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N.H.P.U.C. Case No. DE 10-230

Exhibit No. #2

Witness Michele V. Leone

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Testimony

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

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

Winter 2010-11 Cost of Gas

DG 10-______

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

August 31, 2010

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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 40 Sylvan 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 the Commission and the Massachusetts Department of 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 2010/11 Winter (Peak) Period to be effective beginning November 1, 2010.

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 $0.8220 per therm for residential customers, $0.8234 per therm for commercial/industrial high winter use customers and $0.8186 per therm for commercial/industrial low winter use customers as shown on Proposed Sixteenth Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0009 per therm as shown on Proposed Second Revised Page 89.

Q. Would you please explain tariff page Proposed Third Revised Page 86 and Proposed Sixteenth Revised Page 87?

A. Proposed Third Revised Page 86 and Proposed Sixteenth Revised Page 87 contain the calculation of the 2010/11 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 87, the proposed 2010/11 Average Cost of Gas of $0.8220 per therm is derived by adding the Direct Cost of Gas Rate of $0.7869 per therm to the Indirect Cost of Gas Rate of $0.0351 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $65,369,088. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $2,914,492. The Direct Cost of Gas Rate of $0.7869 and the Indirect Cost of Gas Rate of $0.0351 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 83,071,582 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 86, total $1,741,780. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $63,627,308 to determine the Total Anticipated Direct Cost of Gas of $65,369,088. I should note that as part of the Company's pending general rate case, DG 10-017, the Company's indirect gas costs are currently being reviewed. Once the level of those costs is set, the final result will need to be reconciled through the cost of gas rates, consistent with the temporary and permanent rate orders in that case.

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

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Third Revised Page 86 consists of the following components:

1.	Purchased Gas Demand Costs	$8,314,931
2.	Purchased Gas Commodity Costs	$39,083,750
3.	Storage Demand and Capacity Costs	$1,055,525
4.	Storage Commodity Costs	$7,649,468
5.	Produced Gas Cost	$1,255,498
6.	Hedge Contract Loss/(Savings)	$5,704,479
7.	Hedge Underground Storage Loss/(Savings)	$ 563,657
	Total	$63,627,308

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

A. The allowable adjustments to gas costs, listed on Proposed Third Revised Page 86 are as follows:

1.	Prior Period Under Collection	$2,985,736
2.	Interest	101,158
3.	Broker Revenues	(754,779)
4.	Fuel Financing	130,835
5.	Transportation COG Revenue	(31,147)
6.	Interruptible Sales Margin	(0)
7.	Capacity Release Margin	(730,714)
8.	Fixed Price Administrative Cost	40,691
	Total Adjustments	$1,741,780

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 09-162 for the 2009/2010 Winter Period?

The average cost of gas rate proposed in this filing is $0.1443 per therm lower than the initial rate of $0.9663 approved by the Commission in Order No. 25,032 dated October 29, 2009 in DG 09-162. This decrease in the rate reflects a decrease in the total cost of gas of approximately $13.2 million, or 16% (a $12.5 million decrease in total direct gas costs and a $0.7 million decrease in indirect gas costs). The $12.5 million decrease in the total direct cost of gas is a result of a $15.8 million decrease in commodity costs, offset by a $1.3 million increase in demand costs and a $2.0 million increase in gas costs adjustments.

The $15.8 million decrease in commodity costs is due to a $16.5 million decrease in pipeline commodity costs offset by a $0.7 million increase in supplemental costs (underground storage, LNG, and propane). The $16.5 million decrease in pipeline costs is due to a decrease in commodity costs of $14.3 million and a decrease of $2.2 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are approximately $.19/therm lower than last year, resulting in a $14.3 million decrease while the throughput is down by 3.5 million therms resulting in a decrease in commodity costs of $2.2 million. The $2.0 million increase in adjustments reflects an increase in Prior Period Under Collection of $2.0 million.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2009/2010 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0009 per therm. The rate approved in DG 09-162 was ($0.0003). This increase is largely due to the increase in peaking costs as compared to the 2009/10 period.

Q. What was the actual weighted average firm sales cost of gas rate for the 2009/2010 winter period?

A. The weighted average cost of gas rate was approximately $0.9416 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2009 through April 2010 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.

PRIOR PERIOD UNDER COLLECTION

Q. Please explain the prior period under collection of $2,484,517.

The prior period under collection is detailed in the 2009/2010 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $2,484,517 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2010 including Peak Period costs recovered in May 2010 based on billings for April consumption. The under collection is the result of lower gas revenue billings and sendout than forecasted for the months of March and April 2010. Specifically sales volumes were 6.4 million therms below the forecast, resulting in a reduction in COG revenues of $6.3 million. The reduction in sendout reduced gas costs by $3.8 million, reflecting the fact that the Company incurred the applicable demand costs but avoided the commodity costs associated with the decreased sendout.

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 set at $0.02 per therm higher than the initial proposed COG. Proposed Second Revised Page 88 contains the FPO rates for the 2010/11 Winter period, which are $0.8420 per therm for residential customers, $0.8386 per therm for commercial/industrial low winter use customers, and $0.8434 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2009/2010 winter period of $0.9863 per therm for residential customers, $0.9858 per therm for commercial/industrial low winter use customers, and $0.9865 per therm for commercial/industrial high winter use customers. This represents a $0.1443 per therm, or 14.6%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $76 or 6.1% compared to last winter. The bill impact reflects the implementation of the increase in base distribution rates associated with the temporary rates approved in DG 10-017 effective June 1, 2010 and in the increase approved in DG 10-139 effective July 1, 2010 relating to the cast iron/bare steel main replacement program. The estimated winter period bill for a typical residential heating customer opting for the FPO program would be approximately $19 or 1.6% 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.

<u>HEDGED SUPPLIES</u>

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 3,490,000 Dekatherms (34.9 million therms) at a weighted average fixed price of $6.4191 per Dekatherm. The hedged price reflects the higher cost of gas during the period that the hedged volumes were locked in. The Company shows in Tab 7, Schedule 7, Page 3, that the remaining 480,000 Dekatherms will be hedged at an estimated price of $4.8156 per Dekatherm based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 3,970,000 Dekatherms at a cost of $24,714,066 or approximately $6.2252 per Dth.

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

A. The Company has fifty-four contracts that hedge the price of gas supplies for the 2010/2011 Winter Period with prices ranging from $4.7580 to $7.4970 per Dekatherms. The contracts date as far back as May 15, 2009 and as recently as July 26, 2010. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

Q. Has the Company revised it Natural Gas Price Risk Management Plan?

Yes, the Company has revised in Natural Gas Price Risk Management Plan as approved in DG 10-049. Under its updated Natural Gas Price Risk Management Plan, the Company plans on hedging two-thirds of the forecasted total sales volume in December, January, February and March. In this period the hedge volume would be a combination of storage withdrawals and financial hedges. In the months of November and April the Company would hedge 50% of the forecasted firm sales load since there little to no planned storage withdrawals in these months. The Company is now determining the financial hedge volume based on the total firm sales forecast, including forecasted storage withdrawals and fixed price physical purchases. As shown in Schedule 7, the total hedged volume (which included storage withdrawals and financial hedges) is approximately 61% of the total sendout during the period of November 2010 through April 2011.

LOCAL DISTRIBUTION ADJUSTMENT CHARGE

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 $0.0641 for the residential non heating class and residential heating class, and $0.0422 for the commercial/industrial classes that will be billed from November 1, 2010 through October 31, 2011. The surcharges that are billed under the LDAC are the Conservation Charge, the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, and the Residential Low Income Assistance Program charge as approved per (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 .

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. 24,995 dated July 31, 2009, in DG 09-049 for the period November and December 2010 and the 2011 expenses that were submitted for approval on August 2, 2010 in Docket DE 10-188 for the period January 2011 through October 2011. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs during the period May 2009 through December 2009 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 which is provided in Tab 19, Energy Efficiency, page 5.

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

A. The proposed RLIAP charge is $0.0116. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this charge. For the 2010/11 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 $1,831,683, of which $1,879,126 is for the revenue shortfall resulting from 7,213 customers receiving a 60% discount off their base rates, $8,600 is for estimated administrative costs, and ($56,043) 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 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 2010-2011 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2009 through October 31, 2010 is calculated to be $20,485,074 and the limit for non-fuel purposes is calculated to be $52,528,520.

Q. Have these new limits been communicated to the Company's Treasury Group?

A. Yes.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 91)?

A. Yes, it has. As a result, of the Company's success in its third party cost recovery efforts, which included receiving significant insurance recoveries in prior years, the balance from recoveries from insurance carriers and other responsible parties continues to exceed the remediation costs. As a result, the Company proposes that the Environmental Surcharge remain at zero for the period beginning November 1, 2010 and ending October 31, 2011. The surcharge for the 2007/2008, 2008/2009, and 2009/2010 Winter Period was also $0.0000 per therm. The costs submitted for recovery through the MGP remediation cost recovery mechanism 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 – 8, shows 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 9 - 12. 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 surcharge. Page 13 provides the total remediation and recovery costs and collections by year and in total.

Although the Company is not proposing an Environmental Surcharge for the 2010-2011 period, the Company's filing does summarize its total investigation and remediation costs, recoveries from third parties and surcharge collections to date so that the Commission is aware of the current ending balance. In total, the Company has incurred environmental remediation costs of $28,257,322, litigation costs of $7,178,376, and obtained third party cash recoveries of $22,792,408, for a net expense of $12,643,290. To date, the Company has collected $13,054,749 from its Environmental Surcharge factor. The total recoveries from insurance carriers and other responsible parties currently exceed the total expenses by $411,459. The Company proposes to apply this credit of $411,459 to future remediation and recovery costs. The $411,459 reflects an interest credit of $257,920. This interest has been included as a credit to the General Expense account.

The 2009-2010 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #10)	$136,936
Concord (Pool #6)	$46,190

Laconia (Pool #8)	$262,678
Manchester (Pool #9)	$328,678
Nashua (Pool #9)	$98,975
Keene (Pool #6)	$0
General (Pool #7)	$4,199
Total Remediation	$877,655
Litigation Recovery	0
Litigation Costs	0
Total 2009-2010	$877,655

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2009-10 costs that the Company is submitting. (Copies of the relevant invoices are being provided under separate cover to the Commission audit staff concurrently with this filing.) Consistent with past practice, the Company met with the Commission staff and Consumer Advocate's office earlier this year to update them on the status of environmental matters. Ms. Leone’s testimony describes the Company’s activities with regard to all six sites. The Company is prepared to provide additional testimony and exhibits, if necessary, to further support recovery of these amounts after the Commission Staff has completed its review of these costs.

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, the Company has calculated the customers' portion of the interest credit associated with the recovery of environmental costs from third parties to the extent it exceeds the costs incurred by the Company that have not already been recovered from customers and has included these credits in the "General Expense" category. For 2009-2010 time period, the Company has included $9,395 credits in this account

Q. Does the LDAC include a credits 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.

Q. In the 2009-2010 LDAF, the Company included a credit associated with rate case expense and the true up of temporary rates in DG 08-009 and an emergency response incentive allowed per the EnergyNorth/National Grid Merger in DG 06-107. Did the Company over or under collect these costs during the 2009-2010 period?

A. The Company will not know until October 2010 the amount of the over or undercollection associated with these two factors. The Company proposes to incorporate the reconciliation balance (if any) for these two factors in the true-up of its Temporary Rates and Rate case expense in DG 10-017.

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 base distribution rates approved in Order No. 25,127 in Docket DG 10-139 relating to the cast iron/bare steel main replacement program. The total bill impact for a typical residential heating customer is an decrease of approximately $53, or 4.4% of which $89, or 7.4%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 20009/2010 winter season, offset by an increase of $37 or 3.0 % resulting from the implementation of temporary rates in DG 10-017 and the base rate adjustment in DG 10-139. The total bill impact for a typical commercial/industrial G-41 customer is an decrease of approximately $67, or 3.5%, of which $135, or 7.0%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2009/2010 winter season offset by an increase of $68, or 3.5%, resulting from the implementation of temporary rates in DG 10-017 and the baserate adjustment in DG 10-139. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

<u>OTHER TARIFF CHANGES</u>

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

A. Yes. The Company is submitting Proposed Second Revised Page 155 relating to Supplier Balancing Charges and Proposed Second Revised Page 156 relating to Capacity Allocation.

Q. Please describe the changes to Page 155.

A. In Proposed Second Revised Page 155, the Company is updating the Peaking Demand Charge from $16.43 per MMBtu of Peak MDQ to $18.48 per MMBtu of Peak MDQ, a $2.05 increase.

The increase in the Peaking Demand Charge is a result of the reduction in the forecast of the Peak Day (ie- denominator used to derive the per unit peaking demand rate). This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions First Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to Page 156.

A. Proposed Second Revised Page 156 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
PUBLIC UTILITIES COMMISSION

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

Winter 2010/2011 Cost of Gas
DG 10-______

Prefiled Testimony of Theodore Poe, Jr.

September 1, 2010

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 40 Sylvan 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 2010/11 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 (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 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 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 transportation contracts on Tennessee Gas Pipeline.

- The Company can receive up to 50,000 MMBtu/day of firm supply from Tennessee's Dracut delivery point located in Dracut, Massachusetts. This supply is delivered to the Company on two transportation contracts 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 2009/10 Peak Period Cost Of Gas Filing?

A. There is one. Effective November 1st, 2009, the Company began utilization of its additional 30,000 MMBtu/day of Tennessee capacity from the Concord Lateral Project from Dracut, MA to the Company's citygates. This contract was discussed in Docket DG 07-101 and approved by the Commission in Order No. 24,825. The contract was in effect during the 2009/10 Peak Period, but was not in effect on September 1, 2009 when the Company submitted its Peak Period cost of gas filing with the Commission.

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 long-haul transportation contracts are firm supplies that the Company purchases primarily in the U.S. Gulf Coast. Supplies purchased at the Dracut, MA receipt point can originate from any of a number of locations including Canada, the U.S. Gulf Coast, and LNG terminals.

Q. Have there been any changes in the portfolio of supply contracts that the Company now holds since the Company submitted its 2009/10 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 2009/10 Peak Period filing, in June 2010, the Company has finalized one request for proposals ("RFP") for the upcoming winter for supply for its

Tennessee long-haul transportation capacity. The Company has entered into a capacity management arrangement with J.P. Morgan Ventures Energy Corporation that will provide supply for the upcoming peak period. J.P. Morgan submitted the best overall bid, based on both price and non-price factors. The contract provides for a six-month 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.

In addition, on 1 April 2007, the Company began receiving gas supplies from BP Canada Energy Marketing Corp. for its Tennessee Niagara capacity. I 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. This contract is in place through March 31, 2012.

The Company is in the process of issuing an RFP for peak-period supply for its transportation capacity from Dawn, Ontario. It is also in the process of issuing an RFP with regard to its short-haul transportation capacity from Dracut, MA. Similar to the 2009/10 peak period, the Company intends that this will be a capacity management arrangement that will provide both baseload and swing nomination provisions, with index-based pricing.

Finally, over the 2010 off-peak period, the Company has been injecting supply 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 1 November 2010; the Tennessee FS-MA field is targeted to be 95 percent full by 1 November 2010. 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 2010, it is the Company's plan to have all of its storage fields 100 percent full.

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.

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 three additional sources of gas supply available to it.

First, the Company, along with its Massachusetts affiliates Boston Gas Company, Colonial Gas Company and Essex Gas Company each d/b/a National Grid, is currently 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.

Second, the Company holds a supply-sharing agreement with 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 were 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 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. In the event that the parties are unable to reach agreement, the price defaults to an index based formula tied to the price of electricity.

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 the 1 Bcf Firm Liquid Contract to which all of the National Grid New England companies are a party. During the 2010 off-peak period, the Company offsets boiloff losses by periodically trucking LNG liquid to its facilities. This contract expires on October 31st, 2010, and the Company is currently in negotiations with Distrigas for future service. Additionally, the Company is planning for its dedicated LNG trucking requirements for the peak period.

Following the 2009/10 peak period, the Company's propane facilities were full and they remain ready for the 2010/11 peak period. Additionally, the Company currently has approximately 464,000 gallons of propane stored at the National Grid propane facilities in Massachusetts on behalf of National Grid NH. . The Company has arrangements in place for its propane trucking 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 2010/11?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers of 85,919,143 therms over the period November 1, 2010 through April 30, 2011 under normal weather conditions which is down 0.6 percent from last year's forecasted value of 86,404,722 therms for the period November 1, 2009 through April 30, 2010. In comparison, the normalized actual sendout to sales customers for the November 1, 2009 through April 30, 2010 period was 84,065,663 therms.

Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 94,133,389 therms over the period November 1, 2010 through April 30, 2011 under design weather conditions, down 0.5 percent from last year's forecasted value of 94,562,239 therms for the period November 1, 2009 through April 30, 2010. For the current peak period forecast, design weather requirements are 9.6 percent greater than normal sendout requirements for weather that is 8.6 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 2009/10 winter of 1,168,312 therms, down 4.4 percent from last year's figure of 1,222,692 therms.

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 2010-2011 Cost of Gas

Docket No. DG 10-_______

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

September 1, 2010

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, to discuss the costs for which National Grid NH is seeking rate recovery, and to describe the status of National Grid NH's efforts to seek reimbursement for MGP related liabilities from third parties. 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 2010, the Company held what has been 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 (“RAP”) 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 RAP and required the Company to evaluate additional remedial alternatives that included further soil removal. In November 2007, the Company submitted RAP Addendum No. 1 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 2008 and 2009, technical representatives from National Grid NH , the Town of Gilford, the Liberty Hill neighborhood and NHDES met several times to discuss the comments provided to NHDES during the public comment period, a scope for groundwater modeling and additional limited data collection (submitted in September 2008) and the results of the modeling and data collection conducted in late 2008 and 2009. Based on the results of the modeling, NHDES requested that the Company submit a revised Remedial Action Plan to evaluate the technical changes from the modeling event. On August 17, 2009, the Company submitted Remedial Action Plan Addendum No. 2 to NHDES which revised the November 2007 recommended alternative to include low flow groundwater extraction and treatment. The Company attended a public meeting hosted by NHDES in September 2010 and is awaiting a decision from NHDES on Remedial Action Plan Addendum No. 2..

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

A. In June 2008, National Grid NH remediated the Merrimack River portion of the site by dredging approximately 9,000 cubic yards of coal tar impacted sediments from the river. The river dredging activities were substantially complete in late 2007 and final restoration activities were completed in May 2008. A Final Remedial Action Implementation Report documenting the sediment remediation activities were submitted to NHDES in August 2008. Pre-design investigations in support of preparation of a Remedial Action Plan for the Upland portion of the site were performed between 2007 and 2010, including additional site characterization, coal tar recovery pilot testing and coal tar mobility assessment and modeling. In June 2010, the Company submitted a RAP for the upland portion of the site to NHDES was submitted which recommended source removal, coal tar recovery and installation of a barrier wall proximate to the river.

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

A. The Company began investigation activities at the Concord MGP site in late 2004. Following initial investigation activities, NHDES requested that the Company submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off site. In late 2008, the Company implemented the 2007 NHDES-approved scope of work. In September 2009, the Company submitted a Supplemental Site Investigation Report to NHDES documenting NHDES-approved additional investigation activities at the site performed between 2006 and 2009. NHDES approved the report in February 2010 and directed that certain additional activities be performed, including removal of the contents of certain on-site structures. A workplan for this work was submitted in June 2010 and approved by NHDES in August 2010. The work is expected to be performed in Fall 2010.

With regard to the pond that is located near Exit 13 on Interstate 93, down-gradient from the MGP, when the pond was remediated in 1999, NHDES required that the northern portion remain untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and might require remediation in the future. In 2006, NHDES requested that the Company address the residual contamination in the pond. Following the completion of additional investigation activities of this portion of the site, the Company submitted to NHDES an Interim Data Collection Report in September 2006, a Conceptual Remedial Design in March 2007, and a Presumptive Remedy Approval Request in March 2009. In May 2009, NHDES granted the Presumptive Remedy Approval allowing for the design and implementation of a cap over the pond sediments to move forward. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore the Company is working with these parties to come to agreement on the design features, negotiate access, and clarify the responsibilities of the three parties.

During May 19, 2009 through May 22, 2009, National Grid NH implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. The sediment sampling data report summarizing the results of the investigation is currently being drafted. The Company will meet with NHDES to discuss the report findings and strategy for moving forward when the final report is submitted to NHDES.

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. In June 2008, we installed six extraction wells for pilot testing at the site. The Company completed construction of the coal tar recovery system and it began operating in November 2009. To date, 109 gallons of coal tar has been recovered. The Company continues to assess the performance of the system and plans to submit a progress report to NHDES in September.

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

A. Lower Liberty Hill, Manchester, Concord and Nashua are the four areas where there is significant activity involving the Company. There is little or no activity to report at the Keene or Dover locations at this time. 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. No. Insurance recovery efforts are mostly complete with respect to all of the Company's former MGP sites. With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ENERGY NORTH NATURAL GAS, INC,
d/b/a NATIONAL GRID NH
Peak 2010 – 2011 Winter Cost of Gas Filing

Filed Tariff Sheets

Proposed Nineteenth Revised Page 1
Check Sheet

Proposed Nineteenth Revised Page 3
Check Sheet

Proposed Second Revised Page 5
Check Sheet

Proposed Nineteenth Revised Page 76
Firm Rate Schedules

Proposed Third Revised Page 86
Anticipated Cost of Gas

Proposed Sixteenth Revised Page 87
Calculation of Firm Sales Cost of Gas Rate

Proposed Second Revised Page 88
Calculation of Firm Sales Cost of Gas Rate

Proposed Second Revised Page 89
Calculation of Firm Transportation Cost of Gas Rate

Proposed Second Revised Page 91
Environmental Surcharge - Manufactured Gas Plants

Proposed Second Revised Page 92
Rate Case Expense

Proposed Second Revised Page 94
Local Distribution Adjustment Charge Calculation (LDAC)

Proposed Second Revised Page 155
Attachment B - Schedule of Administrative Fees and Charges

Proposed Second Revised Page 156
Attachment C - Capacity Allocators

CHECK SHEET

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3	Nineteenth Revised
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13	Original
14	Original
15	Original
16	Original
17	Original
18	Original
19	First Revised
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156	Second Revised

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$ 10.99			$ 10.99	$ 10.99			$ 10.99
All therms	$ 0.1695	$ 0.8220	$ 0.0641	$ 1.0556	$ 0.1695	$ 0.7545	$ 0.0410	$ 0.9650
Residential Heating - R-3								
Customer Charge per Month per Meter	$ 15.78			$ 15.78	$ 15.78			$ 15.78
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2774	$ 0.8220	$ 0.0641	$ 1.1635	$ 0.2774	$ 0.7545	$ 0.0404	$ 1.0723
All therms over the first block per month at	$ 0.2091	$ 0.8220	$ 0.0641	$ 1.0952	$ 0.2091	$ 0.7545	$ 0.0404	$ 1.0040
Residential Heating - R-4								
Customer Charge per Month per Meter	$ 6.31			$ 6.31	$ 6.31			$ 6.31
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.1110	$ 0.8220	$ 0.0641	$ 0.9971	$ 0.1110	$ 0.7545	$ 0.0404	$ 0.9059
All therms over the first block per month at	$ 0.0836	$ 0.8220	$ 0.0641	$ 0.9697	$ 0.0836	$ 0.7545	$ 0.0404	$ 0.8785
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$ 39.45			$ 39.45	$ 39.45			$ 39.45
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.3344	$ 0.8234	$ 0.0422	$ 1.2000	$ 0.3344	$ 0.7548	$ 0.0194	$ 1.1086
All therms over the first block per month at	$ 0.2175	$ 0.8234	$ 0.0422	$ 1.0831	$ 0.2175	$ 0.7548	$ 0.0194	$ 0.9917
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$ 112.73			$ 112.73	$ 112.73			$ 112.73
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.2971	$ 0.8234	$ 0.0422	$ 1.1627	$ 0.2971	$ 0.7548	$ 0.0194	$ 1.0713
All therms over the first block per month at	$ 0.1962	$ 0.8234	$ 0.0422	$ 1.0618	$ 0.1962	$ 0.7548	$ 0.0194	$ 0.9704
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$ 473.45			$ 473.45	$ 473.45			$ 473.45
All therms over the first block per month at	$ 0.1789	$ 0.8234	$ 0.0422	$ 1.0445	$ 0.0819	$ 0.7548	$ 0.0194	$ 0.8561
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$ 39.45			$ 39.45	$ 39.45			$ 39.45
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2168	$ 0.8186	$ 0.0422	$ 1.0776	$ 0.2168	$ 0.7538	$ 0.0194	$ 0.9900
All therms over the first block per month at	$ 0.1400	$ 0.8186	$ 0.0422	$ 1.0008	$ 0.1400	$ 0.7538	$ 0.0194	$ 0.9132
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$ 112.73			$ 112.73	$ 112.73			$ 112.73
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.1692	$ 0.8186	$ 0.0422	$ 1.0300	$ 0.1244	$ 0.7538	$ 0.0194	$ 0.8976
All therms over the first block per month at	$ 0.1148	$ 0.8186	$ 0.0422	$ 0.9756	$ 0.0716	$ 0.7538	$ 0.0194	$ 0.8448
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$ 484.72			$ 484.72	$ 484.72			$ 484.72
All therms over the first block per month at	$ 0.1222	$ 0.8186	$ 0.0422	$ 0.9830	$ 0.0585	$ 0.7538	$ 0.0194	$ 0.8317
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$ 484.72			$ 484.72	$ 484.72			$ 484.72
All therms over the first block per month at	$ 0.0399	$ 0.8186	$ 0.0422	$ 0.9007	$ 0.0216	$ 0.7538	$ 0.0194	$ 0.7948

Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 8,314,931	
Supply Costs:	39,083,750	
Storage Gas:		
Demand, Capacity:	$ 1,055,525	
Commodity Costs:	7,649,468	
Produced Gas:	1,255,498	
Hedged Contract (Saving)/Loss	5,704,479	
Hedge Underground Storage Contract (Saving)/Loss	563,657	
Unadjusted Anticipated Cost of Gas		$ 63,627,308
Adjustments:		
Prior Period (Over)/Under Recovery (as of 10/31/10)	$ 2,985,736	
Interest	101,158	
Prior Period Adjustments	-	
Broker Revenues	(754,779)	
Refunds from Suppliers	-	
Fuel Financing	130,835	
Transportation CGA Revenues	(31,147)	
Interruptible Sales Margin	-	
Capacity Release and Off System Sales Margins	(730,714)	
Hedging Costs	-	
Fixed Price Option Administrative Costs	40,691	
Total Adjustments		1,741,780
Total Anticipated Direct Cost of Gas		$ 65,369,088
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Anticipated Direct Cost of Gas 11/01/10 - 04/30/11)	$ 63,627,308	
Lead Lag Days	10.18	
Prime Rate	3.25%	
Working Capital Percentage	0.091%	
Working Capital	$ 57,674	
Plus: Working Capital Reconciliation (Acct 142.20)	(481,137)	
Total Working Capital Allowance		(423,463)
Bad Debt:		
Total Anticipated Direct Cost of Gas 11/01/10 - 04/30/11)	$ 63,627,308	
Less: Refunds	-	
Plus: Total Working Capital	(423,463)	
Plus: Prior Period (Over)/Under Recovery	2,985,736	
Subtotal	$ 66,189,582	
Bad Debt Percentage	2.40%	
Bad Debt Allowance	$ 1,588,550	
Plus: Bad Debt Reconciliation (Acct 175.52)	(20,082)	
Total Bad Debt Allowance		$ 1,568,468
Production and Storage Capacity		$ 1,749,387
Miscellaneous Overhead (11/01/10 - 04/30/11)	$ 25,381	
Times Winter Sales	83,088	
Divided by Total Sales	104,919	
Miscellaneous Overhead		20,100
Total Anticipated Indirect Cost of Gas		$ 2,914,492
Total Cost of Gas		$ 68,283,580

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)		(Col 3)	
Total Anticipated Direct Cost of Gas	$	65,369,088			
Projected Prorated Sales (11/01/10 - 04/30/11)		83,071,582			
Direct Cost of Gas Rate			$	0.7869	per therm
Demand Cost of Gas Rate	$	9,370,456	$	0.1128	per therm
Commodity Cost of Gas Rate		54,256,852	$	0.6531	per therm
Adjustment Cost of Gas Rate		1,741,780	$	0.0210	per therm
Total Direct Cost of Gas Rate	$	65,369,088	$	0.7869	per therm
Total Anticipated Indirect Cost of Gas	$	2,914,492			
Projected Prorated Sales (11/01/10 - 04/30/11)		83,071,582			
Indirect Cost of Gas			$	0.0351	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/10			**$**	**0.8220**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**		**$**	**0.8220**	**/therm**

Maximum	(COG + 25%)	$	1.0275

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$**	**0.8186**	**/therm**

Average Demand Cost of Gas Rate Effective 11/01/10	$ 0.1128			
Times: Low Winter Use Ratio (Winter)	0.9641	Maximum (COG + 25%)	$	1.0233
Times: Correction Factor	1.00630			
Adjusted Demand Cost of Gas Rate	$ 0.1094			
Commodity Cost of Gas Rate	$ 0.6531			
Adjustment Cost of Gas Rate	$ 0.0210			
Indirect Cost of Gas Rate	$ 0.0351			
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.8186			

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/10	**COGwh**	**$**	**0.8234**	**/therm**

Average Demand Cost of Gas Rate Effective 11/01/10	$ 0.1128			
Times: High Winter Use Ratio (Winter)	1.0063	Maximum (COG + 25%)	$	1.0293
Times: Correction Factor	1.0063			
Adjusted Demand Cost of Gas Rate	$ 0.1142			
Commodity Cost of Gas Rate	$ 0.6531			
Adjustment Cost of Gas Rate	$ 0.0210			
Indirect Cost of Gas Rate	$ 0.0351			
Adjusted Com/Ind High Winter Use Cost of Gas Rate	$ 0.8234			

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 65,369,088		
Projected Prorated Sales (11/01/10 - 04/30/11)	83,071,582		
Direct Cost of Gas Rate		$ 0.7869	per therm
Demand Cost of Gas Rate	$ 9,370,456	$ 0.1128	per therm
Commodity Cost of Gas Rate	54,256,852	$ 0.6531	per therm
Adjustment Cost of Gas Rate	1,741,780	$ 0.0210	per therm
Total Direct Cost of Gas Rate	$ 65,369,088	$ 0.7869	per therm
Total Anticipated Indirect Cost of Gas	$ 2,914,492		
Projected Prorated Sales (11/01/10 - 04/30/11)	83,071,582		
Indirect Cost of Gas		$ 0.0351	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 40483		**$ 0.8220**	
FPO Risk Premium		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE 40483		**$ 0.8420**	
RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**	**$ 0.8420**	**/therm**
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$ 0.8386**	**/therm**

Average Demand Cost of Gas Rate Effective 40483	$ 0.1128
Times: Low Winter Use Ratio (Winter)	$ 0.9641
Times: Correction Factor	1.0063
Adjusted Demand Cost of Gas Rate	$ 0.1094
Commodity Cost of Gas Rate	$ 0.6531
Adjustment Cost of Gas Rate	$ 0.0210
Indirect Cost of Gas Rate	$ 0.0351
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.8186
FPO Risk Premium	$ 0.0200
	$ 0.8386

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/10	**COGwh**	**$ 0.8434**	**/therm**

Average Demand Cost of Gas Rate Effective 40483	$ 0.1128
Times: High Winter Use Ratio (Winter)	$ 1.0063
Times: Correction Factor	1.0063
Adjusted Demand Cost of Gas Rate	$ 0.1142
Commodity Cost of Gas Rate	$ 0.6531
Adjustment Cost of Gas Rate	$ 0.0210
Indirect Cost of Gas Rate	$ 0.0351
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.8234
FPO Risk Premium	$ 0.0200
	$ 0.8434

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ 824,271				
LNG	431,227				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	1,255,498				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	12.4%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 155,682				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	83,088,481		70.6%		
FIRM TRANSPORTATION SUBJECT TO FTCG	34,607,498		29.4%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	117,695,979		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	29.4%	x	$ 155,682	=	$ 45,777
PRIOR (OVER) OR UNDER COLLECTION					(13,665)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ 32,112
PROJECTED FIRM TRANSPORTATION THROUGHPUT					34,607,498
FIRM TRANSPORTATION COST OF GAS ADJUSTMENT					$0.0009

Environmental Surcharge - Manufactured Gas Plants

Manfactured Gas Plants

Required annual increase in rates	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/10 - sales and transportation	158,020,633	therms
Surcharge per therm	$0.0000	per therm
Total Environmental Surcharge	$0.0000	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	-
Temporary Rate Reconciliation		-
Rate Case Expense Reconciliaiton Adjustment		-
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	-

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		60,288,480
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		97,732,153
Total Volumes		158,020,633
Rate Case Expense Factor	$	-

Local Distribution Adjustment Charge Calculation

Residential Non Heating Rates - R-1			
Energy Efficiency Charge	$0.0525		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive			
Interruptible Transportation Margin Credit (ITMC)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0116	
LDAC		**$0.0641**	**per therm**

Residential Heating Rates - R-3, R-4			
Energy Efficiency Charge	$0.0525		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0116	
LDAC		**$0.0641**	**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51			
Energy Efficiency Charge	$0.0306		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0000	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0116	
LDAC		**$0.0422**	**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52			
Energy Efficiency Charge	$0.0306		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0000	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0116	
LDAC		**$0.0422**	**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54			
Energy Efficiency Charge	$0.0306		
Demand Side Management Charge	0.0000		
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0.0000		
Manufactured Gas Plants	0.0000		
Environmental Surcharge (ES)		0.0000	
DG 06-107 Merger Emergency Response Incentive		0.0000	
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0116	
LDAC		**$0.0422**	**per therm**

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.11 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	$18.48 MMBTU of Peak MDQ.

