STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2008-09 Cost of Gas

DG 08-______

<u>Prefiled Testimony of Ann E. Leary</u>

August 29, 2008

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Q. Ms. Leary, please state your full name and business address.

A. My name is Ann E. Leary. My business address is 201 Jones Road, Waltham, Massachusetts 02451.

Q. Please state your position with National Grid.

A. I am the Manager of Pricing-New England for the regulated gas companies including EnergyNorth Natural Gas, Inc. d/b/a National Grid NH.

Q. How long have you been employed by National Grid or its affiliates and in what capacities?

A. In 1985, I joined the Essex County Gas Company as Staff Engineer. In 1987, I became a planning analyst and later became the Manager of Rates. Following the acquisition of Essex by Eastern Enterprises in 1998, I became Manager of Rates for Boston Gas. After Eastern was acquired by KeySpan Corporation in November 2000, I continued on as Manager of Rates for the four KeySpan Energy Delivery New England regulated gas companies, Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas Company. My responsibilities remained the same following the acquisition of KeySpan by National Grid.

Q. What do your responsibilities as Manager of Pricing include?

A. As the Manager of Pricing, I am responsible for preparing and submitting various regulatory filings with both the New Hampshire Public Utilities Commission (the

"Commission") and the Massachusetts Department of Public Utilities on behalf of National Grid local gas distribution companies. This includes Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings and reconciliations, energy conservation, performance-based revenue calculations, lost-base revenues, and exogenous cost filings.

Q. Please summarize your educational background.

A. I received a Bachelor of Science in Mechanical Engineering from Cornell University in 1983.

Q. Have you previously testified in regulatory proceedings?

A. I have testified in a number of regulatory proceedings before Commission and the Massachusetts Public Utilities on a variety of rate matters that include:cost allocation studies, rate design, cost of gas adjustment clause proposals, and exogenous cost filings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposed firm sales cost of gas rates for the 2008/09 Winter (Peak) Period to be effective beginning November 1, 2008.

COST OF GAS FACTOR

Q. What are the proposed firm sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $1.2635 per therm for residential customers, $1.2636 per therm for commercial/industrial high winter use customers, and $1.2630 per therm for commercial/industrial low winter use customers as shown on Proposed Seventy-Third Revised Page 84. The Company proposes a firm transportation cost of gas rate of $0.0002 per therm as shown on Proposed Eighth Revised Page 86.

Q. Would you please explain tariff page Proposed Fifteenth Revised Page 83 and Proposed Seventy-Third Revised Page 84?

A. Proposed Fifteenth Revised Page 83 and Proposed Seventy-Third Revised Page 84 contain the calculation of the 2008/09 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 84, the proposed 2008/2009 Average Cost of Gas of $1.2635 per therm is derived by adding the Direct Cost of Gas Rate of $1.2285 per therm to the Indirect Cost of Gas Rate of $0.0350 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 83 and repeated on Page 84, is $111,027,254. The estimated Indirect Cost of Gas, also derived on Page 83 and repeated on Page 84, is $3,163,335. The Direct Cost of Gas Rate of $1.2285 and the Indirect Cost of Gas Rate of $0.0350 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 90,372,901 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments shown on Page 83, total $2,114,930. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $108,912,324 to determine the Total Anticipated Direct Cost of Gas of $111,027,254.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Fifteenth Revised Page 83 consists of the following components:

1.	Purchased Gas Demand Costs	$6,500,887
2.	Purchased Gas Commodity Costs	$79,707,811
3.	Storage Demand and Capacity Costs	$1,171,446
4.	Storage Commodity Costs	$16,341,221
5.	Produced Gas Cost	$2,665,995
6.	Hedge Contract Loss/(Savings)	$2,524,964
	Total	$108,912,324

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Fifteenth Revised Page 83 are as follows:

1.	Prior Period Under Collection	$2,883,321
2.	Interest	336,795
3.	Broker Revenues	(1,249,699)
4.	Fuel Financing	526,256

5.	Transportation CGA Revenue	(5,004)
6.	Interruptible Sales Margin	(2,245)
7.	Capacity Release Margin	(410,806)
8.	Fixed Price Administrative Cost	36,312
	Total Adjustments	$2,114,930

These allowable adjustments are standard accounting adjustments that are made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. Later in this testimony I will discuss the factors contributing to the prior period under collection.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in DG 07-093 for the 2007/2008 Winter Period?

The average cost of gas rate proposed in this filing is $0.0792 per therm higher than the initial rate of $1.1843 approved by the Commission in Order No. 24,797 dated October 31, 2007 in DG 07-093. This increase in the rate reflects an increase in the total cost of gas of approximately $1.1 million, or 0.94% (a $4.0 million increase in total direct gas costs offset by a $2.9 million decrease in indirect gas costs). The $4.0 million increase in the total direct cost of gas is a result of a $4.5 million increase in commodity costs, a $1.7 million decrease in demand costs and a $1.2 million increase in gas costs adjustments.

