BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A LIBERTY	:	Docket No. DG 14-380
UTILITIES	:	
Petition for Approval of a Firm Transportation	:	
Agreement With Tennessee Gas Pipeline	:	
Company, LLC	:	

REDACTED

DIRECT TESTIMONY

OF

MELISSA WHITTEN

ON BEHALF OF THE

THE STAFF OF THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

May 8, 2015

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I. INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Melissa Whitten, and I am a consultant employed by La Capra Associates, Inc., whose headquarters are located at One Washington Mall, Boston, Massachusetts 02108.

Q Please describe your employment experience.

A. I joined La Capra Associates, an energy planning and regulatory economics firm, as a consultant in March 2009 with more than 25 years of prior experience in energy management and financial consulting, including six years as Director of Gas Supply, Transportation and Storage for Cascade Natural Gas Corporation in Seattle, Washington. At Cascade, I was responsible for managing and optimizing the company's portfolio of supply, interstate transportation and storage contracts, supplier evaluation and selection, bi-lateral contract negotiation, and commercial and industrial market development. Prior to that, I worked for a major developer of natural-gas-fired independent-power projects in the Northeast, as well as for Boston Edison (now called Eversource Energy) in both the forecasting and accounting departments. Before taking these positions in the energy sector, I worked as an economist for a major econometric forecasting firm with a focus on financial analysis. My resume is attached as Exhibit MW-1.

Q. Please describe your educational background.

A. I have a bachelor's degree in Economics from the University of Massachusetts, Boston, and a Masters in Business Administration in Finance from the University of Rochester, New York.

Q On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Staff of the New Hampshire Public Utilities Commission ("Staff").

Q. Have you previously submitted testimony before the Commission?

A. No. I have not previously submitted direct testimony before the New Hampshire Public Utilities Commission ("Commission"). However, I have submitted direct testimony in other jurisdictions in cases or dockets involving natural gas distribution utilities, including Maryland, Massachusetts and Pennsylvania. A selected list of testimony filed in these jurisdictions is summarized in Exhibit MW-2.

II. PURPOSE OF TESTIMONY

Q What is the purpose of your testimony?

A. I have been asked by Staff to review the filing made by EnergyNorth Natural Gas d/b/a Liberty Utilities ("EnergyNorth" or the "Company") in Docket DG-14-380 (the "Filing"), in which the Company requests approval of the Precedent Agreement ("PA") recently entered into with Tennessee Gas Pipeline, LLC ("TGP" or "Tennessee"), and make a recommendation whether the PA as filed should be approved or denied. This PA, if approved by the Commission, anticipates that EnergyNorth will sign an agreement for firm transportation ("FT") capacity on Tennessee's proposed Northeast Energy Direct ("NED") Market Path project, which I will refer to below as the "FT NED" capacity agreement. The purpose of my testimony is to present my recommendation, based on my assessment of whether the information presented by EnergyNorth in this Filing supports its conclusion that the "FT NED" capacity agreement is necessary to meet existing and future customer load requirements and will do so in a reliable and least-cost manner. As discussed in further detail below, I base my assessment on specific findings that rely upon my review of the evidence provided by the Company in its Filing and supplemented by responses to discovery propounded by Staff, the Office of the Consumer Advocate ("OCA"), and the Pipe Line Awareness Network for the Northeast, Inc. ("PLAN").

Q. Do you sponsor any exhibits with your testimony?

A. Yes, In addition to the Exhibits MW-1 and MW-2, described above, I sponsor seven additional exhibits described below:

Exhibit MW-3	Map of TGP NED project in Massachusetts and Northeast Region
Exhibit MW-4	Map of Energy North High Pressure System
Exhibit MW-5	Table III Revised for removal of LPG Vaporization MDQ
Exhibit MW-6	Forecast Detail from IRP – by
Exhibit MW-7	Chart: IRP Forecast by Customer Class
Exhibit MW-8	Table I Revised
Exhibit MW-9	Company Responses to Data Requests

Q. How is your testimony organized?

A. My testimony is organized in seven sections, including Introduction, Purpose of Testimony, Standard of Review, Background (on the Company and the PA), Design Day Demand Forecast methodology, Evaluation of Alternatives to NED Capacity, and Conclusions and Recommendations.

III. SUMMARY OF FINDINGS

Q Please summarize your findings regarding the Company's petition.

A. I find that the Company has demonstrated a need for incremental capacity to meet design-peak-day and annual-throughput requirements within the next five years based on the forecast they presented. However, their forecast is based on the assumption that growth trends observed in the past will continue into the future without providing sufficient explanation identifying the demographic factors and economic drivers that would support this growth trend. As a result, while the growth trend is likely to continue in the very near term, it is not clear whether and why it will continue over the longer term.

Further, while the Company's position that the FT NED agreement will provide certain benefits is plausible, it raises additional concerns that are left unaddressed in the Filing. The benefits that the Company says will be provided by the FT NED agreement are summarized below.

- The FT NED agreement will increase reliability on the system by providing an additional interconnect on the west side of its distribution system at Merrimack, so the Company would no longer be reliant upon a single interconnect with TGP on the east side of its distribution system.
- There are five existing interconnects with TGP on the east side of the Company's distribution system, all on the TGP Concord Lateral, which runs at a lower pressure than the mainline.[1] The Company can reconfigure its system to serve the high growth area of Nashua/Hudson from the west interconnect. Once it does so, the gas that otherwise would have been diverted to the Nashua Hudson Lateral will flow further north to downstream

[1] Company response to Staff Tech-7.

market districts of Londonderry, Manchester, Hooksett, Allenstown, and Concord market areas.[2]

- This second interconnect at Merrimack is assumed to deliver gas supply at a much higher pressure rating and will provide for delivery of primary firm gas supply at a higher pressure than available on the Concord Lateral, which will allow the Company to extend its distribution system on the west side to cost-effectively serve new customers,[3] presumably residential as well as commercial and industrial ("C&I") customers.

There are five concerns raised by the Company's reliance upon these purported benefits to support its request for approval of the PA and the subsequent FT NED agreement:

1) The Company anticipates being short capacity as soon the 2016/2017 and 2017/2018 winter periods. However, this a full two years prior to the winter of 2018/2019, the time when the NED project is anticipated to enter service. So, for the interim two winters, the Company must find firm supply to meet that deficit. The Company acknowledges that it will solicit citygate deliveries to meet its seasonal needs for that two-year period, which suggests that there

[2] Company response Staff Tech-7, page 1 of 2. See also Exhibit MW-4 for copy of a map of the Company's existing connections to Concord Lateral provided as Attachment Staff Tech-47.
[3] DG 14-380, DaFonte Direct, page 6 at 8-12.

are viable alternatives to acquiring long-term interstate-pipeline capacity to meet a design peak day need.[4]

2) The Company's forecast of design day demand growth appears to be due entirely to projected growth in the C&I sector, while demand from the residential sector is projected to decline over the same time frame. The Company proposes to recover the cost of the FT NED capacity, however, from all customer classes through the cost of gas adjustment mechanism.

3) The Company indicated in its filing that the high-pressure interconnect on the west side of its system will facilitate distribution system expansion, including the residential sector as well as the C&I sector.[5]

4) The Company acknowledges that approval of the PA will result in excess capacity throughout the 20 year term of the FT-NED agreement.

5) And, finally, the Company has indicated that it does not plan to retire or relinquish other assets in the near-term, besides the replacement of its existing contract for firm TGP service from Dracut to the Concord Lateral, to offset the cost of the FT agreement.