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	Low Annual /Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-42	Medium Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-52	High Annual / Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-43	High Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-53	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%
G-54	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%

CHECK SHEET

The title page and pages 1-91 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

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1	~~Eighteenth~~ Nineteenth Revised
2	Original
3	~~Eighteenth~~ Nineteenth Revised
4	Original
5	~~First~~ Second Revised
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8	Original
9	Original
10	Original
11	Original
12	Original
13	Original
14	Original
15	Original
16	Original
17	Original
18	Original
19	First Revised
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82	Original
83	Original
84	Original
85	Original
86	~~Second~~ Third Revised
87	~~Seventeenth~~ Sixteenth Revised
88	~~First~~ Second Revised
89	~~First~~ Second Revised
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91	~~First~~ Second Revised
92	~~First~~ Second Revised
93	Original
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154	Original
155	~~First~~ Second Revised
156	~~First~~ Second Revised

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate	Delivery Charge	Cost of Gas Rate Page 87	LDAC Page 94	Total Rate
Residential Non Heating - R-1								
Customer Charge per Mon h per Meter	$ 10 99			$ 10.99	$ 10.99			$ 10.99
All Therms	$ 0.1695	$ 0.8220	$ 0.0641	$ 1.0556	$ 0.1695	$ 0.7545	$ 0.0410	$ 0.9650
	~~$ 0.1695~~	~~$ 0.9385~~	~~$ 0.0410~~	~~$ 1.1490~~				
Residential Heating - R-3								
Customer Charge per Mon h per Meter	$ 15.78			$ 15.78	$ 15.78			$ 15.78
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2774	$ 0.8220	$ 0.0641	$ 1.1635	$ 0.2774	$ 0.7545	$ 0.0404	$ 1.0723
	~~$ 0.2774~~	~~$ 0.9385~~	~~$ 0.0404~~	~~$ 1.2563~~				
All therms over the first block per month at	$ 0.2091	$ 0.8220	$ 0.0641	$ 1.0952	$ 0.2091	$ 0.7545	$ 0.0404	$ 1.0040
	~~$ 0.2091~~	~~$ 0.9385~~	~~$ 0.0404~~	~~$ 1.1880~~				
Residential Heating - R-4								
Customer Charge per Mon h per Meter	$ 6 31			$ 6.31	$ 6.310			$ 6.31
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.1110	$ 0.8220	$ 0.0641	$ 0.9971	$ 0.1110	$ 0.7545	$ 0.0404	$ 0.9059
	~~$ 0.1110~~	~~$ 0.9385~~	~~$ 0.0404~~	~~$ 1.0899~~				
All therms over the first block per month at	$ 0.0836	$ 0.8220	$ 0.0641	$ 0.9697	$ 0.0836	$ 0.7545	$ 0.0404	$ 0.8785
	~~$ 0.0836~~	~~$ 0.9385~~	~~$ 0.0404~~	~~$ 1.0625~~				
Commercial/Industrial - G-41								
Customer Charge per Mon h per Meter	$ 39.45			$ 39.45	$ 39.45			$ 39.45
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.3344	$ 0.8234	$ 0.0422	$ 1.2000	$ 0.3344	$ 0.7548	$ 0.0194	$ 1.1086
	~~$ 0.3344~~	~~$ 0.9387~~	~~$ 0.0194~~	~~$ 1.2925~~				
All therms over the first block per month at	$ 0.2175	$ 0.8234	$ 0.0422	$ 1.0831	$ 0.2175	$ 0.7548	$ 0.0194	$ 0.9917
	~~$ 0.2175~~	~~$ 0.9387~~	~~$ 0.0194~~	~~$ 1.1756~~				
Commercial/Industrial - G-42								
Customer Charge per Mon h per Meter	$ 112.73			$ 112.73	$ 112.73			$ 112.73
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.2971	$ 0.8234	$ 0.0422	$ 1.1627	$ 0.2971	$ 0.7548	$ 0.0194	$ 1.0713
	~~$ 0.2971~~	~~$ 0.9387~~	~~$ 0.0194~~	~~$ 1.2552~~				
All therms over the first block per month at	$ 0.1962	$ 0.8234	$ 0.0422	$ 1.0618	$ 0.1962	$ 0.7548	$ 0.0194	$ 0.9704
	~~$ 0.1962~~	~~$ 0.9387~~	~~$ 0.0194~~	~~$ 1.1543~~				
Commercial/Industrial - G-43								
Customer Charge per Mon h per Meter	$ 473.45			$ 473.45	$ 473.45			$ 473.45
All therms over the first block per month at	$ 0.1789	$ 0.8234	$ 0.0422	$ 1.0445	$ 0.0819	$ 0.7548	$ 0.0194	$ 0.8561
	~~$ 0.1789~~	~~$ 0.9387~~	~~$ 0.0194~~	~~$ 1.1370~~				
Commercial/Industrial - G-51								
Customer Charge per Mon h per Meter	$ 39.45			$ 39.45	$ 39.45			$ 39.45
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2168	$ 0.8186	$ 0.0422	$ 1.0776	$ 0.2168	$ 0.7538	$ 0.0194	$ 0.9900
	~~$ 0.2168~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 1.1742~~				
All therms over the first block per month at	$ 0.1400	$ 0.8186	$ 0.0422	$ 1.0008	$ 0.1400	$ 0.7538	$ 0.0194	$ 0.9132
	~~$ 0.1400~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 1.0974~~				
Commercial/Industrial - G-52								
Customer Charge per Mon h per Meter	$ 112.73			$ 112.73	$ 112.73			$ 112.73
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.1692	$ 0.8186	$ 0.0422	$ 1.0300	$ 0.1244	$ 0.7538	$ 0.0194	$ 0.8976
	~~$ 0.1692~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 1.1266~~				
All therms over the first block per month at	$ 0.1148	$ 0.8186	$ 0.0422	$ 0.9756	$ 0.0716	$ 0.7538	$ 0.0194	$ 0.8448
	~~$ 0.1148~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 1.0722~~				
Commercial/Industrial - G-53								
Customer Charge per Mon h per Meter	$ 484.72			$ 484.72	$ 484.72			$ 484.72
All therms over the first block per month at	$ 0.1222	$ 0.8186	$ 0.0422	$ 0.9830	$ 0.0585	$ 0.7538	$ 0.0194	$ 0.8317
	~~$ 0.1222~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 1.0796~~				
Commercial/Industrial - G-54								
Customer Charge per Mon h per Meter	$ 484.72			$ 484.72	$ 484.72			$ 484.72
All therms over the first block per month at	$ 0.0399	$ 0.8186	$ 0.0422	$ 0.9007	$ 0.0216	$ 0.7538	$ 0.0194	$ 0.7948
	~~$ 0.0399~~	~~$ 0.9380~~	~~$ 0.0194~~	~~$ 0.9973~~				

Issued: August 31, 2010
Effective: November 1, 2010

Issued: By____________________________
Nickolas Stavropoulos
Title: President

Anticipated Cost of Gas
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2010 THROUGH OCTOBER 31, 2010~~
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 3,253,976~~		$ 8,314,931	
Supply Costs:	~~$ 10,860,930~~		39,083,750	
Storage Gas:				
Demand, Capacity:			1,055,525	
Commodity Costs:	~~-~~		7,649,468	
Produced Gas:	~~71,646~~		1,255,498	
Hedged Contract Savings	~~874,590~~		5,704,479	
Hedge Underground Storage Contract (Savings)/Loss			563,657	
Unadjusted Anticipated Cost of Gas		~~$ 15,061,143~~		$ 63,627,308
Adjustments:				
Prior Period (Over)/Under Recovery (as of ~~October 1, 2009~~ May 1, 2010)	~~$ 38,753~~		$ 2,985,736	
Interest	~~9,179~~		101,158	
Prior Period Adjustments	~~-~~		-	
Broker Revenues	-		(754,779)	
Refunds from Suppliers			-	
Fuel Financing	~~-~~		130,835	
Transportation CGA Revenues			(31,147)	
Interruptible Sales Margin	~~-~~		-	
Capacity Release and Off System Sales Margin	~~-~~		(730,714)	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs			40,691	
Total Adjustments		~~47,932~~		1,741,780
Total Anticipated Direct Cost of Gas		~~$ 15,109,075~~		$ 65,369,088
Anticipated Indirect Cost of Gas				
Working Capital:				
Total anticipated Direct Cost of Gas ~~(5/01/2010 - 10/31/2010)~~(11/01/10 - 04/30/11)	~~$ 15,061,143~~		$ 63,627,308	
Lead Lag Days	~~10.18~~		10.18	
Prime Rate	~~3.25%~~		3.25%	
Working Capital Percentage	~~0.091%~~		0.091%	
Working Capital	~~13,652~~		$ 57,674	
Plus: Working Capital Reconciliation ~~(Acct 142.40)~~ (Acct 142.20)	~~(93,103)~~		(481,137)	
Total Working Capital Allowance		~~$ (79,451)~~		$ (423,463)
Bad Debt:				
Total anticipated Direct Cost of Gas ~~(5/01/2010 - 10/31/2010)~~(11/01/10 - 04/30/11)	~~$ 15,061,143~~		$ 63,627,308	
Less: Refunds	-		-	
Plus: Total Working Capital	~~(79,451)~~		(423,463)	
Plus: Prior Period (Over)/Under Recovery	~~38,753~~		2,985,736	
Subtotal	~~$ 15,020,446~~		$ 66,189,582	
Bad Debt Percentage	~~2.40%~~		2.40%	
Bad Debt Allowance	~~360,491~~		$ 1,588,550	
Plus: Bad Debt Reconciliation ~~(Acct 175.54)~~ (Acct 175.52)	~~51,447~~		(20,082)	
Total Bad Debt Allowance		~~411,938~~		1,568,468
Produc ion and Storage Capacity		~~-~~		1,749,387
Miscellaneous Overhead ~~(5/01/2010 - 10/31/2010)~~ (11/01/10 - 4/30/11)	~~$ 25,381~~		$ 25,381	
Times ~~Summer~~ Winter Sales	~~21,908~~		83,088	
Divided by Total Sales	~~105,710~~		104,919	
Miscellaneous Overhead		~~5,260~~		20,100
Total Anticipated Indirect Cost of Gas		~~$ 337,747~~		$ 2,914,492
Total Cost of Gas		~~$ 15,446,822~~		$ 68,283,580

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Nickolas Stavropoulos
Title: President

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
~~**PERIOD COVERED SUMMER PERIOD, MAY 1, 2010 THROUGH OCTOBER 31, 2010**~~
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 15,109,075~~		$ 65,369,088		
Projected Prorated Sales ~~(05/01/10 - 10/31/2010)~~ (11/01/10 - 04/30/11)	~~21,428,146~~		83,071,582		
Direct Cost of Gas Rate		~~0.7051~~		$ 0.7869	per therm
Demand Cost of Gas Rate	~~$ 3,253,976~~	~~0.1519~~	$ 9,370,456	$ 0.1128	
Commodity Cost of Gas Rate	~~11,807,167~~	~~0.5510~~	54,256,852	$ 0.6531	
Adjustment Cost of Gas Rate	~~47,932~~	~~0.0022~~	1,741,780	$ 0.0210	
Total Direct Cost of Gas Rate	~~$ 15,109,075~~	~~0.7051~~	$ 65,369,088	$ 0.7869	
Total Anticipated Indirect Cost of Gas	~~$ 337,747~~		$ 2,914,492		
Projected Prorated Sales ~~(05/01/10 - 10/31/2010)~~ (11/01/10 - 04/30/11)	~~21,428,146~~		83,071,582		
Indirect Cost of Gas		~~$ 0.0158~~		$ 0.0351	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/10				$ 0.8220	per Therm
~~**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05 01 10**~~		~~$ 0.7209~~			

RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**	**$ 0.8220**	**/therm**
~~**RESIDENTIAL COST OF GAS RATE 05 01 10**~~	~~**COGsr**~~	~~**$ 0.7126**~~	~~**therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~**$ 0.0082**~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE 06/01/2009**~~	~~**COGsr**~~	~~**$ 0.7208**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~**$ 0.0812**~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE 07 01 2009**~~	~~**COGsr**~~	~~**$ 0.8020**~~	~~**therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~**$ (0.0635)**~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE 08/01/2009**~~	~~**COGsr**~~	~~**$ 0.7385**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$~~	~~per therm~~
~~**RESIDENTIAL COST OF GAS RATE 09 01 2009**~~	~~**COGsr**~~	~~**$ 0.7385**~~	~~**therm**~~

Maximum (COG + 25%) ~~$ 0.8908~~ $ 1.0275

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$ 0.8186**	**/therm**
~~**COM/IND LOW WINTER USE COST OF GAS RATE 05/01/10**~~	~~**COGsl**~~	~~**$ 0.7020**~~	~~**/therm**~~
~~**Change in rate due to change in under over recovery**~~		~~$ 0.0082~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE 06/01/2009**~~	~~**COGsl**~~	~~**$ 0.7102**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~**$ 0.0812**~~	~~**/therm**~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE 07/01/2009**~~	~~**COGsl**~~	~~**$ 0.7914**~~	~~**/therm**~~
~~**Change in rate due to change in under over recovery**~~		~~$ (0.0635)~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE 08/01/2009**~~	~~**COGsl**~~	~~**$ 0.7279**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$~~	~~/therm~~
~~**COM/IND LOW WINTER USE COST OF GAS RATE 09/01/2009**~~	~~**COGsl**~~	~~**$ 0.7279**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective 05/~~01/10~~ 11/01/2010	$ 0.1128	~~$ 0.1401~~	Maximum	(COG + 25%)	~~$ 0.8775~~	$ 1.0233
Times: Low Winter Use Ratio (Winter)	0.9641	~~0.9944~~				
Times: Correction Factor	1.0063	~~1.0013~~				
Adjusted Demand Cost of Gas Rate	$ 0.1094	~~$ 0.1395~~				
Commodity Cost of Gas Rate	$ 0.6531	~~$ 0.5447~~				
Adjustment Cost of Gas Rate	0.0210	~~0.0022~~				
Indirect Cost of Gas Rate	0.0351	~~0.0156~~				
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	$ 0.8186	~~$ 0.7020~~				

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/10	**COGwh**	**$ 0.8234**	**/therm**
~~**COM/IND HIGH WINTER USE COST OF GAS RATE 05/01/10**~~	~~**COGsh**~~	~~**$ 0.7029**~~	~~**/therm**~~
~~**Change in rate due to change in under over recovery**~~		~~$ 0.0082~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE 06/01/2009**~~	~~**COGsh**~~	~~**$ 0.7111**~~	~~**/therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$ 0.0812~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE 07/01/2009**~~	~~**COGsh**~~	~~**$ 0.7923**~~	~~**/therm**~~
~~**Change in rate due to change in under over recovery**~~		~~$ (0.0635)~~	~~/therm~~
~~**COM IND HIGH WINTER USE COST OF GAS RATE 08 01 2009**~~	~~**COGsh**~~	~~**$ 0.7288**~~	~~**therm**~~
~~**Change in rate due to change in under/over recovery**~~		~~$~~	~~/therm~~
~~**COM/IND HIGH WINTER USE COST OF GAS RATE 09/01/2009**~~	~~**COGsh**~~	~~**$ 0.7288**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective 05/~~01/10~~ 11/01/2010	$ 0.1128	~~$ 0.1401~~	Maximum	(COG + 25%)	~~$ 0.8786~~	$ 1.0293
Times: High Winter Use Ratio (Winter)	1.0063	~~1.0008~~				
Times: Correction Factor	1.0063	~~1.0013~~				
Adjusted Demand Cost of Gas Rate	$ 0.1142	~~$ 0.1404~~				
Commodity Cost of Gas Rate	$ 0.6531	~~$ 0.5447~~	Minimum			
Adjustment Cost of Gas Rate	$ 0.0210	~~$ 0.0022~~	Maximum			
Indirect Cost of Gas Rate	$ 0.0351	~~$ 0.0156~~				
Adjusted Com/Ind High Winter Use Cost of Gas Rate	$ 0.8234	~~$ 0.7029~~				

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Nickolas Stavropoulos
Title: President

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011
~~**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010**~~
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total An icipated Direct Cost of Gas	~~$ 77,870,546~~		$ 65,369,088		
Projected Prorated Sales ~~(11/01/2009 - 4/30/2010)~~ (11/01/2010 - 4/30/2011)	~~84,282,098~~		83,071,582		
Direct Cost of Gas Rate		~~$ 0.9239~~		$ 0.7869	per therm
Demand Cost of Gas Rate	~~$ 8,016,873~~	~~$ 0.0951~~	$ 9,370,456	$ 0.1128	
Commodity Cost of Gas Rate	~~$ 70,134,740~~	~~$ 0.8321~~	$ 54,256,852	$ 0.6531	
Adjustment Cost of Gas Rate	~~$ (281,067)~~	~~$ (0.0033)~~	$ 1,741,780	$ 0 0210	
Total Direct Cost of Gas Rate	~~$ 77,870,546~~	~~$ 0 9239~~	$ 65,369,088	$ 0.7869	
Total An icipated Indirect Cost of Gas	~~$ 3,573,460~~		$ 2,914,492		
Projected Prorated Sales ~~(11/01/2009 4/30/2010)~~ (11/01/2010 - 4/30/2011)	~~84,282,098~~		83,071,582		
Indirect Cost of Gas		~~$ 0.0424~~		$ 0 0351	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE NOVEMBER 1, 2010 ~~2009~~		~~**$ 0.9663**~~		**$ 0.8220**	
FPO Risk Premium		~~$ 0.0200~~		$ 0 0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE NOVEMBER 1, 2010 ~~2009~~		~~**$ 0.9863**~~		**$ 0.8420**	

RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**	**$ 0.8420**	**/therm**
~~**RESIDENTIAL COST OF GAS RATE 11/01/2009**~~ -	~~**COGwr**~~	~~**$ 0.9863**~~	~~**/therm**~~

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$ 0.8386**	**/therm**
~~**COM/IND LOW WINTER USE COST OF GAS RATE 11/01/2009**~~ -	~~**COGwr**~~	~~**$ 0.9858**~~	~~**/therm**~~

Average Cost of Gas Rate Effective ~~11/01/2009~~ 11/01/2010	~~$ 0.0951~~	$ 0.1128
Times: Low Winter Use Ratio (Winter)	~~$ 0.9944~~	$ 0.9641
Times: Correction Factor	~~$ 1.0008~~	$ 1.0063
Adjusted Demand Cost of Gas Rate	~~$ 0.0946~~	$ 0.1094
Commodity Cost of Gas Rate	~~$ 0.8321~~	$ 0.6531
Adjustment Cost of Gas Rate	~~$ (0.0033)~~	$ 0.0210
Indirect Cost of Gas Rate	~~$ 0.0424~~	$ 0.0351
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 0 9658~~	$ 0.8186
FPO Risk Premium	~~$ 0.0200~~	$ 0.0200
	~~$ 0.9858~~	$ 0.8386

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/10	**COGwh**	**$ 0.8434**	**/therm**
~~**COM/IND HIGH WINTER USE COST OF GAS RATE 11/01/2009**~~ -	~~**COGwr**~~	~~**$ 0.9865**~~	~~**/therm**~~

Average Cost of Gas Rate Effective ~~11/01/2009~~ 11/01/2010	~~$ 0.0951~~	$ 0.1128
Times: High Winter Use Ratio (Winter)	~~$ 1.0008~~	$ 1.0063
Times: Correction Factor	~~$ 1.0008~~	$ 1.0063
Adjusted Demand Cost of Gas Rate	~~$ 0.0953~~	$ 0.1142
Commodity Cost of Gas Rate	~~$ 0.8321~~	$ 0.6531
Adjustment Cost of Gas Rate	~~$ (0.0033)~~	$ 0.0210
Indirect Cost of Gas Rate	~~$ 0.0424~~	$ 0.0351
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 0.9665~~	$ 0.8234
FPO Risk Premium	~~$ 0.0200~~	$ 0.0200
	~~$ 0.9865~~	$ 0.8434

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Nickolas Stavropoulos
Title: President

II. RATE SCHEDULES

Calculation of Firm Transportation Cost of Gas Rate

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2010 THROUGH APRIL 30, 2011

~~PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2009 THROUGH APRIL 30, 2010~~

(Refer to text in Section16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	~~(Col 4)~~	(Col 2)	(Col 3)	(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:						
PROPANE	~~$ -~~			$ 824,271		
LNG	~~$ 657,484~~			431,227		
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPL ES	~~657,484~~			1,255,498		
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	~~12.4%~~			12.4%		
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	~~$ 81,528~~			$ 155,682		
PROJECTED F RM THROUGHPUT (THERMS):						
FIRM SALES	~~83,801,811~~	~~74.4%~~		83,088,481	70.6%	
FIRM TRANSPORTATION SUBJECT TO FTCG	~~28,847,194~~	~~25.6%~~		34,607,498	29.4%	
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	~~112,649,005~~	~~100.0%~~		117,695,979	100 0%	
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	~~25.6%~~	~~81,528~~ =	~~$ 20,878~~	29.4% x	$ 155,682 =	$ 45,777
PRIOR (OVER) OR UNDER COLLECTION			~~(30,075)~~			(13,665)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS			~~$ (9,197)~~			$ 32,112
PROJECTED F RM TRANSPORTATION THROUGHPUT			~~28,847,194~~			34,607,498
F RM TRANSPORTATION COST OF GAS ADJUSTMENT			~~($0.0003)~~			$0 0009

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Title: President

Environmental Surcharge - Manufactured Gas Plants

Manfactured Gas Plants

Required annual increase in rates	~~$0~~	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/10 ~~10/31/09~~ - sales and transportation	~~150,828,182~~	158,020,633	therms
Surcharge per therm	~~$0.0000~~	$0.0000	per therm
Total Environmental Surcharge	~~$0.0000~~	$0.0000	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$ -	~~$ 802,635~~
Temporary Rate Reconciliation	$ -	~~- (3,740,913)~~
Rate Case Expense Reconciliaiton Adjustment	-	
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$ -	~~- $ (2,938,277)~~

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	60,288,480	~~58,353,540~~
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)	97,732,153	~~92,474,643~~
Total Volumes	158,020,633	~~150,828,182~~

Rate Case Expense Factor	$ -	~~$ (0.0195)~~

Local Distribution Adjustment Charge Calculation

Residential Non Heating Rates - R-1

Energy Efficiency Charge	~~$0.0466~~		$0.0525		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0466~~		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0040~~		0.0000	
Rate Case Expense Factor (RCEF)		~~(0.0195)~~		0.0000	
Residential Low Income Assistance Program (RLIAP)		~~0.0099~~		0.0116	
LDAC		**~~$0.0410~~**		**$0.0641**	**per therm**

Residential Heating Rates - R-3, R-4

Energy Efficiency Charge	~~$0.0466~~		$0.0525		
Demand Side Management Charge	~~(0.0006)~~		0.0000		
Conservation Charge (CCx)		~~$0.0460~~		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0040~~		0.0000	
Rate Case Expense Factor (RCEF)		~~(0.0195)~~		0.0000	
Residential Low Income Assistance Program (RLIAP)		~~0.0099~~		0.0116	
LDAC		**~~$0.0404~~**		**$0.0641**	**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51

Energy Efficiency Charge	~~$0.0250~~		$0.0306		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0250~~		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0040~~		0.0000	
Gas Restructuring Expense Factor (GREF)		~~0.0000~~		0.0000	
Rate Case Expense Factor (RCEF)		~~(0.0195)~~		0.0000	
Residential Low Income Assistance Program (RLIAP)		~~0.0099~~		0.0116	
LDAC		**~~$0.0194~~**		**$0.0422**	**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52

Energy Efficiency Charge	~~$0.0250~~		$0.0306		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0250~~		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		0.0000		0.0000	
Interruptible Transportation Margin Credit (ITMC)		0.0040		0.0000	
Gas Restructuring Expense Factor (GREF)		0.0000		0.0000	
Rate Case Expense Factor (RCEF)		(0.0195)		0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0099		0.0116	
LDAC		**~~$0.0194~~**		**$0.0422**	**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54

Energy Efficiency Charge	~~$0.0250~~		$0.0306		
Demand Side Management Charge	~~0.0000~~		0.0000		
Conservation Charge (CCx)		~~$0.0250~~		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	~~0.0000~~		0.0000		
Manufactured Gas Plants	~~0.0000~~		0.0000		
Environmental Surcharge (ES)		~~0.0000~~		0.0000	
Interruptible Transportation Margin Credit (ITMC)		~~0.0040~~		0.0000	
Gas Restructuring Expense Factor (GREF)		~~0.0000~~		0.0000	
Rate Case Expense Factor (RCEF)		~~(0.0195)~~		0.0000	
Residential Low Income Assistance Program (RLIAP)		~~0.0099~~		0.0116	
LDAC		**~~$0.0194~~**		**$0.0422**	**per therm**

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ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	~~$0.12~~	$0.11 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	~~15%~~	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	~~$16.43~~	$18.48 MMBTU of Peak MDQ.

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	~~37%~~ 38.0%	~~20%~~ 21.0%	~~43%~~ 41.0%	100.0%
G-51	Low Annual /Low Winter Use	~~50%~~ 50.0%	~~16%~~ 17.0%	~~34%~~ 33.0%	100.0%
G-42	Medium Annual / High Winter	~~37%~~ 38.0%	~~20%~~ 21.0%	~~43%~~ 41.0%	100.0%
G-52	High Annual / Low Winter Use	~~50%~~ 50.0%	~~16%~~ 17.0%	~~34%~~ 33.0%	100.0%
G-43	High Annual / High Winter	~~37%~~ 38.0%	~~20%~~ 21.0%	~~43%~~ 41.0%	100.0%
G-53	High Annual / Load Factor < 90%	~~50%~~ 50.0%	~~16%~~ 17.0%	~~34%~~ 33.0%	100.0%
G-54	High Annual / Load Factor > 90%	~~50%~~ 50.0%	~~16%~~ 17.0%	~~34%~~ 33.0%	100.0%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing

Table of Contents

1	**ENERGY NORTH NATURAL GAS, INC.**			
2	**d/b/a National Grid NH**			
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 10-11
6		Reference		Nov - Apr
7	(a)	(b)		(c)
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (j), ln 43	$	8,314,931
12	Supply Costs	Sch. 6, col (i), ln 44		39,083,750
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (j), ln 58	$	1,055,525
16	Commodity Costs:	Sch. 6, col (i), ln 47		7,649,468
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	1,255,498
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	5,704,479
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 199	$	563,657
22				
23	**Total Unadjusted Cost of Gas**		$	63,627,308
24				
25	**Adjustments**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	2,985,736
28	Interest 10/31/10 - 04//30/11	Sch. 3, col (q) ln 193		101,158
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(754,779)
32	Fuel Financing	Sch. 4, ln 26 col (e)		130,835
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(31,147)
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(730,714)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		40,691
39				
40	**Total Adjustments**		$	1,741,780
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	65,369,088
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Anticipated Direct Cost of Gas	Ln 23	$	63,627,308
47	Lead Lag Days			10.18
48	Prime Rate			3.25%
49	Working Capital Percentage	per GTC 16(f)		0 091%
50	Working Capital	ln 46 * ln 49		57,674
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 78		(481,137)
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	(423,463)
54				
55	**Bad Debt**			
56	Total Anticipated Direct Cost of Gas	ln 46	$	63,627,308
57	Less Refunds	ln 30		-
58	Plus Working Capital	ln 53		(423,463)
59	Plus Prior Period (Over) Under Recovery	ln 27		2,985,736
60	Subtotal		$	66,189,582
61	Bad Debt Percentage	per GTC 16(f)		2.40%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	1,588,550
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 162		(20,082)
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	1,568,468
67				
68	**Production and Storage Capacity**	per GTC16(f)	$	1,749,387
69				
70	**Miscellaneous Overhead**	per GTC 16(f)	$	25,381
71	Sales Volume	Sch. 10B, ln 23/1000		83,088
72	Divided by Total Sales	Sch. 10B, ln 23/1000		104,919
73	Ratio			79.19%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	20,100
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	2,914,492
78				
79	**Total Cost of Gas**	lns 42 + 77	$	68,283,580
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		83,071,582

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln											
6			Peak Costs								Peak Period
7	For Month of:		May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10											
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
13	Lost Gas (Unaccounted for)		-	249,857	370,008	415,832	357,166	309,553	173,832		1,876,249
14	Company Use		-	129,348	191,549	215,271	184,900	160,252	89,991		971,312
15	Unbilled Therms		-	7,280,123	5,620,265	(1,864,776)	(2,701,537)	(1,821,518)	(3,038,023)	(3,474,534)	0
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	992,558	985,941	1,025,643	870,970	1,025,643	992,558		5,893,314
22	Niagara Supply	Sch. 6, ln 64	-	66,998	675,767	728,703	624,485	800,664	31,431		2,928,047
23	TGP Supply (Direct)	Sch. 6, ln 65	-	5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699		30,809,005
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	5,590,584	5,590,584	5,049,640	-	-		16,230,807
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	5,541,783	367,247	308,520	348,222	6,430,123	6,676,608		19,672,503
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	23,160	23,987	535,154	196,030	47,974	-		826,305
28	Propane Truck	Sch. 6, ln 70	-	-	-	-	-	-	-		-
29	PNGTS	Sch. 6, ln 71	-	65,343	80,232	86,022	75,269	72,788	55,418		435,071
30	Granite Ridge	Sch. 6, ln 72	-	-	-	-	-	-	-		-
31	Subtotal Pipeline Volumes		-	11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713		76,795,052
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	96,774	3,785,782	4,762,625	4,143,103	284,533	-		13,072,818
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	23,160	23,987	588,918	196,030	23,987	23,160		879,241
38	Propane	Sch. 6, ln 81	-	-	-	426,800	137,304	-	-		564,104
39	Subtotal Produced Gas		-	23,160	23,987	1,015,718	333,334	23,987	23,160		1,443,345
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-		(826,305)
43	Propane	Sch. 6, ln 87	-	-	-	-	-	-	-		-
44	TGP Storage Refill	Sch. 6, ln 88	-	(645,163)	(38,048)	-	-	-	(3,882,557)		(4,565,768)
45	Subtotal Refills		-	(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)		(5,392,072)
46											
47	Total Firm Sendout Volumes		-	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
48											

1	**ENERGY NORTH NATURAL GAS, INC.**									
2	**d/b/a National Grid NH**									
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
5										
6			Peak Costs							Peak Period
7	For Month of:		May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Nov - Apr
49	**II. Gas Costs**									
50										
51	**A. Demand Costs**									
52	Supply									
53	Niagra Supply	Sch.5A, ln 12								
54	Subtotal Supply Demand									
55	Less Capacity Credit									
56	Net Pipeline Demand Costs									
57										
58	Pipeline:									
59	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16								
60	Tenn Gas Pipeline 33371	Sch.5A, ln 17								
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18								
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19								
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20								
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21								
65	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22								
66	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 23								
67	Portland Natural Gas Trans Service	Sch.5A, ln 24								
68	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 25								
69	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 26								
70	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 27								
71	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 28								
72	National Fuel FST 2358	Sch.5A, ln 29								
73	Subtotal Pipeline Demand		$ 970,611	$ 793,419	$ 793,419	$ 793,419	$ 793,419	$ 793,419	$ 793,419		$ 5,731,125
74	Less Capacity Credit		(193,845)	(137,157)	(137,157)	(137,157)	(137,157)	(137,157)	(137,157)		(1,016,786)
75	Net Pipeline Demand Costs		$ 776,766	$ 656,262	$ 656,262	$ 656,262	$ 656,262	$ 656,262	$ 656,262		$ 4,714,339
76										
77	Peaking Supply:									
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 34								
79	Granite Ridge Demand	Sch.5A, ln 35								
80	DOMAC Demand FLS-160	Sch.5A, ln 36								
81	Subtotal Peaking Demand		$ 2,022,281	$ 410,725	$ 410,725	$ 410,725	$ 410,725	$ 410,725	$ 337,047		$ 4,412,953
82	Less Capacity Credit		(403,879)	(71,001)	(71,001)	(71,001)	(71,001)	(71,001)	(58,265)		(817,150)
83	Net Peaking Supply Demand Costs		$ 1,618,403	$ 339,724	$ 339,724	$ 339,724	$ 339,724	$ 339,724	$ 278,782		$ 3,595,803
84										
85	Storage:									
86	Dominion - Demand	Sch.5A, ln 46								
87	Dominion - Storage	Sch.5A, ln 47								
88	Honeoye - Demand	Sch.5A, ln 48								
89	National Fuel - Demand	Sch.5A, ln 49								
90	National Fuel - Capacity	Sch.5A, ln 50								
91	Tenn Gas Pipeline - Demand	Sch.5A, ln 51								
92	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52								
93	Subtotal Storage Demand		$ 648,589	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098		$ 1,297,178
94	Less Capacity Credit		(129,533)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)		(241,653)
95	Net Storage Demand Costs		$ 519,057	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411		$ 1,055,525
96										
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 3,641,481	$ 1,313,202	$ 1,313,234	$ 1,313,234	$ 1,313,138	$ 1,313,234	$ 1,239,524		$ 11,447,046
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(727,256)	(227,011)	(227,016)	(227,016)	(227,000)	(227,016)	(214,274)		(2,076,590)
99	Net Demand Charges		$ 2,914,225	$ 1,086,191	$ 1,086,218	$ 1,086,218	$ 1,086,138	$ 1,086,218	$ 1,025,250		$ 9,370,456
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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln			Peak Costs May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period Nov - Apr
6											
7	For Month of:										
102	**B. Commodity Costs**										
103	Pipeline:										
104	Dawn Supply	Sch. 6, ln 12									
105	Niagara Supply	Sch. 6, ln 13									
106	TGP Supply (Direct)	Sch. 6, ln 14									
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
108	Dracut Supply 2 - Swing	Sch. 6, ln 16									
109	City Gate Delivered Supply	Sch. 6, ln 17									
110	LNG Truck	Sch. 6, ln 18									
111	Propane Truck	Sch. 6, ln 19									
112	PNGTS	Sch. 6, ln 20									
113	Granite Ridge	Sch. 6, ln 21									
114	Subtotal Pipeline Commodity Costs		$ -	$ 5,602,107	$ 6,701,736	$ 7,654,721	$ 6,663,481	$ 6,960,911	$ 5,712,047		$ 39,295,003
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 56,636	$ 2,215,221	$ 2,786,813	$ 2,424,305	$ 166,492	$ -		$ 7,649,468
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50									
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 12,010	$ 12,177	$ 912,545	$ 296,084	$ 11,540	$ 11,142		$ 1,255,498
123											
124	Less Storage Refills:										
125	LNG Truck	Sch. 6, ln 37									
126	Propane	Sch. 6, ln 38									
127	TGP Storage Refill	Sch. 6, ln 39									
128	Storage Refill (Trans.)	Sch. 6, ln 40									
129	Subtotal Storage Refill		$ -	$ (332,808)	$ (31,481)	$ (261,284)	$ (95,386)	$ (22,967)	$ (1,997,728)		$ (2,741,654)
130											
131	Total Supply Commodity Costs		$ -	$ 5,337,945	$ 8,897,653	$ 11,092,796	$ 9,288,485	$ 7,115,976	$ 3,725,460		$ 45,458,315
132											
133	**C. Supply Volumetric Transportation Costs**										
134	Dawn Supply	Sch. 6, ln 26									
135	Niagara Supply	Sch. 6, ln 27									
136	TGP Supply (Direct)	Sch. 6, ln 28									
137	Dracut Supply 1 - Baseload	Sch. 6, ln 29									
138	Dracut Supply 2 - Swing	Sch. 6, ln 30									
139	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 356,345	$ 399,544	$ 413,999	$ 368,374	$ 412,099	$ 289,200		$ 2,239,562
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 2,153	$ 84,225	$ 105,957	$ 92,174	$ 6,330	$ -		$ 290,839
142											
143	Total Supply Volumetric Trans. Costs		$ -	$ 358,499	$ 483,769	$ 519,956	$ 460,549	$ 418,429	$ 289,200		$ 2,530,401
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 5,696,443	$ 9,381,422	$ 11,612,752	$ 9,749,033	$ 7,534,405	$ 4,014,660		$ 47,988,716

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Ln			Peak Costs May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period Nov - Apr
5											
6											
7	For Month of:		Peak Costs May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period Nov - Apr
148	**D. Supply and Demand Costs by Source**										
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 970,611	$ 794,379	$ 794,411	$ 794,411	$ 794,315	$ 794,411	$ 794,379		$ 5,736,915
152	Peaking Gas Demand Costs	ln 81	2,022,281	410,725	410,725	410,725	410,725	410,725	337,047		4,412,953
153	Subtotal Purchased Gas Demand Costs		$ 2,992,892	$ 1,205,104	$ 1,205,136	$ 1,205,136	$ 1,205,040	$ 1,205,136	$ 1,131,426		$ 10,149,868
154	Less Capacity Credit	lns 55 + 74 + 82	(597,723)	(208,324)	(208,330)	(208,330)	(208,313)	(208,330)	(195,588)		(1,834,937)
155	Net Purchased Gas Demand Costs		$ 2,395,168	$ 996,780	$ 996,806	$ 996,806	$ 996,727	$ 996,806	$ 935,838		$ 8,314,931
156											
157	Storage Gas Demand Costs										
158	Storage Demand	ln 93	$ 648,589	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098		$ 1,297,178
159	Less Capacity Credit	ln 94	(129,533)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)		(241,653)
160	Net Storage Demand Costs		$ 519,057	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411		$ 1,055,525
161											
162	**Total Demand Costs**	lns 155 + 160	$ 2,914,225	$ 1,086,191	$ 1,086,218	$ 1,086,218	$ 1,086,138	$ 1,086,218	$ 1,025,250		$ 9,370,456
163											
164	Purchased Gas Supply										
165	Commodity Costs	ln 114	$ -	$ 5,602,107	$ 6,701,736	$ 7,654,721	$ 6,663,481	$ 6,960,911	$ 5,712,047		$ 39,295,003
166	Less Storage Inj.(TGP Storage)	ln 127									
167	Less Storage Transportation	ln 128									
168	Less LNG Truck	ln 125									
169	Less Propane Truck	ln 126									
170	Plus Transportation Costs	ln 139									
171	Subtotal Purchased Gas Supply		$ -	$ 5,625,644	$ 7,069,800	$ 7,807,436	$ 6,936,470	$ 7,350,043	$ 4,003,518		$ 38,792,911
172											
173	Storage Commodity Costs										
174	Commodity Costs	ln 117	$ -	$ 56,636	$ 2,215,221	$ 2,786,813	$ 2,424,305	$ 166,492	$ -		$ 7,649,468
175	Transportation Costs	ln 141	-	2,153	84,225	105,957	92,174	6,330	-		290,839
176	Subtotal Storage Commodity Costs		$ -	$ 58,789	$ 2,299,446	$ 2,892,770	$ 2,516,479	$ 172,823	$ -		$ 7,940,307
177											
178	Produced Gas Commodity Costs	ln 122	$ -	$ 12,010	$ 12,177	$ 912,545	$ 296,084	$ 11,540	$ 11,142		$ 1,255,498
179											
180	**SubTotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 5,696,443	$ 9,381,422	$ 11,612,752	$ 9,749,033	$ 7,534,405	$ 4,014,660		$ 47,988,716
181											
182	Hedge Contract (Savings)/Loss	Sch 7, ln 34	$ -	$ 499,143	$ 1,220,185	$ 1,444,724	$ 1,366,799	$ 847,092	$ 326,536		$ 5,704,479
183											
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 6,195,586	$ 10,601,607	$ 13,057,476	$ 11,115,833	$ 8,381,497	$ 4,341,196		$ 53,693,195
185											
186	**Total Demand Costs**	ln 99	$ 2,914,225	$ 1,086,191	$ 1,086,218	$ 1,086,218	$ 1,086,138	$ 1,086,218	$ 1,025,250		$ 9,370,456
187	**Total Supply Costs**	ln 184	-	6,195,586	10,601,607	13,057,476	11,115,833	8,381,497	4,341,196		53,693,195
188											
189	**Total Direct Gas Costs**	lns 186 + 187	$ 2,914,225	$ 7,281,777	$ 11,687,824	$ 14,143,693	$ 12,201,971	$ 9,467,715	$ 5,366,446		$ 63,063,651
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Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
1	**ENERGY NORTH NATURAL GAS, INC.**					
2	**d/b/a National Grid NH**					
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					
5						
6						
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
11	Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
12	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
13	Niagra Supply		Supply	MDQ	3,199	
14	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
15	Granite Ridge Demand		Peaking	MDQ	15,000	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
18	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
19	National Fuel	FST 2358	Transportation	MDQ	6,098	
20	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
21	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
22	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
23	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
24	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
25	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
26	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
27	Tenn Gas Pipeline	33371	Transportation	MDQ	4,000	
28	ANE (TransCanada via Union to Iroquois)	Union Dawn to Iroquois	Transportation	MDQ	4,047	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	72694 Z6-Z6	Transportation	MDQ	30,000	
30	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
31	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
32	DOMAC Liquid Demand Charge	FLS-160	Peaking	MDQ	2,843	
33	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
34						
35	**Supply Costs - Commodity**					
36	City Gate Delivered Supply		Pipeline	Dkt	-	
37	LNG Truck		Pipeline	Dkt	82,630	
38	TGP Supply (Direct)		Pipeline	Dkt	3,080,901	
39	LNG Vapor (Storage)		Produced	Dkt	87,924	
40	Dawn Supply		Pipeline	Dkt	589,331	
41	Niagara Supply		Pipeline	Dkt	292,805	
42	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,623,081	
43	Dracut Supply 2 - Swing		Pipeline	Dkt	1,967,250	
44	Granite Ridge		Pipeline	Dkt	-	
45	TGP Storage		Storage	Dkt	1,307,282	
46	PNGTS		Pipeline	Dkt	43,507	
47	Propane		Produced	Dkt	56,410	
48	Propane Truck		Pipeline	Dkt	-	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,623,081	
52	Dracut Supply 2 - Swing		Pipeline	Dkt	1,967,250	
53	Niagara Supply		Pipeline	Dkt	292,805	
54	TGP Storage - Withdrawals		Pipeline	Dkt	1,307,282	
55	Dawn Supply		Pipeline	Dkt	589,331	
56	TGP Supply (Direct)		Pipeline	Dkt	3,080,901	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			Prior Period Balance Apr-10 Ending Bal Plus May Billings	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period Total
8		Days in Month		31	30	31	31	30	31	30	31	31	28	31	30	31	
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Accunt 175.20 COG (Over)/Under Balance - Interest Calculation**																
11																	
12	**Beginning Balance**	Account 175.20 1/	**$ 3,011,016**	$ 2,985,736	$ 3,505,456	$ 4,034,687	$ 4,141,048	$ 4,641,129	$ 5,202,219	$ 5,758,777	$ 4,343,921	$ 3,031,815	$ 2,520,380	$ 2,159,401	$ 779,836	$ 111,657	$ 3,011,016
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		590,989	600,930	552,767	547,882	593,537	591,777	7,281,777	11,687,824	14,143,693	12,201,971	9,467,715	5,366,446	-	63,627,308
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	294,915	294,915	294,915	294,915	294,915	294,915	-	1,769,487
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(3,052,386)	(8,684,912)	(16,362,651)	(14,941,746)	(12,530,368)	(8,662,754)	(2,803,949)	(67,038,767)
16	Projected Unbilled Revenue									(5,875,059)	(10,410,613)	(8,905,739)	(6,725,598)	(5,255,633)	(2,803,949)		(39,976,591)
17	Reverse Prior Month Unbilled										5,875,059	10,410,613	8,905,739	6,725,598	5,255,633	2,803,949	39,976,591
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(80,251)	(81,757)	(457,673)	(59,905)	(45,576)	(50,327)	(77,578)	(84,544)	(99,918)	(102,086)	(85,843)	(119,658)	-	(1,345,114)
20	Gas Cost Billed	Account 175.20 2/	(25,280)	-	-	-	-	-	-	-	-	-	-	-	-	-	(25,280)
21	Monthly (Over)/Under Recovery		$ 2,985,736	$ 3,496,475	$ 4,024,629	$ 4,129,780	$ 4,629,025	$ 5,189,090	$ 5,743,670	$ 4,330,446	$ 3,021,650	$ 2,512,728	$ 2,153,574	$ 775,785	$ 110,468	$ 111,657	$ (1,349)
22	Average Monthly Balance	(ln 12 + 21)/2		$ 3,253,745	$ 3,765,043	$ 4,082,233	$ 4,385,037	$ 4,915,109	$ 5,472,945	$ 5,044,611	$ 3,682,786	$ 2,772,272	$ 2,336,977	$ 1,467,593	$ 445,152	$ 111,657	
23																	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
25																	
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 8,981	$ 10,057	$ 11,268	$ 12,104	$ 13,129	$ 15,107	$ 13,475	$ 10,165	$ 7,652	$ 5,826	$ 4,051	$ 1,189	$ -	$ 113,006
27																	
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 2,985,736	$ 3,505,456	$ 4,034,687	$ 4,141,048	$ 4,641,129	$ 5,202,219	$ 5,758,777	$ 4,343,921	$ 3,031,815	$ 2,520,380	$ 2,159,401	$ 779,836	$ 111,657	$ 111,657	111,657
29																	
30																	
31	**Calculation of COG with Interest**																
32																	
33	**Beginning Balance**	ln 12	$ 3,011,016	$ 2,985,736	$ 3,505,456	$ 4,034,687	$ 4,141,048	$ 4,641,129	$ 5,202,219	$ 5,758,777	$ 4,329,539	$ 2,996,081	$ 2,460,590	$ 2,078,885	$ 681,262	$ 2,803	$ 3,011,016
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		590,989	600,930	552,767	547,882	593,537	591,777	7,281,777	11,687,824	14,143,693	12,201,971	9,467,715	5,366,446	-	63,627,308
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	294,915	294,915	294,915	294,915	294,915	294,915	-	1,769,487
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(3,057,303)	(8,698,903)	(16,389,010)	(14,965,816)	(12,550,553)	(8,676,709)	(2,808,466)	(67,146,760)
37	Projected Unbilled Revenue									(5,884,523)	(10,427,383)	(8,920,085)	(6,736,433)	(5,264,100)	(2,808,466)		(40,040,989)
38	Reverse Prior Month Unbilled										5,884,523	10,427,383	8,920,085	6,736,433	5,264,100	2,808,466	40,040,989
39	Add Net Adjustments	ln 19		(80,251)	(81,757)	(457,673)	(59,905)	(45,576)	(50,327)	(77,578)	(84,544)	(99,918)	(102,086)	(85,843)	(119,658)	-	(1,345,114)
40	Gas Cost Billed	ln 20	(25,280)		-	-	-	-	-	-	-	-	-	-	-	-	(25,280)
41	Add Interest	ln 26		-	-	-	-	-	-	13,475	10,165	7,652	5,826	4,051	1,189	-	42,360
42	**(Over)/Under Balance**		$ 2,985,736	$ 3,496,475	$ 4,024,629	$ 4,129,780	$ 4,629,025	$ 5,189,090	$ 5,743,670	$ 4,329,540	$ 2,996,136	$ 2,460,711	$ 2,079,053	$ 681,503	$ 3,078	$ 2,803	$ (66,983)
43																	
44	Average Monthly Balance			$ 3,253,745	$ 3,765,043	$ 4,082,233	$ 4,385,037	$ 4,915,109	$ 5,472,945	$ 5,044,158	$ 3,662,837	$ 2,728,396	$ 2,269,822	$ 1,380,194	$ 342,170	$ 2,803	
45																	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		8,981	10,057	11,268	12,104	13,129	15,107	13,474	10,110	7,531	5,659	3,810	914	-	112,145
47																	
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 2,985,736	$ 3,505,456	$ 4,034,687	$ 4,141,048	$ 4,641,129	$ 5,202,219	$ 5,758,777	$ 4,329,539	$ 2,996,081	$ 2,460,590	$ 2,078,885	$ 681,262	$ 2,803	$ 2,803	2,803
49																	
50																	
51	Forecast Sendout Therms	Sch 1								11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
53	Less Forecast Unaccounted For	Sch 1								249,857	370,008	415,832	357,166	309,553	173,832		1,876,249
54	Less Forecast Company Use	Sch 1								129,348	191,549	215,271	184,900	160,252	89,991		971,312
55	Unbilled Volumes									7,280,123	5,620,265	-1,864,776	-2,701,537	-1,821,518	-3,038,023	-3,474,534	0
56	Gross Unbilled									7,280,123	12,900,387	11,035,612	8,334,075	6,512,557	3,474,534	0	
57																	
58																	
59	COB w/o Interest	Sch. 3, pg. 4, ln 211 col. (c)								$0.8070	$0.8070	$0.8070	$0.8070	$0.8070	$0.8070	$0.8070	
60																	
61	COG With Interest	Sch. 3, pg. 4, ln 211 col. (d)								$0.8083	$0.8083	$0.8083	$0.8083	$0.8083	$0.8083	$0.8083	