The $4.5 million increase in commodity costs is due to a $5.0 million increase in pipeline commodity costs offset by a $0.5 million decrease in supplemental costs (underground storage, LNG, and propane). The $5.0 million increase in pipeline costs is due to an increase in commodity costs of $8.8 million offset by a decrease of $3.8 million resulting from reduced throughput volumes. Total commodity gas costs (including hedges) are approximately $.11/therm higher than last year, resulting in a $8.8 million increase which is offset by a decrease in throughput of 3.5 million therms that causes a $3.8 million decrease in gas costs. The two effects net out to the overall net increase in commodity costs of $5.0 million.

The $1.2 million increase in adjustments to the cost of gas primarily reflects an increase in Prior Period Under Collection of $2.0 million offset by an increase in Broker revenue credits of $0.65 million. Small changes to interest, fuel financing, and interruptible margins comprise the remaining $150,000 variance.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2007/2008 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0002 per therm. The rate approved in DG 07-093 was $0.0042. This decrease is largely due to the overcollection in the 2007/08 period resulting from increased transportation throughput during this period.

Q. What was the actual weighted average firm sales cost of gas rate for the 2007/2008 winter period?

A. The weighted average cost of gas rate was approximately $1.1746 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2007 through April 2008 to the monthly therm usage of a typical residential heating customer using 1,250 therms per year, or 932 therms for the six winter period months, for heat, hot water and cooking.

<u>PRIOR PERIOD UNDER COLLECTION</u>

Q. Please explain the prior period under collection of $1,167,763.

The prior period under collection is detailed in the 2007/2008 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $1,167,763 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2008 including Peak cost collections recovered in May 2008. The $1,167,763 under collection is reflected in Schedule 3, Tab 3 as the beginning balance for May 2008 before the addition of May direct gas costs (i.e., costs incurred in May that are related to the peak period) and adjustments. The under collection, which represents approximately one percent of the total gas revenue billed, is the result of lower gas revenue billings than forecasted. This undercollection includes the adjustments resulting from the revisions to bad debt and working capital percentages approved in Order No. 24,858 issued on May 23, 2008 in Docket DG 07-050.

FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program ("FPO")?

A. Yes, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program. In accordance with the approved changes to the FPO program, the FPO rates are calculated at $0.02 per therm higher than the proposed COG filed on September 1 of each year. Proposed Seventh Revised Page 85 contains the FPO rates for the 2008/09 Winter period, which are $1.2835 per therm for residential customers, $1.2830 per therm for commercial/industrial low winter use customers, and $1.2836 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2007/2008 winter period of $1.2043 per therm for residential customers, $1.2038 per therm for commercial/industrial low winter use customers, and $1.2044 per therm for commercial/industrial high winter use customers. This represents a $0.0792 per therm, or 6.6%, increase in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a increase of approximately $123 or 8.6% compared to last winter (please note - this total bill increase includes the increase in base distribution rates approved for temporary rate purposes in Order No.24,888 in DG 08-009). The estimated winter period bill for a typical residential heating customer opting for the FPO program would be approximately $19 or 1.2% higher than the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab

23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG05-127.

HEDGED SUPPLIES

Q. Has the Company hedged any of its winter period supplies pursuant to its proposed Natural Gas Price Risk Management Plan?

A. Yes, it has. As shown in Tab 7, Schedule 7, Page 2, the Company thus far has hedged 4,720,000 Dekatherms (47.2 million therms) at a weighted average fixed price of $9.7305 per Dekatherms. The hedged price reflects the high cost of gas during the period that the hedged volumes were locked in.

Q. On what dates, and at what prices did the Company contract for these supplies?

A. The Company has fifty-eight contracts that hedge the price of gas supplies for the 2008/2009 Winter Period with prices ranging from $7.74 to $14.09 per Dekatherms. The contracts date as far back as May 4, 2007 and as recently as August 8, 2008. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

Under its Natural Gas Price Risk Management Plan, the Company expects to hedge approximately 67.5% of its flowing winter supplies that are priced against NYMEX price indexes (i.e. Dawn Supply, Niagara Supply, Tennessee Gas Pipeline direct purchases and Zone 4, and city gate deliveries). The projected flowing gas (i.e., pipeline) supplies amount to 7,503,371 Dekatherms. Currently, 67.6% of this total is projected to be hedged. The Company shows in Tab 7, Schedule 7, Page 3, that the remaining 350,000

Dekatherms will be hedged at an estimated price of $9.2267 per Dekatherms based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 5,070,000 Dekatherms at a cost of $49,157,511 or approximately $9.6958 per Dth.

<u>LOCAL DISTRIBUTION ADJUSTMENT CHARGE</u>

Q. What are the surcharges that will be billed under the LDAC?

A. The Company is submitting for approval a Local Distribution Adjustment Charge of $0.0259 for the residential non heating class, $0.0265 for the residential heating class and $0.0288 for the commercial/industrial classes that will be billed from November 1, 2008 through October 31, 2009. Under the LDAC approved in (1) the Commission's Order in Docket DG 00-063, the Company's Revenue Neutral Rate Redesign Case, (2) Order No. 24,109 in DG 02-106, Energy Efficiency for Gas Utilities, (3) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, and (4) Order No. 24,508 in DG 05-076, Investigation of Low Income Assistance Program for Natural Gas, the surcharges that are billed under the LDAC are the Conservation Charge, the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant remediation and the Residential Low Income Assistance Program charge.