Q. Please summarize your recommendation to the Commission.

[4] DG 14-380, DaFonte Direct, Bates page 19 at 1-2.
[5] DG 14-380, DaFonte Direct, Bates page 33 at 15-16.

A. The Company has made a credible argument that it has selected a firm interstate pipeline capacity contract that appears to be lowest cost but only among the three alternatives it considered to meet forecasted design peak day need. Unfortunately, the Company's Filing does not provide as support for its petition an evaluation of all feasible options that might provide the same or similar benefits at a lower cost, including:

- contracting for a lower maximum daily quantity (MDQ),
- retaining vintage TGP capacity that it otherwise plans to relinquish,
- procuring seasonal citygate supply under multi-year solicitations, and
- retiring the Company's aging on-system propane air plants.

The Company also fails to support the premise that on-system demand growth will offset excess capacity under this PA in the time frame and magnitude presented in this proceeding. Thus, approval of this PA would create substantial risk for firm ratepayers, who would be obligated to pay for this capacity through rates regardless of whether the Company's growth projection actually materializes as presented.

Based on these observations and findings summarized above, I respectfully recommend that the Commission deny approval of the PA as filed for the following reasons:

- The Filing is not accompanied by sufficient evidence to allow the

Commission to determine that the Company requires the full 115,000 Dth/day of firm capacity to meet a reasonable estimate of design-day demand going forward; and

- The Filing is notably lacking in an adequately-developed cost-benefit analysis of the PA to support its claim that the PA is the "best cost" or least-cost option for ratepayers.

In the event that the Commission were to consider approval of the PA, as filed or as amended by the Company in response to testimony, I would recommend that the Commission impose the following conditions on its approval:

1) An amended or renegotiated precedent agreement should be accompanied by a full cost-benefit analysis of FT NED capacity, which includes a reasonable range of long-term demand forecasts and resource portfolio options. The range of resource options should include not only binary decisions among the three pipeline expansion projects, but also varying amounts of FT NED capacity combined with existing resources and/or alternatives to firm pipeline capacity such as citygate-delivered supply. The demand forecasts should assess the variability of demand futures based on assumptions or forecasts for socioeconomic variables and factors that impact use-per-customer.

2) The Company should be required to exclude from recovery in rates the

remaining propane air plants that will not be required to meet design peak day requirements once the FT NED capacity becomes available, except for the propane air plant located in Tilton, New Hampshire, which the Company has confirmed that it uses for distribution system pressure support.[6]

IV. STANDARD OF REVIEW

Q. What are the legal standards that guided your review and recommendations?

A. While I am not a lawyer, based on advice of counsel, the primary legal standards governing the Commission's review of the PA are related to the Commission's ratemaking authority. *See, e.g.,* RSA 374:1 and 374:2 (public utilities required to provide reasonably safe and adequate service at "just and reasonable" rates); RSA 378:7 (rates collected by a public utility for services rendered or to be rendered must be just and reasonable); and RSA 378:28 (allowing recovery through permanent rates of a return on prudent, and used and useful, plant, equipment, or capital improvement). Typically, the Commission considers whether an investment or commitment is prudent and results in just and reasonable rates in the context of a rate case and after-the-fact. In some circumstances of extraordinarily-large and/or long-term investments, such as the FT NED

[6] Company Response to Staff Tech-20. Were this facility to become no longer needed for distribution support it should also be considered for mothball or retirement status.

agreement, the Commission assesses the prudence, and just and reasonableness, of such an investment before the company commits to it.

Q. Please describe in general terms the process typically followed by a prudent utility to evaluate long-term resource options in light of uncertain future demand.

A. Most utilities evaluate long-term resource options in the context of reasonable estimates of the possible range of demand growth over time. The Integrated Resource Planning ("IRP") process is the best example of a planning exercise regularly performed by most utilities and includes the development and consideration of a range of demand forecasts to allow for planning under a wide range of probable futures that are likely to occur. As a result, these planning load forecasts are typically based on econometric models that quantify the historic relationship between changes in demographic characteristics and macroeconomic drivers and changes in customer count and use per customer over time, plus account for demand reductions due to implementation of energy efficiency programs.[7] Such driver variables may include, for example, population growth, changes in employment, median income, and housing starts for the region. These econometric models are typically developed by rate class and for heating and non-heating rate sub-classes, because the variables that have the most explanatory

[7] Massachusetts D.P.U. 14-91, Liberty Utilities (New England Gas Company) 2013/2014 through 2018/2019 Forecast and Supply Plan, July 2014, Section II. Overview of Planning Load Requirements, page 10.

power can differ for residential versus C&I customer classes and can change over time. These models also support sensitivity analysis to assess the impact of a more optimistic or pessimistic macroeconomic outlook.

Q. What is the overall purpose or goal of the IRP process?

A. The purpose of the IRP process is to determine whether the utility's existing resource portfolio has sufficient flexibility to meets its obligation to serve firm customers on a design peak day, and over a design winter, in a least-cost and reliable manner. More generally, however, it can also be said that the purpose of IRP is to find or define the resource portfolio that minimizes the long-term cost of gas supply in a reliable and flexible manner without also increasing risk to the customers. So, the IRP process helps the Company understand risk inherent in a portfolio, or preferred resource options, by documenting and quantify sensitivity to demographic and economic driver variables.

Q. How does the IRP process facilitate the evaluation of multiple resource portfolio options?

A. The IRP process relies upon the use of industry-standard software, such as the Sendout® modeling system used by the Company, to determine the least-cost dispatch of a given resource portfolio for a given demand forecast and planning horizon, considering the constraints contained in the resource contracts.[8] In addition, the model can compare the resulting annual cost over the life of competing pipeline projects that wholly substitute for one another, or it can evaluate alternative levels of capacity commitment under a single proposed contract by performing multiple runs with different contract MDQ constraints. Thus, the Sendout® modeling process can help to answer not only the question of which contract or combination of contracts is optimal but also the optimal level to commit to under a prospective contract.

Q. Does the evaluation of a precedent agreement for firm pipeline capacity differ from the IRP process?

A. It should be at least as rigorous an evaluation process if not more so, for three reasons. First, the IRP forecast is typically published at multi-year intervals and may be out of date or need to be updated at the time new contract options become available.

Second, and more important, IRPs require the utility to present a plan that looks out over a five-year time horizon and includes an array of resource options that can be generic in nature and sized to fit a specific quantity and number of days of service. By contrast, a major interstate pipeline expansion project, like TGP-

[8] Massachusetts D.P.U. 14-91, Liberty Utilities (New England Gas Company) 2013/2014 through 2018/2019 Forecast and Supply Plan, July 2014, Section II. Overview of Planning Load Requirements, page 10.

NED, typically requires a 15 to 20 year contract commitment for a threshold quantity. Additional risk arises because pipeline projects that provide greater access to supply resources typically require expansion of mainline capacity and appurtenant facilities, which can only be underwritten through the subscription by multiple utility customers. To reach this critical level of participation, some utilities may consider making a commitment several years in advance of design-day need, which can result in excess capacity in the near term. When they are willing to sign up early, during an open season, for the expansion project, in return for some price discount or operational benefit, the utilities are referred to as “anchor shippers.” As a result, an anchor-shipper utility imposes substantial risk on customers because it is allowed to fully recover the cost of the capacity – including excess capacity -- through rates.