65 1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
66 2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			Prior Period Balance														
72			Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period
73		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
74	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
75																	
76	**Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation**																
77																	
78	**Beginning Balance**	Account 142.20 1/	**$ (481,136)**	$ (481,137)	$ (481,918)	$ (482,650)	$ (483,470)	$ (484,297)	$ (485,042)	$ (485,833)	$ (424,018)	$ (330,904)	$ (224,943)	$ (133,669)	$ (55,439)	$ (11,402)	$ (481,136)
79																	
80	Days Lag			10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18		
81	Prime Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
82	Forecast Working Capital	ln 34 * 0.091%		536	545	501	497	538	536	6,600	10,594	12,820	11,060	8,582	4,864	-	57,674
83																	
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	19,290	54,886	103,407	94,427	79,188	54,746	17,720	423,665
85	Projected Unbilled Revenue									37,129	65,792	56,282	42,504	33,214	17,720		252,640
86	Reverse Prior Month Unbilled										(37,129)	(65,792)	(56,282)	(42,504)	(33,214)	(17,720)	(252,640)
87																	
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
89																	
90	Working Capital Billed	Account 142.20 2/	(1)														(1)
91																	
92	Monthly (Over)/Under Recovery		$ (481,137)	$ (480,591)	$ (481,363)	$ (482,139)	$ (482,963)	$ (483,749)	$ (484,495)	$ (422,804)	$ (329,864)	$ (224,177)	$ (133,223)	$ (55,179)	$ (11,313)	$ (11,402)	$ 202
93																	
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ (480,864)	$ (481,641)	$ (482,394)	$ (483,217)	$ (484,023)	$ (484,769)	$ (454,319)	$ (376,941)	$ (277,540)	$ (179,083)	$ (94,424)	$ (33,376)	$ (11,402)	
95																	
96	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
97																	
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ (1,327)	$ (1,287)	$ (1,332)	$ (1,334)	$ (1,293)	$ (1,338)	$ (1,214)	$ (1,040)	$ (766)	$ (446)	$ (261)	$ (89)	$ -	$ (11,727)
99																	
100	**(Over)/Under Balance**	ln 92 + ln 98	$ (481,137)	$ (481,918)	$ (482,650)	$ (483,470)	$ (484,297)	$ (485,042)	$ (485,833)	$ (424,018)	$ (330,904)	$ (224,943)	$ (133,669)	$ (55,439)	$ (11,402)	$ (11,402)	(11,524)
101																	
102																	
103	**Calculation of Working Capital with Interest**																
104																	
105	**Beginning Balance**	ln 78	$ (481,136)	$ (481,137)	$ (481,929)	$ (482,671)	$ (483,501)	$ (484,338)	$ (485,093)	$ (485,895)	$ (422,984)	$ (328,239)	$ (220,438)	$ (127,580)	$ (47,972)	$ (3,154)	$ (481,136)
106	Forecast Working Capital	ln 82		536	545	501	497	538	536	6,600	10,594	12,820	11,060	8,582	4,864	-	57,674
107	Projected Rev. with interest	ln 121 * ln 127		-	-	-	-	-	-	19,668	55,962	105,435	96,279	80,741	55,819	18,068	431,972
108	Projected Unbilled Revenue									37,857	67,082	57,385	43,337	33,865	18,068		257,594
109	Reverse Prior Month Unbilled										(37,857)	(67,082)	(57,385)	(43,337)	(33,865)	(18,068)	(257,594)
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	(1)	-	-	-	-	-	-								(1)
112	Add Interest	ln 98		-	-	-	-	-	-	(1,214)	(1,040)	(766)	(446)	(261)	(89)	-	(3,816)
113	Monthly (Over)/Under Recovery		$ (481,137)	$ (480,601)	$ (481,384)	$ (482,169)	$ (483,004)	$ (483,800)	$ (484,557)	$ (422,983)	$ (328,242)	$ (220,446)	$ (127,593)	$ (47,990)	$ (3,175)	$ (3,154)	$ 4,693
114																	
115	Average Monthly Balance			$ (480,869)	$ (481,656)	$ (482,420)	$ (483,253)	$ (484,069)	$ (484,825)	$ (454,439)	$ (375,613)	$ (274,342)	$ (174,015)	$ (87,785)	$ (25,573)	$ (3,154)	
116																	
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		(1,327)	(1,287)	(1,332)	(1,334)	(1,293)	(1,338)	(1,214)	(1,037)	(757)	(434)	(242)	(68)	-	$ (11,663)
118																	
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	$ (481,137)	$ (481,929)	$ (482,671)	$ (483,501)	$ (484,338)	$ (485,093)	$ (485,895)	$ (422,984)	$ (328,239)	$ (220,438)	$ (127,580)	$ (47,972)	$ (3,154)	$ (3,154)	$ (3,154)
120																	
121	Forecast Therm Sales	ln 52								3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
122	Unbilled Therm	ln 55								7,280,123	5,620,265	(1,864,776)	(2,701,537)	(1,821,518)	(3,038,023)		
123	Gross Unbilled									7,280,123	12,900,387	11,035,612	8,334,075	6,512,557	3,474,534		
124																	
125	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								-$0.0051	-$0.0051	-$0.0051	-$0.0051	-$0.0051	-$0.0051	-$0.0051	
126																	
127	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								-$0.0052	-$0.0052	-$0.0052	-$0.0052	-$0.0052	-$0.0052	-$0.0052	

128 1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
129 2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line			Prior Period Balance														
131			Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	DemandPeriod
132		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
133	(a)	(b)	Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
135	**Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation**																
137	Forecast Direct Gas Costs	ln 34		$ 590,989	$ 600,930	$ 552,767	$ 547,882	$ 593,537	$ 591,777	$ 7,281,777	$ 11,687,824	$ 14,143,693	$ 12,201,971	$ 9,467,715	$ 5,366,446	$ -	63,627,308
138	Forecast Working Capital	ln 106		536	545	501	497	538	536	(474,536)	10,594	12,820	11,060	8,582	4,864		(423,463)
139	Prior Period Balance	ln 42								497,623	497,623	497,623	497,623	497,623	497,623		2,985,736
140	Total Forecast Direct Gas Costs & Working Capital			591,525	601,475	553,268	548,378	594,075	592,314	7,304,864	12,196,041	14,654,136	12,710,654	9,973,919	5,868,933	-	63,203,845
142	**Beginning Balance**	Account 175.52 1/	**$ (19,924)**	$ (20,082)	$ (5,921)	$ 8,518	$ 21,838	$ 35,078	$ 49,448	$ 63,820	$ 30,181	$ 13,321	$ 17,092	$ 23,320	$ 3,696	$ (909)	$ (19,924)
144	Forecast Bad Debt	ln 140 * 0.024		14,197	14,435	13,278	13,161	14,258	14,216	175,317	292,705	351,699	305,056	239,374	140,854		1,588,550
146	Projected Revenues w/o int	ln 183 * ln 187		-	-	-	-	-	-	(71,487)	(203,401)	(383,215)	(349,937)	(293,462)	(202,882)	(65,669)	(1,570,053)
147	Projected Unbilled Revenue									(137,594)	(243,817)	(208,573)	(157,514)	(123,087)	(65,669)		(936,255)
148	Reverse Prior Month Unbilled										137,594	243,817	208,573	157,514	123,087	65,669	936,255
150	Bad Debt Billed	Account 175.52 2/	(158)		-	-	-	-	-		-	-	-	-	-	-	(158)
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
154	Monthly (Over)/Under Recovery		$ (20,082)	$ (5,885)	$ 8,514	$ 21,796	$ 34,999	$ 49,335	$ 63,664	$ 30,055	$ 13,261	$ 17,050	$ 23,270	$ 3,659	$ (913)	$ (909)	$ (1,585)
156	Average Monthly Balance	(ln 142 + ln 154)/2		$ (12,905)	$ 1,297	$ 15,157	$ 28,419	$ 42,207	$ 56,556	$ 46,937	$ 21,721	$ 15,186	$ 20,181	$ 13,490	$ 1,392	$ (909)	
158	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
160	Interest Applied	ln 156 * ln 158 / 365 * Days of Month		$ (36)	$ 3	$ 42	$ 78	$ 113	$ 156	$ 125	$ 60	$ 42	$ 50	$ 37	$ 4		$ 675
162	**(Over)/Under Balance**	ln 154 + ln 160	$ (20,082)	$ (5,921)	$ 8,518	$ 21,838	$ 35,078	$ 49,448	$ 63,820	$ 30,181	$ 13,321	$ 17,092	$ 23,320	$ 3,696	$ (909)	$ (909)	(909)
165	**Calculation of Bad Debt with Interest**																
167	**Beginning Balance**	ln 142	$ (19,924)	$ (20,082)	$ (5,921)	$ 8,518	$ 21,838	$ 35,078	$ 49,448	$ 63,820	$ 30,181	$ 13,321	$ 17,092	$ 23,321	$ 3,696	$ (909)	$ (19,924)
168	Forecast Bad Debt	ln 144		14,197	14,435	13,278	13,161	14,258	14,216	175,317	292,705	351,699	305,056	239,374	140,854	-	1,588,550
169	Projected Revenues with int.	ln 183 * ln 189		-	-	-	-	-	-	(71,487)	(203,401)	(383,215)	(349,937)	(293,462)	(202,882)	(65,669)	(1,570,053)
170	Projected Unbilled Revenue									(137,594)	(243,817)	(208,573)	(157,514)	(123,087)	(65,669)		(936,255)
171	Reverse Prior Month Unbilled										137,594	243,817	208,573	157,514	123,087	65,669	936,255
172	Bad Debt Billed	ln 150	(158)		-	-	-	-	-	-	-	-	-	-	-	-	(158)
173	Add Interest	ln 160		-	-	-	-	-	-	125	60	42	50	37	4	-	319
174	Add Net Adjustments	ln 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		$ (20,082)	$ (5,885)	$ 8,514	$ 21,796	$ 34,999	$ 49,335	$ 63,664	$ 30,181	$ 13,321	$ 17,092	$ 23,321	$ 3,696	$ (909)	$ (909)	$ (1,266)
177	Average Monthly Balance			$ (12,905)	$ 1,297	$ 15,157	$ 28,419	$ 42,207	$ 56,556	$ 47,000	$ 21,751	$ 15,207	$ 20,206	$ 13,509	$ 1,394	$ (909)	
179	Interest Applied	ln 158 * ln 177 / 365 * Days of Month		(36)	3	42	78	113	156	126	60	42	50	37	4	-	$ 676
181	**(Over)/Under Balance**	-ln 173 +ln 175 + ln 179	$ (20,082)	$ (5,921)	$ 8,518	$ 21,838	$ 35,078	$ 49,448	$ 63,820	$ 30,181	$ 13,321	$ 17,092	$ 23,321	$ 3,696	$ (909)	$ (909)	$ (909)
183	Forecast Term Sales	ln 52								3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
184	Unbilled Therm	ln 55								7,280,123	5,620,265	(1,864,776)	(2,701,537)	(1,821,518)	(3,038,023)		
185	Gross Unbilled									7,280,123	12,900,387	11,035,612	8,334,075	6,512,557	3,474,534		
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. (c)								$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. (d)								$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	$0.0189	
193	**Total Interest**	lns 46 + 117 + 179	$ -	$ 7,618	$ 8,774	$ 9,978	$ 10,848	$ 11,949	$ 13,925	$ 12,386	$ 9,134	$ 6,816	$ 5,275	$ 3,605	$ 849	$ -	$ 101,158

190 1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.
191 2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			COG Rate Without Interest	COG Rate With Interest
194				
195	**Calculation of COG**			
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	ln 12, col. (q)	$ 3,011,016	$ 3,011,016
198				
199	Unadjusted Forecast of Gas Costs	ln 13, col. (q)	63,627,308	63,627,308
200				
201	Production & Storage and Misc Overhea	ln 14, col. (q)	1,769,487	1,769,487
202				
203	Adjustments	ln 19, col. (q)	(1,370,394)	(1,370,394)
204				
205	Interest Nov -Apr	ln 46, col. (q)	-	$ 112,145
206				
207	Total Gas To Be Recovered		$ 67,037,417	$ 67,149,562
208				
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	83,071,582	83,071,582
210				
211	Preliminary COG Rate	ln. 207 / ln. 209	$0.8070	$0.8083
212				
213				

Ln			Working Capital Rate without interest	Working Capital Rate with Interest
214	**Calculation of Working Capital Rate**			
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (q)	$ (481,136)	$ (481,136)
217				
218	Unadjusted Working Capital Forecast	ln 82, col. (q)	57,674	57,674
219				
220	Adjustments without interest	ln 88, col. (q)	(1)	(1)
221				
222	Interest Nov -Apr	ln 117, col. (q)	-	$ (11,663)
223				
224	Total Gas To Be Recovered		$ (423,463)	$ (435,126)
225				
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	83,071,582	83,071,582
227				
228	Preliminary Working Capital COG Rate		-$0.0051	-$0.0052
229				
230				

Ln			Bad Debt Rate without Interest	Bad Debt Rate with interest
231	**Calculation of Bad Debt Rate**			
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (q)	$ (19,924)	$ (19,924)
234				
235	Unadjusted Bad Debt Forecast	ln 144, col. (q)	1,588,550	1,588,550
236				
237	Adjustments without interest	ln 152, col. (q)	(158)	(158)
238				
239	Interest Nov -Apr	ln 179, col. (q)	-	$ 676
240				
241	Total Gas To Be Recovered		$ 1,568,468	$ 1,569,144
242				
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	83,071,582	83,071,582
244				
245	Preliminary Bad Debt COG Rate		$0.0189	$0.0189

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

Line	Adjustments		Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	PCB Refunds	Fixed Price Option Administrative Costs	Total Adjustments
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-10		$ -	$ -	$ (52,686)	$ 7,696	$ -				$ -	$ -	$ (80,251)
10	Jun-10		-	-	(39,581)	9,644	-				-	-	(81,757)
11	Jul-10		-	-	(419,657)	11,302	-				-	-	(457,673)
12	Aug-10	1/	-	-	(11,377)	5,942	-				-	-	(59,905)
13	Sep-10	1/	-	-	(10,422)	5,666	-				-	-	(45,576)
14	Oct-10	1/	-	-	(16,023)	5,190	-				-	-	(50,327)
15	Nov-10	1/	-	-	(18,198)	9,252	(3,813)				-	40,691	(77,578)
16	Dec-10	1/	-	-	(28,133)	14,776	(4,544)				-	-	(84,544)
17	Jan-11	1/	-	-	(47,505)	19,101	(6,275)				-	-	(99,918)
18	Feb-11	1/	-	-	(50,896)	20,197	(6,174)				-	-	(102,086)
19	Mar-11	1/	-	-	(24,105)	7,923	(5,429)				-	-	(85,843)
20	Apr-11	1/	-	-	(36,196)	14,146	(4,912)				-	-	(119,658)
21													
22	Subtotal May 10 - Oct 10		$ -	$ -	$ (549,746)	$ 45,440	$ -	$ -	$ (20,412)	$ (250,771)	$ -	$ -	$ (775,489)
23													
24	Subtotal Nov 10 - Apr 11		$ -	$ -	$ (205,033)	$ 85,395	$ (31,147)	$ -	$ (1,912)	$ (457,619)	$ -	$ 40,691	$ (569,626)
25													
26	Total Peak Period		$ -	$ -	$ (754,779)	$ 130,835	$ (31,147)	$ -	$ (22,324)	$ (708,390)	$ -	$ 40,691	$ (1,345,114)
27													

1/ Estimate is based on prior years actual. Exception: Transporta ion Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 10 - Apr 11 calculated on Schedule 16.
2/ Credit from JP Morgan of contract is from 11/01/2020 through 04/30/2011, included in Column I.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Demand Costs**

Ln		Peak	Reference	Peak Costs May 10 -Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak May -Apr Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagra Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days								
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days								
17	Tenn Gas Pipeline 33371		Sch 5B, ln 13 * Sch 5C ln 16 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 18 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 20 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 22 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 24 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 26 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 28 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 30 x days								
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 21 * Sch 5C ln 46 x days								
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 22 * Sch 5C ln 32 x days								
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 34 x days								
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 24 * Sch 5C ln 36 x days								
29	National Fuel FST 2358	peak	Sch 5B, ln 25 * Sch 5C ln 38 x days								
30											
31	Subtotal Pipeline Demand Charges			$ 970,611	$ 793,419	$ 793,419	$ 793,419	$ 793,419	$ 793,419	$ 793,419	$ 5,731,125
32											
33	**Peaking Supply**										
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 28 * Sch 5C ln 28 x days								
35	Granite Ridge Demand	peak	Sch 5B, ln 29 * Sch 5C ln 49 x days								
36	DOMAC Demand FLS-160	peak	Per Contract								
37	Subtotal Peaking Demand Chargs			$ 2,022,281	$ 410,725	$ 410,725	$ 410,725	$ 410,725	$ 410,725	$ 337,047	$ 4,412,953
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 2,992,892	$ 1,205,104	$ 1,205,136	$ 1,205,136	$ 1,205,040	$ 1,205,136	$ 1,131,426	$ 10,149,868
40											
41	Less Transportation Capacity Credit			$ (597,723)	$ (208,324)	$ (208,330)	$ (208,330)	$ (208,313)	$ (208,330)	$ (195,588)	$ (1,834,937)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 2,395,168	$ 996,780	$ 996,806	$ 996,806	$ 996,727	$ 996,806	$ 935,838	$ 8,314,931
44											
45	**Storage**										
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 53 x days	$ 10,520	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ 1,753	$ 21,041
47	Dominion - Storage	peak	Sch 5B, ln 34 * Sch 5C ln 54 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 57 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
49	National Fuel - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 59 x days	78,869	13,145	13,145	13,145	13,145	13,145	13,145	157,738
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 60 x days	173,871	28,979	28,979	28,979	28,979	28,979	28,979	347,743
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 63 x days	150,724	25,121	25,121	25,121	25,121	25,121	25,121	301,447
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 64 x days	173,203	28,867	28,867	28,867	28,867	28,867	28,867	346,407
53											
54	**Subtotal Storage Demand Costs**			$ 648,589	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 108,098	$ 1,297,178
55											
56	Less Transportation Capacity Credit			$ (129,533)	$ (18,687)	$ (18,687)	$ (18,687)	$ (18,687)	$ (18,687)	$ (18,687)	$ (241,653)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 519,057	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 89,411	$ 1,055,525
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 3,641,481	$ 1,313,202	$ 1,313,234	$ 1,313,234	$ 1,313,138	$ 1,313,234	$ 1,239,524	$ 11,447,046
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (727,256)	$ (227,011)	$ (227,016)	$ (227,016)	$ (227,000)	$ (227,016)	$ (214,274)	$ (2,076,590)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 2,914,225	$ 1,086,191	$ 1,086,218	$ 1,086,218	$ 1,086,138	$ 1,086,218	$ 1,025,250	$ 9,370,456
65											
66											

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
<u>Demand Volumes</u>

		Peak	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagra Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline									
	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline		33371	4,000	4,000	4,000	4,000	4,000	4,000
	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
	Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline (Concord Lateral)		72694 Z6-Z6	4,000	4,000	4,000	4,000	4,000	4,000
	Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
	ANE (TransCanada via Union to Iroquois)		Union Dawn to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
	National Fuel	peak	FST 2358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking									
	Tenn Gas Pipeline (Concord Lateral)	peak		26,000	26,000	26,000	26,000	26,000	26,000
	Granite Ridge Demand	peak		15,000	15,000	15,000	15,000	15,000	15,000
	DOMAC Liquid Demand Charge	peak	FLS-160	2,843	2,843	2,843	2,843	2,843	0
Storage									
	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
	Honeoye - Capacity	peak	SS-NY	246,240	246,240	246,240	246,240	246,240	246,240
	National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
	National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
	Tenn Gas Pipeline - Demand	peak	FS-MA	21,844	21,844	21,844	21,844	21,844	21,844
	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Demand Rates

				Nov-10	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**Nov - Apr**
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagra Supply										
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6 5971	31st Rev Sheet No. 4	$0.2199	$0 2128	$0.2128	$0.2356	$0.2128	$0 2199	$0.2190
Tenn Gas Pipeline	33371 Segment 3	$5 0700	1st Rev Sheet No. 30	$0.1690	$0.1635	$0.1635	$0.1811	$0.1635	$0.1690	$0.1683
Tenn Gas Pipeline	33371 Segment 4	$5 5400	1st Rev Sheet No. 30	$0.1847	$0.1787	$0.1787	$0.1979	$0.1787	$0.1847	$0.1839
		$10 6100		$0.3537	$0 3423	$0.3423	$0.3789	$0.3423	$0 3537	$0.3522
Tenn Gas Pipeline	2302 Z5-Z6	$4 9300	1st Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
Tenn Gas Pipeline	8587 Z0-Z6	$16 5900	1st Rev Sheet No. 23	$0.5530	$0 5352	$0.5352	$0.5925	$0.5352	$0 5530	$0.5507
Tenn Gas Pipeline	8587 Z1-Z6	$15.1500	1st Rev Sheet No. 23	$0.5050	$0.4887	$0.4887	$0.5411	$0.4887	$0 5050	$0.5029
Tenn Gas Pipeline	8587 Z4-Z6	$5 8900	1st Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
TGP Dracut	42076 FTA Z6-Z6	$3.1600	1st Rev Sheet No. 23	$0.1053	$0.1019	$0.1019	$0.1129	$0.1019	$0.1053	$0.1049
TGP Concord Lateral	72694 Z6-Z6	$12.1700	per contract	$0.4057	$0 3926	$0.3926	$0.4346	$0.3926	$0.4057	$0.4040
Portland Natural Gas	FT-1999-001	$27.4017	7th Rev Sheet No. 100	$0.9134	$0 8839	$0.8839	$0.9786	$0.8839	$0 9134	$0.9095
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$5 8900	1st Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$5 8900	1st Rev Sheet No. 23	$0.1963	$0.1900	$0.1900	$0.2104	$0.1900	$0.1963	$0.1955
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$4 9300	1st Rev Sheet No. 23	$0.1643	$0.1590	$0.1590	$0.1761	$0.1590	$0.1643	$0.1636
National Fuel	FST 2358	$3 3612	136th Rev Sheet No. 9	$0.1120	$0.1084	$0.1084	$0.1200	$0.1084	$0.1120	$0.1116
ANE TransCanada PipeLines Limited		$10 8267	Union Dawn to Iroquois							
Delivery Pressure Demand Charge		0.7857	Union Dawn to Iroquois							
Sub Total Demand Charges		11 6124								
Conversion rate GJ to MMBTU		1 0551								
Conversion rate to US$		0 9697	08/17/2010							
Demand Rate/US$		$11 8810		$0.3960	$0 3833	$0.3833	$0.4243	$0.3833	$0 3960	$0.3944
Peaking										
Granite Ridge Demand			per contract							
DOMAC Demand FLS-160			per contract							
Storage										
Dominion - Demand	GSS 300076	$1 8773	36th Rev Sheet No. 35	$0.0626	$0 0606	$0.0606	$0.0670	$0.0606	$0 0626	$0.0623
Dominion - Capacity	GSS 300076	$0 0145	36th Rev Sheet No. 35	$0.0005	$0 0005	$0.0005	$0.0005	$0.0005	$0 0005	$0.0005
		$1 8918		$0.0631	$0 0610	$0.0610	$0.0676	$0.0610	$0 0631	$0.0627
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0 2071	$0.2071	$0.2292	$0.2071	$0 2140	$0.2129
National Fuel - Demand	FSS-1 2357	$2.1556	17th Rev. Sheet No. 10	$0.0719	$0 0695	$0.0695	$0.0770	$0.0695	$0 0719	$0.0715
National Fuel - Capacity	FSS-1 2357	$0 0432	17th Rev. Sheet No. 10	$0.0014	$0 0014	$0.0014	$0.0015	$0.0014	$0 0014	$0.0014
		$2.1988		$0.0733	$0 0709	$0.0709	$0.0785	$0.0709	$0 0733	$0.0729
Tenn Gas Pipeline	FS-MA	$1.1500	1st Rev Sheet No. 61	$0.0383	$0 0371	$0.0371	$0.0411	$0.0371	$0 0383	$0.0381
Tenn Gas Pipeline - Space	FS-MA	$0 0185	1st Rev Sheet No. 61	$0.0006	$0 0006	$0.0006	$0.0007	$0.0006	$0 0006	$0.0006
		$1.1685		$0.0390	$0 0377	$0.0377	$0.0417	$0.0377	$0 0390	$0.0388

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APPLICABLE TO SETTLING PARTIES PURSUANT TO THE MARCH 29, 2005, STIPULATION
IN DOCKET NOS. RP97-406, RP00-15, RP00-344 and RP00-632
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE SHEET 35A)

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
===	Storage Demand	$1.7984	$0.0664	$0.0219	($0.0118)	$0.0024	-	$1.8773
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0005	-	-	$0.0051
	Demand Charge Adjustment	$21.5808	$0.7968	$0.2628	($0.1416)	$0.0288	-	$22.5276
	From Customers Balance	$0.6163	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$0.6346
GSS-E [2], [4]								
===	Storage Demand	$2.2113	$0.0664	$0.0219	($0.0118)	$0.0024	-	$2.2902
	Storage Capacity	$0.0369	-	-	-	-	-	$0.0369
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	Authorized Overruns	$1.0657	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$1.0840
ISS [2]								
======	ISS Capacity	$0.0736	$0.0022	$0.0007	($0.0004)	$0.0001	-	$0.0762
	Injection Charge	$0.0154	-	$0.0066	$0.0001	($0.0011)	-	$0.0210
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0011)	$0.0019	$0.0163
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0147	$0.0048	($0.0025)	($0.0006)	$0.0019	$0.6346
	Excess Injection Charge	$0.2245	-	$0.0066	$0.0001	($0.0011)	-	$0.2301

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.28% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 2.56%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6183.
Daily Capacity Release Rate for GSS-E per Dt is $1.0677.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

Issued by: Machelle Grim, Director - Regulation & FERC Compliance
Issued on: September 30, 2009 Effective on: November 1, 2009

subject to an allowable variation of not more than one percent above or below the aggregate of said scheduled daily deliveries of said month.

The amount of gas in storage for Buyer's account at any time (exclusive of Buyer's share of cushion gas) shall be Buyer's Gas Storage Balance at that time and shall not exceed Buyer's Maximum Quantity Stored (MQS).

Seller shall be ready at all times to deliver to Buyer, and Buyer shall have the right at all times to receive from Seller, natural gas up to the MDWQ Seller is obligated to deliver to Buyer on that day.

Buyer's MQS, Buyer's MDWQ and Buyer's ADWQ shall be specified in the Gas Storage Agreement providing for service under this Rate Schedule.

3. RATE

Buyer shall pay Seller for each month of the year during the term of the Gas Storage Agreement a Demand Charge which shall be six dollars and forty one point eight seven cents per MMBTU ($6.4187/MMBTU)** multiplied by the ADWQ as provided for in the Gas Storage Agreement.

4. MINIMUM BILL

The Minimum Bill for each month shall consist of the Demand Charge for the ADWQ as defined in Article 3.

5. COMPRESSOR FUEL ALLOWANCE

Buyer will make available without charge to Seller such additional quantities of gas as needed by Seller for

** The Demand Charge Rate set forth in individual service agreements shall be deemed to have been converted to a thermal billing basis utilizing a factor of 1022/MMBTU per 1 MCF as adjusted pursuant to Section III of the General Terms & Conditions, provided however, the total Maximum Quantity Stored in the field shall not exceed 4.8 BCF and provided that each Buyer shall receive its allowable share of same.

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/: Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 1/ (5)
IT	Commodity	(Max)	$0.1168	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0000	0.0019	$0.0019
IG	Commodity	(Max)	0.3400	-	$0.3400
		(Min)	0.0069	-	$0.0069
FG	Reservation	(Max)	0.0000	-	$0.0000
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0069	0.0019	$0.0088
		(Min)	0.0069	0.0019	$0.0088
	Overrun	(Max)	0.3400	0.0019	$0.3419
		(Min)	0.3400	0.0019	$0.3419
X-58 Conversion Surcharge					
	Reservation	(Max)	0.1221	-	$0.1221
		(Min)	-	-	-
	Commodity	(Max)	-	-	-
		(Min)	-	-	-
W-1	Commodity	(Max)	0.0252	0.0019	$0.0271
		(Min)	0.0000	-	$0.0000
	Overrun	(Max)	0.0252	0.0019	$0.0271
		(Min)	0.0000	-	$0.0000
	Fly-By Rate	(Max)	0.0100	-	$0.0100
		(Min)	0.0000	-	$0.0000
IR-1	First Day	(Max)	0.0532	0.0019	$0.0551
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
IR-2	First Day	(Max)	0.0028	-	$0.0028
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0028	-	$0.0028
	Day	(Min)	0.0000	-	$0.0000
FST	Reservation	(Max)	3.3612	-	$3.3612
		(Min)	0.0000	-	$0.0000
	Commodity	(Max)	0.0063	0.0019	$0.0082
		(Min)	0.0063	0.0019	$0.0082
	Overrun	(Max)	0.1168	0.0019	$0.1187
		(Min)	0.0063	0.0019	$0.0082
	Maximum Volumetric Rate		0.1168	0.0019	$0.1187

1/ All rates exclusive of Fuel and Company Use retention and Transportation LAUF retention. Fuel and Company Use retention for all applicable rate schedules is 1.15%. Transportation LAUF retention for all applicable rate schedules is 0.25%. Transporter may from time to time identify point pair transactions where the Fuel and Company Use retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the Transportation LAUF retention of 0.25%.

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 2/ (5)
ESS	Demand	(Max)	$2.1345	-	$2.1345
		(Min)	0.0000	-	$0.0000
	Capacity	(Max)	0.0432	-	$0.0432
		(Min)	0.0000	-	$0.0000
	Injection/	(Max)	0.0139	0.0019	$0.0158
	Withdrawal	(Min)	0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/		0.0702	0.0019	$0.0721
	Max. Volumetric Cap. Rate 4/		0.0014	-	$0.0014
	Storage Balance Transfer	(Max) 5/	3.8600	-	$3.8600
		(Min) 5/	0.0000	-	$0.0000
ISS	Injection	(Max)	1.0635	0.0019	$1.0654
		(Min)	0.0000	-	$0.0000
	Storage Balance Transfer	(Max) 5/	3.8600	-	$3.8600
		(Min) 5/	0.0000	-	$0.0000
IAS	Usage	(Max) 1/	0.0028	-	$0.0028
		(Min) 1/	0.0000	-	$0.0000
	Advance/Return	(Max)	0.0139	0.0019	$0.0158
		(Min)	0.0000	-	$0.0000
FSS	Demand	(Max)	2.1556	-	$2.1556
		(Min)	0.0000	-	$0.0000
	Capacity	(Max)	0.0432	-	$0.0432
		(Min)	0.0000	-	$0.0000
	Injection/	(Max)	0.0139	0.0019	$0.0158
	Withdrawal	(Min)	0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 3/		0.0709	0.0019	$0.0728
	Max. Volumetric Cap. Rate 4/		0.0014	-	$0.0014
	Storage Balance Transfer	(Max) 5/	3.8600	-	$3.8600
		(Min) 5/	0.0000	-	$0.0000
P-1	First Day	(Max)	0.0575	0.0019	$0.0594
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0071	-	$0.0071
	Day	(Min)	0.0000	-	$0.0000
P-2	First Day	(Max)	0.0071	-	$0.0071
		(Min)	0.0000	-	$0.0000
	Each Subsequent	(Max)	0.0071	-	$0.0071
	Day	(Min)	0.0000	-	$0.0000

1/ Unit Dth Rates per day.
2/ All rates exclusive of Surface Operating Allowance and Storage LAUF retention, where applicable. Surface Operating Allowance for all applicable rate schedules is 1.17%. Storage LAUF retention for all applicable rate schedules is 0.23%.
3/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
4/ Assessed per dekatherm per day on storage balance.
5/ Rate per nomination.

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

-- Maximum $27.4017 --------- $27.4017

-- Minimum $00.0000 --------- $00.0000

Seasonal Recourse Reservation Rate

-- Maximum $52.0632 --------- $52.0632

-- Minimum $00.0000 --------- $00.0000

Recourse Usage Rate

-- Maximum $00.0000 $00.0019 $00.0019

-- Minimum $00.0000 $00.0019 $00.0019

FT-FLEX Recourse Reservation Rate

--Maximum $18.3920 ------- $18.3920

--Minimum $00.0000 ------- $00.0000

Recourse Usage Rate

--Maximum $00.2962 $00.0019 $00.2981

--Minimum $00.0000 $00.0019 $00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum down to -1.00%

Maximum up to +1.00%

____

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

	RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
PCB Adjustment: 1/	0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	L		$0.00						
	1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth

Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 105.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
RATE SCHEDULE IS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA					
Space Rate	$0.0848		$0.0000	$0.0848	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA					
Space Rate	$0.0993		$0.0000	$0.0993	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

TransCanada
In business to deliver

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injec ions, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interrupt ble Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

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RATES AND STATISTICS

Exchange Rates

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Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 17 Aug 2010

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	from $Can / to $Can
Use the:	Nominal rate HELP Cash rate (4%) HELP
Answer:	0.97 CONVERT
Exchange rate:	0.9697

Summary:

On 17 Aug 2010, 1.00 Canadian dollar(s) = 0.97 U.S. dollar(s), at an exchange rate of 0.9697 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:

10-Year Currency Converter

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Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses that are denominated in foreign currencies.