Q. What is the Conservation Charge?

A. The Conservation Charge is designed to recover the expenses and lost margins from the Company's demand side management ("DSM") programs that terminated in 1999, which are $0.0006 per therm for residential heating customers and $0.0000 per therm for commercial/industrial customers (the calculation for the commercial/industrial class rounds to zero at the fourth decimal). The residential Conservation Charge is designed to recover $34,298, of which $29,884 is Lost Margins and $4,415 is for the prior period under collection, on projected sales of 58,718,919 therms. Because the programs were terminated in 1999, there are no additional DSM expenses to be recovered. The commercial/industrial program incurred $799 in Lost Margins and ($3,106) in prior period under collections resulting in the total of ($2,307) to be recovered on 92,181,379 therms of forecasted commercial/industrial throughput. The back-up work papers that derive these figures are provided in Tab 19 of this filing. Also included in the LDAC is the Energy Efficiency Program Charge of $0.0184 per therm for residential customers and $0.0213 per therm for commercial/industrial customers.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover expenses associated with the Company's energy efficiency programs that were approved by the Commission in Order No. 24,636 dated June 8, 2006, in DG 06-032. On March 31, 2008, the Company submitted to the Commission its proposed energy efficiency budget for May 2008 through April 2009 (the third year of the three year approved program). The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs that were approved by the Commission in Order 24,109 dated December 31, 2002 in DG 02-106 and Order 24,636 dated June 8, 2006 in DG 06-032. The incentive calculations that are included in this LDAC filing are based on Exhibit C filed with the Commission on August 27, 2008. Exhibit C, the incentive calculation, is provided in Tab 19, Energy Efficiency, page 5.

Q. In Order No. 24,752 in docket DG 06-154 relating to therm billing issues, the Company agreed to exclude $200,000 in cost recovery associated with energy efficiency expenditures in Program Years 2 and 3. Did the Company reflect these adjustments in its Energy Efficiency Charge?

A. Yes, in March and April 2008, the Company included a credit of $122,165 in DSM measures. The Company plans of spending the remaining $77,835 during the 2008-09 program year and will apply the balance of the credit at that time.

Q. What is the proposed Residential Low Income Assistance Program, RLIAP, charge?

A. The proposed Residential Low Income Assistance Program charge is $0.0075. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this charge. For the 2008/09 Winter Period the Company is providing a 60% base rate discount, consistent with the Settlement agreement approved by the Commission in Order No. 24,669 issued on September 22, 2006 in DG 06-120. The current RLIAP factor is designed to recover $1,134,644 of which $8,650 is for administrative costs, $1,345,568 is for the revenue shortfall resulting from 5,353 customers receiving a 60% discount off their base rates, and ($219,574) is for the prior year reconciling adjustment.

Q. In Order No. 24,824 in docket DG 06-122 relating to short term debt issues, the Company agreed to exclude $250,000 in cost recovery associated with Low Income discount rate. Did the Company reflect these adjustments in its RLIAP charge?

A. Yes, the $250,000 credit is included in the prior year's reconciliation balance as shown in Tab 19 page 2 line 9.

Q. In Order No. 24,824 in docket DG 06-122 relating to short term debt issues, the Company agreed to adjust its short term debt limits each year as part of the Company's Winter Period cost of gas filing. Did the Company calculate the short term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Tab 24 the short term debt limit for fuel and non fuel purposes for the 2008-09 period.

Q. Has the Company updated the Manufactured Gas Plant Remediation surcharge (Tariff Page 88)?

A. Yes, it has. As a result, of the Company's success in its third party cost recovery efforts, which included receiving a significant insurance recovery last year, the total recoveries from insurance carriers and other responsible parties continue to exceed the total remediation costs expensed to date. As a result, the Manufactured Gas Plant (MGP) Remediation surcharge is proposed to remain at zero for the period beginning November 1, 2008 and ending October 31, 2009. The surcharge for the 2007/2008 Winter Period was also $0.0000 per therm. The costs submitted for recovery through the MGP

Remediation surcharge as well as the third party recoveries are presented in the Environmental Cost Summary included in Tab 20 of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Leone in her prefiled testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Tab 20. The Summary included in Tab 20, pages 1 – 7, show the remediation cost pools for the Concord, Manchester, Nashua, Dover, Laconia and Keene sites and a General Pool for costs that cannot be directly assigned to a specific site. The filing also includes amounts recovered from insurance companies shown in the section labeled “Cash Recoveries” on the Environmental Cost Summary, pages 8 - 10. These cash recoveries from insurance companies are listed under the headings for the Concord, Laconia, Manchester, Nashua, Dover, and Keene sites. While the recoveries are displayed on the summary by site, they are not exclusive to a particular site. Because the recoveries are often the result of a general settlement agreement between National Grid, NH and an insurance company covering more than one site, there is usually no distinction made as to how much of the settlement amount is associated with a particular site. The reason the recoveries are presented on the summary in this way is to reflect how the Company is recording them in its accounting records. In compliance with Commission Order No. 23,303, dated September 20, 1999 in docket DG 99-060, the Company is crediting the third-party recoveries, net of expenses associated with those recoveries, to the end of the recovery period with the exception of those recoveries from prior plant operators that are contributions to the on-going expense of site investigation and remediation. Those amounts are netted out against the Company's expenses before any remaining balance is included for recovery through the MGP Remediation surcharge. Page 11 provides the total remediation and recovery costs and collections by year and in total.