Third, in the event that the contract does result in excess capacity, it will have achieved *the opposite* of the IRP goal of minimizing the long-term cost of gas unless it can be demonstrated that the excess capacity has economic value. Therefore, it is even more important for the Company to perform a rigorous uncertainty analysis to demonstrate and explain why this PA is the most robust option. In this context, the most robust option is the one that provides the best economics over the most potential outcomes, and demonstrates that the benefits exceed the cost under a range of plausible futures.

Q. Did the Company evaluate the PA under a range of demand forecast scenarios?

A. No. The Company only updated its key variables in its base case IRP forecast (filed in 2013), for application to the November 2014/October 2015 to November 2018/October 2019 period, and extended the forecast value for the last year by an annual growth factor of 1.0146 (or 1.46% annual increase) for an additional 21 years.[9] The Company's testimony labels the 2014/15-2017/18 period as "short term" and the 2018/19-2037/2038 as "long term,"[10] but forecasts are provided two years beyond 2037/2038.

Q. Is the Company's demand forecast for the PA based on econometric models?

A. Only indirectly. The underlying demand forecast, which is based on the methodology and model specifications of the IRP, does have customer-group or sector detail and utilizes econometric models to analyze the relationship between monthly volumes (modeled by forecasting customer counts and use per customer) and various explanatory variables. However, this forecast is used only in the initial five-year period of the forecast horizon, which extends from 2014/2015 through 2037/2038 (the "PA forecast"). Hence, the years beyond this initial period do not make use of econometric models, meaning the forecast does not include consideration of long-term changes in customers count or use per

[9] Company responses to Staff 3-1. The underlying forecast data that supports this growth rate is found in Company response to Staff Tech-1, Attachment Staff Tech-1,Tab Normal ENGI AprMar, cell O2.
[10] DG 14-380 DaFonte Direct, Bates page 9, lines 4-12

customer beyond use of the growth factor derived from the initial five-year period. I will describe the demand forecast in greater detail in the next section of my testimony.

Q. Does the Company's filing show that the PA results in excess capacity?

A. Yes, it does, however, the Company makes the distinction that excess capacity should instead be called "reserve" capacity.

Q. Did the Company provide a valuation for the excess or reserve capacity that results from its proposed PA?

A. Not in quantitative terms. Rather, the Company described the benefits of the FT-NED capacity in qualitative terms as providing "increased" reliability and "greater" flexibility for specific reasons that I will review, below.

Q. Do you agree with the Company's description of the excess capacity as reserve capacity?

A. No. In the absence of a quantitative analysis of the value of excess capacity in the marketplace, the avoided cost of existing peaking resources, or the cost of unmet design day demand, it appears to be a distinction without a difference. Further, as I will discuss below, when I make my own adjustment to assess the impact of the avoided cost of existing resources, by excluding propane air plant capacity from total design day resources, the excess capacity remains for several years after the start date for NED capacity.

V. BACKGROUND

Q. Please describe EnergyNorth's PA for TGP NED capacity.

A. The PA provides for EnergyNorth to enter into a long-term firm transportation agreement for 115,000 Dth per day of firm transportation capacity on the NED project, with specific primary receipt and delivery points commencing on or about November 1, 2018, and continuing for a primary term of twenty (20) years ("FT NED") capacity.

On the receipt side, the PA anticipates the FT NED agreement will provide for up to 115,000 Dth per day of capacity with a primary receipt point at Wright, NY. This receipt point anticipates the construction and commencement of service of the Constitution Pipeline, which will bring incremental gas supply from the Marcellus-shale producing region in addition to existing supply that can be delivered on the Tennessee system today.

On the delivery side, the FT NED agreement will provide for primary delivery point capacity off the Concord Lateral at the Nashua, Manchester, and Laconia city gates plus primary delivery point capacity at a new interconnect off of the NED mainline, at or near West Nashua. This new city gate interconnect with the

Tennessee mainline **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL],** with EnergyNorth installing approximately 6,000 feet of 12-inch pipe at a cost of approximately $2.3 million, to tie into the new interconnect.

Currently, the entire EnergyNorth system in southern New Hampshire is served exclusively off of the Concord Lateral. As a result, the Company plans to use 50,000 Dth per day of the total under the FT NED agreement to replace EnergyNorth's existing capacity from Dracut to its city gates on the Concord Lateral. The remaining 65,000 Dth per day will be assigned to the new high pressure interconnect with Tennessee planned for the west side of the EnergyNorth's distribution system near West Nashua. If approved, the PA, and subsequent FT NED agreement, will increase the Company's design day firm capacity resources from 155,033 Dth in 2015/16 to 220,033 Dth in 2018/19.

The new interconnect will provide a secondary feed on the west side of the distribution system at an assumed maximum allowable operating pressure ("MAOP") of 1,400 psig, which the Company argues will enhance reliability and allow for more economic future system expansion.[11]

[11] Interestingly, there is some uncertainty surrounding what the exact delivery pressure rating will be, according to the Company's response to Staff Tech-6, which presumably will be confirmed exactly in the final FT-NED agreement. If the MAOP were to be substantially lower, this would reduce the overall value of the project based on the Company's presentation in its Filing.

A map depicting the proposed route of the NED project was provided by the Company as Attachment FCD-1 and is attached as Exhibit MW-3. A more detailed map of the Company's distribution system, which also shows the location of the proposed new interconnect on the west side of the distribution system, was provided as Attachment Staff Tech-47 and is attached as Exhibit MW-4.

Q. Please describe the EnergyNorth's service territory.

A. According to the Company's most recently filed IRP, in docket DG 13-313, Energy North is a local distribution company that provides natural gas service to approximately 87,000 residential and commercial customers in thirty cities and towns in the state of New Hampshire. In May 2012, the Commission approved the transfer of ownership of EnergyNorth to Liberty Energy Utilities (New Hampshire) Corp., in Order No. 25,370. The majority of EnergyNorth's customer base is comprised of residential heating customers having temperature-sensitive demand. The remainder of EnergyNorth's customers are traditional small and medium-size C&I loads, as well as some larger industrial customers.

EnergyNorth's C&I customers have the option of purchasing supply from a competitive supplier and receiving transportation-only service from EnergyNorth, pursuant to the Company's unbundled tariff options. The terms and conditions applicable to transportation-only service specify EnergyNorth's obligation to assign a "slice of system" capacity to certain transportation customers in conjunction with its unbundled tariff service offerings.[12]

Q. Please describe the EnergyNorth's contract resource portfolio.

A. Again, according to the Company's most recent IRP, EnergyNorth's current resource portfolio is comprised of long- and short-haul transportation capacity, and underground storage capacity and associated transportation capacity to meet annual baseload requirements and winter-season heat-sensitive load. With the exception of 1,000 Dth of pipeline capacity delivered off of Portland Natural Gas Transmission System (PNGTS), all of EnergyNorth's upstream long- and short-haul transportation capacity and underground storage is ultimately delivered to the Company off of the TGP system.

The firm transportation contracts that interconnect at the Canadian border source firm gas supplies from both Eastern and Western Canada. The Company's domestic long-haul firm transportation contracts source firm gas supplies primarily from the U.S. Gulf Coast during the winter period and also provide access to natural gas supplies in the Marcellus Shale. Supplies purchased at the

[12] The specific transportation contracts and the allocated amounts from each that are assigned to the Company's Retail Choice program were changed with the Winter 2014-2015 Cost of Gas filing in DG 14-220 on Oct 15, 2014, Da Fonte Revised Direct, page 13 (Bates page 315R).