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Done Internet

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln									
5									Peak
6	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas**								
12	Dawn Supply	ln 63 * ln 102							
13	Niagara Supply	ln 64 * ln 107							
14	TGP Supply (Direct)	ln 65 * ln 123							
15	Dracut Supply 1 - Baseload	ln 66 * ln 112							
16	Dracut Supply 2 - Swing	ln 67 * ln 117							
17	City Gate Delivered Supply	ln 68 * ln 129							
18	LNG Truck	ln 69 * ln 131							
19	Propane Truck	ln 70 * ln 133							
20	PNGTS	ln 71 * ln 138							
21	Granite Ridge	ln 72 * ln 143							
22									
23	Subtotal Pipeline Gas Costs		$ 5,602,107	$ 6,701,736	$ 7,654,721	$ 6,663,481	$ 6,960,911	$ 5,712,047	$ 39,295,003
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 63 * ln 190							
27	Niagara Supply	ln 64 * ln 201							
28	TGP Supply (Direct)	ln 65 * ln 228							
29	Dracut Supply 1 - Baseload	ln 66 * ln 249							
30	Dracut Supply 2 - Swing	ln 67 * ln 249							
31	City Gate Delivered Supply	ln 68 * ln 249							
32	TGP Storage - Withdrawals	ln 77 * ln 165							
33									
34	**Total Volumetric Transportation Costs**		$ 358,499	$ 483,769	$ 519,956	$ 460,549	$ 418,429	$ 289,200	$ 2,530,401
35									
36	**Less - Gas Refill**								
37	LNG Truck	ln 86 * ln 150							
38	Propane	ln 87 * ln 151							
39	TGP Storage Refill	ln 88 * ln 121							
40	Storage Refill (Trans.)	ln 88 * ln 228							
41									
42	Subtotal Refills		$ (332,808)	$ (31,481)	$ (261,284)	$ (95,386)	$ (22,967)	$ (1,997,728)	$ (2,741,654)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 5,627,797	$ 7,154,024	$ 7,913,393	$ 7,028,644	$ 7,356,373	$ 4,003,518	$ 39,083,750
45									
46	**Storage Gas**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 56,636	$ 2,215,221	$ 2,786,813	$ 2,424,305	$ 166,492	$ -	$ 7,649,468
48									
49	**Produced Gas**								
50	LNG Vapor	ln 80 * ln 145							
51	Propane	ln 81 * ln 147							
52									
53	**Total Produced Gas**	ln 50 + ln 51	$ 12,010	$ 12,177	$ 912,545	$ 296,084	$ 11,540	$ 11,142	$ 1,255,498
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 5,696,443	$ 9,381,422	$ 11,612,752	$ 9,749,033	$ 7,534,405	$ 4,014,660	$ 47,988,716
57									
58					**THIS PAGE HAS BEEN REDACTED**				

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									Peak
5									Peak
6	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
59									
60	**Volumes (Therms)**								
61									
62	**Pipeline Gas**	See Schedule 11A							
63	Dawn Supply		992,558	985,941	1,025,643	870,970	1,025,643	992,558	5,893,314
64	Niagara Supply		66,998	675,767	728,703	624,485	800,664	31,431	2,928,047
65	TGP Supply (Direct)		5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699	30,809,005
66	Dracut Supply 1 - Baseload		-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
67	Dracut Supply 2 - Swing		5,541,783	367,247	308,520	348,222	6,430,123	6,676,608	19,672,503
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		23,160	23,987	535,154	196,030	47,974	-	826,305
70	Propane Truck		-	-	-	-	-	-	-
71	PNGTS		65,343	80,232	86,022	75,269	72,788	55,418	435,071
72	Granite Ridge		-	-	-	-	-	-	-
73									
74	Subtotal Pipeline Volumes		11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713	76,795,052
75									
76	**Storage Gas**								
77	TGP Storage		96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
78									
79	**Produced Gas**								
80	LNG Vapor		23,160	23,987	588,918	196,030	23,987	23,160	879,241
81	Propane		-	-	426,800	137,304	-	-	564,104
82									
83	Subtotal Produced Gas		23,160	23,987	1,015,718	333,334	23,987	23,160	1,443,345
84									
85	**Less - Gas Refill**								
86	LNG Truck		(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-	(826,305)
87	Propane		-	-	-	-	-	-	-
88	TGP Storage Refill		(645,163)	(38,048)	-	-	-	(3,882,557)	(4,565,768)
89									
90	Subtotal Refills		(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)	(5,392,072)
91									
92	**Total Sendout Volumes**		11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143
93									
94									
95									

Line	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov- Apr
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								Average Rate
97									
98	**Pipeline Gas**								
99	**Dawn Supply**								
100	NYMEX Price	Sch 7, ln 10/10							
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, ln 10/10							
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10							
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10							
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, ln 10/10							
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, ln 10/10							
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, ln 10/10	**$0.4479**	**$0.4743**	**$0.4882**	**$0.4866**	**$0.4787**	**$0.4667**	**$0.4738**
132									
133	**Propane Truck**	NYMEX - Propane	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
134									
135	**PNGTS**								
136	NYMEX Price	Sch 7, ln 10/10							
137	Additional Cost								
138	**Net Commodity Cost**								
139									
140	**Granite Ridge**								
141	NYMEX Price	Sch 7, ln 10/10							
142	Additional Cost								
143	**Net Commodity Cost**								
144									
145	**LNG Vapor (Storage)**	Sch 16, ln 122 /10	**$0.5186**	**$0.5076**	**$0.4906**	**$0.4869**	**$0.4811**	**$0.4811**	**$0.4943**
146									
147	**Propane**	Sch 16, ln 84 /10	**$1.4612**	**$1.4612**	**$1.4612**	**$1.4612**	**$1.4612**	**$1.4612**	**$1.4612**
148									
149	**Storage Refill**								
150	**LNG Truck**	ln 131	**$0.4479**	**$0.4743**	**$0.4882**	**$0.4866**	**$0.4787**	**$0.4667**	**$0.4943**
151	**Propane**	ln 133	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$1.4612**
152									
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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

5									Peak
6	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									
155									Average Rate
156	**TGP Storage**								
157	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.5852	$0.5851	$0 5851	$0.5851	$0.5851	$0.5851	$0.5852
158									
159	TGP - Max Commodity - Z 4-6	Original Sheet No. 24	$0 00834	$0.00834	$0.00834	$0.00834	$0.00834	$0 00834	$0.00834
160	TGP - Max Comm. ACA Rate - Z 4-6	Original Sheet No. 24	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0 00853	$0.00853	$0.00853	$0.00853	$0.00853	$0 00853	$0.00853
162	TGP - Fuel Charge % - Z 4-6	Original Sheet No. 32	2.17%	2.17%	2.17%	2.17%	2.17%	1 92%	2.13%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0 01270	$0.01270	$0.01270	$0.01270	$0.01270	$0 01123	$0.01245
164	TGP - Withdrawal Charge	1st Rev Sheet No. 61	$0 00102	$0.00102	$0.00102	$0.00102	$0.00102	$0 00102	$0.00102
165	**Total Volumetric Transportation Rate - TGP (Storage)**		$0 02225	$0.02225	$0.02225	$0.02225	$0.02225	$0 02078	$0.02200
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.60748**	**$0.60739**	**$0.60739**	**$0.60739**	**$0.60739**	**$0.60593**	**$0.60716**
168									
169									
170	**Per Unit Volumetric Transportation Rates**								
171	**Dawn Supply Volumetric Transportation Charge**								
172	**Commodity Costs**	ln 102	**$0.4889**	**$0.5073**	**$0.5102**	**$0.5136**	**$0.5047**	**$0.4967**	**$0.5036**
173									
174	TransCanada - Commodity Rate/GJ	Union Dawn to Iroquois	$0 00141	$0.00141	$0.00141	$0.00141	$0.00141	$0 00141	$0.00141
175	Conversion Rate GL to MMBTU		1.0551	1.0551	1 0551	1 0551	1.0551	1.0551	1.0551
176	Conversion Rate to US$	08/17/2010	0.9697	0.9697	0.9697	0 9697	0.9697	0.9697	0.9697
177	Commodity Rate/US$	ln 174 x ln 175 x ln 176	$0 00145	$0.00145	$0.00145	$0.00145	$0.00145	$0 00145	$0.00145
178	TransCanada Fuel %	Union Dawn to Iroquois	1 00%	1.63%	1.41%	1.62%	1.60%	1.47%	1.46%
179	TransCanada Fuel * Percentage	ln 172 x ln 178	$0 00489	$0.00827	$0.00719	$0.00832	$0.00808	$0 00730	$0.00734
180	Subtotal TransCanada		**$0.00633**	**$0.00972**	**$0.00864**	**$0.00977**	**$0.00952**	**$0.00875**	**$0.00879**
181	IGTS - Z1 RTS Commodity	31st Rev Sheet No. 4	$0 00030	$0.00030	$0.00030	$0.00030	$0.00030	$0 00030	$0.00030
182	IGTS - Z1 RTS ACA Rate Commodity	24th Rev Sheet 4A	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
183	IGTS - Z1 RTS Deferred Asset Surcharge	24th Rev Sheet 4A	$0 00003	$0.00003	$0.00003	$0.00003	$0.00003	$0 00003	$0.00003
184	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**	**$0.00052**
185	TGP NET-NE - Comm. Segments 3 & 4	1st Rev Sheet No. 30	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
186	IGTS -Fuel Use Factor - Percentage	24th Rev Sheet 4A	1 00%	1.00%	1.00%	1.00%	1.00%	1 00%	1.00%
187	IGTS -Fuel Use Factor - Fuel * Percentage	ln 172 x ln 186	**$0.00489**	**$0.00507**	**$0.00510**	**$0.00514**	**$0.00505**	**$0.00497**	**$0.00504**
188	TGP NET-284 - Fuel Charge % Z 4-6	Original Sheet No. 105	1 54%	1.54%	1.54%	1.54%	1.54%	1 54%	1.54%
189	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 172 x ln 188	**$0.00753**	**$0.00781**	**$0.00786**	**$0.00791**	**$0.00777**	**$0.00765**	**$0.00776**
190	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01946**	**$0.02331**	**$0.02231**	**$0.02352**	**$0.02305**	**$0.02207**	**$0.02229**
191									
192									
193	**Niagara Supply Volumetric Transportation Charge**								
194	**Commodity Costs**	Ln 107							
195									
196	TGP FTA - FTA Z 5-6 Comm. Rate	Original Sheet No. 24							
197	TGP FTA - FTA Z 5-6 - ACA Rate	Original Sheet No. 24							
198	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
199	TGP FTA Fuel Charge % Z 5-6	Original Sheet No. 32							
200	TGP FTA Fuel * Percentage	ln 194 x ln 199							
201	**Total Volumetric Transportation Rate - Niagra Supply**								
202									
203									
204					**THIS PAGE HAS BEEN REDACTED**				

Line	For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov- Apr
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
205									
206									
207	**TGP Direct Volumetric Transportation Charge**								Average Rate
208	**Commodity Costs**	Ln 121	**$0.4479**	**$0.4743**	**$0.4882**	**$0.4866**	**$0.4787**	**$0.4667**	**$0.4738**
209									
210	TGP - Max Comm. Base Rate - Z 0-6	Original Sheet No. 24	$0 01608	$0.01608	$0.01608	$0.01608	$0.01608	$0 01608	$0.01608
211	TGP - Max Commodity ACA Rate - Z 0-6	Original Sheet No. 24	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
212	Subtotal TGP - Max Comm. Rate Z 0-6		$0 01627	$0.01627	$0.01627	$0.01627	$0.01627	$0 01627	$0.01627
213	Prorated Percentage		32 60%	32.60%	32.60%	32.60%	32.60%	32 60%	32.60%
214	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**	**$0.00530**
215	TGP - Max Comm. Base Rate - Z 1-6	Original Sheet No. 24	$0 01503	$0.01503	$0.01503	$0.01503	$0.01503	$0 01503	$0.01503
216	TGP - Max Commodity ACA Rate - Z 1-6	Original Sheet No. 24	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
217	Subtotal TGP - Max Commodity Rate - Z 1-6		$0 01522	$0.01522	$0.01522	$0.01522	$0.01522	$0 01522	$0.01522
218	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
219	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**	**$0.01026**
220	TGP - Fuel Charge % - Z 0 -6	Original Sheet No. 32	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.50%
221	Prorated Percentage		32.6%	32.6%	32 6%	32 6%	32.6%	32.6%	32.6%
222	Prorated TGP Fuel Charge % - Z 0-6		2 84%	2.84%	2.84%	2.84%	2.84%	2.42%	2.77%
223	TGP - Fuel Charge % - Z 1 -6	Original Sheet No. 32	7 82%	7.82%	7.82%	7.82%	7.82%	6 67%	7.63%
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		5 27%	5.27%	5.27%	5.27%	5.27%	4 50%	5.14%
226	TGP - Fuel Charge % - Z 0-6	ln 208 x ln 222	**$0.01272**	**$0.01347**	**$0.01386**	**$0.01382**	**$0.01359**	**$0.01129**	**$0.01312**
227	TGP - Fuel Charge % - Z 1-6	ln 208 x ln 225	**$0.02361**	**$0.02500**	**$0.02573**	**$0.02565**	**$0.02523**	**$0.02098**	**$0.02437**
228	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.05189**	**$0.05403**	**$0.05516**	**$0.05503**	**$0.05439**	**$0.04783**	**$0.05305**
229									
230	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
231	**Commodity Costs**	Ln 121	**$0.4479**	**$0.4743**	**$0.4882**	**$0.4866**	**$0.4787**	**$0.4667**	**$0.4738**
232									
233	TGP - Max Comm. Base Rate - Z 6-6	Original Sheet No. 24	$0 00642	$0.00642	$0.00642	$0.00642	$0.00642	$0 00642	$0.00642
234	TGP - Max Commodity ACA Rate - Z 6-6	Original Sheet No. 24	$0 00019	$0.00019	$0.00019	$0.00019	$0.00019	$0 00019	$0.00019
235	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**	**$0.00661**
236	TGP - Fuel Charge % - Z 6-6	Original Sheet No. 32	0 89%	0.89%	0.89%	0.89%	0.89%	0 85%	0.88%
237	TGP - Fuel Charge	ln 231 x ln 236	**$0.00399**	**$0.00422**	**$0.00435**	**$0.00433**	**$0.00426**	**$0.00397**	**$0.00419**
238	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.01060**	**$0.01083**	**$0.01096**	**$0.01094**	**$0.01087**	**$0.01058**	**$0.01080**
239									
240									
241	**TGP Dracut**								
242	**Commodity Costs - NYMEX Price**	Ln 112							
243									
244	TGP - Trans Charge - Comm. - Z 6-6	Original Sheet No. 24							
245	TGP - Trans Charge - ACA Rate - Z6-6	Original Sheet No. 24							
246	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
247	TGP - Fuel Charge % - Z 6-6	Original Sheet No. 32							
248	TGP - Fuel Charge	ln 242 x ln 247							
249	**Total Volumetric Transportation Rate - TGP Dracut**								
250									
251									

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--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:		
Commodity	0.0019	
DEFERRED ASSET SURCHARGE:		
Commodity		
Zone 1	0.0003	
Zone 2	0.0002	
Inter-Zone	0.0005	
MEASUREMENT VARIANCE/FUEL USE FACTOR:		
Minimum		0.00%
Maximum (Non-Eastchester Shipper)		1.00%
Maximum (Eastchester Shipper)		4.50%
Maximum (Brookfield Shipper)		1.20%

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary
Issued on: Sep 30, 2009 Effective: Nov 01, 2009

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 105.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
RATE SCHEDULE IS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(PCB) 2/	Current Adjustment	Retention Percent 1/
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA					
Space Rate	$0.0848		$0.0000	$0.0848	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA					
Space Rate	$0.0993		$0.0000	$0.0993	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

NET-284 RATE SCHEDULE (continued)

5. FUEL AND USE (continued)

Shipper	Transportation Quantity (Dth)	Segments U	1	2	3	4	Fuel and Use
Bay State (from Granite) - Pleasant St.	3,706				*	*	1.26%
Bay State (from Granite) - Agawam	6,068				*		0.96%
Boston Gas d/b/a National Grid	35,000				*	*	1.31%
Boston Gas d/b/a National Grid	8,600				*	*	1.31%
Barclays Bank PLC	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc. d/b/a National Grid	4,000				*	*	1.54%
Essex Gas Company d/b/a National Grid	2,000				*	*	1.44%
Iroquois Gas Transmission (Connecticut Natural, Yankee Gas)	37,000				*		0.68%
Lockport Energy Associates	13,184	*	*				6.21%
New York State Electric & Gas Corp	14,816	*	*				6.21%
Northern Utilities (from Granite) Pleasant St.	844				*	*	1.26%
Northern Utilities (from Granite) Agawam	1,382				*		0.96%
The Narragansett Electric Company d/b/a National Grid	1,000				*	*	1.25%
Yankee Gas Services Company (Wright)	9,000				*		1.07%
Total	150,610						

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FT-G

Base Commodity Rate

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0458		$0.0688	$0.0889	$0.0997	$0.1137	$0.1250	$0.1627
L		$0.0305						
1	$0.0688		$0.0591	$0.0795	$0.0893	$0.1033	$0.1145	$0.1522
2	$0.0899		$0.0795	$0.0452	$0.0549	$0.0700	$0.0802	$0.1178
3	$0.0997		$0.0893	$0.0549	$0.0385	$0.0682	$0.0784	$0.1161
4	$0.1148		$0.1044	$0.0700	$0.0682	$0.0420	$0.0478	$0.0853
5	$0.1250		$0.1145	$0.0802	$0.0784	$0.0478	$0.0446	$0.0784
6	$0.1627		$0.1522	$0.1178	$0.1161	$0.0853	$0.0784	$0.0661

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable fuel retention percentages are listed on Sheet No. 32, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

TransCanada
In business to deliver

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injec ions, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interrupt ble Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

TransCanada Fuel Ratios

November 2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.3010**	**1.00**	0.31

December 2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.3010**	**1.63**	0.94

January 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.4070**	**1.41**	0.72

February 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

http://www.transcanada.com/Mainline/

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.4070**	**1.62**	0.93

March 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

http://www.transcanada.com/Mainline/

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.4070**	**1.60**	0.91

April 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

http://www.transcanada.com/Mainline/

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	**0.4070**	**1.47**	0.78

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Ln	For Month of: (a)	Reference (b)	Nov-10 (c)	Dec-10 (d)	Jan-11 (e)	Feb-11 (f)	Mar-11 (g)	Apr-11 (h)	Peak Strip Average (i)
8	**I. NYMEX Opening Prices as of:**								
9	Opening Prices (15 day average)		4.4789	4.7433	4.8824	4.8659	4.7875	4.6671	$ 4.7375
10	NYMEX	ln 273	4.4789	4.7433	4.8824	4.8659	4.7875	4.6671	$ 4.7375
11	December Trigger								
12	January Trigger								
13	February Trigger								
14	March Trigger								
15	April Trigger								
16									
17									
18									
19									
20	**II. Development of Hedging Costs and Savings**								
21									
22	**TGP (Direct) Volumes**								Total
23	Hedged Volumes (Dth)	ln 107	350,000	860,000	1,000,000	970,000	610,000	180,000	3,970,000
24	Market Priced Volumes (Dth)		840,160	449,184	317,786	210,400	769,408	996,430	3,583,368
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10	1,190,160	1,309,184	1,317,786	1,180,400	1,379,408	1,176,430	7,553,368
26									
27									Weighted Average
28	Hedge Price	ln 242	$ 5.9050	$ 6.1622	$ 6.3271	$ 6.2749	$ 6.1761	$ 6.4812	$ 6.2252
29	NYMEX Price	ln 10	$ 4.4789	$ 4.7433	$ 4.8824	$ 4.8659	$ 4.7875	$ 4.6671	$ 4.7883
30									
31	Hedged Volumes at Hedged Price	ln 23 * ln 28	$ 2,066,746	$ 5,299,451	$ 6,327,124	$ 6,086,690	$ 3,767,446	$ 1,166,608	$ 24,714,066
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29	1,567,603	4,079,267	4,882,400	4,719,891	2,920,355	840,072	19,009,587
33									
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32	$ 499,143	$ 1,220,185	$ 1,444,724	$ 1,366,799	$ 847,092	$ 326,536	$ 5,704,479
35									
36	Total Financial Hedge	ln 23	3,500,000	8,600,000	10,000,000	9,700,000	6,100,000	1,800,000	39,700,000
37	Total Underground Storage	Sch 6, Ln 77	96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
38	Sub Total		3,596,774	12,385,782	14,762,625	13,843,103	6,384,533	1,800,000	52,772,818
39	Total Throughput	Sch 6, ln 92	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143
40	Hedge Percentage	ln 38 / ln 39	31%	73%	78%	85%	45%	23%	61%

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line						Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Strip Average
5												
6	For Month of:				Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41												
42	Hedged Volumes (Dth)											
43	Hedge #	1	Trade Date	15-May-09	Swaps							
44	Hedge #	2	Trade Date	15-May-09	Swaps							
45	Hedge #	3	Trade Date	29-May-09	Swaps							
46	Hedge #	4	Trade Date	29-May-09	Swaps							
47	Hedge #	5	Trade Date	12-Jun-09	Swaps							
48	Hedge #	6	Trade Date	12-Jun-09	Swaps							
49	Hedge #	7	Trade Date	25-Jun-09	Swaps							
50	Hedge #	8	Trade Date	25-Jun-09	Swaps							
51	Hedge #	9	Trade Date	10-Jul-09	Swaps							
52	Hedge #	10	Trade Date	10-Jul-09	Swaps							
53	Hedge #	11	Trade Date	27-Jul-09	Swaps							
54	Hedge #	12	Trade Date	27-Jul-09	Swaps							
55	Hedge #	13	Trade Date	07-Aug-09	Swaps							
56	Hedge #	14	Trade Date	07-Aug-09	Swaps							
57	Hedge #	15	Trade Date	21-Aug-09	Swaps							
58	Hedge #	16	Trade Date	21-Aug-09	Swaps							
59	Hedge #	17	Trade Date	11-Sep-09	Swaps							
60	Hedge #	18	Trade Date	11-Sep-09	Swaps							
61	Hedge #	19	Trade Date	25-Sep-09	Swaps							
62	Hedge #	20	Trade Date	25-Sep-09	Swaps							
63	Hedge #	21	Trade Date	09-Oct-09	Swaps							
64	Hedge #	22	Trade Date	09-Oct-09	Swaps							
65	Hedge #	23	Trade Date	23-Oct-09	Swaps							
66	Hedge #	24	Trade Date	23-Nov-09	Swaps							
67	Hedge #	25	Trade Date	30-Nov-09	Swaps							
68	Hedge #	26	Trade Date	30-Nov-09	Swaps							
69	Hedge #	27	Trade Date	30-Nov-09	Swaps							
70	Hedge #	28	Trade Date	14-Dec-09	Swaps							
71	Hedge #	29	Trade Date	14-Dec-09	Swaps							
72	Hedge #	30	Trade Date	30-Dec-09	Swaps							
73	Hedge #	31	Trade Date	30-Dec-09	Swaps							
74	Hedge #	32	Trade Date	15-Jan-10	Swaps							
75	Hedge #	33	Trade Date	15-Jan-10	Swaps							
76	Hedge #	34	Trade Date	29-Jan-10	Swaps							
77	Hedge #	35	Trade Date	29-Jan-10	Swaps							
78	Hedge #	36	Trade Date	12-Feb-10	Swaps							
79	Hedge #	37	Trade Date	12-Feb-10	Swaps							
80	Hedge #	38	Trade Date	26-Feb-10	Swaps							
81	Hedge #	39	Trade Date	26-Feb-10	Swaps							
82	Hedge #	40	Trade Date	12-Mar-10	Swaps							
83	Hedge #	41	Trade Date	12-Mar-10	Swaps							
84	Hedge #	42	Trade Date	26-Mar-10	Swaps							
85	Hedge #	43	Trade Date	26-Mar-10	Swaps							
86	Hedge #	44	Trade Date	09-Apr-10	Swaps							
87	Hedge #	45	Trade Date	09-Apr-10	Swaps							
88	Hedge #	46	Trade Date	23-Apr-10	Swaps							
89	Hedge #	47	Trade Date	23-Apr-10	Swaps							
90	Hedge #	48	Trade Date	07-May-10	Swaps							
91	Hedge #	49	Trade Date	21-May-10	Swaps							
92	Hedge #	50	Trade Date	21-May-10	Swaps							
93	Hedge #	51	Trade Date	11-Jun-10	Swaps							
94	Hedge #	52	Trade Date	25-Jun-10	Swaps							
95	Hedge #	53	Trade Date	09-Jul-10	Swaps							
96	Hedge #	54	Trade Date	26-Jul-10	Swaps							
97												
98												
99												
100												
101												
102												
103												
104	Subtotal Hedge Volumes					330,000	760,000	870,000	820,000	530,000	180,000	3,490,000
105	Remaining					20,000	100,000	130,000	150,000	80,000	-	480,000
106	Total Volumes					350,000	860,000	1,000,000	970,000	610,000	180,000	3,970,000
107												
108												

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line													Peak
5													Peak
6	For Month of:					Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7			(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
109	Strike Price												Weighted Average
110	Hedge #	1	Trade Date	15-May-09	Swaps								
111	Hedge #	2	Trade Date	15-May-09	Swaps								
112	Hedge #	3	Trade Date	29-May-09	Swaps								
113	Hedge #	4	Trade Date	29-May-09	Swaps								
114	Hedge #	5	Trade Date	12-Jun-09	Swaps								
115	Hedge #	6	Trade Date	12-Jun-09	Swaps								
116	Hedge #	7	Trade Date	25-Jun-09	Swaps								
117	Hedge #	8	Trade Date	25-Jun-09	Swaps								
118	Hedge #	9	Trade Date	10-Jul-09	Swaps								
119	Hedge #	10	Trade Date	10-Jul-09	Swaps								
120	Hedge #	11	Trade Date	27-Jul-09	Swaps								
121	Hedge #	12	Trade Date	27-Jul-09	Swaps								
122	Hedge #	13	Trade Date	07-Aug-09	Swaps								
123	Hedge #	14	Trade Date	07-Aug-09	Swaps								
124	Hedge #	15	Trade Date	21-Aug-09	Swaps								
125	Hedge #	16	Trade Date	21-Aug-09	Swaps								
126	Hedge #	17	Trade Date	11-Sep-09	Swaps								
127	Hedge #	18	Trade Date	11-Sep-09	Swaps								
128	Hedge #	19	Trade Date	25-Sep-09	Swaps								
129	Hedge #	20	Trade Date	25-Sep-09	Swaps								
130	Hedge #	21	Trade Date	09-Oct-09	Swaps								
131	Hedge #	22	Trade Date	09-Oct-09	Swaps								
132	Hedge #	23	Trade Date	23-Oct-09	Swaps								
133	Hedge #	24	Trade Date	23-Nov-09	Swaps								
134	Hedge #	25	Trade Date	30-Nov-09	Swaps								
135	Hedge #	26	Trade Date	30-Nov-09	Swaps								
136	Hedge #	27	Trade Date	30-Nov-09	Swaps								
137	Hedge #	28	Trade Date	14-Dec-09	Swaps								
138	Hedge #	29	Trade Date	14-Dec-09	Swaps								
139	Hedge #	30	Trade Date	30-Dec-09	Swaps								
140	Hedge #	31	Trade Date	30-Dec-09	Swaps								
141	Hedge #	32	Trade Date	15-Jan-10	Swaps								
142	Hedge #	33	Trade Date	15-Jan-10	Swaps								
143	Hedge #	34	Trade Date	29-Jan-10	Swaps								
144	Hedge #	35	Trade Date	29-Jan-10	Swaps								
145	Hedge #	36	Trade Date	12-Feb-10	Swaps								
146	Hedge #	37	Trade Date	12-Feb-10	Swaps								
147	Hedge #	38	Trade Date	26-Feb-10	Swaps								
148	Hedge #	39	Trade Date	26-Feb-10	Swaps								
149	Hedge #	40	Trade Date	12-Mar-10	Swaps								
150	Hedge #	41	Trade Date	12-Mar-10	Swaps								
151	Hedge #	42	Trade Date	26-Mar-10	Swaps								
152	Hedge #	43	Trade Date	26-Mar-10	Swaps								
153	Hedge #	44	Trade Date	09-Apr-10	Swaps								
154	Hedge #	45	Trade Date	09-Apr-10	Swaps								
155	Hedge #	46	Trade Date	23-Apr-10	Swaps								
156	Hedge #	47	Trade Date	23-Apr-10	Swaps								
157	Hedge #	48	Trade Date	07-May-10	Swaps								
158	Hedge #	49	Trade Date	21-May-10	Swaps								
159	Hedge #	50	Trade Date	21-May-10	Swaps								
160	Hedge #	51	Trade Date	11-Jun-10	Swaps								
161	Hedge #	52	Trade Date	25-Jun-10	Swaps								
162	Hedge #	53	Trade Date	09-Jul-10	Swaps								
163	Hedge #	54	Trade Date	26-Jul-10	Swaps								
164													
165													
166													
167													
168													
169													
170													
171	Subtotal Weigthed Average Hedge Prices						$5.9914	$6.3488	$6.5430	$6.5327	$6.3858	$6.4812	6.4191
172	NYMEX						$4.4789	$4.7433	$4.8824	$4.8659	$4.7875	$4.6671	4.8156
173													
174													

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**
5

Line										Peak
6	For Month of:		Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
175	Hedge Dollars									
176	Hedge # 1	Trade Date 15-May-09 Swaps								
177	Hedge # 2	Trade Date 15-May-09 Swaps								
178	Hedge # 3	Trade Date 29-May-09 Swaps								
179	Hedge # 4	Trade Date 29-May-09 Swaps								
180	Hedge # 5	Trade Date 12-Jun-09 Swaps								
181	Hedge # 6	Trade Date 12-Jun-09 Swaps								
182	Hedge # 7	Trade Date 25-Jun-09 Swaps								
183	Hedge # 8	Trade Date 25-Jun-09 Swaps								
184	Hedge # 9	Trade Date 10-Jul-09 Swaps								
185	Hedge # 10	Trade Date 10-Jul-09 Swaps								
186	Hedge # 11	Trade Date 27-Jul-09 Swaps								
187	Hedge # 12	Trade Date 27-Jul-09 Swaps								
188	Hedge # 13	Trade Date 07-Aug-09 Swaps								
189	Hedge # 14	Trade Date 07-Aug-09 Swaps								
190	Hedge # 15	Trade Date 21-Aug-09 Swaps								
191	Hedge # 16	Trade Date 21-Aug-09 Swaps								
192	Hedge # 17	Trade Date 11-Sep-09 Swaps								
193	Hedge # 18	Trade Date 11-Sep-09 Swaps								
194	Hedge # 19	Trade Date 25-Sep-09 Swaps								
195	Hedge # 20	Trade Date 25-Sep-09 Swaps								
196	Hedge # 21	Trade Date 09-Oct-09 Swaps								
197	Hedge # 22	Trade Date 09-Oct-09 Swaps								
198	Hedge # 23	Trade Date 23-Oct-09 Swaps								
199	Hedge # 24	Trade Date 23-Nov-09 Swaps								
200	Hedge # 25	Trade Date 30-Nov-09 Swaps								
201	Hedge # 26	Trade Date 30-Nov-09 Swaps								
202	Hedge # 27	Trade Date 30-Nov-09 Swaps								
203	Hedge # 28	Trade Date 14-Dec-09 Swaps								
204	Hedge # 29	Trade Date 14-Dec-09 Swaps								
205	Hedge # 30	Trade Date 30-Dec-09 Swaps								
206	Hedge # 31	Trade Date 30-Dec-09 Swaps								
207	Hedge # 32	Trade Date 15-Jan-10 Swaps								
208	Hedge # 33	Trade Date 15-Jan-10 Swaps								
209	Hedge # 34	Trade Date 29-Jan-10 Swaps								
210	Hedge # 35	Trade Date 29-Jan-10 Swaps								
211	Hedge # 36	Trade Date 12-Feb-10 Swaps								
212	Hedge # 37	Trade Date 12-Feb-10 Swaps								
213	Hedge # 38	Trade Date 26-Feb-10 Swaps								
214	Hedge # 39	Trade Date 26-Feb-10 Swaps								
215	Hedge # 40	Trade Date 12-Mar-10 Swaps								
216	Hedge # 41	Trade Date 12-Mar-10 Swaps								
217	Hedge # 42	Trade Date 26-Mar-10 Swaps								
218	Hedge # 43	Trade Date 26-Mar-10 Swaps								
219	Hedge # 44	Trade Date 09-Apr-10 Swaps								
220	Hedge # 45	Trade Date 09-Apr-10 Swaps								
221	Hedge # 46	Trade Date 23-Apr-10 Swaps								
222	Hedge # 47	Trade Date 23-Apr-10 Swaps								
223	Hedge # 48	Trade Date 07-May-10 Swaps								
224	Hedge # 49	Trade Date 21-May-10 Swaps								
225	Hedge # 50	Trade Date 21-May-10 Swaps								
226	Hedge # 51	Trade Date 11-Jun-10 Swaps								
227	Hedge # 52	Trade Date 25-Jun-10 Swaps								
228	Hedge # 53	Trade Date 09-Jul-10 Swaps								
229	Hedge # 54	Trade Date 26-Jul-10 Swaps								
230										
231										
232										
233										
234										
235										
236										
237	Subtotal Hedge Dollars			$1,977,169	$4,825,118	$5,692,412	$5,356,810	$3,384,449	$1,166,608	$22,402,566
238	Remaining			89,577	474,333	634,712	729,880	382,997	-	2,311,500
239										
240		Target Hedged Dollars		$2,066,746	$5,299,451	$6,327,124	$6,086,690	$3,767,446	$1,166,608	$24,714,066
241										
242		Weighted Average Hedged Cost per Unit		$5.9050	$6.1622	$6.3271	$6.2749	$6.1761	$6.4812	$6.2252
243										
244						**THIS PAGE HAS BEEN REDACTED**				

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line										
5										Peak
6	For Month of:	Reference		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
245	NYMEX Settlement - 15 Day Average									
246		Days	Date							
247										
248			02-Aug	4.9080	5.1450	5.2820	5.2530	5.1520	4.9700	
249			03-Aug	4.8510	5.1070	5.2450	5.2170	5.1190	4.9460	
250			04-Aug	4.9090	5.1490	5.2850	5.2520	5.1520	4.9820	
251		1	05-Aug	4.7950	5.0470	5.1840	5.1550	5.0580	4.9090	
252		2	06-Aug	4.7270	5.0010	5.1390	5.1120	5.0350	4.8790	
253			07-Aug							
254			08-Aug							
255		3	09-Aug	4.5960	4.8890	5.0280	5.0130	4.9230	4.7950	
256		4	10-Aug	4.5550	4.8170	4.9490	4.9330	4.8470	4.7160	
257		5	11-Aug	4.5460	4.7770	4.9060	4.8890	4.8110	4.6760	
258		6	12-Aug	4.5730	4.8480	4.9730	4.9570	4.8750	4.7430	
259		7	13-Aug	4.5850	4.8690	5.0020	4.9860	4.9030	4.7710	
260			14-Aug							
261			15-Aug							
262		8	16-Aug	4.4560	4.7250	4.8650	4.8500	4.7720	4.6540	
263		9	17-Aug	4.4730	4.7320	4.8690	4.8550	4.7750	4.6570	
264		10	18-Aug	4.4730	4.7340	4.8720	4.8550	4.7780	4.6580	
265		11	19-Aug	4.4020	4.6630	4.8100	4.7930	4.7170	4.6070	
266		12	20-Aug	4.3420	4.6060	4.7520	4.7360	4.6620	4.5610	
267			21-Aug							
268			22-Aug							
269		13	23-Aug	4.2790	4.5390	4.6840	4.6730	4.6030	4.5110	
270		14	24-Aug	4.2490	4.4920	4.6360	4.6240	4.5580	4.4660	
271		15	25-Aug	4.1320	4.4110	4.5670	4.5570	4.4950	4.4030	
272										
273			15 Day Average	4.4789	4.7433	4.8824	4.8659	4.7875	4.6671	

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Residential Heating Rate R-3

November 1, 2010 - April 30, 2011 | **May 1, 2010 - October 31, 2010**

Residential Heating (R3)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
	07/01/2010	06/01/2010															
Winter:																	
Cust. Chg	$15.78		$15.78	$15.78	$15.78	$15.78	$15.78	$15.78	$94.68								
Headblock	$0.2774		$27.74	$27.74	$27.74	$27.74	$27.74	$27.74	$166.44								
Tailblock	$0.2091		$1.88	$10.46	$18.19	$18.40	$13.80	$6.69	$69.42								
HB Threshold	100																
Summer:																	
Cust. Chg	$15.78	$15.62								$14.03	$15.62	$15.78	$15.78	$15.78	$15.78	$92.77	$187.45
Headblock	$0.2774	$0.2747								$4.93	$5.49	$5.55	$5.55	$5.55	$5.55	$32.62	$199.06
Tailblock	$0.2091	$0.2070								$13.01	$7.25	$2.09	$2.09	$4.60	$10.66	$39.70	$109.13
HB Threshold	20	20															
Total Base Rate Amount			$45.40	$53.98	$61.71	$61.92	$57.32	$50.21	$330.54	$31.98	$28.36	$23.42	$23.42	$25.93	$31.99	$165.09	$495.64
CGA Rate - (Seasonal)			$0.8220	$0.8220	$0.8220	$0.8220	$0.8220	$0.8220	$0.8220	$0.7126	$0.7208	$0.7998	$0.7385	$0.7385	$0.7385	$0.7339	$0.7996
CGA amount			$89.60	$123.30	$153.71	$154.54	$136.45	$108.50	$766.10	$64.13	$39.64	$23.99	$22.16	$31.02	$52.43	$233.38	$999.48
LDAC			$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	$0.0641	0.0641	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0581
LDAC amount			$6.99	$9.62	$11.99	$12.05	$10.64	$8.46	$59.74	$3.64	$2.22	$1.21	$1.21	$1.70	$2.87	$12.85	$72.59
Total Bill			**$141.99**	**$186.89**	**$227.41**	**$228.51**	**$204.41**	**$167.18**	**$1,156.39**	**$99.75**	**$70.23**	**$48.63**	**$46.79**	**$58.64**	**$87.29**	**$411.32**	**$1,567.71**

Residential Heating (R3)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter:	08/01/2009	07/01/2009															
Cust. Chg	$14.03		$14.03	$14.03	$14.03	$14.03	$14.03	$14.03	$84.18								
Headblock	$0.2467		24.67	24.67	24.67	24.67	24.67	24.67	$148.02								
Tailblock	$0.1859		$1.67	$9.30	$16.17	$16.36	$12.27	$5.95	$61.72								
HB Threshold	100																
Summer:																	
Cust. Chg	$14.03	$13.95								$11.46	$11.46	$13.95	$14.03	$14.03	$14.03	$78.96	$163.14
Headblock	$0.2467	$0.2453								$6.71	$6.71	$4.91	$4.93	$4.93	$4.93	$33.13	$181.15
Tailblock	$0.1859	$0.1849								$13.65	$6.83	$1.85	$1.86	$4.09	$9.48	$37.75	$99.47
HB Threshold	20	20															
Total Base Rate Amount			$40.37	$48.00	$54.87	$55.06	$50.97	$44.65	$293.92	$31.82	$25.00	$20.71	$20.82	$23.05	$28.44	$149.85	$443.76
		08/24/2008															
CGA Rate - (Seasonal)		$11.46	$0.9663	$0.9239	$0.8975	$0.9155	$1.0230	$0.9385	$0.9416	$0.6722	$0.6324	$0.6200	$0.6077	$0.5866	$0.5272	$0.6106	$0.8574
CGA amount		$0.3356	$105.33	$138.58	$167.83	$172.12	$169.82	$123.88	$877.54	$60.50	$34.78	$18.60	$18.23	$24.64	$37.43	$194.18	$1,071.72
		$0.1950															
LDAC		20	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	$0.0404	0.0404	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0260	$0.0367
LDAC amount			$4.40	$6.06	$7.55	$7.60	$6.71	$5.33	$37.65	$2.34	$1.43	$0.78	$0.78	$1.09	$1.85	$8.27	$45.92
Total Bill			**$150.10**	**$192.63**	**$230.25**	**$234.77**	**$227.49**	**$173.86**	**$1,209.12**	**$94.66**	**$61.21**	**$40.09**	**$39.83**	**$48.78**	**$67.72**	**$352.29**	**$1,561.41**

DIFFERENCE:

Total Bill	**($8.12)**	**($5.74)**	**($2.84)**	**($6.26)**	**($23.08)**	**($6.69)**	**($52.73)**	**$5.09**	**$9.02**	**$8.54**	**$6.95**	**$9.86**	**$19.57**	**$59.03**	**$6.30**
% Change	**-5.41%**	**-2.98%**	**-1.23%**	**-2.67%**	**-10.15%**	**-3.85%**	**-4.36%**	**5.37%**	**14.73%**	**21.30%**	**17.45%**	**20.21%**	**28.90%**	**16.75%**	**0.40%**
Base Rate	$5.03	$5.98	$6.84	$6.86	$6.35	$5.56	$36.62	$0.15	$3.36	$2.71	$2.60	$2.87	$3.55	$15.25	$51.87
% Change	12.46%	12.46%	12.46%	12.46%	12.46%	12.46%	12.46%	0.49%	13.45%	13.11%	12.47%	12.47%	12.47%	10.18%	11.69%
CGA & LDAC	($13.15)	($11.72)	($9.68)	($13.12)	($29.43)	($12.25)	($89.35)	$4.93	$5.65	$5.83	$4.36	$6.98	$16.02	$43.78	($45.57)
% Change	-12.48%	-8.46%	-5.77%	-7.63%	-17.33%	-9.89%	-10.18%	8.15%	16.26%	31.32%	23.89%	28.35%	42.81%	22.54%	-4.25%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-41

November 1, 2010 - April 30, 2011 | **May 1, 2010 - October 31, 2010**
Commercial Rate (G-41)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$39.45		$39.45	$39.45	$39.45	$39.45	$39.45	$39.45	$236.70								
Headblock	$0.3344		$33.44	$33.44	$33.44	$33.44	$33.44	$33.44	$200.64								
Tailblock	$0.2175		$20.23	$36.76	$43.07	$35.24	$29.15	$15.44	$179.87								
HB Threshold	100																
Summer:																	
Cust. Chg	$39.45	$39.07								$35.08	$39.07	$39.45	$39.45	$39.45	$39.45	$231.95	$468.65
Headblock	$0.3344	$0.3312								$5.95	$6.62	$6.69	$6.69	$6.69	$6.69	$39.32	$239.96
Tailblock	$0.2175	$0.2154								$18.76	$13.14	$11.31	$11.31	$15.01	$26.54	$96.06	$275.93
HB Threshold	20	20															
Total Base Rate Amount			$93.12	$109.65	$115.96	$108.13	$102.04	$88.33	$617.21	$59.79	$58.83	$57.45	$57.45	$61.15	$72.67	$367.34	$984.55
CGA Rate - (Seasonal)			$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.7029	$0.7111	$0.7901	$0.7288	$0.7288	$0.7288	$0.7287	$0.7963
CGA amount			$158.92	$221.49	$245.37	$215.73	$192.68	$140.80	$1,174.99	$82.24	$57.60	$56.89	$52.47	$64.86	$103.49	$417.55	$1,592.54
LDAC			$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0357
LDAC amount			$8.14	$11.35	$12.58	$11.06	$9.87	$7.22	$60.22	$2.27	$1.57	$1.40	$1.40	$1.73	$2.75	$11.12	$71.34
Total Bill			**$260.18**	**$342.49**	**$373.90**	**$334.91**	**$304.59**	**$236.35**	**$1,852.42**	**$144.30**	**$118.00**	**$115.73**	**$111.32**	**$127.74**	**$178.92**	**$796.00**	**$2,648.43**

November 1, 2010 - April 30, 2011
Commercial Rate (G-41)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	08/01/2009	07/01/2009															
Cust. Chg	$35.08		$35.08	$35.08	$35.08	$35.08	$35.08	$35.08	$210.48								
Headblock	$0.2974		29.74	29.74	29.74	29.74	29.74	29.74	$178.44								
Tailblock	$0.1934		$17.99	$32.68	$38.29	$31.33	$25.92	$13.73	$159.94								
HB Threshold	100																
Summer:																	
Cust. Chg	$35.08	$34.88								$28.58	$28.58	$34.88	$35.08	$35.08	$35.08	$197.28	$407.76
Headblock	$0.2974	$0.2956								$7.46	$7.46	$5.91	$5.95	$5.95	$5.95	$38.68	$217.12
Tailblock	$0.1934	$0.1923								$23.54	$14.80	$10.00	$10.06	$13.34	$23.59	$95.34	$255.28
HB Threshold	20	20															
Total Base Rate Amount			$82.81	$97.50	$103.11	$96.15	$90.74	$78.55	$548.86	$59.59	$50.85	$50.79	$51.08	$54.37	$64.62	$331.31	$880.17
		08/24/2008															
CGA Rate - (Seasonal)		$28.58	$0.9665	$0.9241	$0.8977	$0.9157	$1.0232	$0.9387	$0.9408	$0.6727	$0.6329	$0.6205	$0.6082	$0.5871	$0.5277	$0.6032	$0.8440
CGA amount		$0.3732	$186.53	$248.57	$267.50	$239.92	$239.43	$160.52	$1,342.47	$78.71	$51.26	$44.68	$43.79	$52.25	$74.93	$345.62	$1,688.09
		$0.2427															
LDAC		20	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0218
LDAC amount			$3.74	$5.22	$5.78	$5.08	$4.54	$3.32	$27.68	$3.25	$2.25	$2.00	$2.00	$2.47	$3.95	$15.93	$43.61
Total Bill			**$273.08**	**$351.30**	**$376.40**	**$341.15**	**$334.70**	**$242.38**	**$1,919.01**	**$141.54**	**$104.37**	**$97.47**	**$96.88**	**$109.10**	**$143.50**	**$692.86**	**$2,611.87**

DIFFERENCE:

Total Bill	**($12.91)**	**($8.80)**	**($2.49)**	**($6.24)**	**($30.12)**	**($6.03)**	**($66.59)**	**$2.75**	**$13.64**	**$18.26**	**$14.44**	**$18.64**	**$35.41**	**$103.15**	**$36.55**
% Change	**-4.73%**	**-2.51%**	**-0.66%**	**-1.83%**	**-9.00%**	**-2.49%**	**-3.47%**	**1.94%**	**13.07%**	**18.74%**	**14.91%**	**17.08%**	**24.68%**	**14.89%**	**1.40%**
Base Rate	$10.31	$12.14	$12.84	$11.97	$11.30	$9.78	$68.35	$0.20	$7.98	$6.66	$6.36	$6.77	$8.05	$36.03	$104.38
% Change	12.45%	12.45%	12.45%	12.45%	12.45%	12.45%	12.45%	0.34%	15.70%	13.11%	12.46%	12.46%	12.46%	10.87%	11.86%
CGA & LDAC	($23.22)	($20.94)	($15.34)	($18.21)	($41.42)	($15.82)	($134.94)	$2.55	$5.65	$11.61	$8.08	$11.86	$27.36	$67.12	($67.83)
% Change	-12.45%	-8.43%	-5.73%	-7.59%	-17.30%	-9.85%	-10.05%	3.24%	11.03%	25.98%	18.45%	22.70%	36.52%	19.42%	-4.02%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-42

November 1, 2010 - April 30, 2011 | **May 1, 2010 - October 31, 2010**
C&I High Winter Use Medium G-42

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
	07/01/2010	06/01/2010															
Winter:																	
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$112.73	$676.38								
Headblock	$0.2971		$297.10	$297.10	$297.10	$297.10	$297.10	$297.10	$1,782.60								
Tailblock	$0.1962		$108.50	$309.60	$444.39	$608.81	$471.27	$289.00	$2,231.58								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,339.17
Headblock	$0.2971	$0.2942								$105.68	$117.68	$118.84	$63.28	$108.14	$118.84	$632.47	$2,415.07
Tailblock	$0.1962	$0.1943								$149.72	$58.48	$2.75	$0.00	$0.00	$58.66	$269.62	$2,501.19
HB Threshold	400	400															
Total Base Rate Amount			$518.33	$719.43	$854.22	$1,018.64	$881.10	$698.83	$4,690.56	$355.64	$287.79	$234.32	$176.01	$220.87	$290.23	$1,564.87	$6,255.43
CGA Rate - (Seasonal)			$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.8234	$0.7029	$0.7111	$0.7901	$0.7288	$0.7288	$0.7288	$0.7234	$0.8060
CGA amount			$1,278.74	$2,122.73	$2,688.40	$3,378.41	$2,801.21	$2,036.27	$14,305.75	$884.25	$498.48	$327.10	$155.23	$265.28	$509.43	$2,639.78	$16,945.53
LDAC			$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0382
LDAC amount			$65.54	$108.79	$137.78	$173.15	$143.56	$104.36	$733.18	$24.41	$13.60	$8.03	$4.13	$7.06	$13.56	$70.79	$803.97
Total Bill			**$1,862.61**	**$2,950.95**	**$3,680.41**	**$4,570.20**	**$3,825.87**	**$2,839.46**	**$19,729.49**	**$1,264.29**	**$799.87**	**$569.45**	**$335.38**	**$493.22**	**$813.23**	**$4,275.44**	**$24,004.94**

November 1, 2010 - April 30, 2011
C&I High Winter Use Medium G-42

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
	08/01/2009	07/01/2009															
Winter:																	
Cust. Chg	$100.24		$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44								
Headblock	$0.2642		264.20	264.20	264.20	264.20	264.20	264.20	$1,585.20								
Tailblock	$0.1745		$96.50	$275.36	$395.24	$541.47	$419.15	$257.04	$1,984.76								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$100.24	$99.66								$80.44	$80.44	$99.66	$100.24	$100.24	$100.24	$561.26	$1,162.70
Headblock	$0.2642	$0.2627								$123.80	$123.80	$105.08	$56.27	$96.17	$105.68	$610.80	$2,196.00
Tailblock	$0.1745	$0.1735								$175.38	$61.52	$2.43	$0.00	$0.00	$52.18	$291.50	$2,276.27
HB Threshold	400	400															
Total Base Rate Amount		08/24/08	$460.94	$639.80	$759.68	$905.91	$783.59	$621.48	$4,171.40	$379.62	$265.76	$207.17	$156.51	$196.41	$258.10	$1,463.57	$5,634.97
CGA Rate - (Seasonal)		$80.44	$0.9665	$0.9241	$0.8977	$0.9157	$1.0232	$0.9387	$0.9424	$0.6727	$0.6329	$0.6205	$0.6082	$0.5871	$0.5277	$0.6191	$0.8863
CGA amount		$0.3095	$1,500.97	$2,382.23	$2,930.87	$3,757.15	$3,480.91	$2,321.37	$16,373.51	$846.26	$443.66	$256.89	$129.55	$213.70	$368.86	$2,258.92	$18,632.43
		$0.2044															
LDAC		400	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0209
LDAC amount			$30.13	$50.01	$63.34	$79.60	$66.00	$47.98	$337.06	$34.97	$19.49	$11.51	$5.92	$10.12	$19.43	$101.44	$438.50
Total Bill			**$1,992.04**	**$3,072.05**	**$3,753.89**	**$4,742.66**	**$4,330.50**	**$2,990.83**	**$20,881.97**	**$1,260.84**	**$728.92**	**$475.57**	**$291.98**	**$420.23**	**$646.39**	**$3,823.93**	**$24,705.90**

DIFFERENCE:

Total Bill	**($129.44)**	**($121.10)**	**($73.48)**	**($172.47)**	**($504.63)**	**($151.37)**	**($1,152.47)**	**$3.45**	**$70.96**	**$93.88**	**$43.40**	**$72.99**	**$166.84**	**$451.51**	**($700.96)**
% Change	**-6.50%**	**-3.94%**	**-1.96%**	**-3.64%**	**-11.65%**	**-5.06%**	**-5.52%**	**0.27%**	**9.73%**	**19.74%**	**14.86%**	**17.37%**	**25.81%**	**11.81%**	**-2.84%**
Base Rate	$57.39	$79.63	$94.54	$112.73	$97.51	$77.35	$519.16	($23.97)	$22.03	$27.15	$19.50	$24.47	$32.14	$101.31	$620.46
% Change	12.45%	12.45%	12.44%	12.44%	12.44%	12.45%	12.45%	-6.32%	8.29%	13.10%	12.46%	12.46%	12.45%	6.92%	11.01%
CGA & LDAC	($186.83)	($200.73)	($168.02)	($285.19)	($602.14)	($228.72)	($1,671.63)	$27.42	$48.93	$66.74	$23.90	$48.52	$134.70	$350.21	($1,321.42)
% Change	-12.45%	-8.43%	-5.73%	-7.59%	-17.30%	-9.85%	-10.21%	3.24%	11.03%	25.98%	18.45%	22.70%	36.52%	15.50%	-7.09%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-52

November 1, 2010 - April 30, 2011 / **May 1, 2010 - October 31, 2010**
Commercial Rate (G-52)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:	07/01/2010	06/01/2010															
Cust. Chg	$112.73		$112.73	$112.73	$112.73	$112.73	$112.73	$112.73	$676.38								
Headblock	$0.1692		$169.20	$169.20	$169.20	$169.20	$169.20	$169.20	$1,015.20								
Tailblock	$0.1148		$82.89	$124.67	$152.68	$153.03	$148.21	$100.11	$761.58								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$112.73	$111.63								$100.24	$111.63	$112.73	$112.73	$112.73	$112.73	$662.79	$1,339.17
Headblock	$0.1244	$0.1232								$110.60	$123.20	$124.40	$124.40	$124.40	$124.40	$731.40	$1,746.60
Tailblock	$0.0716	$0.0709								$32.49	$26.52	$17.69	$13.60	$15.04	$23.20	$128.53	$890.11
HB Threshold	1,000	1,000															
Total Base Rate Amount			$364.82	$406.60	$434.61	$434.96	$430.14	$382.04	$2,453.16	$243.33	$261.35	$254.82	$250.73	$252.17	$260.33	$1,522.72	$3,975.88
CGA Rate - (Seasonal)			$0.8186	$0.8186	$0.8186	$0.8186	$0.8186	$0.8186	$0.8186	$0.7020	$0.7102	$0.7892	$0.7279	$0.7279	$0.7279	$0.7296	$0.7845
CGA amount			$1,409.63	$1,707.60	$1,907.34	$1,909.79	$1,875.41	$1,532.42	$10,342.19	$1,060.02	$975.81	$984.13	$866.20	$880.76	$963.74	$5,730.67	$16,072.86
LDAC			$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	$0.0422	0.0422	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0335
LDAC amount			$72.67	$88.03	$98.33	$98.45	$96.68	$79.00	$533.15	$29.29	$26.66	$24.19	$23.09	$23.47	$25.69	$152.39	$685.54
Total Bill			**$1,847.11**	**$2,202.23**	**$2,440.28**	**$2,443.20**	**$2,402.23**	**$1,993.45**	**$13,328.51**	**$1,332.64**	**$1,263.82**	**$1,263.14**	**$1,140.02**	**$1,156.40**	**$1,249.75**	**$7,405.77**	**$20,734.28**

November 1, 2010 - April 30, 2011
Commercial Rate (G-52)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:	08/01/2009	07/01/2009															
Cust. Chg	$100.24		$100.24	$100.24	$100.24	$100.24	$100.24	$100.24	$601.44								
Headblock	$0.1505		150.50	150.50	150.50	150.50	150.50	150.50	$903.00								
Tailblock	$0.1021		$73.72	$110.88	$135.79	$136.10	$131.81	$89.03	$677.33								
HB Threshold	1,000																
Summer:																	
Cust. Chg	$100.24	$99.66								$80.36	$80.36	$99.66	$100.24	$100.24	$100.24	$561.10	$1,162.54
Headblock	$0.1106	$0.1100								$145.30	$145.30	$110.00	$110.60	$110.60	$110.60	$732.40	$1,635.40
Tailblock	$0.0637	$0.0633								$42.64	$31.27	$15.64	$12.10	$13.38	$20.64	$135.66	$812.99
HB Threshold	1,000	1,000															
Total Base Rate Amount			$324.46	$361.62	$386.53	$386.84	$382.55	$339.77	$2,181.77	$268.30	$256.93	$225.30	$222.94	$224.22	$231.48	$1,429.16	$3,610.93
		08/24/08															
CGA Rate - (Seasonal)		$80.36	$0.9658	$0.9234	$0.8970	$0.9150	$1.0225	$0.9380	$0.9429	$0.6707	$0.6309	$0.6185	$0.6062	$0.5851	$0.5257	$0.6081	$0.8145
CGA amount		$0.1453	$1,663.11	$1,926.13	$2,089.92	$2,134.71	$2,342.54	$1,755.91	$11,912.33	$1,012.76	$866.86	$771.27	$721.38	$707.97	$696.03	$4,776.26	$16,688.59
		$0.0836															
LDAC		1,000	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	$0.0194	0.0194	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0278	$0.0226
LDAC amount			$33.41	$40.47	$45.20	$45.26	$44.45	$36.32	$245.10	$41.98	$38.20	$34.67	$33.08	$33.64	$36.81	$218.37	$463.47
Total Bill			**$2,020.97**	**$2,328.22**	**$2,521.66**	**$2,566.81**	**$2,769.53**	**$2,132.00**	**$14,339.20**	**$1,323.03**	**$1,161.98**	**$1,031.23**	**$977.40**	**$965.83**	**$964.31**	**$6,423.78**	**$20,762.98**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($173.86)**	**($125.99)**	**($81.38)**	**($123.61)**	**($367.31)**	**($138.55)**	**($1,010.69)**	**$9.61**	**$101.84**	**$231.91**	**$162.62**	**$190.57**	**$285.44**	**$981.99**	**($28.70)**
% Change	**-8.60%**	**-5.41%**	**-3.23%**	**-4.82%**	**-13.26%**	**-6.50%**	**-7.05%**	**0.73%**	**8.76%**	**22.49%**	**16.64%**	**19.73%**	**29.60%**	**15.29%**	**-0.14%**
Base Rate	$40.36	$44.98	$48.08	$48.12	$47.59	$42.26	$271.39	($24.97)	$4.42	$29.52	$27.79	$27.95	$28.85	$93.56	$364.95
% Change	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	-9.31%	1.72%	13.10%	12.47%	12.47%	12.46%	6.55%	10.11%
CGA & LDAC	($214.22)	($170.97)	($129.46)	($171.73)	($414.89)	($180.81)	($1,282.08)	$34.58	$97.42	$202.39	$134.83	$162.62	$256.59	$888.43	($393.65)
% Change	-12.88%	-8.88%	-6.19%	-8.04%	-17.71%	-10.30%	-10.76%	3.41%	11.24%	26.24%	18.69%	22.97%	36.87%	18.60%	-2.36%

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Residential Heating

	Winter 2009-10	Winter 2010-11
Customer Charge	$14.03	$15.78
First 100 Therms	$0.2467	$0.2774
Excess 100 Therms	$0.1859	$0.2091
LDAC	$0.0404	$0.0641
CGA	$0.9416	$0.8220
Total Adjust	$0.9820	$0.8861

		Winter 2009-10 CGA @	Winter 2010-11 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.9820	$0.8861	($0.10)	-10%						
Cooking alone	5	$20.17	$21.60	$1.42	7%	$1.90	9%	-$0.60	-3%	$0.12	1%
	10	$26.32	$27.42	$1.10	4%	$2.06	8%	-$1.20	-4%	$0.24	1%
	20	$38.60	$39.05	$0.45	1%	$2.36	6%	-$2.39	-6%	$0.47	1%
Water Heating alone	30	$50.89	$50.69	($0.21)	0%	$2.67	5%	-$3.59	-7%	$0.71	1%
	45	$69.32	$68.14	($1.18)	-2%	$3.13	5%	-$5.38	-8%	$1.07	2%
	50	$75.46	$73.96	($1.51)	-2%	$3.29	4%	-$5.98	-8%	$1.19	2%
Heating Alone	80	$106.18	$103.04	($3.14)	-3%	$4.05	4%	-$8.97	-9%	$1.78	2%
	125	$175.44	$168.27	($7.17)	-4%	$5.59	3%	-$15.90	-9%	$3.15	2%
	150	$195.29	$186.89	($8.40)	-4%	$5.98	3%	-$17.94	-10%	$3.56	2%
	200	$253.68	$241.65	($12.03)	-5%	$7.14	3%	-$23.91	-10%	$4.74	2%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Variance Analysis of the Components of the 2009-10 Actual Results vs Proposed Winter 2010-11 Cost of Gas Rate

	WINTER SALES ACTUAL RESULTS (6 months actual)			**WINTER 2010-11 (6 months Proposed)**		
Therm Sales	73,960,615			83,071,582		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 7,011,816	$ 0.0948		$ 9,370,456	$ 0.1128
Purchased Gas	70,464,050	41,899,383	0.5665	71,402,980	39,083,750	0.4705
Storage Gas	6,078,800	3,863,102	0.0522	13,072,818	7,649,468	0.0921
Produced Gas	276,060	230,970	0.0031	1,443,345	1,255,498	0.0151
Hedging (Gain)/Loss		16,493,046	0.2230		6,268,136	0.0755
Total Volumes and Cost	76,818,910	$ 69,498,318	$ 0.9397	85,919,143	$ 63,627,308	$ 0.7659
Prior Period Balance		$ 779,942	$ 0.0105		2,985,736	$ 0.0359
Interest		51,658	0.0007		101,158	0.0012
Prior Period Adjustment		(116,154)	(0.0016)		-	-
Broker Revenues		(777,372)	(0.0105)		(754,779)	(0.0091)
Refunds from Suppliers		-	-		-	-
Fuel Financing		130,926	0.0018		130,835	0.0016
Transportation CGA Revenues		9,404	0.0001		(31,147)	(0.0004)
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(391,544)	(0.0053)		(730,714)	(0.0088)
Hedging Costs		-	-		-	-
Misc Overhead		20,121	0.0003		5,281	0.0001
Occupant Disallowance/Credits		-				
Production & Storage		1,749,387	0.0237			
FPO Admin Costs		-	-		40,691	0.0005
Indirect Gas Costs		1,102,718	0.0149		2,909,211	0.0350
Total Adjusted Cost		$ 72,057,402	**$ 0.9743**		$ 68,283,580	**$ 0.8220**

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Capacity Assignment Calculations 2010-2011
Derivation of Class Assignments and Weightings

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
 a The base use portion of the class design day demand based on base use
 b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

		Column A	Column B	Column C	Column D	Column E	Column F
		Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg	619	651	0.5%		156	495
2	RATE R-3-Resi Htg	60,544	64,337	46.8%		3,993	60,344
3	RATE G-41 (T)	22,322	23,761	17.3%		851	22,910
4	RATE G-51 (S)	2,481	2,605	1.9%		627	1,978
5	RATE G-42 (V)	31,102	33,077	24.1%		1,653	31,424
6	RATE G-52	4,119	4,311	3.1%		1,247	3,064
7	RATE G-43	4,354	4,615	3.4%		463	4,152
8	RATE G-53	1,514	1,595	1.2%		297	1,298
9	RATE G-54	2,319	2,449	1.8%		384	2,065
10							
11	Total	129,373	137,401	100.0%		9,671	127,730
12							-
13	Residential Total	61,163	64,988	**47.298%**		4,148	60,840
14	LLF Total	57,778	61,453	**44.725%**		2,966	58,487
15	HLF Total	10,432	10,960	**7.977%**		2,556	8,404
16	Total	129,373	137,401	100.0%		9,671	127,730
17							
18	C&I Breakdown						
19	LLF Total					2,966	58,487
20	HLF Total					2,556	8,404
21	Total					5,522	66,891
22							
23	C&I Breakdown Percentage						
24	LLF Total					53.715%	87.436%
25	HLF Total					46 285%	12.564%
26	Total					**100.0%**	**100.0%**

27						
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.
29	Pipeline			$5,110,048	53,718	$7.9273
30	Storage			$3,917,934	28,115	$11.6128
31						
32	Peaking			$7,016,421		
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)			$853,183		
34	Subtotal Peaking Costs			$7,869,604	55,567	$11.8020
35	Total			$16,897,587	137,400	$10.2484
36						
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.
38	Pipeline - Baseload			919,948	9,671	$7.9273
39	Pipeline - Remaining			4,190,100	44,047	$7.9273
40	Storage			3,917,934	28,115	$11.6128
41	Peaking			7,869,604	55,567	$11.8020
42	Total			16,897,587	137,400	$10.2484
43						
44						
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.
46	Pipeline - Base	Line 38 * Line 13 Col C	**47.298%**	435,117	4,574	$7.9273
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**47.298%**	1,981,841	20,834	$7.9273
48	Storage	Line 40 * Line 13 Col C	**47.298%**	1,853,100	13,298	$11.6128
49	Peaking	Line 41 * Line 13 Col C	**47.298%**	3,722,162	26,282	$11.8020
50	Total		**47.298%**	7,992,199	64,987	$10.2484

ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

Peak 2010 - 2011 Winter Cost of Gas Filing

Capacity Assignment Calculations 2010-2011

Derivation of Class Assignments and Weightings

							Ratios for COG
51							
52							**Ratios for COG**
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		484,831	5,097	$7.9273	
55	Pipeline - Remaining	Line 39 - Line 47		2,208,259	23,214	$7.9272	
56	Storage	Line 40 - Line 48		2,064,834	14,817	$11.6128	
57	Peaking	Line 41 - Line 49		4,147,442	29,285	$11.8020	
58	Total		**52.702%**	8,905,365	72,413	$10.2484	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		260,429	2,738	$7.9264	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		1,930,817	20,297	$7.9273	
64	Storage	Line 56 * Line 24 Col F		1,805,411	12,956	$11.6125	
65	Peaking	Line 57 * Line 24 Col F		3,626,364	25,606	$11.8018	
66	Total		**45.1131%**	7,623,021	61,597	$10.3130	**1.0063**
67			53.715%	86%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		224,402	2,359	$7.9272	
71	Pipeline - Remaining	Line 55 - Line 63		277,442	2,917	$7.9260	
72	Storage	Line 56 - Line 64		259,423	1,861	$11.6166	
73	Peaking	Line 57 - Line 65		521,078	3,679	$11.8030	
74	Total		**7.5889%**	1,282,345	10,816	$9.8800	**0.9641**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 7.9273	$ 7.9273	$ 7.9273	
80	Storage			$ 11.6128	$ 11.6128	$ 11.6128	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 10.2484	$ 10.3130	$ 9.8800	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			39.10%	**37.40%**	**48.78%**	
88	Storage			20.46%	**21.03%**	**17.21%**	
89	Peaking			40.44%	**41.57%**	**34.01%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			47.30%	42.88%	9.82%	100.00%
96	Storage			47.30%	46.08%	6.62%	100.00%
97	Peaking			47.30%	46.08%	6.62%	100.00%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Correction Factor Calculation

Data Source: Schedule 10B	Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
G-41	1,013,490	1,623,765	3,602,815	3,292,443	2,696,656	1,672,112	13,901,281
G-42	1,291,603	1,877,047	3,519,263	3,200,164	2,782,899	1,968,286	14,639,261
G-43	129,290	198,537	248,632	286,526	262,030	218,315	1,343,329
High Winter Use	2,434,383	3,699,349	7,370,710	6,779,133	5,741,584	3,858,713	29,883,871
G-51	223,039	287,505	476,133	409,819	371,687	292,921	2,061,103
G-52	335,738	410,527	586,983	540,696	490,622	413,803	2,778,369
G-53	43,174	43,488	56,534	60,359	55,763	55,709	315,027
G-54	1,415	1,454	1,520	1,424	1,150	1,438	8,401
Low Winter Use	603,365	742,974	1,121,170	1,012,298	919,222	763,870	5,162,900
Gross Total	3,037,748	4,442,323	8,491,880	7,791,431	6,660,807	4,622,582	35,046,771

Total Sales	35,046,771	
Low Winter Use	5,162,900	
Winter Ratio for Low Winter Use =	**0.96410**	Schedule 10A p 2, ln 74
High Winter Use	29,883,871	
Winter Ratio for High Winter Use =	**1.00630**	Schedule 10A p 2, ln 66

Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))

Correction Factor = **99.9917%**

Allocation Calculation for Miscellaneous Overhead

Projected Winter Sales Volume	(11/1/10 - 4/30/11)	83,088,481	Sch.10B
Projected Annual Sales Volume	(11/1/10 - 10/31/11)	104,918,580	Sch.10B
Percentage of Winter to Annual Sales		79.19%	

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **2010 - 2011 Winter Cost of Gas Filing**
5
6 **Dry Therms**

		Nov-10	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**Subtotal PK 10-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Subtotal OP 11**	**Total**
7	**Firm Sales**															
8																
9	R-1	76,097	96,615	140,412	123,354	112,712	96,897	646,087	87,137	70,277	66,408	53,127	46,749	62,700	386,397	1,032,484
10	R-3	3,995,775	5,849,614	10,924,311	9,875,535	7,206,755	5,034,076	42,886,065	2,964,508	1,771,182	1,470,839	1,181,263	1,183,200	2,040,145	10,611,137	53,497,203
11	R-4	164,200	373,422	719,297	724,855	1,546,824	980,960	4,509,559	463,564	300,279	132,413	104,546	94,095	154,337	1,249,234	5,758,793
12	Total Residential.	4,236,072	6,319,650	11,784,020	10,723,744	8,866,291	6,111,933	48,041,710	3,515,209	2,141,739	1,669,660	1,338,936	1,324,044	2,257,182	12,246,769	60,288,480
13																
14	G-41	1,013,490	1,623,765	3,602,815	3,292,443	2,696,656	1,672,112	13,901,281	817,486	386,769	272,735	217,398	209,535	410,348	2,314,272	16,215,553
15	G-42	1,291,603	1,877,047	3,519,263	3,200,164	2,782,899	1,968,286	14,639,261	1,207,425	589,484	426,425	345,772	350,132	643,693	3,562,930	18,202,191
16	G-43	129,290	198,537	248,632	286,526	262,030	218,315	1,343,329	98,627	56,346	32,774	33,235	29,862	37,488	288,332	1,631,661
17	G-51	223,039	287,505	476,133	409,819	371,687	292,921	2,061,103	253,731	214,431	197,394	172,814	172,517	198,794	1,209,682	3,270,785
18	G-52	335,738	410,527	586,983	540,696	490,622	413,803	2,778,369	359,635	323,765	305,024	278,393	280,256	307,632	1,854,706	4,633,074
19	G-53	43,174	43,488	56,534	60,359	55,763	55,709	315,027	47,737	43,129	38,736	35,704	37,637	39,841	242,783	557,810
20	G-54	1,415	1,454	1,520	1,424	1,150	1,438	8,401	17,484	18,210	19,505	18,956	17,648	18,822	110,626	119,027
21	Total C/I	3,037,748	4,442,323	8,491,880	7,791,431	6,660,807	4,622,582	35,046,771	2,802,126	1,632,134	1,292,591	1,102,273	1,097,587	1,656,618	9,583,329	44,630,100
22																
23	**Sales Volume**	**7,273,820**	**10,761,973**	**20,275,900**	**18,515,175**	**15,527,097**	**10,734,516**	**83,088,481**	**6,317,335**	**3,773,873**	**2,962,251**	**2,441,209**	**2,421,631**	**3,913,800**	**21,830,099**	**104,918,580**
24																
25	Transportation Sales															
26																
27	G-41	187,316	275,777	516,084	514,617	456,874	324,938	2,275,605	169,292	92,565	75,231	58,829	62,239	100,321	558,477	2,834,083
28	G-42	1,006,362	1,399,546	2,539,920	2,325,662	2,090,381	1,445,726	10,807,596	839,182	383,837	300,155	253,697	274,246	508,449	2,559,566	13,367,162
29	G-43	417,394	617,195	720,237	886,632	795,189	721,610	4,158,257	562,043	317,729	191,916	183,419	177,231	215,023	1,647,361	5,805,618
30	G-51	45,403	45,843	104,316	84,760	79,300	65,797	425,418	46,296	40,122	36,360	30,370	32,373	41,084	226,605	652,022
31	G-52	192,334	252,384	361,822	341,494	305,230	253,767	1,707,032	185,235	175,034	166,575	154,201	162,278	164,315	1,007,639	2,714,671
32	G-53	750,093	774,852	970,111	1,058,124	973,852	981,510	5,508,541	708,614	640,443	581,400	541,959	576,878	605,891	3,655,185	9,163,726
33	G-54	1,638,279	1,683,239	1,759,850	1,648,214	1,330,918	1,664,548	9,725,048	1,388,612	1,446,648	1,549,569	1,506,104	1,426,828	1,521,962	8,839,722	18,564,771
34																
35	Total Trans. Sales	**4,237,181**	**5,048,836**	**6,972,340**	**6,859,501**	**6,031,744**	**5,457,896**	**34,607,498**	**3,899,275**	**3,096,379**	**2,901,204**	**2,728,580**	**2,712,074**	**3,157,045**	**18,494,555**	**53,102,053**
36																
37	Total All Sales	**11,511,001**	**15,810,809**	**27,248,240**	**25,374,676**	**21,558,841**	**16,192,412**	**117,695,979**	**10,216,609**	**6,870,252**	**5,863,455**	**5,169,789**	**5,133,705**	**7,070,844**	**40,324,654**	**158,020,633**

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 10 - April 11

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	992,558	985,941	1,025,643	870,970	1,025,643	992,558	5,893,314
Niagara Supply	66,998	675,767	728,703	624,485	800,664	31,431	2,928,047
TGP Supply (Direct)	5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699	30,809,005
Dracut Supply 1 - Baseload	-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
Dracut Supply 2 - Swing	5,541,783	367,247	308,520	348,222	6,430,123	6,676,608	19,672,503
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	23,160	23,987	535,154	196,030	47,974	-	826,305
Propane Truck	-	-	-	-	-	-	0
PNGTS	65,343	80,232	86,022	75,269	72,788	55,418	435,071
Granite Ridge	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713	76,795,052
Storage Gas:							
TGP Storage	96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
Produced Gas:							
LNG Vapor	23,160	23,987	588,918	196,030	23,987	23,160	879,241
Propane	-	-	426,800	137,304	-	-	564,104
Subtotal Produced Gas	23,160	23,987	1,015,718	333,334	23,987	23,160	1,443,345
Less - Gas Refills:							
LNG Truck	(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-	(826,305)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(645,163)	(38,048)	-	-	-	(3,882,557)	(4,565,768)
Subtotal Refills	(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)	(5,392,072)
Total Sendout Volumes	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
42 **Normal and Design Year Volumes** **Schedule 11B**
43
44
45 **Volumes (Therms)** **Design Year**
46
47 **For the Months of November 10 - April 11**
48

49								**Peak**
50		**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**Nov - Apr**
51	Pipeline Gas:							
52	Dawn Supply	992,558	992,558	1,025,643	926,388	1,025,643	992,558	5,955,349
53	Niagara Supply	77,750	748,554	800,664	649,298	800,664	51,282	3,128,212
54	TGP Supply (Direct)	5,288,681	5,507,044	5,537,647	4,963,618	5,537,647	4,296,123	31,130,760
55	Dracut Supply 1 - Baseload	-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
56	Dracut Supply 2 - Swing	6,598,030	1,053,766	1,483,874	980,978	7,446,668	7,295,302	24,858,619
57	City Gate Delivered Supply	-	-	-	-	-	-	0
58	LNG Truck	23,160	23,987	558,314	172,871	47,974	-	826,305
59	Propane Truck	-	-	-	-	-	-	0
60	PNGTS	65,343	80,232	86,022	75,269	72,788	55,418	435,071
61	Granite Ridge	-	-	-	-	-	-	-
62	Other Purchased Resources	-	-	-	-	-	-	-
63	Subtotal Pipeline Volumes	13,045,523	13,996,724	15,082,748	12,818,062	14,931,383	12,690,683	82,565,123
64								
65	Storage Gas:							
66	TGP Storage	287,842	4,550,052	5,528,549	4,775,032	624,485	30,604	15,796,563
67								
68	Produced Gas:							
69	LNG Vapor	23,160	23,987	612,905	172,871	23,987	23,160	880,068
70	Propane	-	-	239,868	297,767	-	-	537,636
71	Subtotal Produced Gas	23,160	23,987	852,773	470,638	23,987	23,160	1,417,704
72								
73	Less - Gas Refills:							
74	LNG Truck	(23,160)	(23,987)	(558,314)	(172,871)	(47,974)	-	(826,305)
75	Propane	-	-	-	-	-	-	-
76	TGP Storage Refill	(784,121)	(4,136)	-	-	-	(4,031,440)	(4,819,697)
77	Subtotal Refills	(807,281)	(28,122)	(558,314)	(172,871)	(47,974)	(4,031,440)	(5,646,002)
78								
79	Total Sendout Volumes	12,549,244	18,542,641	20,905,756	17,890,861	15,531,881	8,713,006	94,133,389

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1 **ENERGY NORTH NATURAL GAS, INC.** **Schedule 11C**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Capacity Utilization**
5 **Volumes (Therms)**
6

Line		Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
7-10									
11	**Pipeline Gas:**								
12	Dawn Supply	5,893,314	4,000	7,240,000	81%	5,955,349	4,000	7,240,000	82%
13	Niagara Supply	2,928,047	3,122	5,650,820	52%	3,128,212	3,122	5,650,820	55%
14	TGP Supply (Direct)	30,809,005	21,596	39,088,760	79%	31,130,760	21,596	39,088,760	80%
15	Dracut Supply 1 & 2	35,903,310	50,000	90,500,000	40%	41,089,426	50,000	90,500,000	45%
18	LNG Truck	826,305	-	-	-	826,305	-	-	-
19	Propane Truck	-	-	-	-	-	-	-	-
20	PNGTS	435,071	1,000	1,810,000	24%	435,071	1,000	1,810,000	24%
21	Granite Ridge	-	-	-	-	-	-	-	-
22	Other Purchased Resources	-	-	-	-	-	-	-	-
23									
24	Subtotal Pipeline Volumes	76,795,052				82,565,123			
25									
26	**Storage Gas:**								
27	TGP Storage	13,072,818		25,801,310	51%	15,796,563		25,801,310	61%
28									
29	**Produced Gas:**								
30	LNG Vapor	879,241				880,068			
31	Propane	564,103.9				537,636			
32									
33	Subtotal Produced Gas	1,443,345				1,417,704			
34									
35	**Less - Gas Refills:**								
36	LNG Truck	(826,305)				(826,305)			
37	Propane	-				-			
38	TGP Storage Refill	(4,565,768)				(4,819,697)			
39									
40	Subtotal Refills	(5,392,072)				(5,646,002)			
41									
42	Total Sendout Volumes	85,919,143				94,133,389			

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ENERGY NORTH NATURAL GAS, INC. **Schedule 11D**
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2010 / 11 Heating Season
(Therms)

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

72 EDD at Manchester, N.H.

Requirements

Firm Sales	1,168,312
Interruptible Sales	0
Firm Transportation	205,688
Interruptible Transportation	0
Total Requirements	1,374,000

Resources

Purchased Pipeline Gas	790,100
Underground Storage Gas	281,100
Propane Air Production	197,500
LNG Produced Gas	105,300
Third-Party Supply	0
Total Resources	1,374,000