As I have noted, due to the significant third party cash recovery received last year the Company is not proposing an Environmental surcharge for the 2008-09 period. The Company's filing, however, does summarize its total remediation, recoveries and surcharge collections incurred to date so that the Commission is aware of the current ending balance. In total, the Company has incurred environmental remediation costs of $28,429,511 litigation costs of $11,559,183, obtained third party cash recoveries of $27,333,183, and transfer credit of $3,331 for a net expense of $12,652,180. To date, the Company has collected $13,028,973 from its Environmental Surcharge factor. As a result, of the third party cash recoveries received last year, the total recoveries from insurance carriers and other responsible parties currently exceed the total remediation costs by $376,794. The Company proposes to apply this credit of $376,794 to future remediation and recovery costs. This $376,794 over recovery includes an interest credit of $215,756, which represents 80% of interest associated with the environmental over recoveries, as approved in Order No. 24,881 in docket DG 07-129. This interest has been included as a credit to the General Expense account.

The 2007-2008 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #9)	$95,374
Concord (Pool #5)	($3,163)
Laconia (Pool #7)	$456,179
Manchester (Pool #8)	$3,207,639
Nashua (Pool #8)	$97,191
Keene (Pool #5)	$32
General (Pool #6)	($164,988)
Total Remediation	$3,688,264
Litigation Recovery	($1,033,751)
Litigation Costs	$639,811
Total 2007-08	$3,294,324

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2007-08 costs that the Company is submitting for recovery. (Copies of the relevant invoices are being provided under a separate cover to the Commission auditing staff concurrently with this filing.) Consistent with past practice, the Company met with the staff and Consumer Advocate's office earlier this year to update them on the status of environmental matters. While the Company has provided in Tab 20 of this filing written summaries of the status of each MGP site, it is prepared to provide additional testimony and exhibits, as necessary, to support recovery of these amounts if the Commission staff believes that it is necessary after it has completed its review of these costs. In addition, the Company is providing more detailed testimony from Ms. Leone to discuss the Company's efforts to seek recovery of its environmental costs from relevant third parties.

Q. In Order No. 24,849 in docket DG 07-129, the Commission ordered the Company to apply 80 percent of the interest earned from the over recovery of environmental response costs to future remediation costs. Has the Company reflected these interest credits in this filing?

A. Yes, as I noted above, the Company has calculated the customers' portion of the interest credit associated with the over recovery of environmental costs and has included these credits in the "General Expense" category. The Company has included $215,756 credits in this account.

Q. Does the LDAC include a surcharge for Interruptible Transportation Margins?

A. The Company is proposing no surcharge for Interruptible Transportation Margins because it has not provided any service under the classification over the past year and therefore has not earned any margins for this surcharge.

CUSTOMER BILL IMPACTS

Q. What is the estimated impact of the proposed firm sales cost of gas rate and revised LDAC surcharges on an average heating customer's seasonal bill as compared to the rates in effect last year?

A. The bill impact analysis is presented in Tab 8, Schedule 8 of this filing. Please note that these bill impacts include the increase resulting from the implementation of the temporary base distribution rates approved in Order No. 24,888 in docket DG 08-009. The total bill impact for a typical residential heating customer is an increase of approximately $132, or 9.4% of which $90 or 6.4% is from the increase in the COG and LDAC as compared to the average COG and LDAC for 2007/2008 winter season, and $42 or 3.0% is from the increase resulting from the implementation of temporary base rates. The total bill impact for a typical commercial/industrial G-41 customer is an increase of approximately $232, or 10.5% of which $157 or 7.1% is from the increase in the COG and LDAC as compared to the average COG and LDAC for 2007/2008 winter season, and $75 or 3.4% is from the increase resulting from the implementation of temporary base rates. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Eighth Revised Page 153 relating to Supplier Balancing Charges and Proposed Eighth Revised Page 155 relating to Capacity Allocation.

Q. Please describe the changes to Page 153.

A. In Proposed Eighth Revised Page 153, the Company is updating the Supplier Balancing charges from $0.10 per MMBtu to $0.12 per MMBtu, a $0.02 per MMBtu increase; and the Peaking Demand Charge from $14.41 per MMBtu of Peak MDQ to $9.72 per MMBtu of Peak MDQ, a $ 4.69 decrease. The increase in the Supplier Balancing Charge is based on the calculation that updates the volumes and costs supporting the charge. The calculation is presented in Tab 21 of this filing. It includes the eight-page Back Up Calculations to III Delivery Terms and Conditions, Eighth Revised Page 153 Attachment D – Supplier Balancing Charge.

