact of the EnergyNorth proposal?**

A. Yes. I estimated the net savings or costs that would result from changing the receipt point for the 50,000 Dth/day of existing Tennessee transportation service from Dracut to Wright and moving the 2.46 Bcf that EnergyNorth actually purchased in the New England market area during the 2014-15 winter season to Wright. I used the forward basis prices for New England (Algonquin Citygates index) and Wright (Iroquois Zone 1 index) from Attachment PLAN 1-3 and the costs for the NED project and EnergyNorth's existing Dracut transportation service from Attachment Staff 2-1. *See* attached Exhibits JAR-5 and JAR-8. The results are shown in Table 5. The estimated annual cost savings of $6.1 million is much less than the incremental fixed and variable transportation cost of [redacted] million, resulting in a net cost to EnergyNorth customers of [redacted] million per year.

[13] *See* attached Exhibit JAR-5 (and particularly, the referenced Attachment PLAN 1-3 therein), for source data.

**TABLE 5: Estimated Cost Impact of Proposed Receipt Point Shift**

| | | | NOV | DEC | JAN | FEB | MAR | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Purchase Quantity | MDth | 0 | 413.0 | 861.3 | 902.3 | 284.2 | 2,460.7 |
| 2 | Henry Hub Price | $/Dth | 4.218 | 4.396 | 4.537 | 4.515 | 4.453 | |
| 3 | Dracut Basis | $/Dth | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 4 | Dracut Price | $/Dth | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 5 | Dracut Gas Cost | $000 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | Wright Basis | $/Dth | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 7 | Wright Price | $/Dth | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 8 | Wright Gas Cost | $000 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 9 | Commodity Savings | $000 | | | | | | [redacted] |
| 10 | Added Fuel Cost | $000 | | | | | | [redacted] |
| 11 | Added Variable Cost | $000 | | | | | | [redacted] |
| 12 | Added Demand Cost | $000 | | | | | | [redacted] |
| 13 | Total Added Cost | $000 | | | | | | [redacted] |
| 14 | Net (Savings)/Cost | $000 | | | | | | [redacted] |

**Q. Is it possible that the net cost of this proposal to EnergyNorth customers would be higher than the estimate that is shown in Table 5?**

A. Yes, it is certainly possible that the net cost to EnergyNorth customers would be higher. Although the forward prices used for these estimates reflect a modest reduction in the New England price basis, forward prices are not forecasts, so they do not necessarily reflect the full potential for new pipeline expansion projects to lower New England gas prices and narrow the price differential between Dracut and Wright. If the difference between New England prices and prices at Wright and Waddington returns to the levels experienced before the run-up in New England prices began in 2012-13, as shown on Table 4, the commodity cost savings will be much lower, and the net cost of the proposed receipt point shift to EnergyNorth consumers will be higher. Also, the numbers shown in Table 5 do not account for the possibility that cost overruns for the NED project [redacted].

**Q. Why do you use forward basis prices for your analysis instead of the EnergyNorth basis projections?**

A. The basis projections for Dracut and Wright that are shown in Table 5 apply to the same time period and are taken from the same independent source. This is not true for the basis numbers used by EnergyNorth.

**Q. What is the source of EnergyNorth's basis projections for Wright?**

A. For its modeling analysis, EnergyNorth uses price basis projections for Wright that are derived from an analysis done by members of the gas distributor group that negotiated the NED transportation service with Tennessee (the "LDC Consortium"). According to EnergyNorth, the projections are "based on various historical and forward looking basis relationships", which are described in the worksheets provided as Attachment PLAN 1-3. *See* attached Exhibit JAR-5. EnergyNorth did not participate in the development of the basis projections, and is unable to provide supporting materials that are referenced in the LDC Consortium worksheets.[14]

The LDC Consortium assumes that new pipelines will be built to transport Marcellus shale gas to Wright, causing gas prices at Wright to closely track Marcellus area prices. The price basis at Wright is calculated by averaging the forward prices for two Pennsylvania points, and adding an assumed cost for gas transportation. These basis projections do not account for gas flows into Wright from other markets, or the possibility that limits on pipeline capacity between the Marcellus region and Wright could cause the gap between gas prices in Pennsylvania and gas prices at Wright to remain wider than the LDC Consortium has assumed.