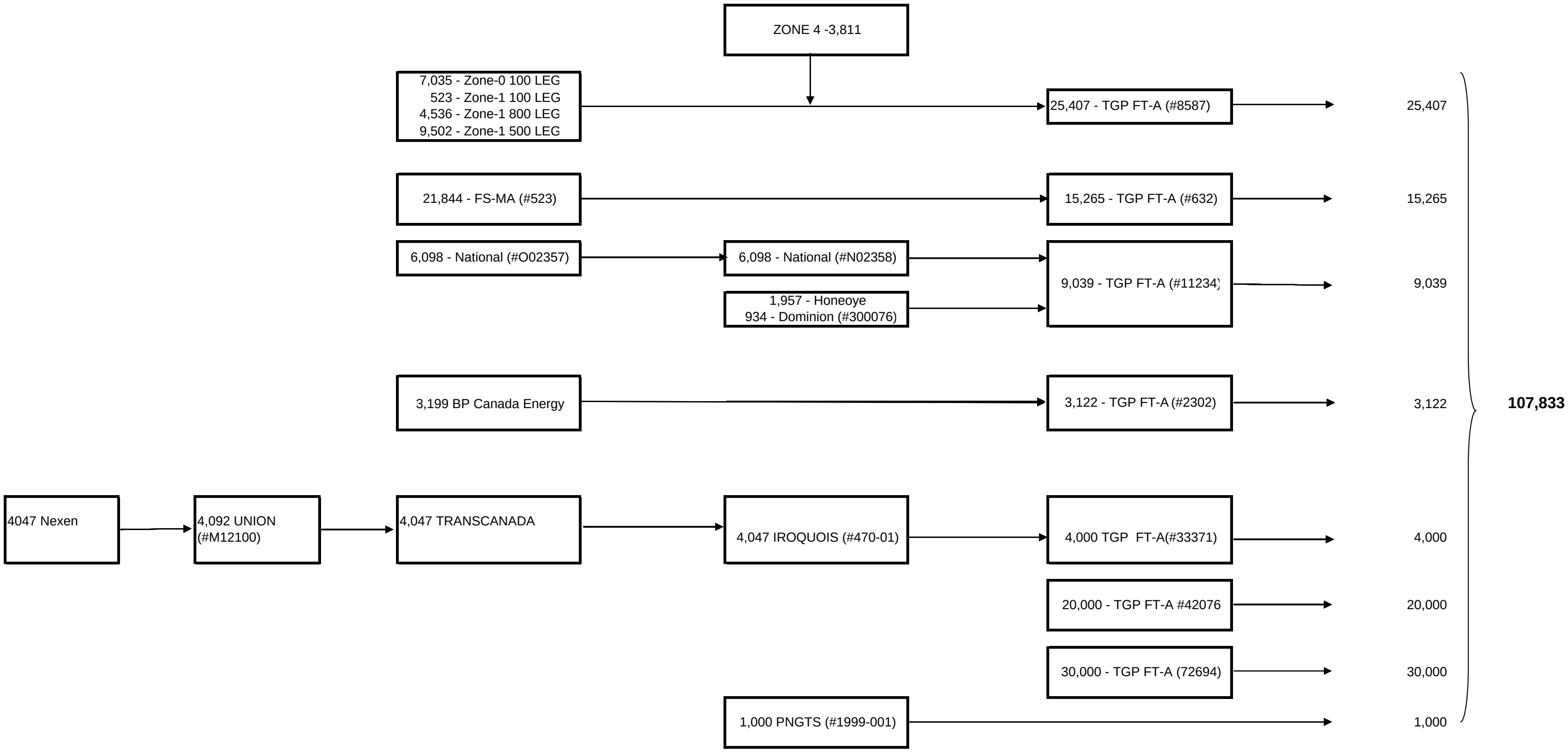
Please refer to the ENGI 2010 IRP filing (DG 10-041) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Theodore Poe, Jr.
Manager, Energy Planning

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Granite Ridge Energy, LLC (Formerly AES Londonderry, L.L.C.)	-	-	Supply	15,000	450,000	09/30/10	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD No Supply for April through October 2010	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
Distrigas of Renew Massachusetts Corp.	FLS	FLS160	Liquid Refill	Up to 15 trucks	1,000,000 National Grid Total	10/31/2010	-	Terminates
TBD Corporation	-	-	Supply	May 2010 = 21,000 Oct 2010 = 16,000	7,607,500	10/31/2010	-	Terminates
JP Morgan	-	-	Supply	21,596	3,908,876	04/30/2011	N/a	Terminates
Eastern Propane Gas			Trucking	28,500 Gallons	900,000 Gallons	03/31/2011	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2016	03/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/2011	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2011	03/31/2011	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2011	03/31/2011	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/01/2017	10/31/2011	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	09/30/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	33371	Transportation	4,000	1,460,000	10/31/2011	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2015	10/31/2010	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2017	04/30/2016	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2017	10/31/2015	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2009 - Apr 2010 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	15,253,278	36.55%	85.10%
G-42	17,082,632	40.93%	57.55%
G-43	1,513,746	3.63%	21.68%
G-51	3,062,838	7.34%	83.30%
G-52	4,328,763	10.37%	62.88%
G-53	481,597	1.15%	5.29%
G-54	13,770	0.03%	0.08%
Total C/I	41,736,623	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	2,670,958	5.34%	14.90%
G-42	12,598,226	25.20%	42.45%
G-43	5,468,386	10.94%	78.32%
G-51	613,894	1.23%	16.70%
G-52	2,555,535	5.11%	37.12%
G-53	8,624,994	17.25%	94.71%
G-54	17,464,601	34.93%	99.92%
Total C/I	49,996,594	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	17,924,236	19.54%	100.00%
G-42	29,680,858	32.36%	100.00%
G-43	6,982,132	7.61%	100.00%
G-51	3,676,732	4.01%	100.00%
G-52	6,884,298	7.50%	100.00%
G-53	9,106,591	9.93%	100.00%
G-54	17,478,371	19.05%	100.00%
Total C/I	91,733,218	100.00%	

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak	**Peak**	**Total**	
	May 09 - Oct 09	**Nov 09-Apr 10**	**May 09 - Apr 10**	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	18,035,980	66,698,550	84,734,530	
All Others	2,126,110	10,120,360	12,246,470	
	20,162,090	76,818,910	96,981,000	
				Ratio
Total Winter Supplies				76,818,910
Total Pipeline Deliveries				84,734,530
Ratio Winter Supplies to Pipeline Supplies				0.907

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

C&I Sales Normalized (Therms)	**Jul-09**	**Aug-09**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	241,351	248,603	489,954	15,656,710	3.13%
G-42	393,635	309,516	703,151	19,079,103	3.69%
G-43	22,764	33,583	56,347	1,167,489	4.83%
G-51	181,820	160,551	342,371	3,173,321	10.79%
G-52	277,488	251,228	528,716	4,950,208	10.68%
G-53	27,840	19,980	47,820	491,411	9.73%
G-54	957	846	1,803	9,741,926	0.02%
Total C/I	1,145,855	1,024,307	2,170,162	54,260,169	4.00%

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas

Ln			May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	**ENERGY NORTH NATURAL GAS, INC.**														
2	**d/b/a National Grid NH**														
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**														
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**														
6	**Underground Storage Gas**														
7			May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		1,900,153	1,948,021	1,976,602	2,006,247	2,006,247	2,151,861	2,297,475	2,352,314	1,977,540	1,501,278	1,086,968	1,058,514	1,900,153
11	Injections (MMBtu)	Sch 11A ln 37 /10	51,376	28,783	29,841	-	145,614	145,614	64,516	3,805	-	-	-	-	469,549
13	Subtotal		1,951,529	1,976,804	2,006,443	2,006,247	2,151,861	2,297,475	2,361,991	2,356,119	1,977,540	1,501,278	1,086,968	1,058,514	
15	Storage Sale		-					-							
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(3,508)	(202)	(196)	-	-	-	(9,677)	(378,578)	(476,262)	(414,310)	(28,453)	-	(1,311,188)
19	Ending Balance (MMBTu)		1,948,021	1,976,602	2,006,247	2,006,247	2,151,861	2,297,475	2,352,314	1,977,540	1,501,278	1,086,968	1,058,514	1,058,514	1,058,514
22	Beginning Balance		$ 11,826,132	$ 12,042,348	$ 12,163,507	$ 12,316,225	$ 12,316,225	$ 12,884,957	$ 13,500,745	$ 13,766,544	$ 11,571,426	$ 8,784,613	$ 6,360,307	$ 6,193,815	11,826,132
24	Injections	ln 11 * ln 36	236,577	121,159	152,718	-	568,732	615,788	322,435	20,103	-	-	-	-	2,037,512
26	Subtotal		$ 12,062,709	$ 12,163,507	$ 12,316,225	$ 12,316,225	$ 12,884,957	$ 13,500,745	$ 13,823,180	$ 13,786,647	$ 11,571,426	$ 8,784,613	$ 6,360,307	$ 6,193,815	
28	Storage Sale		$ -					$ -							
30	Withdrawals	ln 17 * ln 34	$ (20,361)	$ -	$ -	$ -	$ -	$ -	$ (56,636)	$ (2,215,221)	$ (2,786,813)	$ (2,424,305)	$ (166,492)	$ -	$ (7,669,829)
32	Ending Balance		$ 12,042,348	$ 12,163,507	$ 12,316,225	$ 12,316,225	$ 12,884,957	$ 13,500,745	$ 13,766,544	$ 11,571,426	$ 8,784,613	$ 6,360,307	$ 6,193,815	$ 6,193,815	$ 6,193,815
34	Average Rate For Withdrawals	ln 18 /ln 9	$6.1812	$6.1531	$6.1383	$6.1389	$5.9878	$5.8763	$5 8523	$5.8514	$5 8514	$5 8514	$5.8514	$5.8514	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$4.6048	$4.2094	$5.1177	$0 0000	$3.9058	$4.2289	$4 9977	$5.2836	$5.4340	$5.4161	$5.3314	$5.1454	
38	For Informational Purposes								Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
39	Summer Hedge Contracts - Vols Dth								85,700	85,700	85,700	85,700	85,700	85,700	514,200
40	Average Hedge Price								$5.4995	$5.4995	$5.4995	$5.4995	$5.4995	$5.4995	
41	NYMEX								$4 2710	$4.1482	$4 2485	$4 3322	$4.3959	$4.5087	
43	Hedged Volumes at Hedged Price								$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 2,827,857
44	Less Hedged Volumes at NYMEX								366,025	355,501	364,094	371,270	376,731	386,398	2,220,019
45	Hedge (Savings)/Loss								$ 105,285	$ 115,809	$ 107,216	$ 100,040	$ 94,578	$ 84,911	$ 607,838
47	Month Dollar Average	ln (22 + ln 32) /2				$ 12,316,225	$ 12,600,591	$ 13,192,851	$ 13,633,644	$ 12,668,985	$ 10,178,019	$ 7,572,460	$ 6,277,061	$ 6,193,815	
49	Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0 80%	0.93%	0.52%	
51	Inventory Finance Charge	ln 47 * ln 49				$ 7,855	$ 7,366	$ 14,905	$ 15,214	$ 13,495	$ 8,244	$ 5,063	$ 4,865	$ 2,709	
52	Financial Expenses					500	500	500	500	500	500	500	500	500	
53	Total Inventory Finance Charges					$ 8,355	$ 7,866	$ 15,405	$ 15,714	$ 13,995	$ 8,744	$ 5,563	$ 5,365	$ 3,209	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
5
57
58 **Liquid Propane Gas (LPG)**

Ln			May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
59															
60			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
61	Beginning Balance		136,265	136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	136,265
62															
63	Injections	Sch 11A ln 36 /10	-	-	-	-	-	-	-	-	-	-	-	-	-
64															
65	Subtotal		136,265	136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	
66															
67	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	-	(42,680)	(13,730)	-	-	(56,410)
68															
69	Adjustment for change in temperature		(12)	(95)	(57)	-	-	-	-	-	-	-	-	-	(164)
70															
71	Ending Balance		136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	79,691	79,691
72															
73															
74	Beginning Balance		$ 1,992,243	$ 1,990,927	$ 1,989,553	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,365,078	$ 1,164,449	$ 1,164,449	$ 1,992,243
75															
76	Injections	ln 63 * ln 86	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	Subtotal		$ 1,992,243	$ 1,990,927	$ 1,989,553	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,365,078	$ 1,164,449	$ 1,164,449	
79															
80	Withdrawals	ln 69 * ln 84	(1,316)	(1,374)	(833)	-	-	-	-	-	(623,642)	(200,629)	-	-	(827,794)
81															
82	Ending Balance		$ 1,990,927	$ 1,989,553	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,365,078	$ 1,164,449	$ 1,164,449	$ 1,164,449	$ 1,164,449
83															
84	Average Rate For Withdrawals		$14.6204	$14.6120	$14 6120	$14 6120	$14.6120	$14.6120	$14 6120	$14.6120	$14 6120	$14 6120	$14 6120	$14.6120	
85															
86	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$0.0000	$0.0000	$0 0000	$0 0000	$0.0000	$0.0000	$0 0000	$0.0000	$0 0000	$0 0000	$0.0000	$0.0000	
87															
88															
89	Month Dollar Average	ln (74 + ln 82) /2				$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,988,720	$ 1,676,899	$ 1,264,763	$ 1,164,449	$ 1,164,449	
90															
91	Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0 80%	0.93%	0.52%	
92															
93	Inventory Finance Charge	ln 89 * ln 91				$ 1,268	$ 1,163	$ 2,247	$ 2,219	$ 2,118	$ 1,358	$ 846	$ 903	$ 509	
94															
95															
96															
97															

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas

Ln	Liquid Natural Gas (LNG)		May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Estimate)	Sep-10 (Estimate)	Oct-10 (Estimate)	Nov-10 (Estimate)	Dec-10 (Estimate)	Jan-11 (Estimate)	Feb-11 (Estimate)	Mar-11 (Estimate)	Apr-11 (Estimate)	Total
101	Beginning Balance		10,040	8,223	9,447	7,293	7,293	7,293	7,293	7,293	7,293	1,917	1,917	4,315	10,040
103	Injections	Sch 11A ln 35 /10	43	3,054	(325)	-	-	-	2,316	2,399	53,515	19,603	4,797	-	85,402
105	Subtotal		10,083	11,277	9,122	7,293	7,293	7,293	9,609	9,692	60,808	21,520	6,714	4,315	
107	Withdrawals	Sch 11A ln 30 /10	(1,860)	(1,830)	(1,829)	-	-	-	(2,316)	(2,399)	(58,892)	(19,603)	(2,399)	(2,316)	(93,443)
109	Ending Balance		8 223	9 447	7 293	7 293	7 293	7 293	7 293	7 293	1 917	1 917	4 315	1 999	1 999
112	Beginning Balance		$ 56,349	$ 45,714	$ 51,112	$ 39,458	$ 39,458	$ 39,458	$ 39,458	$ 37,821	$ 37,022	$ 9,402	$ 9,333	$ 20,760	$ 56,349
114	Injections	ln 103 * ln 124	(294)	15,299	(1,758)	-	-	-	10,373	11,378	261,284	95,386	22,967	-	414,634
116	Subtotal		$ 56,054	$ 61,013	$ 49,354	$ 39,458	$ 39,458	$ 39,458	$ 49,831	$ 49,198	$ 298,306	$ 104,788	$ 32,300	$ 20,760	
118	Withdrawals	ln 107 * ln 122	(10,340)	(9,901)	(9,896)	-	-	-	(12,010)	(12,177)	(288,903)	(95,455)	(11,540)	(11,142)	(461,364)
120	Ending Balance		$ 45,714	$ 51,112	$ 39,458	$ 39,458	$ 39,458	$ 39,458	$ 37,821	$ 37,022	$ 9,402	$ 9,333	$ 20,760	$ 9,619	$ 9,619
122	Average Rate For Withdrawals		$5.5593	$5.4104	$5.4104	$5.4104	$5.4104	$5.4104	$5.1859	$5.0764	$4 9057	$4 8694	$4.8109	$4.8109	
124	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$4.4789	$5.0096	$4 8824	$4 8659	$4.7875	$4.6671	$4.4789	$4.7433	$4 8824	$4 8659	$4.7875	$4.6671	
127	Month Dollar Average	ln (112 + ln 120) /2				$ 39,458	$ 39,458	$ 39,458	$ 38,639	$ 37,421	$ 23,212	$ 9,368	$ 15,047	$ 15,190	
129	Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0 80%	0.93%	0.52%	
131	Inventory Finance Charge	ln 127 * ln 129				$ 25	$ 23	$ 45	$ 43	$ 40	$ 19	$ 6	$ 12	$ 7	
134	Total Fuel Financing	lns 53 + 93 + 131				$ 9,648	$ 9,052	$ 17,696	$ 17,976	$ 16,153	$ 10,121	$ 6,415	$ 6,279	$ 3,726	

Line			May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
1	**ENERGY NORTH NATURAL GAS, INC.**								
2	**d/b/a National Grid NH**								
3	**Peak 2010 - 2011 Winter Cost of Gas Filing**								
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**								
5									
137									
138	Summer Hedge Program								
139			May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
140	Trade Dates	Contracts	(a)	(b)	(c)	(d)	(e)	(f)	(g)
141	29-May-09								
142	25-Jun-09								
143	27-Jul-09								
144	21-Aug-09								
145	10-Sep-09								
146	23-Oct-09								
147	23-Nov-09								
148	30-Dec-09								
149	29-Jan-10								
150	26-Feb-10								
151	26-Mar-10								
152	23-Apr-10								
153									
154									
155			85,700	85,700	85,700	85,700	85,700	85,700	514,200
156									
157		Prices							
158	29-May-09								
159	25-Jun-09								
160	27-Jul-09								
161	21-Aug-09								
162	10-Sep-09								
163	23-Oct-09								
164	23-Nov-09								
165	30-Dec-09								
166	29-Jan-10								
167	26-Feb-10								
168	26-Mar-10								
169	23-Apr-10								
170									
171									
172									
173		Dollars							
174	29-May-09								
175	25-Jun-09								
176	27-Jul-09								
177	21-Aug-09								
178	10-Sep-09								
179	23-Oct-09								
180	23-Nov-09								
181	30-Dec-09								
182	29-Jan-10								
183	26-Feb-10								
184	26-Mar-10								
185	23-Apr-10								
186									
187									
188			$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 2,827,857
189									
190	Average Hedge Contract Price		5.4995	5.4995	5.4995	5.4995	5.4995	5.4995	5.4995
191	NYMEX		4 2710	4.1550	4.7170	4.7740	4.2413	4.2618	4.4033
192									
193	Hedged Volumes at Hedged Price		$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 471,310	$ 2,827,857
194	Less Hedged Volumes at NYMEX		366,025	356,084	404,247	409,132	363,477	365,236	2,264,200
195	Hedge (Savings)/Loss		$ 105,285	$ 115,226	$ 67,063	$ 62,178	$ 107,833	$ 106,073	563,657
196									
197	Options Loss		$ -	$ -	$ -	-	-	-	$ -
198									
199	Total		$ 105,285	$ 115,226	$ 67,063	$ 62,178	$ 107,833	$ 106,073	$ 563,657
200									
201									

THIS PAGE HAS BEEN REDACTED

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-10	4,237,181	$0.0009	$ 3,813
Dec-10	5,048,836	0.0009	4,544
Jan-11	6,972,340	0.0009	6,275
Feb-11	6,859,501	0.0009	6,174
Mar-11	6,031,744	0.0009	5,429
Apr-11	5,457,896	0.0009	4,912
Total	**34,607,498**		**$ 31,147**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed Second Revised Page 89 for calculation of rate.

McLane

McLane, Graf,
Raulerson & Middleton
Professional Association

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July 29, 2010

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: DG 09-162
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2009-10 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Enclosed are seven copies of the redacted version of the 2009-10 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc d/b/a National Grid NH ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 25,032 dated October 29, 2009 in Docket DG 09-162 This report has been filed electronically with the New Hampshire Public Utilities Commission in accordance with Order Number 24,223 issued on October 24, 2003, in which the Commission found that the filing requirement would be satisfied by filing one electronic copy and one paper copy with the Commission. The Company has also filed separately a confidential version with the Commission.

The filing shows an under collection for the 2009-10 Winter Period of $2,985,736 summarized as follows:

Winter Period Beginning Balance	$779,942
Less: Cost of Gas Revenue Billed	($67,990,127)
Add: Cost of Gas Allowable (5/1/09 -10/31/09)	$2,563,524
Add: Cost of Gas Allowable (11/1/09 -4/30/10)	$67,632,398
Winter Period Ending Balance	$2,985,736

This filing consists of a six-page summary and nine supporting schedules. Page 1 of the Summary compares the actual deferred gas costs to the projections submitted in the Company's filing, including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of $2,985,736. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing, resulting in over collections of $20,082 and $481,137, respectively, for a net under collection for all the gas accounts of $2,484,517. The Bad Debt and Working Capital over collections are the result of the Settlement Agreement in DG 10-051, which the Commission approved in its Order No. 25,094 dated April 29, 2010, revising the bad debt percentage from 1.75% to 2.54% effective May 1, 2009, and adjusting the working capital percentage from .148% to .091% effective May 1, 2009. Page 3 of the Summary compares actual demand charges of $7,011,816 to the $8,016,873 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $60,533,363 compared to $68,266,408 in the filing. The $7,733,045 decrease in commodity costs was caused mainly by lower sendout volumes and prices than originally forecast. The results show that the actual demand and commodity costs were $8,738,103 lower than filed. Page 5 of the Summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather ($3,295,894), changes in demand ($6,619,799), and changes in gas prices $1,177,590. Page 6 of the Summary shows the calculation of the actual Transportation Cost of Gas Revenue compared to the filing.

The attached Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, and interest applied. The third page of Schedule 1 provides the same information for bad debt associated with the cost of gas. Schedule 2 provides the details of gas cost by source. Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital. It shows the monthly beginning account balances, working capital allowable, the working capital collections and the interest applied to derive the monthly ending balances. Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items. Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class. Schedule 8 provides a summary of the monthly commodity costs and related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Please do not hesitate to contact me with questions regarding this filing.

Sincerely,

Steven V. Camerino

Enclosures
cc: Meredith A. Hatfield, Esq.
Thomas P. O'Neill, Esq.
Ann E. Leary

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
NOVEMBER 2009 THROUGH APRIL 2010

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 175.20				
Balance 05/01/09- (Over) / Under	$935,450	$779,942	2/	($155,508)
Peak Gas Costs 5/1/09 - 10/31/09	$3,331,124	$3,454,276	3/	123,152
Fuel Financing 5/1/09 - 10/31/09	97,371	45,531	3/	(51,840)
Prior Period Adjustment 5/1/09-10/31/09	-	(116,154)	3/	(116,154)
Broker Revenue 5/1/09 - 10/31/09	(622,400)	(572,339)	3/	50,061
280 Day Margins 5/1/09 - 10/31/09	-	-	4/	-
IT Sales Margins 5/1/09 - 10/31/09	-	-	4/	-
Off System Sales Margin 5/1/09 - 10/31/09	(73,523)	(13,070)	4/	60,453
Capacity Release 5/1/09 - 10/31/09	(354,811)	(266,941)	4/	87,870
Interest 5/1/09 - 10/31/09	38,237	32,222	3/	(6,015)
Sum 5/1/09 - 10/31/09 costs	$2,415,998	$2,563,524		$147,526
Beginning Balance 10/31/09 (Over)/Under	$3,351,448	$3,343,466		($7,982)
Interest 11/1/09 - 4/30/10	17,216	40,615		23,399
Prior Period Adjustments	-	-		0
Interruptible Sales Margin 11/1/09 - 4/30/10	-	-		-
280-Day Margin 11/1/09 - 4/30/10	-	-		-
Off System Sales Margin 11/1/09 -4/30/10	(28,322)	(1,912)		26,410
Capacity Release Credits 11/1/09 - 4/30/10	(178,872)	(109,620)		69,252
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	40,691	0		(40,691)
Broker Revenues 11/1/09 - 4/30/10	(268,209)	(205,033)		63,176
Production & Storage	1,749,387	1,749,387		0
Misc Overhead	20,121	20,121		0
Fuel Financing 11/1/09 - 4/30/10	112,934	85,395		(27,539)
Transportation Cost of Gas Revenue	8,654	9,404		750
Total Adjustment to Costs	$1,473,600	$1,588,356		$114,756
Gas Costs 11/1/09 - 4/30/10	$74,820,489	$66,044,041		($8,776,448)
Total Gas Costs and Adjustments 11/09 - 4/10	$76,294,089	$67,632,398		($8,661,691)
Gas Cost Billed	($79,645,537)	(67,990,127)		$11,655,410
Total (Over) / Under 04/30/09	$0	$2,985,736		$2,985,736

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
NOVEMBER 2009 THROUGH APRIL 2010

	Original Filing 1/	Actual		Difference
Bad Debts Account 175.52				
Beginning Balance	($212,161)	($212,161)		$0
BD Costs 5/1/09-10/31/09	84,740	80,707	5/	(4,033)
Interest 5/1/09-10/31/09	(2,769)	(2,985)	5/	(216)
Beginning Balance 10/31/09 (Over)/Under	($130,190)	($143,116)		($4,248)
Bad Debt Costs 11/1/08 - 4/30/10	1,924,252	1,699,964		(224,288)
Bad Debt CGA Billed	(1,792,798)	(1,575,361)		217,437
Adjustment	-	-		0
Interest	(1,264)	(1,569)		(305)
Total (Over) / Under 04/30/09	$0	($20,082)		($20,082)
Working Capital Account 142.20				
Beginning Balance	($63,719)	($63,719)		$0
WC Costs 5/1/09-10/31/09	5,116	3,189	6/	(1,927)
Interest 5/1/09-10/31/09	(978)	(8,548)	6/	(7,570)
Beginning Balance 10/31/09 (Over)/Under	($59,581)	($525,428)		($9,496)
Working Capital Costs 11/1/08-4/30/10	65,724	59,764		(5,960)
Working Capital CGA Billed	(5,672)	(7,396)		(1,724)
Adjustment	-	-		0
Interest	(471)	(8,077)		(7,606)
Total (Over) / Under 04/30/09	$0	($481,137)		($481,137)
Total 175.20, 175.52, 142.20	$0	$2,484,517		$2,484,517

1/ As filed 09-01-09 in the Winter 2009-2010 Cost of Gas DG 09-162

2/ The beginning balance is the sum of the actual April 30, 2009 balance $779,942 less the May 2009 Billings of $3,541,223 plus reverse prior month unbilled $3,541,223

3/ The 5/1/09 - 10/31/09 costs are per Schedule 1, page 1, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

4/ The 5/1/09 - 10/31/09 costs are per Schedule 4, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

5/ The 5/1/09 - 10/31/09 costs are per Schedule 1, page 3, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

6/ The 5/1/08 - 10/31/09 costs are per Schedule 5, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2009 THROUGH APRIL 2010

	Filing (a)	1/ Actual May 09 - Oct 09 (b)	Actual Nov 09 - Apr 10 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen					
IEC					
Subtotal Supply Demand Charges	$4,922	$0	$8,609	$8,609	$3,687
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$139,186	$139,186	($21,005)
TGP NET 33371	254,640	-	221,526	221,526	($33,114)
TGP FTA Z5-Z6 2302	92,349	-	80,178	80,178	($12,171)
TGP FTA Z0 - Z6 8587	2,158,540	-	1,864,372	1,864,372	($294,168)
TGP Dracut FTA Z6 - Z6 42076	379,200	-	236,669	236,669	($142,531)
TGP (Concord Lateral) Z6-Z6	2,190,600	-	2,183,055	2,183,055	($7,545)
Portland Natual Gas Pipeline	164,410	-	139,550	139,550	($24,861)
ANE (Uniongas and TransCanada)	196,023	-	252,877	252,877	$56,854
TGP FTA 632	1,078,930	478,704	488,980	967,684	($111,246)
TGP FTA 11234	616,332	279,688	286,981	566,668	($49,664)
National Fuel	245,959	82,560	110,459	193,019	($52,940)
Subtotal Pipeline Demand Charges	$7,537,174	$840,951	$6,003,833	$6,844,785	($692,389)
Peaking Supply					
Granite Ridge					
Chevron					
DOMAC					
Repsol					
Transgas Trucking					
Subtotal Peaking Supply	$608,069	$116,999	$376,158	$493,157	($114,912)
Propane					
Energy North Propane	$0	$0	$44	$ 44	$44
Storage:					
Demand & Capacity Charges	$1,297,225	$ 574,333	$ 547,205	$ 1,121,538	($175,687)
Other:					
Capacity Managed	($1,430,516)	$ (31,146)	($865,595)	$ (896,741)	$533,775
Pipeline Refunds	$0	$ -	(559,575.60)	$ (559,576)	($559,576)
Total Demand Charges (Forward to Page 4)	$8,016,873	$1,501,137	$5,510,679	$7,011,816	($1,005,058)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2009 Cost of Gas Reconciliation, DG 09-050 filed January 28, 2010.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2009 THROUGH APRIL 2010

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	**$8,016,873**		**$7,011,816**		**($1,005,058)**	
TGP						
Therms						
Cost						
Spot Gas						
Therms						
Cost						
Canadian						
Therms						
Cost						
PNGTS						
Therms						
Cost						
Granite Ridge						
Therms						
Cost						
City Gate Delivered Supply						
Therms						
Cost						
DOMAC						
Therms						
Cost						
Storage gas - commodity withdrawn						
Therms						
Cost						
Propane						
Therms						
Cost						
LNG						
Therms						
Cost						
Hedging (Gains) Losses						
Other - Cashout, Broker Penalty, Canadian Managed						
Therms						
Cost						
Prior period Adj						
Subtotal:						
Volumes (net of fuel retention)	86,404,722		76,818,910		(9,585,812)	
Cost	$ 68,266,408	0 7901	$ 60,533,363	0 7880	$ (7,733,045)	(0 0021)
Total Demand and Commodity Costs	$ 76,283,281		$ 67,545,179		$ (8,738,103)	
Demand (therms):	86,404,722		76,818,910		(9,585,812)	
Firm Gas Sales	84,282,098		73,960,615		(10,321,483)	
Lost Gas (Unaccounted For)	1,280,734		1,997,292		716,558	
Unbilled Therms	-		(7,431)		(7,431)	
Fuel Retention	-		-		-	
Company Use	841,891		868,434		26,543	
Total Demand	86,404,722		76,818,910		(9,585,812)	
						-

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate	(A-B)*C Difference
TGP				
Spot Gas				
AES				
PNGTS				
ANE/BP NEXEN				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Volume Weather Varaince	76,818,910	82,285,580		$ (3,295,894)

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate	(B-A)*C Difference
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Demand Variance (Less: Fuel Retention)	86,404,722	76,818,910		$ (9,915,693)
Demand Variance Net of Weather Variance				(6,619,799)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate	(C-B)*A Difference
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Commodity Cost Rate Variance	76,818,910			$ (443,966)
Demand Charge Variance (from page 3)				(1,005,058)
Other Rate Variance (from page 4)				
Hedging (Gains)/Losses				2,912,564
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments				(285,950)
Total Rate Variance				$ 1,177,590
Due to Weather Variance				(3,295,894)
Due to Demand Variance (from above)				(6,619,799)
Total Gas Cost Variance				$ (8,738,103)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162

	FILING	ACTUAL
Cost of Propane	$ -	$ 61,816
Cost of LNG	657,484	128,020
Total Costs	657,484	189,836
Percentage of Supplies Used For Pressure Support Purposes	12.4%	12.4%
Cost of Supplies Used For Pressure Support Purposes	81,528	23,540
Firm Therms Sold	83,801,811	73,960,615
Firm Therms Transported	28,847,194	31,345,540
Total Therms	112,649,005	105,306,155
Actual Liquid Cost/Therm	0.0007	0.0002
Firm Therms Transported	28,847,194	31,345,540
Liquid Costs Allocated to Transported Therms	20,878	7,007
Prior (Over) or under Collection	(30,075)	(30,075)
Total	(9,197)	(23,068)
Costs Recovered:		
Therms Transported	28,847,194	31,345,540
Recovery Rate	(0.0003)	(0.0003)
Costs Recovered	(9,197)	(9,404)
(Over) / Under Collection For Period	-	(13,665)

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Total
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ 3,343,466	$ 2,489,552	$ 1,445,581	$ 2,545,270	$ 2,983,595	$ 2,543,469	$ 3,011,016	**$ 3,343,466**
2									
3	Add: Actual Costs	6,675,106	14,091,677	17,297,920	13,603,630	9,508,475	4,867,234		**66,044,041**
4									
5	Add FPO Admin Costs	-	-	-	-	-	-		-
6	Add: MISC OH	3,354	3,354	3,354	3,354	3,354	3,354		**20,121**
7	Add: Production and Storage	291,565	291,565	291,565	291,565	291,565	291,565		**1,749,387**
8	Add: Fuel Financing	9,252	14,776	19,101	20,197	7,923	14,146		**85,394 88**
9	Reverse Fuel Finance Estimate		-			-			-
10	Add new Fuel Finance Estimate		-			-			-
11									
12	Less: CUSTOMER BILLINGS	(2,430,541)	(9,215,917)	(17,691,580)	(15,224,509)	(12,138,410)	(8,030,486)	(3,249,282)	**(67,980,724)**
13	Estimated Unbilled	(5,344,722)	(11,542,794)	(10,314,221)	(8,518,906)	(6,609,220)	(3,224,002)		**(45,553,865)**
14	Reverse Prior Month Unbilled		5,344,722	11,542,794	10,314,221	8,518,906	6,609,220	3,224,002	**45,553,865**
15	Sub-Total Accrued Customer Billings	(7,775,262)	(15,413,989)	(16,463,007)	(13,429,194)	(10,228,724)	(4,645,268)	(25,280)	**(67,980,724)**
16									
17	Less: REFUND	-	-	-	-	-	-		-
18									
19	Less: Broker Revenues	(18,198)	(28,133)	(47,505)	(50,896)	(24,105)	(36,196)	-	**(205,033)**
20									
21	NON FIRM MARGIN AND CREDITS	(47,509)	(8,644)	(7,238)	(7,213)	(6,232)	(34,696)	-	**(111,532)**
22									
23	ENDING BALANCE PRE INTEREST	**$ 2,481,772**	**$ 1,440,157**	**$ 2,539,770**	**$ 2,976,711**	**$ 2,535,851**	**$ 3,003,607**	**$ 2,985,736**	**$ 2,945,121**
24									
25	MONTH'S AVERAGE BALANCE	2,912,619	1,964,854	1,992,676	2,760,991	2,759,723	2,773,538		
26									
27	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
28									
29	INTEREST APPLIED	7,780	5,424	5,500	6,884	7,618	7,409		**40,615**
30									
31	ENDING BALANCE	**$ 2,489,552**	**$ 1,445,581.15**	**$ 2,545,270**	**$ 2,983,595**	**$ 2,543,469**	**$ 3,011,016**	**$ 2,985,736**	**$ 2,985,736**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-09** **30**	**Dec-09** **31**	**Jan-10** **31**	**Feb-10** **28**	**Mar-10** **31**	**Apr-10** **30**	**May-10**	**Total**
1	BEGINNING BALANCE	$ 520,566	$ 42,382	$ 42,499	$ 42,616	$ 42,722	$ 42,840	$ 42,954	**520,566**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(2,151,248)	-	-	-	-	-	-	**(2,151,248)**
8	Estimated Unbilled		-	-	-	-	-		**-**
9	Reverse Prior Month Unbilled	1,672,313	-	-	-	-	-	-	**1,672,313**
10	Sub-Total Accrued Customer Billings	(478,934)	-	-	-	-	-	-	(478,934)
11									
12	Add: ADJUSTMENTS	-	-	-	-	-	-	-	-
13									
14	ENDING BALANCE PRE INTEREST	**$ 41,631**	**$ 42,382**	**$ 42,499**	**$ 42,616**	**$ 42,722**	**$ 42,840**	**$ 42,954**	**$ 41,631**
15									
16	MONTH'S AVERAGE BALANCE	281,098	42,382	42,499	42,616	42,722	42,840		
17									
18	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
19									
20	INTEREST APPLIED	751	117	117	106	118	114		**1,323**
21									
22	ENDING BALANCE	**$ 42,382**	**$ 42,499**	**$ 42,616**	**$ 42,722**	**$ 42,840**	**$ 42,954**	**$ 42,954**	**$ 42,954**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-09** **30**	**Dec-09** **31**	**Jan-10** **31**	**Feb-10** **28**	**Mar-10** **31**	**Apr-10** **30**	**May-10**	**Total**
1	BEGINNING BALANCE	$ (143,116)	$ (146,419)	$ (148,132)	$ (101,713)	$ (68,213)	$ (37,230)	$ (19,924)	**(143,116)**
2									
3	Add: COST ALLOW	172,454	361,993	443,542	349,622	245,536	126,818		**$ 1,699,964**
4									
5	Adjustment						-	-	-
6									
7	Less: CUSTOMER BILLINGS	(54,890)	(211,359)	(418,438)	(363,729)	(276,801)	(175,108)	(75,037)	**(1,575,361)**
8	Estimated Unbilled	(120,481)	(272,423)	(250,762)	(202,945)	(140,552)	(74,879)		**(1,062,041)**
9	Reverse Prior Month Unbilled		120,481	272,423	250,762	202,945	140,552	74,879	**1,062,041**
10	Sub-Total Accrued Customer Billings	(175,371)	(363,301)	(396,778)	(315,911)	(214,408)	(109,435)	(158)	(1,575,361)
11									
12	ENDING BALANCE PRE INTEREST	**$ (146,033)**	**$ (147,726)**	**$ (101,369)**	**$ (68,001)**	**$ (37,085)**	**$ (19,848)**	**$ (20,082)**	**$ (18,513)**
13									
14	MONTH'S AVERAGE BALANCE	(144,575)	(147,073)	(124,751)	(84,857)	(52,649)	(28,539)		
15									
16	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
17									
18	INTEREST APPLIED	(386)	(406)	(344)	(212)	(145)	(76)		**$ (1,569)**
19									
20	ENDING BALANCE	**$ (146,419)**	**$ (148,132)**	**$ (101,713)**	**$ (68,213)**	**$ (37,230)**	**$ (19,924)**	**$ (20,082)**	**$ (20,082)**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-09** **30**	**Dec-09** **31**	**Jan-10** **31**	**Feb-10** **28**	**Mar-10** **31**	**Apr-10** **30**	**May-10**	**Total**
1	BEGINNING BALANCE	$ 57,023	$ 62,362	$ 62,534	$ 62,707	$ 62,863	$ 63,037	$ 63,205	**57,023**
2									
3	Add: COST ALLOW	-	-	-	-	-	-		**$ -**
4									
5	Less: CUSTOMER BILLINGS	(24,895)	-	-	-	-	-	-	**(24,895)**
6	Estimated Unbilled		-	-	-	-	-		-
7	Reverse Prior Month Unbilled	30,074	-	-	-	-	-	-	**30,074**
8	Sub-Total Accrued Customer Billings	5,180	-	-	-	-	-	-	**5,180**
9									
10	ENDING BALANCE PRE INTEREST	**$ 62,203**	**$ 62,362**	**$ 62,534**	**$ 62,707**	**$ 62,863**	**$ 63,037**	**$ 63,205**	**$ 62,203**
11									
12	MONTH'S AVERAGE BALANCE	59,613	62,362	62,534	62,707	62,863	63,037		
13									
14	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
15									
16	INTEREST APPLIED	159	172	173	156	174	168		**1,002**
17									
18	ENDING BALANCE	**$ 62,362**	**$ 62,534**	**$ 62,707**	**$ 62,863**	**$ 63,037**	**$ 63,205**	**$ 63,205**	**$ 63,205**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
GAS COSTS BY SOURCE
SCHEDULE 2A