The decrease in the Peaking Demand Charge is also the result of an update of the volumes and costs that support the calculation of the charge. This calculation is also presented Tab 21. It includes the four-page Back Up Calculations to III Delivery Terms and Conditions Eighth Revised Page 153, Attachment D – Peaking Demand Charge.

Q. Please describe the changes to Page 155.

A. Proposed Eighth Revised Page 155 updates the Capacity Allocator percentages used to allocate pipeline, storage and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Tab 22 contains the six-page worksheet that backs up the calculations for the updated allocators.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NEW HAMPSHIRE
BEFORE THE
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EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2008/2009 Cost of Gas
DG 08-______

Prefiled Testimony of Theodore Poe, Jr.

August 29, 2008

Q. Mr. Poe, please state your name, address and position with National Grid New Hampshire.

A. My name is Theodore Poe, Jr. My business address is 201 Jones Road, Waltham, Massachusetts 02451. My title is Lead Analyst.

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

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science Degree in Geology. From 1981 to 1989, I worked as a Research Associate with Jensen Associates, Inc. of Boston where I was responsible for the development of a variety of computer forecasting models of natural gas supply and demand for interstate pipeline and local distribution companies. In 1989, when I joined Boston Gas Company, I was responsible for modeling and forecasting the natural gas resource requirements of its customers. Since 1998, I have assumed the added responsibilities of forecasting the natural gas requirements of various service territories that are now part of National Grid, including EnergyNorth Natural Gas, Inc., which does business under the name National Grid NH.

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

A. I am a member of the Northeast Gas Association, the New England-Canada Business Council and the American Meteorological Society.

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

A. Yes, I have testified in a number of proceedings before the Commonwealth of Massachusetts Department of Public Utilities and the State of New Hampshire Public Utilities Commission.

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

A. The purpose of this testimony is to summarize the gas supply and transportation portfolio and the forecasted sendout requirements for National Grid NH (the "Company") for the 2008/09 peak season. This information is provided in significantly more detail in the schedules that the Company is filing.

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

A. The Company currently holds contracts on Tennessee Gas Pipeline (76,833 MMBtu/day) and Portland Natural Gas Transmission (1,000 MMBtu/day) to provide a daily deliverability of 77,833 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 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 transportation contracts on Union Gas, TransCanada, Iroquois Gas Transmission System, and Tennessee Gas Pipeline.
- 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 transported on Company-held transportation contracts on Tennessee Gas Pipeline for delivery.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held transportation contract on Portland Natural Gas Transmission for delivery to its Berlin division.

Second, the Company holds the following contracts to allow for delivery of up to 41,596 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 transportation contracts on Tennessee Gas Pipeline.

- The Company can receive up to 20,000 MMBtu/day of firm supply from Tennessee's Dracut delivery point located in Dracut, Massachusetts. This supply is delivered to the Company on a transportation contract on Tennessee Gas Pipeline.

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

Q. Have there been any changes in the portfolio of transportation contracts that the Company now holds since the Company submitted its 2007/08 Peak Period Cost Of Gas Filing?

A. No, there have been none.

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

A. The transportation contracts associated with the Canadian supplies receive firm supplies from both Eastern and Western Canada. The supplies associated with the Company's domestic transportation contracts are firm supplies that the Company purchases primarily in the U.S. Gulf Coast.

Q. Have there been any changes in the portfolio of supply contracts that the Company now holds since the Company submitted its 2007/08 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 2007/08 Peak Period filing, the Company has issued or participated in Requests For Proposals (“RFP”) for the upcoming winter for the following supply resources:

1. Supply for its Tennessee long-haul transportation capacity;
2. Supply for its Tennessee transportation capacity from Dracut;
3. Supply provided as a citygate service, and
4. Supply for its transportation capacity from Dawn, Ontario

On 4 August 2008, the Company issued an RFP for the first three supply packages listed above. Bid responses were received by the Company on 14 August 2008.

- The Company awarded the bid to fill its Tennessee long-haul transportation capacity to Chevron Natural Gas ("Chevron"). Chevron submitted the best overall bid, based on both price and non-price factors. The contract provides for a sixmonth supply with both baseload and swing nomination provisions. The price for this supply is index based. The indices correlate to the respective receipt points on the Company's long-haul transportation contract.
- The Company awarded the bid to fill its Tennessee transportation capacity from Dracut to FPL Energy ("FPL"). FPL submitted the best overall bid, based on both price and non-price factors. The contract provides for a five-month supply with both baseload and swing nomination provisions. The supply will be baseloaded during the months of December, January and February. In the months of November and March, the Company has the right to nominate between zero and the maximum daily quantity on any day. The price for this supply is index based with a discount.
- The Company awarded the bid for a firm citygate supply service to Virginia Power Energy Marketing ("VPEM"). VPEM submitted the best overall bid, based on both price and non-price factors. The contract provides for up to 8,000 MMBtus/day and 1,208,000 MMBtus/year during the November 2008

through October 2009 period. The contract provides both baseload and swing nomination provisions, with index-based pricing.