**Q. What is the source of EnergyNorth's basis projections for Dracut?**

A. The LDC Consortium did not prepare price basis estimates for the New England market, so EnergyNorth developed its own basis projections for this proceeding. For model scenarios requested by Staff and intervenors that include purchases at Dracut, EnergyNorth created basis projections for the winter months using the most extreme daily prices from the last three winters.[15] These Dracut basis numbers, which were derived from past prices, are not consistent with the LDC Consortium's Wright basis numbers, which utilize the forward prices and assume future development of gas pipeline infrastructure. An analysis that is based on comparing these two very different sets of numbers would be flawed.

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14 *See* attached Exhibit JAR-6, Petitioner's Response to Data Request PLAN 2-13.

15 *See* attached Exhibit JAR-4.

To illustrate the problem, Table 6 shows the EnergyNorth Dracut price basis assumptions from PLAN 3-2 and the EnergyNorth Wright basis projections from Attachment Staff 2-1. *See* attached Exhibits JAR-4 and JAR-8. The average winter basis for Dracut (the difference from Henry Hub) is $9.50/Dth. This is not as high as the actual basis for the 2013-14 winter, shown by Table 2, but is higher than all other recent years. The average winter basis for Wright of $1.08/Dth, by contrast, is toward the low end of the range of historical winter averages for Waddington, where gas generally trades at prices close to, but slightly lower than, Wright (see Table 4). Using a relatively high price basis for Dracut and a relatively low price basis for Wright would bias the analysis in favor of transportation service from Wright.

**TABLE 6: EnergyNorth Wright and Dracut Basis Projections ($/Dth)**

| | NOV | DEC | JAN | FEB | MAR | Average |
|---|---|---|---|---|---|---|
| Dracut | 2.34 | 9.81 | 19.94 | 9.81 | 5.58 | 9.50 |
| Wright | 0.237 | 1.177 | 1.648 | 1.299 | 1.059 | 1.08 |
| Difference | 2.10 | 8.63 | 18.29 | 8.51 | 4.52 | 8.41 |

## IV. PROPOSAL FOR INCREMENTAL LONG-HAUL CAPACITY

**Q. Please explain EnergyNorth's proposal to contract for 65,000 Dth/day of additional long-haul transportation service from Wright.**

A. EnergyNorth proposes to contract for additional firm gas supply to meet increases in design day requirements in its existing market area. To measure this need, EnergyNorth updated the design day forecast from its most recent Integrated Resource Plan.[16] According to EnergyNorth, the updated base planning load forecast reflects a slightly lower growth rate that reflects declining use per customer. EnergyNorth then adjusts the forecast to incorporate more recent information about capacity-exempt transportation customers returning to utility service, and add an estimate of potential sales to the iNATGAS compressed natural gas facility, a new special contract sales customer. Based on the updated forecast, EnergyNorth estimates a design day surplus of 8,065 Dth for the 2014-15 winter season, but projects that a design day supply deficiency could occur by

[16] *See* DG 13-313.

the 2016-17 gas year. The design day deficiency is projected to grow to 27,388 Dth/day by 2024-25 (Table 7).