	FOR THE MONTH OF:	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
1	**DEMAND**							
2								
3	ALBERTA NORTHEAST							
4	BP							
5	TOTAL CANADIAN	$ 18,457 98	$ 31,081 69	$ 28,675 88	$ 55,737 27	$ 42,731 19	$ 44,534 92	**$ 221,218.93**
6								
7	PEAKING SUPPLY	(12,047 78)	(12,608 75)	(12,608 75)	(13,403 46)	(12,004 25)	(1,515 03)	(64,188 02)
8								
9	TRANSPORT CAPACITY	579,408 15	1,271,460 87	912,325 58	977,129 59	971,114 33	967,164 86	**5,678,603.38**
10								
11	STORAGE FIXED COSTS	95,969 76	133,471 25	147,681 84	(3,905 12)	101,673 87	72,313 07	**547,204.67**
12								
13	LNG	-	98,462 92	98,462 92	169,742 44	73,678 08	0 02	**440,346.38**
14								
15	PROPANE	7 94	3 97	11 91	11 91	15 88	(7 94)	**43.67**
16								
17	CANADIAN CAPACITY MANAGED	(6,104 43)	(6,303 43)	(25,883 07)	(43,094 40)	(157,497 69)	(626,711 50)	**(865,594.52)**
18	Ppipeline Refunds	-	(421,568 97)	-	-	-	(138,006 63)	**(559,575.60)**
19	OTHER	500 00	500 00	500 00	500 00	500 00	500 00	**3,000.00**
20								
21	CAPACITY RELEASE ADJUSTMENT	47,509 14	6,890 06	7,237 66	7,213 26	6,232 38	34,537 30	**109,619.80**
22								
23	**TOTAL DEMAND**	**$ 723,700.76**	**$ 1,101,389.61**	**$ 1,156,403.97**	**$ 1,149,931.49**	**$ 1,026,443.79**	**$ 352,809.07**	**$ 5,510,678.69**
24								
25	**COMMODITY**							
26								
27	ALBERTA NORTHEAST / BP							
28	Nexem							
29	SEMPRA							
30	SUBTOTAL CANADIAN COMMODITY							
31								
32	PIPELINE TRANSPORT COMM							
33	Distrigas							
34	VPEM Citigate Delivery							
35								
36	GAS SUPPLY							
37								
38	STORAGE COMMODITY							
39								
40	LNG							
41								
42	PROPANE							
43								
44	**OTHER COST ADJUSTMENTS**							
45	CANDIAN CAPACITY MANAGED							
46	SUPPLIER CASHOUT							
47	NET OTHER COST ADJUSTMENTS	(122,645 67)	4,614 55	(155,638 04)	(37,683 23)	(24,010 74)	49,412 65	**(285,950.48)**
48								
49	**SUBTOTAL COMMODITY COST**	**$ 5,951,404.76**	**$ 12,997,629.61**	**$ 16,141,516.39**	**$ 12,453,698.04**	**$ 8,482,031.48**	**$ 4,531,556.24**	**$ 60,557,836.52**
50								
51	OFF SYSTEM SALES COST							
52	NON-FIRM COST							
53								
54	**TOTAL COMMODITY COST**	**$ 5,951,404.76**	**$ 12,990,287.05**	**$ 16,141,516.39**	**$ 12,453,698.04**	**$ 8,482,031.48**	**$ 4,514,425.00**	**$ 60,533,362.72**

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56 **ENERGY NORTH NATURAL GAS, INC**
57 **D/B/A NATIONAL GRID NH**
58 **NOVEMBER 2009 THROUGH APRIL 2010**
59 **GAS COSTS SUMMARY**
60 **SCHEDULE 2A**
61

	FOR THE MONTH OF:	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
62	**FOR THE MONTH OF:**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
63								
64	**Total Peak Demand**	**$ 723,700.76**	**$ 1,101,389.61**	**$ 1,156,403.97**	**$ 1,149,931.49**	**$ 1,026,443.79**	**$ 352,809.07**	**$ 5,510,678.69**
65	**Off-Peak Demand**	-	-	-	-	-	-	-
66	**Total Demand**	**$ 723,700.76**	**$ 1,101,389.61**	**$ 1,156,403.97**	**$ 1,149,931.49**	**$ 1,026,443.79**	**$ 352,809.07**	**$ 5,510,678.69**
67								
68	**Total Peak Commodity**	**$ 5,951,404.76**	**$ 12,990,287.05**	**$ 16,141,516.39**	**$ 12,453,698.04**	**$ 8,482,031.48**	**$ 4,514,425.00**	**$ 60,533,362.72**
69	**Off-Peak Commodity**	-	-	-	-	-	-	-
70	**Total Commodity**	**$ 5,951,404.76**	**$ 12,990,287.05**	**$ 16,141,516.39**	**$ 12,453,698.04**	**$ 8,482,031.48**	**$ 4,514,425.00**	**$ 60,533,362.72**
71								
72	**Firm Sendout Costs**	**$ 6,675,105.52**	**$ 14,091,676.66**	**$ 17,297,920.36**	**$ 13,603,629.53**	**$ 9,508,475.27**	**$ 4,867,234.07**	**$ 66,044,041.41**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	**DEMAND**							
2	**Supply**							
3	ALBERTA NORTHEAST							
4	Northeast Gas Markets/BP							
5	**Subtotal Canadian Supply**	**$ 18,457.98**	**$ 31,081.69**	**$ 28,675.88**	**$ 55,737.27**	**$ 42,731.19**	**$ 44,534.92**	**$ 221,218.93**
6	**Peaking Suppy**							
7	Repsol							
8	Granite Ridge							
9	Cheveron							**5,280.59**
10	VPEM Demand Charges							
11	**Subtotal Peaking Supply**	**$ (12,047.78)**	**$ (12,608.75)**	**$ (12,608.75)**	**$ (13,403.46)**	**$ (12,004.25)**	**$ (1,515.03)**	**$ (64,188.02)**
12								
13	**Transport Capacity**							
14	Iroquois 470-01-RTS	$ 23,106.65	$ 23,132.36	$ 23,252.82	$ 23,218.57	$ 23,227.08	$ 23,248.69	**$ 139,186.17**
15	National Fuel N02358	20,438.86	18,127.56	18,069.82	17,958.90	17,932.01	17,932.01	**110,459.16**
16	PNGTS FT-1999-001	21,921.36	21,921.36	21,921.36	27,401.70	21,921.36	21,921.36	**137,008.50**
17	TGP 632 FTA	21,293.66	134,600.48	78,784.64	78,784.64	78,525.48	78,790.53	**470,779.43**
18	TGP 2302 FTA Zone 5-6	13,335.65	13,291.28	13,399.74	13,366.50	15,406.25	11,378.44	**80,177.86**
19	TGP 8587 FTA	368,134.36	246,362.99	312,910.77	312,178.12	312,024.79	312,761.20	**1,864,372.23**
20	TGP 11234 FTA	18,987.50	46,525.59	46,201.77	46,113.42	46,184.10	46,207.66	**250,220.04**
21	TGP 33371 NET	37,209.27	36,540.84	36,890.97	36,901.58	36,933.41	37,050.12	**221,526.19**
22	TGP 72694 NET	-	730,200.00	359,708.69	366,092.60	363,991.65	363,061.80	**2,183,054.74**
23	TGP 42076 FTA	54 980.84	758.41	1 185.00	55 113.56	54 968.20	54 813.05	**221,819.06**
24	**Subtotal Transport Capacity**	**$ 579,408.15**	**$ 1,271,460.87**	**$ 912,325.58**	**$ 977,129.59**	**$ 971,114.33**	**$ 967,164.86**	**$ 5,678,603.38**
25								
26	**Storage Fixed**							
27	Sempra	$ -	$ -	$ -	$ -	$ 6,000.00	$ -	**$ 6,000.00**
28	Dominion 300076-Storage	2,867.64	2,864.55	2,605.42	2,715.61	2,854.53	2,870.82	**16,778.57**
29	NFG Deliverability FSS 2357	36,594.09	74,327.30	33,636.29	(2,003.44)	36,849.14	36,911.36	**216,314.74**
30	Tenn Reservation FSMA 523	47,763.64	47,535.01	93,953.47	(4,619.41)	47,225.81	23,786.50	**255,645.02**
31	HONEOYE STORAGE SS-NY	8,744.39	8,744.39	17,486.66	2.12	8,744.39	8,744.39	**52,466.34**
32	**Subtotal Storage**	**$ 95,969.76**	**$ 133,471.25**	**$ 147,681.84**	**$ (3,905.12)**	**$ 101,673.87**	**$ 72,313.07**	**$ 547,204.67**
33								
34	**LNG / DISTRIGAS FLS 164**							
35	**LNG/ DISTRIGAS FLS160**							
36	**Transgas Trucking**							
37	**Subtotal Distrigas**	$ -	$ 98,462.92	$ 98,462.92	$ 169,742.44	$ 73,678.08	$ 0.02	**$ 440,346.38**
38								
39	**Propane**							
40	**En Propane**	$ 7.94	$ 3.97	$ 11.91	$ 11.91	$ 15.88	$ (7.94)	**43.67**
41								
42	**Intercontinental Exchange**	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	**3,000.00**
43								
44	**Capacity Managed - Canadian**							
45								
46	**PNGTS Refund per RP02-13**							
47	**TGP Pipeline Refund**	$ -	$ (421,568.97)	$ -	$ -	$ -	$ (138,006.63)	**(559,575.60)**
48								
49	**Demand Subtotal**	**$ 676,191.62**	**$ 1,094,499.55**	**$ 1,149,166.31**	**$ 1,142,718.23**	**$ 1,020,211.41**	**$ 318,271.77**	**$ 5,401,058.89**
50								
51	**Capacity Release Adjustment**							
52	ALBERTA NORTHEAST							
53	TGP - FT-A 632							
54	TGP - FT-A 11234							
55	TGP - FT-A 8587							
56	PNGTS - FT							
57								
58								
59	**TOTAL DEMAND**	**$ 723,700.76**	**$ 1,101,389.61**	**$ 1,156,403.97**	**$ 1,149,931.49**	**$ 1,026,443.79**	**$ 352,809.07**	**$ 5,510,678.69**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

60	**FOR THE MONTH OF:**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
61								
62	**COMMODITY**							
63								
64	**Canadian Supply**							
65	BP							
66	Nexen							
67	Sempra							
68	**Subtotal Canadian Commodity**							
69								
70	**Pipeline Transport**							
71	ANE Union/Dawn							
72	Dominion							
73	El Paso							
74	Iroquois							
75	National Fuel							
76	PNGTS							
77	HONEOYE							
78	**Subtotal Transp Commodity**							
79								
80	**City Gate Delivery**							
81	DISTRIGAS							
82	VPEM							
83	**Subtotal Citygate Delivery**							
84								
85	**PNGTS Supply**							
86	Dte Energy							
87	Emera							
88	Conoco							
89	**Subtotal PNGTS**							
90								
91	**Gas Supply**							
92	Andarko							
93	Chevron							
94	Colonial Energy							
95	Cheniere							
96	Conoco							
97	Emera							
98	Enjet							
99	ETC							
100	FPL Energy							
101	Hess							
102	L. Dreyfus							
103	Macquarie							
104	NJR Energy							
105	Nextera							
106	PSE&G							
107	Repsol							
108	Shell US							
109	Tenaska							
110	Total Gas & Power							
111	United LLC							
112	**Total Other TGP Supply**							
113								
114	**Peaking Supply**							
115	Granite Ridge (formerly AES)							
116								
117	NYMEX Hedging - Settlement							
118								
119	**STORAGE WITHDRAWALS**							
120								
121	**STORAGE INJECTIONS**							
122								
123	DISTRIGAS (FCS 064)							
124	LNG VAPOR							
125	LNG BOIL OFF							
126	**Subtotal LNG**							
127								
128	**PROPANE**							
129	Propane Storage Withdrawal							
130	Energy North Propane							
131	**Subtotal Propane**							
132								
133	Broker Cashout							
134	Other Taxes W. Virginia							
135	**Subtotal Cashouts**							
136								
137	Capacity Managed - Canadian							
138	Broker Inventory							
139	**Subtotal Capacity Managed**							
140								
141	**TOTAL COMMODITY**							
142								
143	Off System Gas Sales Cost							
144	NON-FIRM COST							
145								
146	**NET COMMODITY COST**	**$ 5,951,404.76**	**$ 12,990,287.05**	**$ 16,141,516.39**	**$ 12,453,698.04**	**$ 8,482,031.48**	**$ 4,514,425.00**	**$ 60,533,362.72**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
147	**FOR THE MONTH OF:**		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**Total**
148									
149	Peak Demand 175.20		$ 723,700.76	$ 1,101,389.61	$ 1,156,403.97	$ 1,149,931.49	$ 1,026,443.79	$ 352,809.07	$ 5,510,678.69
150	Peak Commodity 175.20		5,951,404.76	12,990,287.05	16,141,516.39	12,453,698.04	8,482,031.48	4,514,425.00	60,533,362.72
151	Total Peak Gas Costs		**$ 6,675,105.52**	**$ 14,091,676.66**	**$ 17,297,920.36**	**$ 13,603,629.53**	**$ 9,508,475.27**	**$ 4,867,234.07**	**$ 66,044,041.41**
152									
153	Off-Peak Demand 175.40	OP	-	-	-	-	-	-	-
154	Off-Peak Comm 175.40	OP	-	-	-	-	-	-	-
155	Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
156									
157	Firm Sendout Costs		**$ 6,675,105.52**	**$ 14,091,676.66**	**$ 17,297,920.36**	**$ 13,603,629.53**	**$ 9,508,475.27**	**$ 4,867,234.07**	**$ 66,044,041.41**

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	**Nov-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Total**	**Total**
		OffPeak	Peak						Peak	Peak	OffPeak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1	43,546	22,466	83,309	123,502	105,569	91,502	74,363	43,220	**543,931**	**43,546**
4	R-1 FPO	3,683	1,658	6,882	10,639	8,833	7,571	6,289	3,509	**45,381**	**3,683**
5	R-3	1,926,915	1,278,405	4,633,856	9,007,885	7,823,752	5,202,330	3,335,509	1,401,539	**32,683,276**	**1,926,915**
6	R-3 FPO	308,576	216,678	771,969	1,477,771	1,259,546	841,274	562,296	236,050	**5,365,584**	**308,576**
7	R-4	75,205	41,616	274,425	546,899	534,276	1,082,384	640,163	311,203	**3,430,966**	**75,205**
8	R-4 FPO	22,832	13,683	70,664	143,113	132,266	213,564	106,428	51,776	**731,494**	**22,832**
9	Total Residential	2,380,757	1,574,506	5,841,105	11,309,809	9,864,242	7,438,625	4,725,048	2,047,297		
10	**COMMERCIAL/INDUSTRIAL**										
11	G41 - G43	1,316,110	734,804	3,139,779	6,705,088	5,860,033	4,393,269	2,643,016	1,027,128	**24,503,117**	**1,316,110**
12	G41 - G43 (FPO)	77,495	57,639	249,693	549,840	423,411	358,563	210,954	89,815	**1,939,915**	**77,495**
13	Total G41- G43	1,393,605	792,443	3,389,472	7,254,928	6,283,444	4,751,832	2,853,970	1,116,943		
14	G51 - G63	356,098	195,721	641,863	1,009,418	865,236	749,760	597,829	334,085	**4,393,912**	**356,098**
15	G51 - G63 (FPO)	18 631	14 303	50 525	70 821	63 546	55 118	44 189	24 537	**323,039**	**18,631**
16	Total G51-G63	374,729	210,024	692,388	1,080,239	928,782	804,878	642,018	358,622		
17	Total Sales Volumes	4,149,091	2,576,973	9,922,965	19,644,976	17,076,468	12,995,335	8,221,036	3,522,862	**73,960,615**	**4,149,091**
18	**TRANSPORTATION**										
19	G41 - G43	1,085,587	419,274	2,119,244	3,622,643	3,429,341	2,806,380	1,921,067	973,457	**15,291,406**	**1,085,587**
20	G51 - G63	2,404,030	70,393	2,602,036	3,029,009	2,949,257	2,459,644	2,680,676	2,263,119	**16,054,134**	**2,404,030**
21	Total Transportation Volumes	3 489 617	489 667	4 721 280	6 651 652	6 378 598	5 266 024	4 601 743	3 236 576	**31,345,540**	**3,489,617**
22	**Total Volumes**	**7,638,708**	**3,066,640**	**14,644,245**	**26,296,628**	**23,455,066**	**18,261,359**	**12,822,779**	**6,759,438**	**105,306,155**	**7,638,708**
23											
24	**RATES**										
25	Residential	0.51940	0.94490	0.92840	0.89230	0.88280	0.93500	0.97390	0.91710		
26	Residential (FPO)	0.51940	0.9649	0.96490	0.96490	0.96490	0.96490	0.96490	0.96490		
27	C/I Sales G41 to G43	0.51990	0.94510	0.92940	0.89330	0.88240	0.93100	0.97770	0.91730		
28	C/I Sales G41 to G43 (FPO)	0.51990	0.9651	0.96510	0.96510	0.96510	0.96510	0.96510	0.96510		
29	C/I Transport G41 to G43	0.00000	-0.0003	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030		
30	C/I Sales G51 to G63	0.51790	0.94440	0.92890	0.89240	0.88200	0.93320	0.97410	0.91660		
31	C/I Sales G51 to G63 (FPO)	0.51790	0.9644	0.96440	0.96440	0.96440	0.96440	0.96440	0.96440		
32	C/I Transport G51 to G63	0.00000	-0.0003	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030		
33											
34	**REVENUES**										
35	Residential	$ 1,062,519	$ 1,268,516	$ 4,634,192	$ 8,635,935	$ 7,471,663	$ 5,961,762	$ 3,944,329	$ 1,610,393	**$ 33,526,790**	**$ 1,062,519**
36	Residential (FPO)	$ 174,046	$ 223,875	$ 819,697	$ 1,574,257	$ 1,351,482	$ 1,025,118	$ 651,320	$ 281,109	**$ 5,926,859**	**$ 174,046**
37	C/I Sales G41 to G43	$ 684,246	$ 694,463	$ 2,918,111	$ 5,989,655	$ 5,170,893	$ 4,090,133	$ 2,584,077	$ 942,185	**$ 22,389,517**	**$ 684,246**
38	C/I Sales G41 to G43 (FPO)	$ 40,290	$ 55,627	$ 240,979	$ 530,651	$ 408,634	$ 346,049	$ 203,592	$ 86,680	**$ 1,872,212**	**$ 40,290**
39	C/I Transport G41 to G43	$ -	$ (126)	$ (636)	$ (1,087)	$ (1,029)	$ (842)	$ (576)	$ (292)	**$ (4,587)**	**$ -**
40	C/I Sales G51 to G63	$ 184,423	$ 184,839	$ 596,227	$ 900,805	$ 763,138	$ 699,676	$ 582,345	$ 306,222	**$ 4,033,252**	**$ 184,423**
41	C/I Sales G51 to G63 (FPO)	$ 9,649	$ 13,794	$ 48,726	$ 68,300	$ 61,284	$ 53,156	$ 42,616	$ 23,663	**$ 311,539**	**$ 9,649**
42	C/I Transport G51 to G63	$ -	$ (21)	$ (781)	$ (909)	$ (885)	$ (738)	$ (804)	$ (679)	**$ (4,816)**	**$ -**
43	**Winter Gas Cost Rev filed**	**$ 2,155,173**	**$ 2,440,968**	**$ 9,256,515**	**$ 17,697,606**	**$ 15,225,181**	**$ 12,174,315**	**$ 8,006,898**	**$ 3,249,282**	**$ 68,050,764**	**$ 2,155,173**
44											
45	Winter Proration	$ -	$ (10,427)	$ (31,752)	$ (3,508)	$ 1,264	$ (33,696)	$ 24,182	$ -	**(53,937)**	**-**
46											
47	Less Occupant Billing	$ 3,925	$ -	$ 8,846	$ 2,518	$ 1,937	$ 2,209	$ 594	$ -	**16,104**	**3,925**
48	Total	$ 2,151,248	$ 2,430,541	$ 9,215,917	$ 17,691,580	$ 15,224,509	$ 12,138,410	$ 8,030,486	$ 3,249,282	$ 67,980,724	$ 2,151,248
49											
50	**Summer Gas Cost Billed (Acct 175.40)**	**$ 2,151,248**									**$ 2,155,173**
51											
52	Winter Gas Costs Billed (Acct 175.20)		**$ 2,430,688**	**$ 9,217,333**	**$ 17,693,576**	**$ 15,226,422**	**$ 12,139,990**	**$ 8,031,866**	**$ 3,250,253**	**$ 67,990,127**	
53	Winter Transportation Gas Costs Billed (Acct 175.20)	**-**	**(147)**	**(1,416)**	**(1,995)**	**(1,914)**	**(1,580)**	**(1,381)**	**(971)**	**$ (9,404)**	**$ -**
54	**Total Winter Gas Cost Billed (Acct 175.20)**	**$ -**	**$ 2,430,541**	**$ 9,215,917**	**$ 17,691,580**	**$ 15,224,509**	**$ 12,138,410**	**$ 8,030,486**	**$ 3,249,282**	**$ 67,980,724**	**$ 2,155,173**
55											
56				$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57	Total Sales CGA Billed	**$ 2,151,248**	**$ 2,430,541**	**$ 9,215,917**	**$ 17,691,580**	**$ 15,224,509**	**$ 12,138,410**	**$ 8,030,486**	**$ 3,249,282**	**$ 67,980,724**	**$ 2,151,248**
58											
59	Plus Working Capital Gas Cost Billed	7,468	258	992	1,964	1,708	1,300	822	352	**7,396**	**7,468**
60	Plus Bad Debt Cost Billed	24,895	54,890	211,359	418,438	363,729	276,801	175,108	75,037	**1,575,361**	**24,895**
61	Plus Broker Revenues	-	18,198.39	28,132.63	47,504.98	50,896.38	24,104.78	36,195.99	-	**205,033**	**-**
62											
63	**Total Winter Gas Costs Billed**	**$ 2,183,610**	**$ 2,503,886**	**$ 9,456,401**	**$ 18,159,488**	**$ 15,640,841**	**$ 12,440,615**	**$ 8,242,612**	**$ 3,324,671**	**$ 69,768,514**	**$ 2,183,610**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)

	FOR MONTH OF:	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	Firm Gas Purchases		8,549,860	17,700,130	19,325,140	15,419,480	10,460,760	5,363,540	76,818,910
2	Firm Sales		2,576,973	9,922,965	19,644,976	17,076,468	12,995,335	8,221,036	70,437,753
3	Company Use		94,202	183,551	194,629	187,074	122,695	86,283	868,434
4	Unaccounted For %		2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	
5	Unaccounted For Gas		222,296	460,203	502,454	400,906	271,980	139,452	1,997,292
6	COG Factor- Gas Cost Only		$0.9449	$0.9025	$0.8761	$0.8941	$1.0016	$0.9171	
7	COG Factor- Bad Debt Factor		$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	
8	COG Factor- Working Capital Factor		$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	
9									
10	Unbilled Volume								
11	Beginning Bal		-	5,656,389	12,789,799	11,772,881	9,527,912	6,598,662	
12	Incremental Unbilled		5,656,389	7,133,411	(1,016,919)	(2,244,968)	(2,929,250)	(3,083,231)	
13	Ending Balance	-	5,656,389	12,789,799	11,772,881	9,527,912	6,598,662	3,515,431	
14									
15	COG Factor- Gas Cost Only		$0.9449	$0.9025	$0.8761	$0.8941	$1.0016	$0.9171	
16	Gross Unbilled Gas Cost	$1,672,313	$5,344,722	$11,542,794	$10,314,221	$8,518,906	$6,609,220	$3,224,002	
17									
18	Monthly Incremental Gas Cost		$3,672,409	$6,198,072	($1,228,573)	($1,795,314)	($1,909,686)	($3,385,218)	
19									
20	COG Factor- Bad Debt Only		$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	
21	Gross Unbilled Bad Debt Cost	$19,318	$120,481	$272,423	$250,762	$202,945	$140,552	$74,879	
22									
23	Monthly Incremental Bad Debt Cost		$101,163	$151,942	($21,660)	($47,818)	($62,393)	($65,673)	
24									
25	COG Factor- Working Capital Only		$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	
26	Gross Unbilled Working Capital Cost	$5,795	$566	$1,279	$1,177	$953	$660	$352	
27									
28	Monthly Incremental Working Capital Cost		($5,230)	$713	($102)	($224)	($293)	($308)	

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	INTERRUPTIBLE							
2								
3	280 DAY							
4								
5	OFF SYSTEM GAS SALES MARGIN							
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT							
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	**$ (47,509)**	**$ (8,644)**	**$ (7,238)**	**$ (7,213)**	**$ (6,232)**	**$ (34,696)**	**$ (111,532)**

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	**Nov-09** 30	**Dec-09** 31	**Jan-10** 31	**Feb-10** 28	**Mar-10** 31	**Apr-10** 30	**May-10**	**Total**
1	BEGINNING BALANCE	$ (525,428)	$ (521,640)	$ (512,006)	$ (499,590)	$ (489,980)	$ (483,716)	$ (481,136)	**$ (525,428)**
2									
3	Add: COST ALLOW	6,008	12,765	15,673	12,324	8,613	4,380		**59,764**
4									
5	Less: CUSTOMER BILLINGS	(258)	(992)	(1,964)	(1,708)	(1,300)	(822)	(352)	**(7,396)**
6	Estimated Unbilled	(566)	(1,279)	(1,177)	(953)	(660)	(352)		**(4,986)**
7	Reverse Prior Month Unbilled	-	566	1,279	1,177	953	660	352	**4,986**
8	Subtotal: Accrued Customer Billings	(823)	(1,706)	(1,863)	(1,483)	(1,007)	(514)	(1)	**(7,396)**
9									
10	Adjustment	-	-	-	-	-	-	-	-
11									
12	ENDING BALANCE PRE INTEREST	**(520,243)**	**(510,581)**	**(498,196)**	**(488,748)**	**(482,374)**	**(479,849)**	**(481,137)**	**(473,060)**
13									
14	MONTH'S AVERAGE BALANCE	(522,836)	(516,111)	(505,101)	(494,169)	(486,177)	(481,783)		
15									
16	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
17	INTEREST APPLIED	(1,397)	(1,425)	(1,394)	(1,232)	(1,342)	(1,287)		**(8,077)**
18	ENDING BALANCE	**$ (521,640)**	**$ (512,006)**	**$ (499,590)**	**$ (489,980)**	**$ (483,716)**	**$ (481,136)**	**$ (481,137)**	**$ (481,137)**

ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Total
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ (91,430)	$ (93,349)	$ (93,607)	$ (93,865)	$ (94,099)	$ (94,359)	$ (94,611)	**(91,430)**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$ -**
4									**0**
5	Less: CUSTOMER BILLINGS	(7,468)	-	-	-	-	-	-	**(7,468)**
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	5,795	-	-	-	-	-	-	**5,795**
8	Subtotal: Accrued Customer Billings	(1,673)	-	-	-	-	-	-	**(1,673)**
9									
10	ENDING BALANCE PRE INTEREST	**(93,103)**	**(93,349)**	**(93,607)**	**(93,865)**	**(94,099)**	**(94,359)**	**(94,611)**	**(93,103)**
11									
12	MONTH'S AVERAGE BALANCE	(92,266)	(93,349)	(93,607)	(93,865)	(94,099)	(94,359)		
13									
14	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
15	INTEREST APPLIED	(246)	(258)	(258)	(234)	(260)	(252)		**(1,508)**
16	ENDING BALANCE	**$ (93,349)**	**$ (93,607)**	**$ (93,865)**	**$ (94,099)**	**$ (94,359)**	**$ (94,611)**	**$ (94,611)**	**$ (94,611)**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	**Demand**	$ 676,192	$ 1,092,746	$ 1,149,166	$ 1,142,718	$ 1,020,211	$ 318,113	**5,399,147**
2	**Commodity**	5,951,405	12,990,287	16,141,516	12,453,698	8,482,031	4,514,425	**60,533,363**
3	**Total Gas Costs**	**$ 6,627,596**	**$ 14,083,033**	**$ 17,290,683**	**$ 13,596,416**	**$ 9,502,243**	**$ 4,832,538**	$ 65,932,509
4								
5	**Lead Lag Days**	**10 18**	**10 18**	**10.18**	**10.18**	**10.18**	**10 18**	
6	**Prime Rate**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	
7								
8	**Working Capital Rate**	0 00091	0 00091	0 00091	0 00091	0 00091	0 00091	
9								
10	**Total Working Capital Costs**	**$ 6,008**	**$ 12,765**	**$ 15,673**	**$ 12,324**	**$ 8,613**	**$ 4,380**	**$ 59,764**
11								
12	**Prior Period Undercollection**	155,908	155,908	155,908	155,908	155,908	155,908	**935,450**
13								
14	**Subtotal Gas Costs, Working Capital & Under Collection**	6,789,512	14,251,707	17,462,264	13,764,649	9,666,764	4,992,827	**66,927,723**
15								
16	**Bad Debt Rate 1/**	0 0254	0 0254	0 0254	0 0254	0 0254	0 0254	
17								
18	**Total Bad Debt Cost**	**$ 172,454**	**$ 361,993**	**$ 443,542**	**$ 349,622**	**$ 245,536**	**$ 126,818**	**$ 1,699,964**

ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Total Gas Costs**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4								
5	Working Capital Rate	0 00091	0 00091	0 00091	0 00091	0 00091	0 00091	
6								
7	**Total Working Capital Costs**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8								
9	Prior Period Undercollection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10								
11	Subtotal Gas Costs, Working Capital & Under Collection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12								
13	Bad Debt Rate	0 0254	0 0254	0 0254	0 0254	0 0254	0 0254	
14								
15	**Total Bad Debt Cost**	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	OffPeak Nov-09	Peak Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak May-10	Total Peak
1	**VOLUMES**									
2	**RESIDENTIAL**									
3	R-1, R-3 and R-4	2,045,666	1,342,487	4,991,590	9,678,286	8,463,597	6,376,216	4,050,035	1,755,962	**36,658,173**
4	R-1, R-3 and R-4 (FPO)	335,091	232,019	849,515	1,631,523	1,400,645	1,062,409	675,013	291,335	**6,142,459**
5										
6	**COMMERCIAL/INDUSTRIAL**									
7	G41 - G43	1,316,110	734,804	3,139,779	6,705,088	5,860,033	4,393,269	2,643,016	1,027,128	**24,503,117**
8	G41 - G43 (FPO)	77,495	57,639	249,693	549,840	423,411	358,563	210,954	89,815	**1,939,915**
9	G51 - G63	356,098	195,721	641,863	1,009,418	865,236	749,760	597,829	334,085	**4,393,912**
10	G51 - G63 (FPO)	18,631	14,303	50,525	70,821	63,546	55,118	44,189	24,537	**323,039**
11										
12	**TRANSPORTATION**									
13	G41 - G43	1,085,587	419,274	2,119,244	3,622,643	3,429,341	2,806,380	1,921,067	973,457	**15,291,406**
14	G51 - G63	2,404,030	70,393	2,602,036	3,029,009	2,949,257	2,459,644	2,680,676	2,263,119	**16,054,134**
15										
16	**TOTAL VOLUME**	**7,638,708**	**3,066,640**	**14,644,245**	**26,296,628**	**23,455,066**	**18,261,359**	**12,822,779**	**6,759,438**	**105,306,155**
17										
18	**WORKING CAPITAL RATES**									
19	Residential R1, R3 & R4	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
20	Residential R1, R-3 & R4 (FPO)	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
21	C/I Sales G41 to G43	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
22	C/I Sales G41 to G43 (FPO)	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
23	C/I Sales G51 to G63	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
24	C/I Sales G51 to G63 (FPO)	$0 0018	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	$0 0001	
25										
26	**WORKING CAPITAL COSTS COLLECTED**									
27	Residential	$ 3,682	$ 134	$ 499	$ 968	$ 846	$ 638	$ 405	$ 176	**$ 3,666**
28	Residential (FPO)	603	23	85	163	140	106	68	29	**614**
29	C/I Sales G41 to G43	2,369	73	314	671	586	439	264	103	**2,450**
30	C/I Sales G41 to G43 (FPO)	139	6	25	55	42	36	21	9	**194**
31	C/I Sales G51 to G63	641	20	64	101	87	75	60	33	**439**
32	C/I Sales G51 to G63 (FPO)	34	1	5	7	6	6	4	2	**32**
33										
34	**SUMMER GAS COST WORKING CAPITAL COLLE**	**$ 7,468**	**$ 258**	**$ 992**	**$ 1,964**	**$ 1,708**	**$ 1,300**	**$ 822**	**$ 352**	**$ 7,396**
35										
36	**BAD DEBT RATES**									
37	Residential R1, R3 & R4	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
38	Residential R1 & R3 (FPO)	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
39	C/I Sales G41 to G43	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
40	C/I Sales G41 to G43 (FPO)	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
41	C/I Sales G51 to G63	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
42	C/I Sales G51 to G63 (FPO)	$0 0060	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	$0 0213	
43										
44	**BAD DEBTS COLLECTED**									
45	Residential R1, R3 & R4	$ 12,274	$ 28,595	$ 106,321	$ 206,147	$ 180,275	$ 135,813	$ 86,266	$ 37,402	**$ 780,819**
46	Residential R1, R-3 & R4 (FPO)	2,011	4,942	18,094 67	34,751 44	29,833 74	22,629 31	14,377 78	6,205 44	**130,834**
47	C/I Sales G41 to G43	7,897	15,651	66,877 29	142,818 37	124,818 70	93,576 63	56,296 24	21,877 83	**521,916**
48	C/I Sales G41 to G43 (FPO)	465	1,228	5,318 46	11,711 59	9,018 65	7,637 39	4,493 32	1,913 06	**41,320**
49	C/I Sales G51 to G63	2,137	4,169	13,671 68	21,500 60	18,429 53	15,969 89	12,733 76	7,116 01	**93,590**
50	C/I Sales G51 to G63 (FPO)	112	305	1,076 18	1,508 49	1,353 53	1,174 01	941 23	522 64	**6,881**
51										
52	**SUMMER BAD DEBTS COLLECTED**	**$ 24,895**	**$ 54,890**	**$ 211,359**	**$ 418,438**	**$ 363,729**	**$ 276,801**	**$ 175,108**	**$ 75,037**	**$ 1,575,361**

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

	FOR THE MONTH OF:	**Nov-09**		**Dec-09**		**Jan-10**		**Feb-10**		**Mar-10**		**Apr-10**		**Total**	
		Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	**Dollar**	**Volume Dkt**
	TENNESEE COMMODITY														
1	Gas Supply														
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TGP SUPPLY														
6															
7	PNGTS														
8	TOTAL TGP & PNGTS														
9															
10															
11															
12	**CITIGATE DELIVERY**														
13	VPEM														
14	Distrigas														
15															
16															
17	BP COMMODITY														
18	SEMPRA														
19	NEXEN														
20	TOTAL CANADIAN COMMODITY														
21															
22															
23	**LNG**														
24	Distrigas (FCS 064)														
25															
26	LNG Vapor														
27	LNG Injections														
28	Subtotal LNG														
29															
30															
31															
32	**Propane**														
33	Propane Withdrawal														
34	EN Propane														
35	Total Propane														
36															
37															
38	Storage Withdrawals														
39															
40															
41	Hedging Settlements														
42															
43	Cashouts														
44															
45	Capacity Managed														
46															
47	Taxes														
48															
49	Non-Firm Costs														
50															
51															
52	**NET COMMODITY COST**	**$ 5,951,405**	**854,986**	**$ 12,990,287**	**1,770,013**	**$ 16,141,516**	**1,932,514**	**$ 12,453,698**	**1,541,948**	**$ 8,482,031**	**1,046,076**	**$ 4,514,425**	**536,354**	**$ 60,533,363**	**7,681,891**

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ENERGY NORTH NATURAL GAS, INC

D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-09	11/01 - 11/30	**3.25%**	30	3.2500%
Dec-09	12/01 - 012/31	**3.25%**	31	3.2500%
Jan-10	01/01 - 01/31	**3.25%**	31	3.2500%
Feb-10	02/01 - 02/28	**3.25%**	28	3.2500%
Mar-10	03/01 - 03/31	**3.25%**	31	3.2500%
Apr-10	04/01 - 04/30	**3.25%**	30	3.2500%

Local Distribution Adjustment Charge Calculation

			Reference
Residential Non Heating Rates - R-1			
Energy Efficiency Charge	$0.0525		Energy Efficiency Page 1
Demand Side Management Charge	0 0000		
Conservation Charge (CCx)		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	0 0000		
Manufactured Gas Plants	0 0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0000	Emergency Response Incentive
Rate Case Expense Factor (RCEF)		0.0000	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0116	RILAP Page 1
LDAC		**$0.0641 per therm**	
Residential Heating Rates - R-3, R-4			
Energy Efficiency Charge	$0.0525		Energy Efficiency Page 1
Demand Side Management Charge	0 0000		Conserva ion Charge
Conservation Charge (CCx)		$0.0525	
Relief Holder and pond at Gas Street, Concord, NH	0 0000		
Manufactured Gas Plants	0 0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0000	Emergency Response Incentive
Rate Case Expense Factor (RCEF)		0.0000	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0116	RILAP Page 1
LDAC		**$0.0641 per therm**	
Commercial/Industrial Low Annual Use Rates - G-41, G-51			
Energy Efficiency Charge	$0.0306		Energy Efficiency Page 1
Demand Side Management Charge	0 0000		Conserva ion Charge
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0 0000		
Manufactured Gas Plants	0 0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0000	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0116	RILAP Page 1
LDAC		**$0.0422 per therm**	
Commercial/Industrial Medium Annual Use Rates - G-42, G-52			
Energy Efficiency Charge	$0.0306		Energy Efficiency Page 1
Demand Side Management Charge	0 0000		Conserva ion Charge
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0 0000		
Manufactured Gas Plants	0 0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0000	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0116	RILAP Page 1
LDAC		**$0.0422 per therm**	
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54			
Energy Efficiency Charge	$0.0306		Energy Efficiency Page 1
Demand Side Management Charge	0 0000		Conserva ion Charge
Conservation Charge (CCx)		$0.0306	
Relief Holder and pond at Gas Street, Concord, NH	0 0000		
Manufactured Gas Plants	0 0000		Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0000	
DG 06-107 Emergency Response Incentive		0.0000	Emergency Response Incentive
Gas Restructuring Expense Factor (GREF)		0.0000	
Rate Case Expense Factor (RCEF)		0.0000	Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0116	RILAP Page 1
LDAC		**$0.0422 per therm**	

Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Resdential Customers

Rate Case Expense	$	-
Temporary Rate Reconciliation		-
Rate Case Expense Reconciliaiton Adjustment		
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	-

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		60,288,480
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		97,732,153
Total Volumes		158,020,633
Rate Case Expense Factor	$	-

DG 06-107 Merger Settlement - Emergency Response Incentive

Emergency Response Merger Incentive

Merger Incentive - Emergency Response	$	-
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
		150,828,182
Total Volumes		
Rate Case Expense Factor	$	-

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Residential Low Income Assistance Program (RLIAP)