As a member of the Northeast Gas Markets consortium of LDCs, the Company participated in several rounds of RFPs for winter supply for its capacity from Dawn, Ontario. As a result of these RFPs, the Company will purchase these volumes from Sempra Energy Trading, LLC, who submitted the best overall bid based on both price and non-price factors. These are baseload volumes with NYMEX-based pricing.

On 1 April 2007, the Company began receiving gas supplies from BP Canada Energy Marketing Corp. for its Tennessee Niagara capacity. I had previously described this contract in my 2007 Off-Peak Period Cost of Gas Testimony. The contract allows for monthly nominating flexibility, with an index-based price.

For its Portland Natural Gas Transmission capacity, the Company continues to contract on a month-to-month basis for supplies, purchased at the Company's primary receipt point designated as Pittsburg, NH, and delivered to its citygate station in Berlin, NH.

For its underground storage supplies, the Company began storage refill in April 2008. The objective of the summer refill program is to purchase supply as ratably as possible throughout the seven-month April through October off-peak period. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, 100 percent full by 1 November 2008; the Tennessee FS-MA field is targeted to be 95 percent full by 1 November 2008. 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 1 December 2008, 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 four additional sources of gas supply available to it.

First, the Company has a contract with Distrigas of Massachusetts ("Distrigas") to provide firm supply of up to 8,000 MMBtu/day and 1,208,000 MMBtu/year. This supply is delivered to the Company's city gate stations as a firm delivered service. This contract is set to expire on October 31, 2008 and will be replaced with the VPEM supply discussed above.

Second, the Company holds a contract with Distrigas to provide liquid-only supply of 50,000 MMBtu/year that the Company can use to refill its own LNG storage tanks. This contract will expire on October 31, 2009. Also, the Company, along with its

Massachusetts affiliates Boston Gas Company, Colonial Gas Company and Essex Gas Company each d/b/a National Grid, is a party to a contract with Distrigas for up to 1 Bcf of liquid-only supply that can be used to refill any of the National Grid LNG storage tanks in New England, including those serving New Hampshire.

Third, the Company holds a supply-sharing agreement with AES Londonderry, LLC (presently known as Granite Ridge Energy, LLC) to provide up to 15,000 MMBtu/day and 450,000 MMBtu per contract year. The pricing terms of this contract have been previously disclosed to the Commission, and they will not be discussed here because of their confidential nature. This contract is only available to the Company during the December through February period of each contract year. The initial term of this contract expired in 2007. On October 23, 2007, the Company executed an amendment to the original contract to account for a number of changes, including an additional five year term, starting with the 2007/08 peak period. In addition, the amended agreement requires the parties to negotiate the pricing formula prior to the start of each contract year. The Company is currently in negotiations regarding the price to be paid for this supply for this upcoming winter season.

Finally, when supplies are available and when it is cost-effective, the Company can obtain supplies from other supply vendors. The natural gas market within the Northeast United States has evolved to the point that firm supplies, deliverable to the Company's city gate stations, are available on most days throughout the year.

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 operational vaporization rate of 23,712 MMBtu/day and a combined workable storage capacity of 13,057 MMBtu. Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua and Tilton that have a combined operational vaporization rate of 35,000 MMBtu/day and a combined workable storage capacity of 100,993 MMBtu.

The Company's LNG facilities are refilled with liquid from Distrigas using either or both of: 1) the ENGI liquid-only contract and 2) the 1 Bcf Firm Liquid Contract to which all of the National Grid New England companies are a party. During the 2008 off-peak period, the Company offset boiloff losses by periodically trucking LNG liquid to its facilities. The Company is currently in the process of issuing an RFP for its dedicated LNG trucking requirements for the peak period.

Following the 2007/08 peak period, the Company's propane facilities were full and they remain ready for the 2008/09 peak period. Additionally, the Company currently has approximately 622,000 gallons of propane stored at the National Grid propane facilities in Massachusetts on behalf of National Grid NH. . The Company is currently in the process of issuing an RFP for its winter propane supply and transportation needs for the upcoming peak period.

Q. Mr. Poe, 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 2008/09?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers of 95,368,818 therms over the period November 1, 2008 through April 30, 2009 under normal weather conditions, down 5.4% from last year’s value of 100,833,527 therms. Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 103,985,815 therms over the period November 1, 2008 through April 30, 2009 under design weather conditions, down 6.3% from last year’s value of 111,010,897 therms. This shows that design weather requirements are 9.0 percent greater than normal sendout requirements for weather that is 8.5 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 transportation and storage contracts. Schedule 11D shows the Company's forecasted design day sendout for sales customers for the upcoming 2008/09 winter of 1,306,916 therms, down 1.4 percent from last year's figure of 1,325,706 therms. The principal factor driving the year-to-year decreases is the increased shift from sales service to the Company's Customer Choice transportation program.