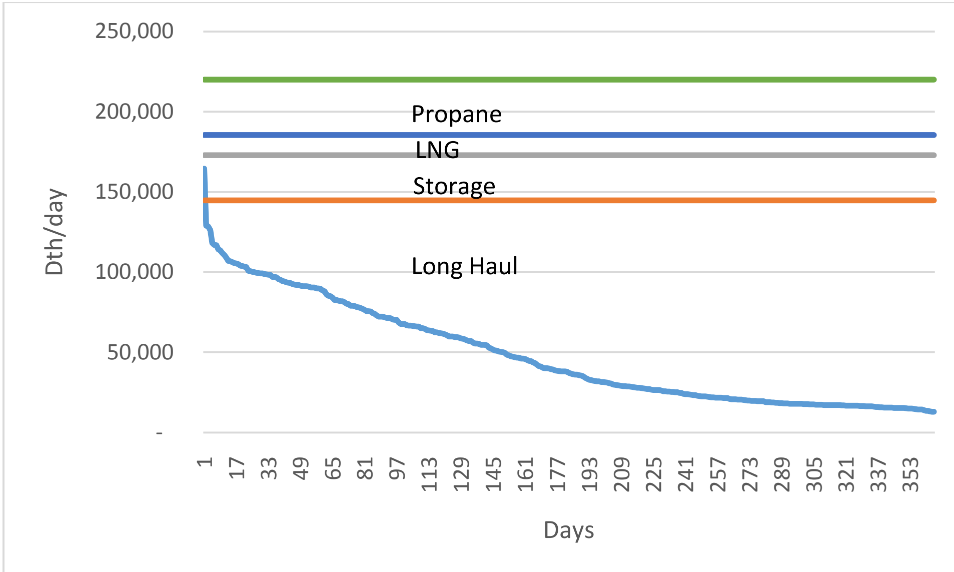
**TABLE 7: Design Day Requirements vs. Existing Supply Resources (Dth/day)**[17]

| | | 2014-15 | 2018-19 | 2024-25 |
|---|---|---|---|---|
| 1 | Existing Load | 145,184 | 154,823 | 171,513 |
| 2 | Returning Capacity Exempt Load | 1,784 | 1,903 | 2,108 |
| 3 | Subtotal | 146,968 | 156,726 | 173,621 |
| 4 | iNATGAS | 0 | 7,800 | 8,800 |
| 5 | Total | 146,968 | 164,526 | 182,421 |
| | | | | |
| 6 | Existing Resources | 155,033 | 155,033 | 155,033 |
| 7 | Surplus/(Deficiency) | 8,065 | (9,493) | (27,388) |
| 8 | Surplus/(Deficiency) w/o iNATGAS | 8,065 | (1,693) | (18,588) |

EnergyNorth's proposal to contract for 65,000 Dth/day of additional long-haul transportation capacity would meet its projected design day requirements over a 24-year planning horizon. This represents a 61 percent increase in firm pipeline delivery entitlements at EnergyNorth citygates. Figure 3 shows how EnergyNorth's firm design day deliverability would compare to projected 2018-19 requirements with the proposed conversion of 50,000 Dth/day of pipeline service from short-haul to long-haul and the addition of 65,000 Dth/day of long-haul capacity. EnergyNorth's firm supply of 220,033 Dth/day would result in a design day reserve margin of 42 percent.

17 *See* DaFonte Testimony, Bates p. 12, for source data.

**Figure 3: Projected 2018-19 Requirements with Proposed Design Day Resources**




**Q. Should EnergyNorth contract for firm transportation capacity based on its estimated design day requirements in 2037-38?**

A. No. A 10-year planning horizon is more appropriate for pipeline capacity decisions for several reasons. First, long-range requirements forecasts are uncertain. If the actual growth rate in requirements turns out to be lower, the potential for over-contracting becomes greater as you go further out in time.

Second, even assuming that EnergyNorth's forecasts are correct, contracting for firm transportation capacity based on projected design day requirements in 2037-38 would give EnergyNorth surplus design day capacity over the entire 20-year term of the proposed transportation contract.

Finally, contracting based on a 10-year planning horizon would give EnergyNorth sufficient time to arrange for additional firm supply to meet requirements beginning in 2025 and later. Pipeline projects to bring new supplies into the New England market are not rare. Table 8 lists expansion projects that have been placed in service within the last 10 years and projects that are under review, or have begun the pre-filing process, at FERC. This list does not include the potential expansion of the TCPL and PNGTS systems or the proposed Algonquin Northeast Access project, both of which could be in service as early as 2018.