Dracut, MA, receipt point originate from multiple locations including Canada, the U.S. Gulf Coast, and Liquefied Natural Gas ("LNG") terminals.[13]

EnergyNorth's peaking supplies, to meet that portion of design peak day demand or extended cold snap conditions not covered by baseload annual and seasonal supply, are provided in two ways:

1) The Company's on-system liquid propane gas ("LPG") and LNG facilities located in Manchester, Concord, Nashua, and Tilton, plus
2) Citygate-delivered supply contracts that are embedded in asset management agreements ("AMA").

The Company confirmed in its Filing, should the Commission approve the PA, it will continue to retain all of its LPG facilities in its resource portfolio.

The citygate supply contracts embedded in AMAs are secured on a short-term basis as a result of selecting the winning bidders who respond to the Company's annual RFP. This practice is confirmed in the Company's revised Winter 2014/2015 Cost of Gas filing, notifying the Commission that it issued an RFP for AMAs that would include an obligation for the winning bidder to provide citygate delivery of gas supply during the winter of 2014-2015:

[13] DG 14-220, DaFonte Revised Direct, p. 6 (308R) at 6-11, and Schedule 11C-Revised, page 1 of 1.

> Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2013/14 Peak Period filing, the Company has issued four requests for proposals ("RFP") for the upcoming winter for supply. The first is for a baseload Tennessee Zone 6 citygate or Dracut supply; the second is for its Canadian firm transportation capacity interconnecting with Iroquois Gas Transmission, Inc. in Waddington, NY, ("ANE"); the third is for its Tennessee long-haul capacity from the Gulf Coast and the Zone 4 market area; and the last is for a Tennessee 1 Zone 6 citygate or Dracut swing supply with a call option. [14]

This update to the most recent Winter Cost of Gas Filing confirms that the Company received several proposals in response to RFPs for citygate-delivered supplies and expects to be able to acquire winter supply service with a call or swing provision "to meet day-to-day increases in demand."

The inclusion of a swing provision in the AMAs suggests that the suppliers ultimately selected are willing to provide firm supply in excess of the pipeline capacity released or assigned under the AMA in exchange for a market area price, and, thus, would be willing to meet a greater proportion of the Company's design peak day needs going forward.

VI. DESIGN DAY DEMAND FORECAST

Q. Please summarize your concerns with the Company's design peak day forecast.

[14] DG 14-220, DaFonte Rev Direct, Bates pp. 308R-310R, October 15, 2014.

A. A review of the Company's design day and annual demand forecast reveals certain underlying assumptions that raise two concerns with the Company's petition for approval of the PA. The Company summarizes its design day demand forecast in Tables I, II, and III, for the 24 year period from 2014/2015 through 2037/2038.[15] As stated in the Company's testimony, the first four years of this time period correspond to the Updated IRP Design Day forecast and the remaining values are the Design Day projection for the 20-year primary term of the FT NED agreement.[16] However, the forecast for 2018/19 is estimated by using the methodology underlying the IRP while the 2019/20 through 2037/38 forecasts are based on application of a growth factor to the 2018/19 values. My four concerns about the Company's design peak day forecast are summarized, below:

1) The Total Updated Design Day forecast shown in the last column in Table I – but called simply "Design Day Demand" in Tables II and III -- is higher than the as-filed 2013 IRP forecast shown in the first column, due not to increased economic activity across the Company's service territory but rather to simple projections for reverse migration of existing C&I capacity-exempt customer demand and estimated sales for a new customer, iNATGAS, who will not

[15] DG 14-380, Direct Testimony of F. DaFonte, Table 1, Bates page 12, Table II, Bates page 16-17, Table III, Bates page 18.
[16] The IRP forecast horizon extends through 2018/2019, the last year of which is the first year of the primary term for the FT NED agreement.

commence service until the second year;

2) Comparing this updated Design Day Demand to existing Design Day Resources totaling 155,033 Dth/d results in a Design Day Deficit by the third year of the forecast horizon, 2016/2017, as shown in Table II, however, if no adjustment were made for reverse migration and iNATGAS sales, the deficit does not occur until three years later, in the 2018/2019 planning year;

3) If the underlying assumptions for the Design Day Demand forecast are too optimistic, the "reserve" capacity will be higher than that shown in the last column of Table III;

4) The Company provided a higher design-day demand forecast than shown in Tables I, II, and III of their direct testimony in response to a request to analyze the impact of "mothballing" one or more of the propane facilities.[17] In that response, it appears that the Company is stating that the demand forecast is dependent on whether there would be any decision to retire the facilities. As a consequence, they show a forecast that is greater than what was presented in their original testimony due to two factors: (a) revisions to forecasts of capacity-exempt customers, and (b) consideration of expansion of the Company's Keene division and potential new service territories. I agree that it is prudent to use the latest available information in a forecast, but I do not agree that the demand forecast should be dependent on the availability of

[17] Company Response to Staff Tech-23.

certain supply resources.

Q. Please explain what the term "reserve" capacity means in the context of the Design Day Demand forecast.

A. The Company allows the definition of the term "reserve" capacity to be inferred from Table III, whose last column is called "Reserve / (Deficiency)" and shows that a positive number in this column means that Design Day Resources with NED capacity are greater than Design Day Demand. In other words, the reserve capacity is the amount that is in excess of firm customers' needs even on the coldest days of the year, but that firm customers nonetheless must pay for through rates. The Company rationalizes that "reserve capacity is inherent with any new long-term capacity commitment."[18] But, this observation does not recognize the fact that the amount of reserve capacity is to a large extent within the Company's control, because it chooses the amount of capacity it contracts for and it is responsible for preparing a reliable and appropriate design day forecast.

Q. How much "reserve" capacity is inherent in the Design Day Demand forecast presented in the Company's Filing?

A. According to Table III, the amount of reserve capacity under the FT NED agreement shown in the last column starts out as high as 55,507 Dth in

[18] DG 14-380, Direct Testimony of F. DaFonte, Bates page 19 at 2-3.

2018/2019, or 25% of design-day resources, and declines by half after 10 years and ultimately to 1%, or 2,514 Dth, after 20 years, by 2037/2038. This analysis assumes that the propane assets would still be included and provide design day resources of 34,600 Dth.

Q. Does the Company still show "reserve" capacity on a Design Day if the aggregate vaporization capacity of the Company's on-system Propane facilities is excluded?

A. Yes. The Company states that the aggregate vaporization capacity for its four on-system propane air plants is approximately 34, 600 Dth/d and that when this amount is excluded from Design Day Resources a deficiency occurs within nine years of the addition of NED capacity, by 2026/2027, as shown in the revised version of Table III in Exhibit MW-5.[19] As discussed above, the Company has provided an increased design day forecast in response Staff Tech-23, which causes the deficiency to move to 2023/2024. Depending upon which design day forecast is used, in either case excess capacity exists for several years after FT-NED capacity becomes available.

Q. Please explain your findings regarding the design day forecast.

[19] DG 14-380, Direct Testimony of F. DaFonte, Bates page 19 at 13-14 and Responses to Staff Tech-23

A. The Company's design day forecast for the first five years of the FT NED agreement is based on the Company's demand forecast methodology presented in its last IRP, updated for changes in economic and energy efficiency data during the gap between the IRP and the PA filing.[20] During this five-year period (2014/15-2018/19), the Company's expected average annual growth rate is 1.6 percent, not including capacity-exempt customers, iNATGAS, and any new potential customers from the Keene Division.[21] The supporting detail accompanying the IRP revealed that the Company did not directly model design day demand by customer group.