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

A. Yes, it does.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Re: EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

Winter 2008-09 Cost of Gas

Docket No. DG 08-_______

Pre-filed Direct Testimony of
Michele V. Leone
on behalf of
EnergyNorth Natural Gas, Inc.
d/b/a National Grid NH

August 29, 2008

I. BACKGROUND

Q. Please provide your name, job title and job description.

A. My name is Michele Leone. I am the Manager of the New England Site Investigation and Remediation Program for National Grid, through which I provide services to EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH" or the "Company".) I am responsible for overseeing the management of the investigation and remediation of MGP sites for National Grid NH as well as for the Company's Massachusetts and Rhode Island affiliates.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science in Environmental Engineering from Syracuse University, and a Master of Science in Engineering in Environmental Engineering from the University of Michigan at Ann Arbor. I have been employed by National Grid since December 2000 in the Site Investigation and Remediation Group, managing the investigation and remediation of MGP sites. Prior to my employment by National Grid, I held the position of Project Manager for an environmental consulting firm, with responsibility for the investigation and remediation of numerous hazardous waste sites and for providing technical support to expert witnesses in litigation cases.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the status of site investigation and remediation efforts at various MGP sites in New Hampshire, to briefly describe the MGP-related activities performed by the various contractors and consultants the costs for which National Grid NH is seeking rate recovery, and to describe the efforts that National Grid NH has made to seek reimbursement for MGP related liabilities from third parties in order to diminish the costs submitted for recovery from the Company's customers. My testimony is intended to update the information provided by the Company in prior cost of gas proceedings. The costs associated with these investigations and remediation efforts and certain of the amounts recovered from third parties are included in the schedules and other data prepared by Ms. Leary as part of the Company's cost of gas filing.

STATUS OF INVESTIGATION AND REMEDIATION ACTIVITIES

Q. Will you please briefly describe the status of each of the Company's MGP sites?

A. Rather than reviewing each of these sites in a question and answer format, consistent with past practice, the description of the status of investigation and remediation efforts at each site as well as the various efforts to recover the site investigation and remediation costs from third parties are summarized in materials included with Tab 20 of the Company's filing. These summaries follow the format that has previously been agreed upon in discussions between the Company and Commission staff. In addition, as previously ordered by the Commission, in July the Company held what has become an annual technical session with the Commission staff (as well as the Consumer Advocate) to keep the Commission apprised of the status of site investigation and remediation efforts, as well as cost recovery efforts against third parties.

Q. In 2004, the Company began an investigation of a disposal area associated with the Laconia MGP. Please briefly describe the current status of the Company's investigation and any significant events over the course of the past year.

A. The disposal area, known as Lower Liberty Hill, is located in what is now a residential neighborhood in Gilford. The Company completed investigation activities at Lower Liberty Hill in 2007 and the results indicate that soil and groundwater contamination from MGP waste products have impacted locations formerly occupied by four residential properties and a portion of an abutting stream. These impacts are primarily located in sub-surface soils, and in deep groundwater. No drinking water impacts have been found. A Remedial Action Plan was submitted to NHDES in February 2007, which recommended a remedial alternative consisting of a subsurface containment wall, limited soil removal and an impermeable cap. In September 2007, NHDES, responded to the February 2007 Remedial Action Plan and required the Company to evaluate additional remedial alternatives that included further soil removal. In November 2007, the Company submitted a revised Remedial Action Plan to NHDES. The revised plan recommended a remedial alternative that included construction of a subsurface containment wall, removal of tar-saturated soils to a depth of approximately 45 feet, and installation of an impermeable cap on the four residential properties owned by the Company. On February 29, 2008, NHDES issued a letter to the Company indicating that it had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the

NHDES requirements and that a final decision would be reached following a public meeting and comment period. Following a public meeting in March and a six week public comment period, NHDES issued a letter on June 26, 2008, deferring its final decision on the recommended remedial alternative for the Lower Liberty Hill site pending further data analysis following the development of a scope of work prepared after consultations between NHDES, the Town of Gilford and National Grid NH . In July and August 2008, technical representatives from National Grid NH , the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company will submit a Scope of Work for groundwater modeling and additional data collection to NHDES in September 2008 and expects to complete the modeling and data collection activities in the first quarter of 2009, assuming that NHDES approves of the scope in September 2008.

Q. Please briefly describe the current status of the Company's remediation work at the Manchester MGP.

A. In June 2008, the Company began remedial activities in the Merrimack River near the former MGP in Manchester. As part of these activities, National Grid NH dredged approximately 9,000 cubic yards of coal tar impacted sediments from the river. Because of the limited space available to handle the sediments once they were dredged from the river, National Grid NH I has had to lease space from the

City of Manchester to dewater, stabilize and prepare the impacted sediment for transport to the disposal facility. National Grid NH negotiated with the City to close the River Walk adjacent to the construction site to eliminate unsafe pedestrian traffic through the area. The river dredging activities were substantially complete in late 2007 and final restoration activities were completed in May 2008. Draft and final Remedial Action Implementation Reports documenting the sediment remediation activities were submitted to NHDES in May and August 2008, respectively. Pre-design investigations and preparation of a Remedial Action Plan are ongoing on the upland portion of the former MGP site in 2007/2008. In addition, National Grid NH has begun interim remediation activities at the site. Following a review of the data to be collected during some of the pilot interim activities, the upland Remedial Action Plan is expected to be completed and submitted to NHDES in fall 2009.