**TABLE 8: Recent and Proposed Pipeline Expansion Projects**

| Project | Pipeline | Capacity (Dth) | Receipt Point | Delivery Point | Start Date | Status | FERC Docket |
|---|---|---|---|---|---|---|---|
| Northeast ConneXion | Tennessee | 110,300 | South Texas | Various | 2007 | In service | CP05-412 |
| Phase IV Expansion | M&N | 393,000 | Baileyville, ME | Beverly, MA | 2009 | In service | CP06-335 |
| Northampton Expansion | Tennessee | 4,300 | Wright, NY | Greenfield, MA | 2012 | In Service | CP11-36 |
| Algonquin Incremental Market (AIM) | Algonquin | 342,000 | Ramapo, NY | Various | 2016 | Certificate issued | CP14-96 |
| Connecticut Expansion | Tennessee | 72,100 | Wright, NY | Various | 2016 | Application filed | CP14-529 |
| Atlantic Bridge | Algonquin/ M&N | 153,000 | Mahwah, NJ | Various | 2017 | Pre-filing | PF15-2 |
| NE Energy Direct-Market Path (NED) | Tennessee | Up to 2,200,000 | Wright, NY | Various | 2018 | Pre-filing | PF14-22 |

**Q. Do other New England LDCs use a 10 year planning horizon for similar contract decisions?**

A. Yes, Boston Gas and Bay State Gas recently applied to the Massachusetts Department of Public Utilities for approval of Tennessee contracts related to the NED expansion project.[18] Both companies propose to contract for additional firm transportation capacity based on projected growth in planning load requirements over a 10-year planning horizon.

**Q. Do you have concerns about EnergyNorth's requirements forecast?**

A. Yes, it appears that EnergyNorth overstates the iNATGAS requirement. In the absence of an operating history, EnergyNorth develops a design day forecast for iNATGAS that appears to be based on the maximum possible physical operation of the facility.[19] The iNATGAS facility is scheduled to begin operations in 2015, and design day gas use is projected to grow to 8,800 Dth by 2020-21.[20] However, iNATGAS is only committed to

[18] *See* Dockets D.P.U. 15-34 and D.P.U. 15-39.
[19] *See* attached Exhibit JAR-10, Petitioner's Response to Data Request Staff 1-2.
[20] DaFonte Testimony, Bates p. 12 (Table I).

be a sales customer for one year. If iNATGAS subsequently chooses to convert from sales service to transportation service, EnergyNorth's obligation to hold design day resources to assign to iNATGAS will be based on the customer's estimated design day load at the time of the conversion, and would not increase unless iNATGAS returned to sales service. If iNATGAS converts to transportation service after one year, EnergyNorth's requirement for iNATGAS would be limited to the design day demand at the end of the first year of operation, which is projected to be less than 4,000 Dth/day. Given the uncertainty about the iNATGAS requirements, it would be reasonable for EnergyNorth to use a design day requirement of lower than 8,800 Dth/day for supply planning purposes.

**Q. What do you conclude with respect to EnergyNorth's need to contract for additional firm gas supplies?**

A. It would be reasonable for EnergyNorth to contract for additional firm gas supply resources based on its projected requirements over the next ten years. Based on the projected design day shortfall of 27,388 Dth/day for the 2024-25 planning year, as shown on Table 7, and considering the uncertainty associated with any long-term requirements forecast, it would be appropriate for EnergyNorth to contract for a quantity of additional long-term firm supply between 25,000 Dth/day and 30,000 Dth/day. This need could be met with long-haul firm transportation service, or a combination of new pipeline capacity, including the various projects listed above, and other supply resources.

**Q. Should EnergyNorth contract for extra transportation capacity that might be used to mothball propane peaking facilities?**

A. No. EnergyNorth raises the possibility that it would mothball propane peaking facilities in order to manage reserve capacity resulting for the proposed transportation contract.[21] EnergyNorth does not make a specific proposal to mothball or retire any of its propane peaking facilities, or provide any analysis to compare the cost of continuing to maintain and operate the propane facilities to the cost of acquiring new gas or supplies. EnergyNorth does not suggest that contracting for year-around long-haul pipeline

[21] DaFonte Testimony, Bates pp. 19-20.

transportation service is the best option to replace propane peaking deliverability that is used at a very low load factor.