Q. How does the Company model design day demand?

A. The Company uses design-day and design-year planning standards to calculate the total requirements on a monthly basis for each customer group. The Company applies the normal and design-year daily heating degree day ("HDD") patterns to its 2012/13 regression equations, which yields estimates for daily customer requirements for normal and design years. In the final step of the process, the Company scales the five-year daily forecast of normal-year customer requirements by the 2012/13 ratio of each day's design-year to normal-year daily requirements ratio. The product is a five-year daily design-year forecast of customer requirements. This is especially important because the increase in C&I

[20] Response to Staff Tech-1.
[21] DG 14-380, DaFonte Direct, Bates page 11 at 8 – p. 12 at 1-3.

transportation customer count and volume accounts for a large amount of total load growth.

Q. How does the Company model C&I Transportation customer demand?

A. The IRP's C&I transportation customer count models for the base-case and high-case scenarios use a date-time trend variable that has a significant impact on the models; in essence, it appears that the Company utilizes a single explanatory variable (besides dummy and autoregressive terms) in the form of a trend to forecast customer growth.[22] In looking at the actual growth versus the predicted growth (over the 2006-2012 planning years) in planning-year volumes, the average compounded annual growth rate ("CAGR") forecast for the C&I heating transportation customers overpredicts the actual CAGR by 3.2 percent (23.4% vs. 20.2%), and the forecast for the C&I non-heating transportation customers overpredicts the actual CAGR by 0.8 percent (15.7% vs. 14.9%).

More important is the fact that the models predict C&I transportation volumes' CAGR of 8.4 percent over the IRP forecast horizon 2014/15 – 2018/19, while the CAGR for overall load is predicted to be 1.9 percent, because the other customer groups show flat or declining growth in volume. Thus, the growth in the C&I transportation sector is driving the Company's overall demand forecast.

[22] See BATES Page 133 of the November 1, 2013 IRP.

Q. Please describe the difference between design day forecast in the IRP and the PA.

A. EnergyNorth prepared its IRP design day forecast in conjunction with National Grid.[23] During the five-year IRP forecast period (2013/14 – 2017/2018), the Company modeled energy efficiency programs as supply-side resources using the average of annual growth rates from 2013-2018, calculated as 1.46%. The Company thereafter extended out the average annual growth rate (1.46 percent) through 2040 in order to model energy efficiency programs as supply side resources.

The PA Filing was submitted 18 months after the IRP and has been updated to include current econometric data and updated energy efficiency data, resulting in a lower overall growth rate. This lower growth rate is caused by the new energy efficiency targets causing use-per-customer to decrease. The Company acknowledges, the 1.46% growth rate in the IRP is only slightly higher than in the updated forecasted. As a result, when the 1.46% was subsequently used to extend the updated forecast provided for the PA, this caused the design-day forecast in the PA to be slightly (approximately 2.6 percent) lower over the entire study period or an average difference of 0.11 percent per year. [24]

[23] Company response to Staff 3-1.
[24] Company response to Staff 3-1.

Q. How does the 1.46 percent annual Design Day load growth after 2018/19 compare to load growth found in the prior 5 year period?

A. The 1.46 percent annual-load-growth value is lower than the annual-load or design-day growth forecast for the first five-year period (2014/15 – 2018/19) in both the IRP and the PA Forecast. The annual average growth rate over this period for the IRP, in the "Design Day IRP" column, and the "Design Day Updated" column shown in Table III, are 2.4 percent and 1.7 percent, respectively. If the "Total Design Day" column from Staff Tech-23 is used, the average annual growth rate increases to 3.3 percent. However, the 1.46% does include the unsupported assumption of strong growth in C&I transportation customers that was discussed above.

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Q. Please describe the Company's iNATGAS assumptions used in the PA Forecast.

A. In docket DG 14-091, EnergyNorth received Commission approval for a special 15-year-term contract with iNATGAS, which expects to begin operations at a new CNG facility on or about March 31, 2015. iNATGAS is assumed to be a sales customer during its first year of operation and afterwards will be free to transition to a transportation-only customer. EnergyNorth assumes that the volume of gas required of iNATGAS will ramp up during the forecast period, until it reaches a maximum capacity in 2020/21, with an estimated design day requirement of 8,800 Dth, and then will remain at that level through the rest of the forecast period. The Company's design day forecast incorporates iNATGAS as an out of model adjustment that it adds to the model-produced forecast to calculate the "Total Updated Design Day" shown in Table III.

Q. Do you agree with the Company's design day forecast assumptions for iNATGAS?

A. No. The Company does not sufficiently support its forecast for iNATGAS' design peak day requirement. However, when asked to show the design-day and design-year capacity requirements over the next five years, with and without the iNATGAS accelerated sales level assumed in Attachment SRH-1 (Bates page 007), the Company showed that the design day with iNATGAS was below the annual pipeline-capacity-deliverability volume except for the final year (2017/18) of the (IRP) forecast. The Company explained that it could address the shortfall through a "best cost alternative available in the market" until the new pipeline projects it was considering were expected to be in-service. Table III shows that for the post 2017/2018 period there will be sufficient capacity to meet assumed iNATGAS peak day requirements. The Company's explanation for how they arrived at the estimated 8,800 Dth/d maximum is not adequate, however, since it is based on Company speculation regarding the relationship between assumed growth in annual usage and maximum daily demand as the Company's business expands over time.[25]

Q. What is the Company's obligation to plan for iNATGAS demand?

A. iNATGAS is a firm sales customers that has an obligation to take or pay for minimum purchases of gas supply **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** under its special contract with the Company.[26] Assuming a lower design-day maximum below the Company's estimated 8,800 Dth over the PA Forecast horizon would not necessarily prevent iNATGAS from meeting its minimum purchase level obligations. However, using a slightly lower estimate for iNATGAS's maximum daily demand would not be enough by itself to significantly reduce the excess capacity shown in Table III.

Q. Please describe how the Company forecasts capacity-exempt transportation customers returning to service for the PA.

A. The Company states that, over the last year, it has experienced a return to sales service of approximately 13 percent, or 1,784 Dth of its roughly 14,000 Dth per day capacity-exempt customer load, as shown in Table I. In the PA, the Company

[25] During informal discussions at the March 17, 2015 Technical Session, Mr. DaFonte explained that the estimate was based on an assumed storage capacity of CNG tanker trucks and the number of trucks that could be filled each day adjusted for limits of market demand in the early years, leading to an assumed maximum daily quantity of 8,800 Dth/day shown in Table I.
[26] DG 14-091 Attachment WJC-1, Section 1.5, p.38 of 55

assumes that the capacity-exempt customer load returning to sales service over the forecast period will be "relatively flat," growing by less than 1,000 Dth per design day (from 1,784 in 2014/15 to 2,534 in 2037/38), or about 1.5% CAGR over the forecast period. In response to Staff Tech-23, the return of capacity exempt customers increases from 3,363[27] in 2014/2015 to 4,776 in 2037/38, which matches the same growth rate as found in the initial PA Forecast. The PA projects the reverse migration of capacity-exempt customers separate from the C&I transportation load included in the Updated Design Day Demand, *i.e.*, as an out-of-model adjustment, similar to the projection shown for the iNATGAS customer load forecast.

