STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Winter 2013/2014 Cost of Gas
DG 13-______

Prefiled Testimony of Francisco C. DaFonte

September 3, 2013

Q. Mr. DaFonte, please state your name, business address and position with EnergyNorth Natural Gas, Inc. ("EnergyNorth" or "the Company")

A. My name is Francisco C. DaFonte. My business address is 11 Northeastern Boulevard, Salem, New Hampshire 03079. My title is Sr. Director, Energy Procurement.

Q. Mr. DaFonte, please summarize your educational background, and your business and professional experience.

A. I attended the University of Massachusetts at Amherst where I majored in Mathematics with a concentration in Computer Science. In the summer of 1985 I was hired by Commonwealth Gas Company (now NSTAR Gas Company), where I was employed primarily as a supervisor in gas dispatch and gas supply planning for nine years. In 1994, I joined Bay State Gas Company (now Columbia Gas of Massachusetts) where I held various positions including Director of Gas Control and Director of Energy Supply Services. At the end of October 2011, I was hired as the Director of Energy Procurement by Liberty Energy Utilities (New Hampshire) Corp. and promoted to Sr. Director in July 2013. In this capacity, I provide gas procurement services to EnergyNorth.

Q. Mr. DaFonte, are you a member of any professional organizations?

A. Yes. I am a member of the Northeast Energy & Commerce Association, the American Gas Association, the National Energy Services Association and the New England Canada Business Council.

Q. Mr. DaFonte, have you previously testified in regulatory proceedings?

A. Yes, I have testified in a number of proceedings before the New Hampshire Public Utilities Commission, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Indiana Utility Regulatory Commission and the Federal Energy Regulatory Commission.

Q. Mr. DaFonte, what is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to summarize the gas supply and firm transportation portfolio and the forecasted sendout requirements for EnergyNorth for the 2013/14 peak season. This information is provided in significantly more detail in the schedules that the Company is filing.

Q. Mr. DaFonte, would you describe the firm transportation contract portfolio that the Company now holds?

A. The Company currently holds firm transportation contracts on Tennessee Gas Pipeline (106,833 MMBtu/day) and Portland Natural Gas Transmission (1,000 MMBtu/day) to provide a daily deliverability of 107,833 MMBtu/day to its city gate stations. Schedule 12, page 1 in the Company's filing is a schematic diagram of these contracts, and Schedule 12, page 2 is a table listing these contracts. These contracts provide delivery of natural gas from three sources.

First, the Company holds firm transportation contracts to allow for delivery of up to 8,122 MMBtu/day of Canadian supply. These consist of the following:

- The Company can receive up to 4,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Union Gas Limited, TransCanada PipeLines Limited, Iroquois Gas Transmission System, and Tennessee Gas Pipeline ("Tennessee").
- The Company can receive up to 3,122 MMBtu/day of firm Canadian supply from the Canadian/New York border at Niagara Falls, NY. This supply is delivered to the Company on Company-held firm transportation contracts on Tennessee.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held firm transportation contract on Portland Natural Gas Transmission System for delivery to its Berlin service territory.

Second, the Company holds the following firm transportation contracts to allow for delivery of up to 71,596 MMBtu/day of domestic supply from the producing and market areas within the United States.

- The Company can receive up to 21,596 MMBtu/day of firm domestic supplies from Texas and Louisiana production areas. These supplies are delivered to the Company on firm transportation contracts on Tennessee.

- The Company can receive up to 50,000 MMBtu/day of firm supply from Tennessee's Dracut receipt point located in Dracut, Massachusetts. This supply is delivered to the Company on two firm transportation contracts on Tennessee.

Third, the Company holds the following firm transportation contracts to allow for delivery of up to 28,115 MMBtu/day of domestic supply from underground storage fields in the New York/Pennsylvania area or the purchase of flowing supply in or downstream of Tennessee Zones 4 and 5.

- The Company can receive up to 19,076 MMBtu/day of firm domestic supplies from its Tennessee FS-MA storage contract. This contract allows for a storage inventory capacity of 1,560,391 MMBtu. These supplies are delivered to the Company on firm transportation contracts on Tennessee.
- The Company can receive up to 9,039 MMBtu/day of firm domestic supplies from its storage contracts with National Fuel Gas Supply Corporation, Honeoye Storage Corporation and Dominion Transmission, Inc.. In aggregate, these contracts allow for a storage inventory capacity of 1,019,740 MMBtu. These supplies are delivered to the Company on a firm transportation contract on Tennessee.