**Q. Should EnergyNorth contract for extra transportation capacity that might be used to expand its distribution system?**

A. No. EnergyNorth says that Tennessee transportation capacity tied to the NED project would create opportunities for possible expansion of its distribution system.[22] EnergyNorth has not provided detailed information about potential requirements in new market areas, the economic feasibility of serving specific markets, or an implementation plan to show how and when these markets might be connected. It is premature for EnergyNorth to contract for long-term firm transportation service starting in November 2018 in order to supply these potential new markets.

## V. ENERGYNORTH'S ANALYSIS OF PIPELINE ALTERNATIVES

**Q. Please describe how EnergyNorth evaluated the available gas supply alternatives.**

A. EnergyNorth compared Tennessee's NED project option to two other pipeline transportation paths: the Algonquin/M&N path and the TCPL/PNGTS path. EnergyNorth used its gas supply planning model to estimate the total gas supply cost with each of the three options over a 20-year period. For each option, EnergyNorth assumed that 115,000 Dth/day of long-haul transportation capacity is added from either Wright or Ramapo, NY beginning November 1, 2018.

The Algonquin/M&N option involves an incremental expansion of the existing Algonquin pipeline from Northern New Jersey or Southeastern New York, and transportation service on M&N to move gas from Beverly to Dracut. EnergyNorth modeled the Atlantic Bridge project, which is scheduled to be in service in late 2017. Spectra Energy is offering transportation service on the same path with the Access Northeast project, which has a planned in-service date in 2018.

The TCPL/PNGTS path can be used to access gas supplies at Waddington or Wright. Firm service from Waddington would require an expansion of existing transportation

[22] DaFonte Testimony, Bates p. 7.

facilities by TCPL, but is not expected to require any new facilities on PNGTS. EnergyNorth modeled the "C2C" project option, which also includes transportation on IGTS from Wright to Waddington, which would involve an additional cost. The option of purchasing gas at Waddington was not considered.

The gas transportation options based on the Algonquin/M&N and TCPL/PNGTS paths are feasible, and are flexible with respect to contract quantities and timing. While both paths would require Tennessee service from Dracut that would be priced at an uncertain incremental rate, expansion of the Concord Lateral would increase pipeline capacity to EnergyNorth markets located north of Nashua, reducing dependence on LNG and propane peaking in these areas.

**Q. Do you have any concerns about EnergyNorth's modeling of the NED alternative?**

A. Yes. EnergyNorth appears to have understated the costs and overstated the savings under the NED alternative. On the cost side, EnergyNorth would need to build a new distribution line to connect its Nashua-area distribution system to a new West Nashua gate station. EnergyNorth estimates the cost of this line to be $2.3 million, but the owning and operating cost for this required capital expenditure is not included in the EnergyNorth analysis.[23]

Another problem with EnergyNorth's analysis is that the entire distribution system is treated as a single network node for modeling purposes.[24] This does not affect EnergyNorth's analysis of the Atlantic Bridge and C2C options because these supplies would be delivered through Concord Lateral, which physically connects to all areas of the EnergyNorth distribution system. However, the additional gas supply from the new NED pipeline would be physically delivered only to the Nashua market. EnergyNorth's modeling does not account for the fact that existing transportation capacity on the

[23] *See* attached Exhibit JAR-11, Petitioner's Response to Data Request PLAN 1-14.
[24] *See* attached Exhibit JAR-12, Petitioner's Response to Data Request OCA 1-1 (particularly the referenced Attachment OCA 1-1(a) therein).