Q. Please describe your concern with the forecast of capacity-exempt transportation customers returning to service.

A. My concern is that the Design Day Demand in the IRP or Design Day Updated demand in the PA Filing already includes the historical trend for reverse migration of capacity-exempt customers.[28] It is not clear if the out-of-model adjustment shown in Table I takes this into account. Thus, I am concerned that the impact of reverse migration may be over-estimated. It is also important to note that several factors including "market prices, weather and the nature of their

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[27] Company response to Staff Tech-40 provides support for this figure.
[28] DG 13-313, IRP, Appendix A, pp. 75-77 include a forecast that results in customer growth of approximately 30 customers per month in the "Zero Capacity" category.

contracts with competitive suppliers" [29]will affect the return of capacity-exempt load to sales service over the forecast period. Therefore, perhaps an even more conservative forecast for capacity-exempt customers returning to service would be appropriate.

Q. Do you have any additional concerns with the forecast of C&I transportation demand in the PA?

A. Yes. I remain concerned that the forecast design day demand, as presented in Table III, actually incorporates a *declining* design day demand for sales customers that is masked by the assumption that customer demand (and number of customers) will continue to grow at the same historic rate, without any additional justification based on demographic factors or economic drivers. This assumption tends to suggest C&I customers converting from sales to transportation service without distinguishing this trend from the substantial amount of capacity-exempt reverse migration to sales service. When a C&I customer converts from sales to transportation service, it is possible that there will be no change in the planning load for the design day. But when a capacity-exempt customer reverse migrates to sales service, even as an intermediate step until they subsequently convert to a transportation-only customer, there is an addition to planning load. As mentioned above, however, the Company assumes as part of its IRP-derived PA Forecast a

[29] DG 14-380, DaFonte Direct, p. 10 at lines 1-2.

trend projection for capacity exempt reverse migration without presenting any economic analysis for support, so it remains possible that this trend is overstated.

A further concern I have is that the out-of-model Capacity Exempt adjustment accounts for a substantial share of the total difference between the IRP and the PA Forecast. This can be seen by taking the Company's Table I and adjusting it on a step by step basis to transition from the Design Day IRP in the first column to the Total Updated Design Day demand in the last column. Exhibit MW-8 illustrates this adjustment process. In Exhibit MW-8, Table I-revised shows that while column C, Design Day Updated, continues to grow over time, it is much lower than the IRP. The Company's rough estimate of design day demand for iNATGAS (Column E) does account for a significant amount of the increase in the forecast (Column F). But it is also clear that Capacity Exempt reverse migration (Column G) accounts for between 30% and 50% of the difference between Total Updated Design Day demand and the original IRP forecast (Column J). This amount of difference due to a trend assumption suggests that the PA Forecast is being driven by the aggressive out-of-model adjustment for Capacity Exempt reverse migration

Q. What does this tell you about the source for the design day excess capacity created by the PA?

A. It suggests that driver for design day excess capacity is likely due to a) an unsubstantiated reversal in the trend for declining residential sales, and b) an assumed, but not justified, strong growth in C&I transportation customer sales. A revised forecast that relied upon econometric demand models combined with a more conservative assumption regarding capacity-exempt customer migration could result in a lower level of excess capacity in the early years of the PA. This is the type of scenario analysis that should have been done as part of the Company's Filing.

VII. EVALUATION OF ALTERNATIVES

Q. What alternatives to NED did the Company evaluate?

A. EnergyNorth evaluated participation in the TGP NED project in conjunction with two other pipeline projects that could satisfy all or a portion of its design day capacity needs: Spectra's Atlantic Bridge project and TransCanada/PNGTS's C2C project.

Q. Please briefly describe the Atlantic Bridge and the C2C projects?

A. The Atlantic Bridge project is the next expansion of the existing Algonquin Gas Transmission system following the AIM project. The Atlantic Bridge project also flows gas from west to east via the Hudson Valley in NY, through southern CT and southern MA, but then it extends further north into Spectra's Hubline system onto Spectra's Maritimes and Northeast Pipeline ("M&NE") system, and ultimately extends south to Dracut, MA, where their facilities interconnect with Tennessee's existing pipeline system. Because the Company currently has 50,000 Dth per day of existing capacity at Dracut, it could obtain the remaining 65,000 Dth/d of capacity on Atlantic Bridge for a blended cost of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[30]

The C2C project is a joint undertaking of PNGTS and its parent, TransCanada, utilizing much of their existing capacity from the Canadian/New Hampshire border south and east to Portland, ME, where it is jointly shares pipeline facilities with M&NE to the Dracut interconnect with Tennessee. PNGTS's proposal would include an expansion of TransCanada facilities north of the U.S. border and bring supply from Wright, NY, north to Canada via Iroquois Gas Transmission and then across to the PNGTS border interconnect on TransCanada.

Both projects end at Dracut and must use the Concord Lateral to deliver the incremental gas supply to the Company's citygates, as shown on Exhibit MW-4. However, according to the Company, both contractual agreements and operating

[30] DG 14-380, DaFonte Direct, Bates page 32, line 7. As discussed in Section VII below, this cost should be updated.

characteristics prevent the Concord Lateral from providing the full 115,000 Dth/d reliably year-round:

> The Concord Lateral has an MAOP of 750 psig but operates in the 300# to 600# range and has been lower than 300# on many occasions. The Tennessee tariff only requires that Tennessee deliver a minimum pressure on the lateral of 100#. As such, any restriction or curtailment on the lateral as a result of an operational or force majeure event would adversely impact delivery pressure to the EnergyNorth city gates. In particular, the Hudson Lateral has experienced less than optimal pressures in the past when the Concord Lateral pressures were low."[31]

Q. What is meant by the statement that observation that "contractual agreements" prevent the Concord Lateral from providing the full 115,000 Dth/d?

A. This is a reference to the restriction in the pipeline tariff that imposes only a minimum delivery pressure requirement for TGP rather than guaranteeing a maximum delivery pressure to match that for the upstream pipeline path segment. In order to correctly estimate the cost of these alternatives to NED, the cost to upgrade the Concord Lateral, to reach the maximum operating pressure, must be added to each option in addition to the mainline-expansion project costs.

[31] Company response to Staff Tech-7, page 1 of 3.

Q. What advantage does the NED project offer over Atlantic Bridge or C2C?

A. The Company points out that neither project provides the added reliability of the NED project. The NED project [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] feeding the west end of EnergyNorth's distribution system, as described above. The addition of a high-pressure interconnect on the west side of the distribution system at a presumed MAOP of 1,400 psig, along with planned investments in the distribution system, should provide system support to an extent that would allow the Company the leeway to consider mothballing or retiring all of the propane air plants not used to for pressure support, which would further reduce costs for ratepayers.

Q. Has the Company evaluated the impact of mothballing or removing the propane air plants from service?

A. In response to discovery propounded by Staff, the Company considered the impact on the Design Day Reserve/(Deficit) if the propane air plants were removed from service. The Company assumes that, collectively, the propane air plants can provide 34,600 Dth on a design peak day. Given the Company's Total Updated Design Day forecast presented in this Filing, and assuming the availability of the FT-NED capacity, the Company estimates that it would have a Design Day Reserve through the winter of 2026/2027, or eight years after the in-service date of the NED capacity. The window between now and when the NED project is scheduled to enter service should give the Company more than enough time to evaluate whether any of the propane air plants are needed for distribution support.[32]

Q. Did the Company compare the total cost of service under the three alternatives?

A. Yes. The Company provided Table IV, showing that the annual costs under the two alternative projects were approximately the same over the life of the contract, but the cost of the FT-NED contract was as much as $700,000, or 15%, less. The Company also provided, as a confidential response to Staff discovery, a comparison of the negotiated rates on a unitized basis that shows NED is slightly less expensive. However, these costs are based on an assumed cost for the upgrade of the Dracut lateral that needs to be refined and updated.