Q. Have there been any changes in the portfolio of firm transportation contracts that the Company now holds since the Company submitted its 2012/13 Peak Period Cost Of Gas Filing?

A. The portfolio of firm transportation contracts that the Company currently holds has not changed since the Company's 2012/13 Peak Period Cost of Gas Filing.

Q. Would you describe the source of gas supplies used with these firm transportation contracts?

A. 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 Dracut, MA receipt point, on the other hand, can originate from any of a number of locations including Canada, the U.S. Gulf Coast, and LNG terminals.

Q. Will there be any changes in the portfolio of supply contracts held by the Company since the Company submitted its 2012/13 Peak Period Cost Of Gas Filing?

A. Yes. Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2012/13 Peak Period filing, the Company has issued four requests for proposals ("RFP") for the upcoming winter for supply: one for its Tennessee Zone 6 firm transportation capacity; one for its Canadian firm transportation capacity interconnecting with Iroquois Gas Transmission, Inc. in Waddington, NY, ("ANE"); one for its Tennessee long-haul capacity from the Gulf Coast and the Zone 4 market area; and another for a citygate delivered supply.

Q. Could you describe the RFP process in more detail?

A. Yes. The Company issued an RFP for an Asset Management Agreement ("AMA") to manage and provide a delivered citygate supply utilizing its Zone 6 capacity with a primary receipt point at Dracut, MA. Unfortunately, the Company did not receive any bids for this AMA RFP. This was primarily due to the lack of firm winter supplies at Dracut and the delay in new gas production from the Deep Panuke project off-shore in Nova Scotia.

The Company has since issued another RFP for a citygate delivered supply with no requirement to utilize the Company's Zone 6 capacity from Dracut. The Company has recently learned that the Deep Panuke project has begun flowing some volumes of gas and is hopeful that this will lead to firm supply bids. As currently structured, the RFP is requesting a six-month delivered citygate supply with both baseload and swing nomination provisions. The price for this supply is expected to be market area index based. The index would most likely correlate to the Tennessee Zone 6 index.

The Company is also in the process of conducting an RFP process for ANE supply originating from Dawn, Ontario. The Company intends for this to also be an AMA transaction that will provide a firm baseload supply during the peak period with index-based pricing.

With regards to its Tennessee long-haul firm transportation from the U.S. Gulf Coast, the Company is also in the process of conducting an RFP for an AMA transaction coupled with a delivered service during the peak period.

Q. Could you provide the status of the Company's storage refill plan?

A. Yes. During the 2013 off-peak period, the Company has been injecting supplies into its underground storage fields. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, 100 percent full by November 1, 2013; the Tennessee FS-MA field is targeted to be 95 percent full by November 1, 2013. The 5 percent unfilled portion of FS-MA storage provides a buffer which allows the Company operational flexibility to inject some of its Tennessee long-haul supply into storage if needed due to weather fluctuations during the month of November. By December 1, 2013, it is the Company's plan to have all of its storage fields 100 percent full.

Q. Would you describe the additional sources of gas supply available to the Company that do not require pipeline transportation capacity?

A. The Company has two additional sources of gas supply available to it.

First, the Company plans to contract with Distrigas for liquid-only supply that can be used to refill its LNG storage tanks during the peak period. Additionally, the Company will be contracting for dedicated LNG trucking in order to refill its LNG storage inventory. Since the Company's LNG storage capability is limited, having dedicated LNG trucks allows the Company to replenish inventory as it is used, provides supply security for the customers, and enables the Company to adhere to its seven-day storage inventory requirement (Puc 506.03).

Second, the Company plans to contract for some winter propane refill supplies to be used during cold snaps when market area supplies exceed the price of the propane supplies. In addition, the Company will contract for firm trucking capacity to ensure that the propane supplies will get delivered and to allow the Company to adhere to its seven-day storage inventory requirement (Puc 506.03).

Q. Please describe the supplemental gas supply facilities available to the Company?

A. The Company owns three LNG vaporization facilities in Concord, Manchester and Tilton that have a combined design vaporization rate of approximately 22,800 MMBtu/day but are limited operationally to a combined workable storage capacity of approximately 12,600 MMBtu. Any vaporization that occurs above the workable storage capacity of each facility requires same day trucking refill that, at this time, is not required to satisfy the Company's design day demand. The Company's LNG facilities are refilled with liquid from Distrigas.

Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua and Tilton that have a combined design vaporization rate of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 100,993 MMBtu. Following the 2012/13 peak period, the Company's propane facilities were refilled and they are ready for the 2013/14 peak period. The Company will also have arrangements in place for its propane trucking needs for the upcoming peak period.

Together, these LNG and propane facilities provide the Company and its customers with necessary system pressure support during peak days as well as a critical gas supply source to meet design day requirements. These facilities contribute to the Company's reliable, flexible and least-cost resource portfolio.

Q. Mr. DaFonte, what was the source of the projected sendout requirements and costs used in this filing?

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts.

Q. Would you please describe the forecasted sendout requirements for the peak period of 2013/14?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers of 77,133,381 therms over the period November 1, 2013 through April 30, 2014 under normal weather conditions which is down 3.6 percent from last year’s forecasted value of 79,988,370 therms for the period November 1, 2012 through April 30, 2013.

Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 86,356,210 therms over the period November 1, 2013 through April 30, 2014 under design weather conditions, down 2.9 percent from last year’s forecasted value of 88,940,431 therms for the period November 1, 2012 through April 30, 2013. For the current peak period forecast, design weather requirements are 14.8 percent greater than normal sendout requirements for weather that is 10.9 percent colder than normal.

In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally-available contract quantities, and the utilization rates of its pipeline firm transportation and storage contracts.

Schedule 11D shows the Company’s forecasted design day sendout for sales customers for the upcoming 2013/14 winter of 1,067,969 therms, down 5.8 percent from last year’s figure of 1,133,557 therms, which is attributable to the increased shifting of sales load to firm transportation load.

Q. Mr. DaFonte, can you provide a general overview of the Company's current hedging program?

A. Yes. The program uses various financial risk management tools and underground storage in order to provide more price stability in the cost of gas to firm sales customers and to fix the cost of gas for participants in the Company's Fixed Price Option ("FPO") Program. It is not intended to achieve reductions in customers' overall gas costs.

The Company may use derivatives (swaps, call and put options) and/or physical supplies to hedge the price for a portion of its gas supply portfolio for the period from October through May of each year. The Company may use a combination of financial hedges, storage withdrawals and fixed price contracts to hedge a monthly target hedge percentage. The purchase and sale of derivatives may be either physical or financial.

The peak period hedge target volume is determined using the specific monthly hedge percentages listed below as a portion of the Company's total firm sales forecast for each month listed. Overall, the Company will not hedge less than 30% or more than 80% of the forecasted firm sales load in the peak period. The total volume hedged shall include financial, fixed price contracts and storage volumes and will initially be a percentage of the most recent firm sales forecast, as of March 1st of each year, prior to the start of the execution of the strategy for a given period. Hedge volumes will be revised based on the most recent firm sales forecast as of October 1st. If the hedge volume changes by more than 5%, based on the new forecast, then the remaining execution volumes will be adjusted proportionately for the remainder of the term of the strategy starting in November. The total financial hedge volume will be calculated as the firm sales volumes multiplied by the volume target below minus forecasted storage withdrawals minus fixed priced physical contracts.

The following monthly hedge percentages are used to set the total hedge <u>volume target</u>:

October	40%
November	50%
December	66%
January	66%
February	66%
March	66%
April	50%
May	40%

Q. Mr. DaFonte, has the hedging program worked as intended?

A. Yes. Since its inception, and through subsequent revisions, the program has managed to minimize price volatility for customers during periods when natural gas prices fluctuated considerably right through 2008 when futures prices reached an all-time high of approximately $13.00 per Dth on the New York Mercantile Exchange (“NYMEX”).

Q. Mr. DaFonte, what has happened to natural gas futures prices since that time?

A. As I mentioned previously, the NYMEX reached a peak price of approximately $13.00 per Dth in 2008. Since that time, the NYMEX futures prices have dropped precipitously over the last five years and have remained in the low $3.00 per Dth range over the last two years and the NYMEX futures prices are currently averaging in the low $4.00 range going out as far as 2018.