Q. Please briefly describe the current status of the Company's remediation work at the Nashua MGP.

A. In November 2007, the Company submitted and NHDES approved a workplan for a coal tar recovery pilot test at the Nashua MGP site. Permitting activities for the pilot test activities began in late 2007, with the Company applying for two local and one state permit. The Company attended numerous hearings related to obtaining the permits and obtained the three permits in April and late May 2008. In June 2008, we installed six extraction wells for pilot testing at the site. The Company is currently completing the construction of the coal tar recovery system (i.e,. the equipment that will be use to pump, collect and temporarily store the coal tar on-site) and anticipates starting coal tar recovery in late 2008.

Q. What other MGP investigation and remediation activity has the Company undertaken in the last year?

A. Lower Liberty Hill, Manchester and Nashua are the three sites where there is significant activity involving the Company. However, smaller investigation and monitoring efforts are ongoing at Concord Pond. In addition, the Company recently bid the NHDES-approved scope of work for additional investigation activities at the Concord MGP and awarded the contract in late July 2008. The Company met with NHDES at the site in August and expects the investigation to commence in fall 2008, pending access being provided by several property owners. As I mentioned previously, the summaries included in the Company's cost of gas filing provide additional detail regarding all of the Company's former MGP sites.

III STATUS OF INSURANCE COVERAGE LITIGATION

Q. Have there been any recent significant developments in the Company's efforts to seek contribution from its insurance carriers that you wish to discuss?

A. There have been several significant developments during the past year in the Company’s third party cost recovery efforts. As of early 2007, all of ENGI's insurance coverage claims for the Concord, Nashua, Laconia and Dover MGP sites had been resolved by way of settlement or verdict in favor of the Company.

As a result, significant recoveries, both for indemnity and reimbursement of attorneys fees, had been obtained.

By the middle of 2007, all but one of the insurance companies subject to the Company's federal court claim for coverage on the Manchester MGP liability had settled, resulting again in significant recoveries. In the Manchester coverage action, the Company had settled with five of the six insurance company defendants named in the suit. The sole remaining defendant was American Reinsurance (AmRe), an excess carrier which had provided one year of coverage for calendar year 1972.

Prior to the start of trial in April 2006, Am Re stipulated to all factual issues that would have been at issue in the declaratory judgment action, but took the position that its defense rested solely on a question of law – whether a proper allocation of liability to all available insurers would insulate it from any duty to indemnify. the Company argued that upon the triggering of coverage, each insurer becomes jointly and severally liable to indemnify the Company , up to its policy limits. AmRe argued that liability should be prorated, by some formula, to all insurers and that under any pro-ration formula, the Company would not reach AmRe's policy limits. A second issue arose over whether the Company was entitled, under New Hampshire's Declaratory Judgment Act, RSA 491:22-b, to recover its attorneys' fees and costs from AmRe, even if AmRe was successful in its coverage argument. Essentially, AmRe argued that it was responsible for the Company's litigation costs only if AmRe ended up actually having to indemnify the Company for environmental costs after payments by all other available insurers. The Company , on the other hand, argued that because it had previously established that its claim against AmRe would be covered by the policy if the Company's expenses at the Manchester MGP site were great enough to reach the level at which the AmRe policy attached, it was irrelevant whether AmRe actually ended up having to pay any of the Company's environmental expenses.

Because these remaining issues were unsettled under New Hampshire law, the federal court certified questions to the New Hampshire Supreme Court to obtain definitive statements of New Hampshire Law. In an opinion dated October 18, 2007, the Supreme Court of New Hampshire answered the questions of law that had been directed to it by Judge Barbadoro of the United States District Court for the District of New Hampshire. To the allocation question, the Supreme Court ruled that pro-ration is a superior allocation methodology to that of joint and several liability and therefore found in favor of AmRe. As a result, the Company could not recover any MGP remediation expenses from AmRe. As to the question of attorneys' fees and costs, the Court ruled that if the insured has obtained rulings against an excess insurer that will require the insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is entitled to recover its reasonable attorneys' fees and costs regardless of whether because of coverage from other insurers the excess insurer is ever required to actually make payment to the insured. The matter was then remanded back to Judge Barbadoro at the United States District Court for final adjudication. Judge

Barbadoro directed the parties to mediate any remaining disputes with respect to the amount of attorneys fees owed, and a confidential final settlement was reached and the case dismissed in July, 2008.

At this point all of the insurance coverage cases, except the case related to the Keene MGP, are completed. It is anticipated the allocation decision from the Supreme Court, discussed above, will facilitate settlement discussions with the one insurance company that has not yet settled in that case, making trial of the Keene coverage case unlikely in the next year; although it is still a possibility.

Q. Does this conclude your direct testimony?

A. Yes, it does.