Q. Did the Company evaluate any other supply side options besides the Atlantic Bridge and the C2C project?

A. No. In fact, the Company affirmatively states that it chose to consider only these two proposed pipeline projects in the event that the NED project is not completed.[33]

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[32] Company Response to Staff Tech-23, page 2 of 5, see especially Table Staff Tech 23(a).
[33] DG 14-380, DaFonte Direct, Bates page 28, lines 1-2 and Bates page 31, lines 9-11.

Q. Did the Company provide a range of feasible contract resource alternatives sufficient to allow the Sendout® model to evaluate different levels of capacity for the PA?

A. No, not as part of its Filing. However, the Company did provide additional model runs in response to discovery propounded by the OCA, where the OCA specified that varying MDQ levels to be evaluated.

Q. Is this lack of robust scenario analysis in this Filing consistent with prudent utility planning?

A. No. Scenario analysis is considered appropriate and prudent for IRP, which may have only a five to ten year forecast horizon. So it should be even more important to employ robust scenario analysis when considering a single resource option with a much longer contract duration that results in persistent amounts of excess capacity,

Q. Are you satisfied with the cost comparison provided by the Company?

A. No. The Company's cost comparison does not meet the standard of review, or conform to industry best practices for IRP analysis, as discussed above, because it does not consider all feasible resource configurations using NED capacity, nor does it include a reasonable range of demand forecasts. Therefore, the Company has failed to show that the PA is the least cost alternative available.

Q. Has the Company produced any evidence to refute the presumption that any price or operating benefits would be diminished if it negotiated with TGP for a lower maximum daily quantity of NED capacity?

A. No. It has not.

Q. Has the Company presented evidence that TGP would not agree to a revised PA for a lower maximum daily quantity?

A. No. It has not. Moreover, I am aware of other utilities, who have filed petitions for approval of their individual, negotiated precedent agreements before the Massachusetts DPU that have varying MDQs as well as primary terms. For example, The Berkshire Gas Company has submitted a precedent agreement for approval that includes an MDQ of only 36,000 Dth/d and an undisclosed primary term.[34]

Q. Have other utilities entered into precedent agreements for TGP-NED capacity?

[34] DPU 15-48, Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A.http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-48%2fBoucher_Testimony_redacted.pdf, April 21, 2015, page 10 at 25.

A. Yes. At least two other utilities have submitted precedent agreements for regulatory approval in Massachusetts. Columbia Gas of Massachusetts has requested approval of a 20-year contract for 114,300 Dth/d of capacity from Wright, NY, to Dracut, MA, on the Market Path segment of the NED project.[35] Also, National Grid has requested approval of a 20-year contract for 151,926 Dth/d of capacity from Wright, NY, to Dracut, MA.[36]

Q. What impact is the capacity included in other utilities precedent agreements likely to have on the market?

A. If both of these petitions are approved, they would add as much as 100,000 Dth/d of incremental capacity that will not necessarily be fully utilized throughout the year, since utilities purchase capacity to meet design day requirements. This suggests that significant seasonal excess capacity will be available, through capacity release and asset-management agreements entered into between these utilities and third-party marketers, to serve-capacity exempt customers. Thus, the Company should not assume that it will have to plan for as much reverse migration of capacity-exempt customers as has been included its PA Forecast.

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[35] DPU 15-39 Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project, Initial Filing, para 7, p. 3; http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-39%2finitial_filing.pdf,

[36] DPU 15-34 Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project; para 4, p. 2

Q. What additional information and analysis would be required to help make a quantitative assessment of whether the PA is in fact the least cost alternative to meet a reasonable forecast of demand growth?

A. For the cost-benefit analysis to be complete, the Company should fully develop both its demand- and supply-side analyses. This would include at a minimum:

- a revised demand forecast process that incorporates appropriately-specified econometric forecast models at the rate-class level, a review of the current base-case demand forecast for reasonableness, and the development of alternative low- and high-growth case scenarios;
- an assessment of additional resource options, including:
  - replacing the Dracut capacity with the NED capacity but assuming a lower maximum daily quantity, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; and
  - retaining the existing 50,000 Dth/d of Dracut capacity and combining it with a lower quantity of NED capacity to evaluate

the resulting "blended" rate; and

- prior to conducting analyses including existing Dracut capacity in combination with any of the three pipeline project alternatives, the Company should make a more formal request for a quote from TGP to upgrade the Concord Lateral to meet the required delivery pressure needed to make each alternative viable, and revise Confidential Attachment Staff 2-1 accordingly.[37]

Q. Has the Company provided a cost comparison of a lower amount of NED capacity delivered to the new interconnect on the West side coupled with retaining the vintage NED capacity?

A. Not in its original filing. Subsequently, however, it did so in response to discovery propounded by the OCA.

Q. Please summarize the results of the analysis provided in response to OCA 2-5.

A. During the technical session, the Company was asked why they did not consider alternatives to the full MDQ included in the PA. After a discussion of the non-cost benefits described above, the representatives from the OCA requested the Company to perform several Sendout® runs to establish whether the total cost of the capacity at lower MDQs would be higher or lower than the proposed 115,000 Dth/d of NED capacity. In particular, the OCA asked the Company consider

[37] DG 14-380 Confidential DaFonte Direct, page 032 at 5-12.

alternatives that had the same total amount of capacity equal to 115,000 Dth comprised of varying amounts of NED and retained Dracut capacity. The results of these model runs were provided by the Company in response to OCA-2-5.

Q. Please explain what you find interesting about the comparison of total costs for the OCA model runs.

A. I have summarized the total cost results in a table below that also compares the total costs for each of the three projects the Company evaluated. Interestingly, at MDQ levels below 85,000 Dth/d for the NED capacity, the total cost is less than the total cost under the PA MDQ, which the Company described as least cost.

SENDOUT ® RUNS:	Total Costs ($000s)
DG 14-380 DaFonte Direct, p. 34	
Table IV - TGP NED	$3,844,043
Table IV - Atlantic Bridge (Algonquin)	$4,524,607
Table IV - C2C (PNGTS)	$4,380,965
CONFIDENTIAL Attachment OCA-2-5	
105,000 Dth NED SENDOUT Run	$3,853,132
95,000 Dth NED SENDOUT Run	$3,828,595
85,000 Dth NED SENDOUT Run	$3,758,304
75,000 Dth NED SENDOUT Run	$3,676,095
65,000 Dth NED SENDOUT Run	$3,614,816

The total costs in this table do not reflect any cost mitigation from marketing the "reserve" or excess capacity, *i.e.*, these are gross costs before any credits.

However, the OCA did request that these Sendout(R) runs include an assumption for cost mitigation over the full PA Forecast horizon.

A variation on this cost mitigation scenario analysis could reveal the value of excess capacity for a given level of risk. The Company could compare the total costs for the Sendout(R) runs summarized in the table above to a scenario where the Company signed a shorter term PA, *e.g.,* 10 or 15 years, with the right to turn-back or renew the capacity after that period.

Presumably, the pipeline operator would have to recover the same facilities cost but over a shorter time period, so one would expect that the anchor shipper rate would have to be higher than that for a 20 year agreement. However, a higher rate could be offset by carrying the excess capacity an extra five or ten years when the amount of cost mitigation that could be earned might decline as more pipeline expansion projects come on line. This is the type of cost-benefit analysis that the Company should have provided in its original Filing.