Q. Mr. DaFonte, to what do you attribute this decline in natural gas prices and price volatility?

A. The single most influential factor in the reduction and stability of natural gas prices has been the emergence of shale gas in both the supply area and the market area. The proliferation of shale gas has led directly to numerous pipeline projects being constructed to deliver these volumes into the market and has also forced some pipelines to reverse flow on their systems and move gas back into the Gulf Coast, which had traditionally been the source of natural gas flow into major markets in the Northeast.

Q. Mr. DaFonte, did the Company's hedging program minimize the price spikes seen in the New England Market this past winter? If not, why not?

A. The current hedging program is intended to minimize price volatility with regard to supply area purchases. In fact, all OT swaps and options entered into by the Company for its hedging program are based on the Henry Hub pricing point for natural gas futures contracts located in the supply area in Louisiana. The Henry Hub price and correlating NYMEX price is seen as setting the "basis" price for the North American natural gas market. As such, any purchases made in the market area, such as New England, must reflect the cost to deliver the gas to the ultimate purchase location, known as the "basis differential" from the Henry Hub or NYMEX. This basis differential is also impacted greatly by any pipeline restrictions or limitations in getting gas to a specific market area relative to the demand in that market area. This is the very reason why natural gas prices spiked considerably in the New England market this past winter. The fact is that there is much more demand than pipeline capacity available to serve the New England market during the peak winter periods. Thus, while the Henry Hub spot price was relatively stable around $4.00 per Dth during these peak periods, the market area spot prices in New England jumped to over $30 per Dth for a basis differential of $26 per Dth.

To summarize, while the current hedging program focuses on minimizing futures price volatility, it cannot hedge against price spikes attributable to a run up in the basis differential.

Q. Mr. DaFonte, given that the hedging of futures prices does not in and of itself minimize price spikes attributable to basis differential increases, would you recommend any modifications to the current hedging program?

A. Yes. Overall, it is my opinion that the hedging program as currently constituted does not provide customers with meaningful benefits. Currently, customers are paying for the option premiums (insurance against escalating prices) used to hedge future firm purchases at the NYMEX/Henry Hub index price and since there has been very little volatility, the options typically expire "out of the money" and customers do not see any offsetting benefit to the premiums they are paying. In addition, any hedges entered into using OTC swaps, which do not have a specifically identified premium, have been settling above the market causing a net payout at settlement to the swap counterparty. In effect, customers are paying for a hedging program that was developed to manage natural gas price volatility at a time when natural gas supplies were tight and gas prices fluctuated considerably. More recently, the market dynamics have changed with the increase of Shale gas production and the volatility in the MYMEX/ Henry Hub futures has been muted and shows continued signs of stability through 2018.

With all that said, as a first step I would recommend that hedging for the months of May and October be terminated as those months have proven to be even less volatile and are outside of the peak period COG. Second, I would recommend reducing the hedging percentages for all other months by 50%. I am not recommending a full termination of the hedging program at this time only because the Company still offers a Fixed Price Option ("FPO") program to its customers for the peak period and some amount of hedging would need to be done to satisfy the requirements of that program. However, should customer participation in the FPO program continue to decline, I would recommend eliminating the FPO program and the hedging program altogether?

Q. Mr. DaFonte, could a modified hedging program address the volatile basis differentials you described earlier in your testimony?

A. The Company's pipeline capacity portfolio is comprised of nearly 50% of New England market area capacity with a primary purchase point at Dracut, MA. Because the Company must make spot or citygate purchases at the end of the Tennessee system, it is susceptible to price spikes brought about by the lack of available capacity and supply in the region . While it is possible to hedge basis prior to the winter period, it is only feasible if the Company could predict the actual spot or citygate purchases it would require in a given month during the winter period. Unfortunately, since the Company's spot purchases are a function of the weather, it would be impossible to predict the actual purchases required. That is, without the ability to determine the day and volume of a purchase, the Company could be over hedged or under hedged on any given day, which would be considered speculative hedging and would result in significant risk to the Company and its customers.

Since the volatility in the basis differentials in New England is a direct result of the lack of pipeline infrastructure available to access the abundant shale supplies in the Marcellus and Utica shale plays, the most logical way to address the issue is to develop more pipeline infrastructure that accesses these shale supplies. The Company is aware of several new proposed pipeline projects that would tap into the shale plays and bring more natural gas supplies into the New England market and expects that these new projects will help to mitigate much of the volatility in the New England basis differential.

Q. Does this conclude your direct prefiled testimony in this proceeding?

A. Yes, it does.