Concord Lateral would limit the ability to use pipeline supplies at Nashua to meet customer requirements in Manchester and Concord.[25]

**Q. Does EnergyNorth address the risk of inadequate gas supply at Wright?**

A. Not completely. EnergyNorth acknowledges that the Wright, NY point that would be the receipt point for the proposed Tennessee transportation service currently "lacks sufficient liquidity".[26] EnergyNorth is essentially speculating that enough new pipeline capacity will be built from the Marcellus and Utica producing areas to Wright to justify the cost of contracting for firm pipeline capacity from Wright to New Hampshire for a period of 20 years. Only one pipeline from the Marcellus to Wright—the Constitution Pipeline--has been approved by FERC, but has not yet started construction. If there are no further delays, the Constitution Pipeline could begin delivering up to 650,000 Dth/day to IGTS and Tennessee at Wright in 2016. Just two gas exploration and production companies with interests in the Marcellus shale region have contracted for all of the firm capacity on the pipeline. EnergyNorth has had preliminary discussions with the producers, but has not entered into any agreement for firm supply at Wright.[27]

Tennessee has proposed the Northeast Energy Direct Supply Path project, which would extend from North Central Pennsylvania to Wright. An expansion of the Constitution Pipeline expansion has also been proposed. According to EnergyNorth, these projects could bring an additional one Bcf per day of gas to Wright.[28] However, EnergyNorth acknowledges that even with these new pipelines, the supply of Marcellus and Utica shale gas at Wright may not be sufficient to meet the demands of new and existing

[25] Specifically, on days when the total requirement for gas in the markets outside of Nashua exceeds the total Concord Lateral capacity of 106,833 Dth/day under EnergyNorth's contracts with Tennessee, the modeling will use available pipeline gas at Nashua to meet requirements in the other markets. However because the diversion of gas from Nashua to other markets would already be at maximum, EnergyNorth would actually need to dispatch more-expensive LNG or propane peaking resources to meet this portion of its requirement. By modeling the entire distribution system as a single unit, it is likely that EnergyNorth overstates the opportunities to replace peaking supplies with pipeline gas, and underestimates gas costs under the NED alternative.

[26] *See* attached Exhibit JAR-13, Petitioner's Response to Data Request Staff 2-14 (particularly Staff 2-14(f)).

[27] *See* attached Exhibit JAR-14, Petitioner's Response to Data Request PLAN 2-11.

[28] *See* attached Exhibit JAR-13 (particularly Staff 2-14(f)).

shippers on Tennessee and IGTS that hold transportation capacity from Wright and narrow the gap between gas prices in Pennsylvania and Wright. In this case EnergyNorth would need to contract for gas transportation service upstream of Wright to gain access to these lower-cost supplies. EnergyNorth says that it is already in negotiations with Tennessee and other pipeline project sponsors about obtaining pipeline capacity to transport gas to Wright.[29] EnergyNorth does not specify the timing or cost of this additional service, and proposes to defer the Commission review of this service to a later proceeding.[30] However, given the current lack of gas trading activity at Wright, and the risk that new supplies deliverable into Wright will prove to be insufficient, any analysis of the proposed NED contract that does not consider the costs of upstream pipeline capacity is incomplete.

**Q. Given your analysis, what are your recommendations?**

A. EnergyNorth's proposal to contract for 115,000 Dth/day of capacity in Tennessee's NED expansion project is not in the interests of EnergyNorth's customers and should not be approved. The additional fixed pipeline charges associated with extending the transportation path for 50,000 Dth/day of existing transportation service from Dracut, MA to Wright, NY is likely to be exceed the potential savings in gas commodity costs. The proposed addition of 65,000 Dth/day of firm transportation service from Wright is more than two times the quantity of incremental firm gas supply resources that EnergyNorth needs to meet design day requirements over a 10 year planning horizon and should be rejected as well.

**Q. Does that conclude your testimony?**

A. Yes, it does.

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[29] *See* attached Exhibit JAR-15, Petitioner's Response to Data Request PLAN 2-24 (particularly PLAN 2-24(c)).

[30] *See* attached Exhibit JAR-13 (particularly Staff 2-14(e)).

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