Q. Does the Company state that the PA represents the least-cost option to meet design-day growth on its system?

A. Not in the Filing. Instead, the Company seemed to emphasize that the PA is the "best cost" option rather than the least-cost option. Notably, the Company artfully refers to NED as "superior from a cost perspective" to alternatives but stops short of declaring it to be the least cost alternative.[38] However, it is equally noteworthy that the Company appeared to adopt the least-cost justification in its response to Staff Tech-44.

Q. Why do you think the Company might have stressed the description of the PA as the "best cost", rather than "least cost", alternative in the Filing?

A. Perhaps the Company emphasized "best cost," because it had to acknowledge in the Filing that the PA results in excess capacity, and, in spite of this situation, the Company wants to retain the propane air facilities for supply flexibility.

Q. Does the Company provide a fully-quantified cost-benefit analysis to support its conclusion regarding the NED project?

A. No. The Company describes a ranking system based on cost, reliability, flexibility, and viability. The only qualitative component is the cost estimation based on the Sendout® dispatch model, which receives a maximum score of 30 points. The remaining factors are qualitatively-assessed, based on judgment subject to maximum scores of 35, 20 and 15 points, respectively, so that no alternative can have a total score greater than 100 (*i.e.*, 30 + 35 + 20 +15 = 100). As shown in Table V, the three projects considered by the Company rank very closely, separated by only 3 points. However, this is not a quantitative cost-

[38] DG 14-380 DaFonte Direct, page. 37

benefit analysis, because the rank assignment is based largely on subjective judgment.

Also, for the one factor that is quantitative, because it is based on total cost from the Sendout® run, the ranking of 30 for NED and 29 for the other two alternatives are in fact subjectively assigned. The one point difference isn't fully explained and only serves to emphasize that the alternatives are very competitive. Consequently, we are left only with the annual and life-of-contract cost estimates presented in Table IV, which, as I have described above, need to be updated to include more concrete costs and expanded to include more options.

Q. Are you aware of any other advantages that the PA offers?

A. Yes. According to Confidential Attachment FCD-2 filed by the Company, the PA offers additional flexibility by allowing the Company the opportunity to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[39] Further, the PA includes the possibility that the Market Path segment of the NED project may include construction of a 36-inch diameter

[39] Confidential Attachment FCD-2, page 6.

pipeline rather than using 189 miles of 30-inch diameter pipeline, as currently planned. Using 36-inch diameter pipe throughout would increase the delivery capacity of the project, but it is not clear if this would improve the economics of this project compared to the other alternatives.[40]

Q. Are you aware of any factors or events that could change the comparative evaluation of the alternative projects?

A. Yes, according to a recent presentation by Algonquin, on April 23, 2015, the size of the Atlantic Bridge project has been reduced in size because one party gave timely notice to cancel their participation as an anchor shipper. The size of the project has been reduced from 220,000 Dth/d to 153,000 Dth/d, or by about one-third. Checking with Algonquin revealed that if another shipper were to decide at a later date to participate in the Atlantic Bridge project, the negotiated rate would be slightly higher than the rate originally considered by the Company. If so, this would tend to narrow the cost difference between Atlantic Bridge and C2C and increase the difference between Atlantic Bridge and NED, adding uncertainty to the Concord Lateral cost estimate discussed above.[41]

Q. Are you aware of any factors or events that could change the cost of the NED project?

[40] Redacted Attachment FCD-2, pp. 2 and 5.
[41] FERC PF15-22, Atlantic Bridge Monthly Project Report, April 2, 2015.

A. The Company has indicated that it may consider at a later date whether to enter into an agreement for supply-area capacity upstream of the capacity agreed to in the PA. This suggests that the Company is at least willing to contemplate the potential that supply will not be available in sufficient reliable quantities at the Wright, NY, receipt point to maintain its beneficial cost comparison with Atlantic Bridge and C2C. The likelihood of this event is difficult assess until the new Constitution Pipeline project interconnecting at Wright enters service in 2016/17. However, the need for capacity upstream from Wright could be handled as a scenario analysis that showed how high a supply-region rate could be before it completely offset any price advantage the PA has compared with the other two pipeline projects.

VIII. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations for the Commission?

A. I have identified several concerns with the Company's Filing. These are:

a) The Company indicates that it can continue to obtain firm citygate deliveries to meet design day deficits in the near term and does not indicate that it cannot continue to do so at least to cover a portion of the forecasted demand deficit;

b) The PA assumes 115,000 Dth/d of capacity only 50,000 of which will replace existing capacity under the TGP Dracut contract, leaving 65,000 Dth/d of incremental capacity that results in excess capacity of as much as

55,000 Dth/d in the first year of the FT-NED agreement;

c) The Company's very aggressive and speculative forecast of growth in Design Day Demand reduces this excess capacity slowly over time but some remains even after 20 years;

d) As a result, in order to make sure that the PA represents the least-cost, or even just the best-cost alternative, the Company would have to be certain that it could recoup a significant percentage of the total costs of the excess capacity through cost-mitigation measures. However, this would require an even more speculative assumption about the future value of excess pipeline capacity in the secondary market;

e) The Company's argument that the reliability benefit from having a second high-pressure interconnect on the west side of its system is a sufficient reason to impose the cost of the FT-NED contract on all firm ratepayers, even though it will retain all of its needle peaking capacity including the four propane air plants, whose cost is also borne by ratepayers, has not been demonstrated to support a conclusion that the contract is the least-cost alternative;

f) Additionally, the Company argues that the high-pressure interconnect will allow for cost-effective distribution system expansion to add new customers to the system, without providing any details about its growth expectations or a fully-developed plan estimating the cost to obtain targeted levels of new customer growth and the required investment in distribution system expansion to serve these customers.

Based on these observations, and considering the findings summarized above, it is clear that the Company's stated need for 65,000 Dth/d of incremental capacity is not supported. Instead of providing an analysis based on industry best practices rooted in the IRP process, the company has effectively presented a procurement effort in lieu of a plan.

Further, the justification for the PA is based on an aggressive single-scenario demand forecast that would leave the Company with substantial excess capacity that it would not completely absorb or grow into over the life of the contract. As a result, in order to make sure that the PA represents the least-cost or even just the best-cost alternative, the Company would have to be certain – and the Commission would have to be assured - that the Company could recoup a significant percentage of the total costs of the excess capacity through cost-mitigation measures. However, this certainty is not attainable, as any mitigation expectations require an even more speculative assumption about the future value of excess pipeline capacity in the secondary market, in order to be considered offset by the what the Company views as substantial benefits to customers *over time*, if the Company's demand forecasts come to pass.

Therefore, I respectfully recommend that the Commission deny the Company's petition as-filed, or in the alternative require the Company to prepare an amended filing that includes:

1) A fully-developed range of demand forecasts that are based on appropriate long-term drivers of customer count and use-per-customer by rate class,
2) An adequate and viable plan that quantifies the costs and the benefits of pursuing market growth, including the cost of extending the Company's distribution system;
3) A fully-developed range of supply-side portfolio configurations, including varying levels of capacity for the NED project while retaining the vintage Dracut capacity;
4) A proposal to mothball the propane air plants that will not be required to meet design peak day requirements once the FT NED capacity becomes available, except for any plants that the Company needs for distribution system pressure support; and
5) A revised PA that maintains as much flexibility as possible to minimize risk to ratepayers should the deadline for notification to TGP change.

Q. Does this conclude your testimony?

A. At this time, yes it does. I reserve the right to amend or expand this testimony if additional information becomes available.