Ln		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 15.7800	$ 0.2774	$ 0.2091		
3	R-4 Rate at 40% of R-3	$ 6.3100	$ 0.1110	$ 0.0836		
4	Program Subsidy	$ 9.4700	$ 0.1664	$ 0.1255		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 56.82	$ 95.21	$ 25.46	$ 177.49	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 15.7800	$ 0.2774	$ 0.2091		
11	R-4 Rate at 40% of R-3	$ 6.3100	$ 0.1110	$ 0.0836		
12	Program Subsidy	$ 9.4700	$ 0.1664	$ 0.1255		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 56.82	$ 19.67	$ 6.54	$ 83.03	
16						
17	Estimated Annual Subsidy	$ 113.64	$ 114.88	$ 32.00	$ 260.52	
18						
19	Number of Estimated 2010/11 Participants				7,213	1/
20						
21	Annual Subsidy times Number of Particpants (Ln 17 * Ln 19)				$ 1,879,126	
22	Prior Year Ending Balance - RLIAP Page 2				(56,043)	
23	Estimated Annual Administrative Costs				8,600	
24	Total Program Costs				$ 1,831,683	
25						
26	Estimated weather normalized firm therms billed for					
27	the twelve months ended 10/31/11 sales and transportation				158,020,633	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0116**	

1/ Estimated number of participants for 2010-11 is based on the actual number participants as of June 2010, as provided in the RLIAP Quarterly Report as revised and filed on July 28, 2010.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
NOVEMBER 2009 THROUGH OCTOBER 2010
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

											(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (53,229)	$ (97,456)	$ (155,055)	$ (276,840)	$ (370,705)	$ (274,501)	$ (220,226)	$ (174,894)	$ (144,193)	$ (120,786)	$ (94,798)	$ (73,759)	$ (53,229)
4														
5	Add: Actual Costs	42,097	87,727	139,146	139,146	277,881	181,880	131,834	91,463	74,296	72,604	72,828	80,961	1,391,864
6														
7	Less: Collected Revenue	(86,122)	(144,978)	(260,337)	(232,205)	(180,787)	(126,946)	(85,957)	(60,336)	(50,524)	(46,319)	(51,565)	(63,066)	(1,389,141)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (97,255)	$ (154,707)	$ (276,245)	$ (369,899)	$ (273,612)	$ (219,566)	$ (174,350)	$ (143,767)	$ (120,421)	$ (94,501)	$ (73,534)	$ (55,864)	**$ (50,507)**
12														
13	Month's Average Balance	$ (75,242)	$ (126,081)	$ (215,650)	$ (323,370)	$ (322,159)	$ (247,034)	$ (197,288)	$ (159,331)	$ (132,307)	$ (107,644)	$ (84,166)	$ (64,812)	
14														
15	Interest Rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	
16														
17	Interest Applied	$ (201)	$ (348)	$ (595)	$ (806)	$ (889)	$ (660)	$ (545)	$ (426)	$ (365)	$ (297)	$ (225)	$ (179)	**(5,536)**
18														
19	Ending Balance	**$ (97,456)**	**$ (155,055)**	**$ (276,840)**	**$ (370,705)**	**$ (274,501)**	**$ (220,226)**	**$ (174,894)**	**$ (144,193)**	**$ (120,786)**	**$ (94,798)**	**$ (73,759)**	**$ (56,043)**	**$ (56,043)**

Conservation Charge (CC) Factor Calculation

Conservation Charge Factors for Residential Customers (CCres)

DSM Expenses	$0	Backup Page 4 Line 7
Residential Lost Margins	$0	Backup Page 5 Line 5
Residential Conservation Reconciliation Adjustment (CCRres)	(4,523)	Backup Page 2 Line 11
Total Rate Case Expense Recoverable	($4,523)	
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	59,255,995	
Conservation Charge Factor for Residential Customers (CCres)	**$0.0000**	

Conservation Charge Factors for Commercial Customers (CCcomm)

DSM Expenses	$0	Backup Page 4 Line 24
Commercial Lost Margins	$0	Backup Page 5 Line 16
Commercial Conservation Reconciliation Adjustment (CCRcomm)	(3,932)	Backup Page 2 Line 28
Total Rate Case Expense Recoverable	($3,932)	
Forecasted Annual Throughput Volumes for Commercial Customer (A:VOLcomm)	97,732,153	
Conservation Charge Factor for Commercial Customers (CCres)	**$0.0000**	

2009/2010 EnergyNorth Conservation Charge Reconciliation

Line No.		Actual 2009	Actual 2009	Actual 2009	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Estimate 2010	2010	
	Domestic Heating:	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
1	**Beginning balance**	(32,464)	($33,899)	($31,658)	($28,288)	($21,650)	($15,851)	($11,484)	($8,725)	($6,974)	($5,968)	($5,208)	($4,511)	($32,464)
2	Therms sold	2,242,518	3,883,910	5,750,914	11,175,668	9,749,840	7,339,552	4,644,396	2,954,208	1,705,880	1,290,888	1,184,525	-	51,922,299
3	Surcharge (Tariff Pg 91)	(0 0006)	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	-	
4	Revenue collected	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
5	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Lost net rev (Pg 4 Ln 5)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Under/(over)	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
8	Pre-interest ending balance	(33,809)	(31,569)	(28,207)	(21,583)	(15,800)	(11,447)	(8,698)	(6,952)	(5,950)	(5,193)	(4,497)	(4,511)	(4,002)
9	Average monthly balance	(33,137)	(32,734)	(29,932)	(24,935)	(18,725)	(13,649)	(10,091)	(7,839)	(6,462)	(5,580)	(4,853)	(4,511)	(18,233)
10	Interest for month	(90)	(89)	(81)	(68)	(51)	(37)	(27)	(21)	(18)	(15)	(13)	(12)	(521)
11	**Month-end balance**	(33,899)	(31,658)	(28,288)	(21,650)	(15,851)	(11,484)	(8,725)	(6,974)	(5,968)	(5,208)	(4,511)	(4,523)	(4,523)
12	Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%
13														
14		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate		
15		2009	2009	2009	2010	2010	2010	2010	2010	2010	2010	2010	2010	
16	**Commercial Heating:**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
17	**Beginning balance**	(3,807)	($3,817)	($3,827)	($3,838)	($3,848)	($3,858)	($3,869)	($3,879)	($3,890)	($3,900)	($3,911)	($3,922)	($3,807)
18	Therms sold	4,661,905	6,750,085	8,803,140	14,986,819	13,590,824	10,822,734	8,097,731	5,663,319	4,332,261	3,714,352	3,527,312	-	84,950,482
19	Surcharge (Tariff Pg 91)	-	-	-	-	-	-	-	-	-	-	-	-	
20	Revenue collected	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Lost net rev (Pg 4 Ln 16)	-	-	-	-	-	-	-	-	-	-	-	-	-
23			-											-
24	Under/(over)	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Pre-interest ending balance	(3,807)	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,807)
26	Average monthly balance	(3,807)	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,807)
27	Interest for month	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(11)	(11)	(11)	(11)	(11)	(126)
28	**Month-end balance**	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,932)	(3,932)
29	Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	
30														
31		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate		
32		2009	2009	2009	2010	2010	2010	2010	2010	2010	2010	2010	2010	
33	**TOTAL**	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
34	**Beginning balance**	($36,271)	($37,716)	($35,485)	($32,126)	($25,498)	($19,709)	($15,353)	($12,604)	($10,864)	($9,868)	($9,119)	($8,432)	($36,271)
35	Therms sold	6,904,423	10,633,995	14,554,054	26,162,487	23,340,664	18,162,286	12,742,127	8,617,527	6,038,141	5,005,240	4,711,837	-	136,872,781
36	Revenue collected	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
37	Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Lost net revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Under/(over)	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
40	Pre-interest ending balance	(37,616)	(35,386)	(32,034)	(25,420)	(19,648)	(15,306)	(12,567)	(10,832)	(9,840)	(9,094)	(8,408)	(8,432)	(7,808)
41	Interest for month	(100)	(99)	(91)	(78)	(61)	(47)	(38)	(32)	(28)	(26)	(24)	(23)	(647)
42	**Month-end balance**	(37,716)	(35,485)	(32,126)	(25,498)	(19,709)	(15,353)	(12,604)	(10,864)	(9,868)	(9,119)	(8,432)	(8,455)	(8,455)
43	Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	

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2009/2010 EnergyNorth Conservation Charge Reconciliation

Actual Throughput

Line No.		2009 OCT	2009 NOV	2009 DEC	2010 JAN	2010 FEB	2010 MAR	2010 APR	2010 MAY	2010 JUN	2010 JUL	2010 AUG	2010 SEP	TOTAL
	Domestic Heating:													
1	Therms sold - actual	2,242,518	3,883,910	5,750,914	11,175,668	9,749,840	7,339,552	4,644,396	2,954,208	1,705,880	1,290,888	1,184,525	1,197,519	53,119,818
2	Surcharge (Tariff Pg 94)	($0 0006)	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	
3	Revenue - actual	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	719	29,181
4														
5														
6														
7	**Commercial Heating:**													
8	Therms sold - actual	4,661,905	6,750,085	8,803,140	14,986,819	13,590,824	10,822,734	8,097,731	5,663,319	4,332,261	3,714,352	3,527,312	3,498,640	88,449,122
9	Surcharge (Tariff Pg 94)	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	
10	Revenue - actual	-	-	-	-	-	-	-	-	-	-	-	-	-
11														
12														
13	**Total:**													
14	Therms sold - actual	6,904,423	10,633,995	14,554,054	26,162,487	23,340,664	18,162,286	12,742,127	8,617,527	6,038,141	5,005,240	4,711,837	4,696,159	141,568,940
15	Revenue - actual	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	719	29,181

2009/2010 EnergyNorth Conservation Charge Reconciliation

Actual Expenses

Line No.		2009 OCT	2009 NOV	2009 DEC	2010 JAN	2010 FEB	2010 MAR	2010 APR	2010 MAY	2010 JUN	2010 JUL	2010 AUG	2010 SEP	TOTAL
	Residential Expenses Incurred													
1	Administrative	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Total Residential Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9														
10														
11	**Commercial Expenses Incurred**													
12														
13	Administrative:													
14	Delivery Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Photocopies	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Telephone	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Travel	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Legal	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
23														
24	Total Commercial Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-

2009/2010 ENERGYNORTH LOST MARGIN SUMMARY

Line No.		2009 Oct	2009 Nov	2009 Dec	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 June	2010 July	2010 Aug	2010 Sep	TOTAL
	Residential Heating													
	fiscal 2008													
1	Lost Vol Therms (Pg 6 Ln 29)												-	-
2	Tailblock Rate	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.1859	$0.2070	$0.2091	$0.2091	$0.2091	
3	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	
5	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6														
7														
8														
9	**Commercial and Industrial**													
10														
11	**fiscal 2008**													
12	Lost Vol Therms (Pg 5 Ln 53)													-
13	Tailblock Rate	$0.1469	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1636	$0.1652	$0.1652	$0.1652	
14	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
16	Lost Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17														
18														
19	**Total**													
20														
21	**fiscal 2008**													
22	Lost Volume Therms	-	-	-	-	-	-	-	-	-	-	-	-	
23	Tailblock Rate													
24	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	recovery rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	0%	57%
26	recoverable portion	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ENERGYNORTH 2007/2008 LOST MARGIN CALCULATION BACKUP

Line No.	**Actual tailblock margin**	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	
1	**Domestic Heating**	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.2070	0.2091	0.2091	0.2091	
2														
3	**Commercial Heating**	0.1469	0.1757	0.1757	0.1757	0.1757	0.1757	0.1757	0.1757	0.1636	0.1652	0.1652	0.1652	
4														
5	**Normal heating degree days (calendar):**													
6		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total
7														
8	Heating Degree Days	322	602	921	1,077	926	822	498	221	9	-	-	36	5,434
9														
10	Percent of Total	5.93%	11.08%	16.95%	19.82%	17.04%	15.13%	9.16%	4.07%	0.17%	0.00%	0.00%	0.66%	100.00%
11														

Residential Heating

Line		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	F Y 97	FY98	FY99	FY00	FY01
13																				
14								Therms								Pg 8 Ln32	Pg 7 Ln31	Pg 6 Ln14		
15	**program year 2010**																			
16	**DH** - therm savings fiscal															Savings	Savings	Savings	Savings	Savings
17	Oct-08													-	15,432	8,616	6,816	-	0	0
18	Nov-08													-	16,450	3,455	12,996	-	0	0
19	Dec-08													-	25,866	4,342	15,945	5,579	0	0
20	Jan-09													-	25,818	4,088	6,134	15,596	0	0
21	Feb-09													-	36,373	9,277	12,457	14,639	0	0
22	Mar-09													-	31,547	8,055	14,524	8,969	0	0
23	Apr-09													-	36,059	10,465	17,113	8,481	0	0
24	May-09													-	16,633	11,922	4,711	-	0	0
25	Jun-09													-	32,762	23,809	7,258	1,695	0	0
26	Jul-09													-	15,798	12,412	3,386	-	0	0
27	Aug-09													-	17,875	12,514	1,331	4,030	0	0
28	Sep-09													-	34,800	28,758	5,981	61	0	0
29	totals	-	-	-	-	-	-	-	-	-	-	-	-	-	305,409	137,710	108,649	59,050	-	-
30																				
31	Rate	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.2070	0.2091	0.2091	0.2091							
32	Margin	-	-	-	-	-	-	-	-	-	-	-	-	-						
33	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
34		-	-	-	-	-	-	-	-	-	-	-	-	-						
35																				

Commercial Heating

Line		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	Total	F Y 97	FY98	FY99	FY00	FY01
37																				
38								Therms								Pg 8 Ln49	Pg 7 Ln48			
39	**program year 2010**																			
40	**CH** - therm savings															Savings	Savings	Savings	Savings	Savings
41	Oct-08													-	189	-	189	0	0	0
42	Nov-08													-	567	378	189	0	0	0
43	Dec-08													-	1,189	439	750	0	0	0
44	Jan-09													-	945	189	756	0	0	0
45	Feb-09													-	399	189	210	0	0	0
46	Mar-09													-	945	378	567	0	0	0
47	Apr-09													-	189	-	189	0	0	0
48	May-09													-	378	-	378	0	0	0
49	Jun-09													-	1,256	567	689	0	0	0
50	Jul-09													-	549	549	-	0	0	0
51	Aug-09													-	189	189	-	0	0	0
52	Sep-09													-	1,000	-	1,000	0	0	0
53	totals													-	7,795	2,878	4,917	-	-	-
54																				
55	Rate	$0.1469	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1757	$0.1636	$0.1652	$0.1652	$0.1652							
56	Margin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						
57	Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%							
58	Total Recovery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0						

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures: Residential	Actual DSM Expenditures: Low-Income	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
May 10	Actual	(777,780)	($0.0466)	(140,695)	194,285	371,331	68,102	(479,042)	(628,411)	**3.25%**	(1,735)	(480,776)	3,689,942	3,019,211	31
June 10	Actual	(480,776)	($0.0466)	(82,124)	194,285	130,876	304	(431,721)	(456,249)	3.25%	(1,219)	(432,940)	1,849,958	1,762,309	30
July 10	Actual	(432,940)	($0.0466)	(62,377)	194,285	379,088	23,026	(93,202)	(263,071)	3.25%	(726)	(93,928)	1,349,637	1,338,555	31
August 10	Forecast	(93,928)	($0.0466)	(55,476)	194,285	0	0	44,881	(24,524)	3.25%	(68)	44,813	1,190,474	0	31
September 10	Forecast	44,813	($0.0466)	(60,598)	194,285	0	0	178,501	111,657	3.25%	298	178,799	1,300,391	0	30
October 10	Forecast	178,799	($0.0466)	(91,179)	194,285	0	0	281,905	230,352	3.25%	636	282,541	1,956,634	0	31
November 10	Forecast	282,541	($0.0525)	(222,182)	194,285	0	0	254,644	268,593	3.25%	717	255,362	4,236,072	0	30
December 10	Forecast	255,362	($0.0525)	(331,466)	194,285	0	0	118,182	186,772	3.25%	516	118,697	6,319,650	0	31
January 11	Forecast	118,697	($0.0525)	(618,072)	240,490	0	0	(258,884)	(70,093)	3.25%	(193)	(259,078)	11,784,020	0	31
February 11	Forecast	(259,078)	($0.0525)	(562,460)	240,490	0	0	(581,047)	(420,062)	3.25%	(1,047)	(582,095)	10,723,744	0	28
March 11	Forecast	(582,095)	($0.0525)	(465,037)	240,490	0	0	(806,641)	(694,368)	3.25%	(1,917)	(808,558)	8,866,291	0	31
April 11	Forecast	(808,558)	($0.0525)	(320,571)	240,490	0	0	(888,638)	(848,598)	3.25%	(2,267)	(890,905)	6,111,933	0	30
May 11	Forecast	(890,905)	($0.0525)	(184,373)	240,490	0	0	(834,787)	(862,846)	3.25%	(2,382)	(837,169)	3,515,209	0	31
June 11	Forecast	(837,169)	($0.0525)	(112,334)	240,490	0	0	(709,013)	(773,091)	3.25%	(2,065)	(711,078)	2,141,739	0	30
July 11	Forecast	(711,078)	($0.0525)	(87,574)	240,490	0	0	(558,161)	(634,619)	3.25%	(1,752)	(559,913)	1,669,660	0	31
August 11	Forecast	(559,913)	($0.0525)	(70,227)	240,490	0	0	(389,649)	(474,781)	3.25%	(1,311)	(390,960)	1,338,936	0	31
September 11	Forecast	(390,960)	($0.0525)	(69,446)	240,490	0	0	(219,916)	(305,438)	3.25%	(816)	(220,731)	1,324,044	0	30
October 11	Forecast	(220,731)	($0.0525)	(118,389)	240,490	0	0	(98,630)	(159,681)	3.25%	(441)	(99,071)	2,257,182	0	31
November 11	Forecast	(99,071)	($0.0525)	(222,182)	240,490	0	0	(80,762)	(89,917)	3.25%	(240)	(81,003)	4,236,072	0	30
December 11	Forecast	(81,003)	($0.0525)	(331,466)	240,490	0	0	(171,978)	(126,490)	3.25%	(349)	(172,327)	6,319,650	0	31

Estimated Residential Nonheating Conservation Charge Effective November 1, 2010 - October 31, 2011		
Beginning Balance	$	282,541
Program Budget Nov 10-Oct 11		2,793,476
Projected Interest		(15,648)
Projected Budget with Interest	$	3,060,369
Total Charges	**$**	**3,060,369**
Projected Therm Sales		**58,353,540**
Residential Rate		**$0.0524**
Total Charges with Interest	**$**	**3,060,369**
Projected Therm Sales		**58,353,540**
Residential Rate		**$0.0525**

Residential Non Heating Therm Sales	1%	**1,051,312**	**1,032,484**	1%
Residential Heating Therm Sales	38%	**57,302,228**	**59,255,995**	37%
C&I Therm Sales	61%	**92,474,643**	**97,732,153**	62%
Total Therms	100%	**150,828,182**	**158,020,633**	100%
		Year One Budget	Year Two Budget	
		1/01/10 - 12/31/10	**1/01/11 - 12/31/11**	
Low-Income Program Budget		**$ 635,997**	**$ 730,895**	
Other Refund		-	-	
Total Shared Budget		**$ 635,997**	**$ 730,895**	
Residential Program Budget		**$ 1,939,128**	**$ 2,359,779**	
Residential Program Incentive		**$146,238**	**$247,254**	
Total Residential Program Budget		**$ 2,085,366**	**$ 2,607,032**	
Commercial/Industrial Program Budget		**$ 2,411,290**	**$ 3,174,772**	
Commercial/Industrial Program Incentive		**$154,045**	**$253,982**	
Total Commercial/Industrial Program Budget		**$ 2,565,335**	**$ 3,428,754**	
Total Program Budget		**$ 5,286,699**	**$ 6,766,682**	
Shared Expenses Allocation to Residential		$ 246,059	$ 278,853	
Shared Expenses Allocation to C&I		389,938	452,042	
Total Allocated Shared Expenses		**$ 635,997**	**$ 730,895**	
Total Residential (including allocation of Shared Budget)		$ 2,331,426	$ 2,885,886	
Total C&I (including allocation of Shared Budget)		2,955,273	3,880,796	
Total Budget		**$ 5,286,699**	**$ 6,766,682**	

00000112

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Com-Ind	Actual DSM Expenditures Low-Income	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Commercial/ Industrial Therm Sales	# of Days
May 10	Actual	(1,282,952)	($0 0250)	(141,583)	246,273	82,708	90,275	(1,251,553)	(1,267,252)	**3.25%**	(3,498)	(1,255,051)	6,415,202	5,663,319	31
June 10	Actual	(1,255,051)	($0 0250)	(108,307)	246,273	46,243	403	(1,316,712)	(1,285,881)	3.25%	(3,435)	(1,320,147)	4,841,323	4,332,261	30
July 10	Actual	(1,320,147)	($0 0250)	(92,859)	246,273	86,534	30,522	(1,295,949)	(1,308,048)	3.25%	(3,611)	(1,299,560)	3,759,005	3,714,352	31
August 10	Forecast	(1,299,560)	($0 0250)	(87,325)	246,273	0	0	(1,140,612)	(1,220,086)	3.25%	(3,368)	(1,143,980)	3,492,988	0	31
September 10	Forecast	(1,143,980)	($0 0250)	(97,837)	246,273	0	0	(995,544)	(1,069,762)	3.25%	(2,858)	(998,402)	3,913,470	0	30
October 10	Forecast	(998,402)	($0 0250)	(110,504)	246,273	0	0	(862,633)	(930,518)	3.25%	(2 568)	(865 202)	4,420,152	0	31
November 10	Forecast	(865,202)	($0 0306)	(222,613)	246,273	0	0	(841,542)	(853,372)	3.25%	(2,280)	(843,822)	7,274,929	0	30
December 10	Forecast	(843,822)	($0 0306)	(290,429)	246,273	0	0	(887,978)	(865,900)	3.25%	(2,390)	(890,368)	9,491,159	0	31
January 11	Forecast	(890,368)	($0 0306)	(473,205)	323,400	0	0	(1,040,173)	(965,271)	3.25%	(2,664)	(1,042,838)	15,464,220	0	31
February 11	Forecast	(1,042,838)	($0 0306)	(448,319)	323,400	0	0	(1,167,757)	(1,105,297)	3.25%	(2,756)	(1,170,513)	14,650,932	0	28
March 11	Forecast	(1,170,513)	($0 0306)	(388,392)	323,400	0	0	(1,235,505)	(1,203,009)	3.25%	(3,321)	(1,238,826)	12,692,550	0	31
April 11	Forecast	(1,238,826)	($0 0306)	(308,463)	323,400	0	0	(1,223,889)	(1,231,357)	3.25%	(3,289)	(1,227,178)	10,080,479	0	30
May 11	Forecast	(1,227,178)	($0 0306)	(205,063)	323,400	0	0	(1,108,842)	(1,168,010)	3.25%	(3,224)	(1,112,066)	6,701,400	0	31
June 11	Forecast	(1,112,066)	($0 0306)	(144,693)	323,400	0	0	(933,359)	(1,022,712)	3.25%	(2,732)	(936,091)	4,728,513	0	30
July 11	Forecast	(936,091)	($0 0306)	(128,330)	323,400	0	0	(741,021)	(838,556)	3.25%	(2,315)	(743,336)	4,193,795	0	31
August 11	Forecast	(743,336)	($0 0306)	(117,224)	323,400	0	0	(537,160)	(640,248)	3.25%	(1,767)	(538,927)	3,830,853	0	31
September 11	Forecast	(538,927)	($0 0306)	(116,576)	323,400	0	0	(332,104)	(435,516)	3.25%	(1,163)	(333,267)	3,809,661	0	30
October 11	Forecast	(333,267)	($0 0306)	(147,298)	323,400	0	0	(157,166)	(245,216)	3.25%	(677)	(157,842)	4,813,663	0	31
November 11	Forecast	(157,842)	($0 0306)	(222,613)	323,400	0	0	(57,056)	(107,449)	3.25%	(287)	(57,343)	7,274,929	0	30
December 11	Forecast	(57,343)	($0 0306)	(290 429)	323,400	0	0	(24 372)	(40,857)	3.25%	(113)	(24 485)	9,491,159	0	31

Estimated C & I Conservation Charge Effective November 1, 2010 - October 31, 2011	
Beginning Balance	($865,202)
Program Budget	3,726,542
Projected Interest	(31,529)
Program Budget with Interest	$2,829,811
Total Charges	**$2,829,811**
Projected Therm Sales	**92,474,643**
C&I Rate	$0.0306
Total Charges with Interest	**$2,829,811**
Projected Therm Sales	**92,474,643**
Com/Ind Rate	**$0.0306**
Com/Ind Rate from Prior Programs (1)	**$0.0000**
Combined Com/Ind Rate	**$0.0306**

00000113

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Com-Ind	Low-Income	Total	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Therm Sales	# of Days
May 10	Actual	(2,060,732)	n/a	(282,278)	440,558	371,331	82,708	158,377	612,416	(1,730,594)	(1,895,663)	**3.25%**	(5,233)	(1,735,827)	10,105,145	8,682,530	31
June 10	Actual	(1,735,827)	n/a	(190,431)	440,558	130,876	46,243	706	177,825	(1,748,432)	(1,742,130)	3 25%	(4,654)	(1,753,086)	6,691,280	6,094,570	30
July 10	Actual	(1,753,086)	n/a	(155,236)	440,558	379,088	86,534	53,548	519,170	(1,389,152)	(1,571,119)	3 25%	(4,337)	(1,393,488)	5,108,643	5,052,907	31
August 10	Forecast	(1,393,488)	n/a	(142,801)	440,558	0	0	0	0	(1,095,731)	(1,244,610)	3 25%	(3,435)	(1,099,167)	4,683,462	0	31
September 10	Forecast	(1,099,167)	n/a	(158,435)	440,558	0	0	0	0	(817,044)	(958,105)	3 25%	(2,559)	(819,603)	5,213,861	0	30
October 10	Forecast	(819,603)	n/a	(201,683)	440,558	0	0	0	0	(580,728)	(700,166)	3 25%	(1,933)	(582,661)	6,376,786	0	31
November 10	Forecast	(582,661)	n/a	(444,795)	440,558	0	0	0	0	(586,897)	(584,779)	3 25%	(1,562)	(588,460)	11,511,001	0	30
December 10	Forecast	(588,460)	n/a	(621,895)	440,558	0	0	0	0	(769,796)	(679,128)	3 25%	(1,875)	(771,671)	15,810,809	0	31
January 11	Forecast	(771,671)	n/a	(1,091,277)	563,890	0	0	0	0	(1,299,057)	(1,035,364)	3 25%	(2,858)	(1,301,915)	27,248,240	0	31
February 11	Forecast	(1,301,915)	n/a	(1,010,779)	563,890	0	0	0	0	(1,748,804)	(1,525,360)	3 25%	(3,803)	(1,752,607)	25,374,676	0	28
March 11	Forecast	(1,752,607)	n/a	(853,429)	563,890	0	0	0	0	(2,042,146)	(1,897,377)	3 25%	(5,237)	(2,047,383)	21,558,841	0	31
April 11	Forecast	(2,047,383)	n/a	(629,034)	563,890	0	0	0	0	(2,112,527)	(2,079,955)	3 25%	(5,556)	(2,118,083)	16,192,412	0	30
May 11	Forecast	(2,118,083)	n/a	(389,436)	563,890	0	0	0	0	(1,943,629)	(2,030,856)	3 25%	(5,606)	(1,949,235)	10,216,609	0	31
June 11	Forecast	(1,949,235)	n/a	(257,027)	563,890	0	0	0	0	(1,642,372)	(1,795,803)	3 25%	(4,797)	(1,647,169)	6,870,252	0	30
July 11	Forecast	(1,647,169)	n/a	(215,904)	563,890	0	0	0	0	(1,299,182)	(1,473,175)	3 25%	(4,066)	(1,303,249)	5,863,455	0	31
August 11	Forecast	(1,303,249)	n/a	(187,451)	563,890	0	0	0	0	(926,810)	(1,115,029)	3 25%	(3,078)	(929,887)	5,169,789	0	31
September 11	Forecast	(929,887)	n/a	(186,022)	563,890	0	0	0	0	(552,019)	(740,953)	3 25%	(1,979)	(553,999)	5,133,705	0	30
October 11	Forecast	(553,999)	n/a	(265,687)	563,890	0	0	0	0	(255,796)	(404,897)	3 25%	(1,118)	(256,913)	7,070,844	0	31
November 11	Forecast	(256,913)	n/a	(444,795)	563,890	0	0	0	0	(137,818)	(197,366)	3 25%	(527)	(138,345)	11,511,001	0	30
December 11	Forecast	(138,345)	n/a	(621,895)	563,890	0	0	0	0	(196,350)	(167,348)	3 25%	(462)	(196,812)	15,810,809	0	31

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2010 - October 31, 2011	
Beginning Balance	$ (582,660 74)
Program Budget	6,520,017 78
Projected Interest	(47,176 88)
Program Budget with Interest	$5,890,180
Total Charges	**$5,890,180**

00000114

New Hampshire Program Year ONE (January 1, 2010 - December 31, 2010)

Program	Services	Vendor Admin/Support	Company Admin	Communication	Trade Ally Training	Evaluation & Reporting	Other	Budget Total	Participant Goal
Residential									
Low Income	$ 397,977	$ 124,376	$ 90,847	$ 8,890	$ 4,070	$ 9,838	$ -	$ 635,997	260
Residential Weatherization	$ 901,484	$ 61,372	$ 34,464	$ 88,436	$ 42,929	$ 3,380	$ -	$ 1,132,065	1,100
Residential High Efficiency Heating	$ 254,000	$ 10,120	$ 28,200	$ 142,600	$ 22,000	$ 19,880	$ -	$ 476,800	551
Residential Water Heating	$ 77,730	$ 2,055	$ 5,720	$ 12,180	$ 5,000	$ 2,715	$ -	$ 105,400	257
ES Windows	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
Advanced Residential Controls	$ 29,570	$ 995	$ 2,775	$ 5,900	$ 3,000	$ 1,960	$ -	$ 44,200	704
ES Homes	$ 14,400	$ 2,640	$ 1,680	$ 3,600	$ 480	$ 2,044	$ -	$ 24,844	30
Energy Analysis: Internet Audit	$ 16,007	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,007	1,053
Energy Audit and Home Performance	$ 57,020	$ 5,955	$ 3,789	$ 15,460	$ 1,083	$ 5,893	$ -	$ 89,200	900
Building Practices and Demo	$ 30,000	$ 5,500	$ 3,500	$ 7,500	$ 1,000	$ 3,112	$ -	$ 50,612	20
Net Zero Energy Homes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
Air Sealing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	450
Residential Total	**$ 1,778,189**	**$ 213,013**	**$ 170,975**	**$ 284,565**	**$ 79,561**	**$ 48,822**	**$ -**	**$ 2,575,126**	**4,875**
Commercial & Industrial									
Comm Energy Efficiency Program	$ 930,061	$ 71,415	$ 98,000	$ 35,000	$ 25,000	$ 46,169	$ -	$ 1,205,645	227
Multifamily Housing Program	$ 83,342	$ 23,895	$ 30,000	$ 15,000	$ 10,000	$ 5,018	$ -	$ 167,255	20
Comm High Efficiency Heating	$ 260,844	$ 20,000	$ 30,000	$ 15,000	$ 15,000	$ 20,851	$ -	$ 361,695	160
Economic Redevelopment	$ 261,334	$ 17,000	$ 45,000	$ 10,010	$ 7,500	$ 20,851	$ -	$ 361,695	10
Building Practices and Demo	$ 150,000	$ 22,500	$ 40,000	$ 15,000	$ -	$ 22,500	$ -	$ 250,000	3
Energy Analysis: Internet Audit	$ -	$ 7,500	$ 12,500	$ 5,000	$ -	$ -	$ -	$ 25,000	60
Building Operator Certification	$ 20,000	$ 6,000	$ 11,000	$ 3,000	$ -	$ -	$ -	$ 40,000	60
Commercial Total	**$ 1,705,581**	**$ 168,310**	**$ 266,500**	**$ 98,010**	**$ 57,500**	**$ 115,389**	**$ -**	**$ 2,411,290**	**540**
GRAND TOTAL	**$ 3,483,770**	**$ 381,323**	**$ 437,475**	**$ 382,575**	**$ 137,061**	**$ 164,211**	**$ -**	**$ 4,986,415**	**5,415**

00000115

New Hampshire Program Year TWO (January 1, 2011 - December 31, 2011)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	$ 52,000	$ 275,278	$ 397,977		$ 5,641	$ -	$ 730,895	260	70,954
Residential High-Efficiency Heating, Wate	$ 23,067	$ 166,136	$ 475,294		$ 48,592	$ 1,375	$ 714,464	1,983	306,840
New Home Construction with Energy Star	$ 727	$ 28,628	$ 45,000		$ 5,000	$ -	$ 79,355	30	20,400
Res Building Practices and Demo	$ 1,556	$ 4,523	$ 15,000		$ 3,750	$ 500	$ 25,329	10	0
Energy Audit with Home Performance and	$ 30,967	$ 131,244	$ 1,329,164		$ 36,534	$ 12,722	$ 1,540,631	1,200	338,400
Residential Total	**$ 108,316**	**$ 605,809**	**$ 2,262,435**	**$ -**	**$ 99,516**	**$ 14,597**	**$ 3,090,674**	**3,483**	**736,594**
Commercial & Industrial									
Large C & I Retrofit Program	$ 160,000	$ 150,000	$ 1,425,000		$ 58,625	$ 62,669	$ 1,856,294	226	699,027
New Equipment and Construction Progran	$ 95,000	$ 100,000	$ 765,000		$ 34,875	$ 37,280	$ 1,032,155	307	280,381
Small Business Energy Solutions Program	$ 25,792	$ 38,688	$ 202,500		$ 9,349	$ 9,994	$ 286,323	23	111,884
Commercial Total	**$ 280,792**	**$ 288,688**	**$ 2,392,500**	**$ -**	**$ 102,849**	**$ 109,943**	**$ 3,174,772**	**556**	**1,091,292**
GRAND TOTAL	**$ 389,108**	**$ 894,497**	**$ 4,654,935**	**$ -**	**$ 202,365**	**$ 124,540**	**$ 6,265,446**	**4,039**	**1,827,886**

Exhibit-C: KeySpan Energy Delivery - NH DSM/MT Program Year Three (2008-2009): Shareholder Incentive Calculation - August 27, 2009

Program	* Expenditures (Budget) for Program Year 2	* Design Goal for PY 1		Projected Lifetime Therms Savings	Actual Lifetime Therm Savings[2]	Actual LTT/Projected LTT	* Projected TRC[3]	Actual TRC[4]	Actual TRC/Projected TRC	Lifetime Savings Incentive	Cost-effectiveness Incentive	Actual Pre Tax Design Incentive
Residential												
Low Income	$ 442,864	160	Participants	1,082,880	1,536,336	1.419	3.50	6.05	1.73			
Residential Weatherization	$ 89,557	45	Rebates	331,200	1,449,920	4.378	3.52	7.20	2.04			
Residential High Efficiency Heating	$ 271,179	500	Rebates	1,760,000	2,319,680	1.318	7.10	6.14	0.86			
Residential High Efficiency Water Heating	$ 81,708	150	Rebates	227,100	292,202	1.287	3.20	3.17	0.99			
Energy Star Windows	$ 63,008	300	Rebates	168,225	128,412	0.763	2.81	3.08	1.10			
Energy Star Residential Controls	$ 35,231	325	Rebates	254,625	560,535	2.201	6.91	12.81	1.85			
Energy Star Homes	$ 65,561	55	Participants	0	0		0.00					
Energy Analysis: Internet Audit Guide	$ 43,136	600	New Users	0.000	0.00		0.00					
Building Practices and Demo	$ 46,291	12	Projects	0.000	0.00		0.00					
Residential Conservation Services	$ 86,459	200	Participants	0.000	0.00		0.00					
Total	$ 1,224,992	2,347		3,824,030	6,287,085	1.644	3.70	5.31	1.4362	$ 80,256	$ 65,983	$ 146,238
C&I and Mutifamily												
Commercial Energy Efficiency Program	$ 542,617	150	Participants	1,647,585	746,905	0.453	2.91	1.75	0.60			
Multifamily Housing	$ 195,773	60	Participants	458,298	122,213	0.267	2.43	1.13	0.47			
Commercial High Efficiency Heating	$ 121,803	50	Rebates	996,000	4,362,480	4.380	6.44	10.36	1.61			
Economic Redevelopment	$ 330,182	3	Projects	591,396	2,562,717	4.333	2.56	29.21	11.39			
Commercial Building Practices & Tecnology Demonstration	$ 215,301	6	Projects	2,368,277	789,426	0.333	15.7	134.75	8.56			
C&I Energy Analysis Internet Audit	$ 21,122	50	New Users	0	0		0.00	0.00				
Total - C&I and Multifamily	$ 1,426,799	319		6,061,556	8,583,741	1.416	4.52	7.30	1.61	$ 80,819	$ 73,226	$ 154,045
Total of Column	$2,651,791										**TOTAL Incentive**	**$ 300,283**

Notes:

This shareholder incentive calculation is based on the methodology described in NH PUC Order 24,109 of December 31, 2002.

Threshold: KeySpan must achieve a minimum "threshold" performance before being eligible to earn an incentive

For the cost-effectiveness component, KeySpan must achieve an actual year-end TRC of 1.0 before any incentive can be earned

Once the threshold is achieved, the earned incentive will be on a sliding scale from 0% to 12%

Assumptions:

Design Target Incentive = 8%

Incentive Calculation Formula: $Incentive_{res} = Expenditures_{RES} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times \text{Lifetime Therm Savings}_{Actual} / \text{Lifetime Therm Savings}_{Projected})]\}$

Plus

$Incentive_{C\&I} = Expenditures_{C\&I} \times \{[4\% \times (TRC_{Actual} / TRC_{Projected})] + [4\% \times \text{Lifetime Therm Savings}_{Actual} / \text{Lifetime Therm Savings}_{Projected})]\}$

[1]Per a September 9, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the projected lifetime therm savings for each KED New Hampshire natural gas energy efficiency program and the source of the projected benefit/cost ratios by program is KeySpan's response to NH PUC Staff Data Request 2-31, Pages 3 to 6, Docket DG 04-152, filed by attorney Steven V. Camerino on November 22, 2004).

[2]From the updated Exhibit G showing actual Program Year 1 results.

[3,4,5] Per a September 20, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the Lifetime savings and Cost Effectiveness incentive calculations are derived from the updated and streamlined version of the template used by the PUC called "Computation of Actual Performance Incetive-Program Year Two" of DG 02-106 and DG 05-141.
In the Commission approved Settlement Agreement that is part of Order 24,109, the Settling Parties and Staff agree to adopt the simplified Staff template of November 2002 ("Staff Template") attached to the Settlement Agreement as Exhibit G. This template shall be used only for purposes of establishing a benchmark for the Gas Utilities' incentive sharing mechanism described in Section II(H) of the Settlement Agreement. The Staff Template allows for an evaluation of the Programs on a year-by-year basis.

00001117

Exhibit D - Shareholder Incentive Page 1 of 1

National Grid Gas Energy Efficiency

Shareholder Incentive Year ONE- January 1, 2011 - December 31, 2011

Commercial/Industrial Incentive

1. Target Benefit/Cost Ratio	1.47
2. Threshold Benefit/Cost Ratio	1.00
3. Target lifetime MMBTU	1,091,292
4. Threshold MMBTU	709,340
5. Budget	$3,174,772
6. CE Percentage	4.00%
7. Lifetime MMBTU Percentage	4.00%
8. Target C/I Incentive	**$253,982**
9. Cap	**$380,973**

Residential Incentive

10. Target Benefit/Cost Ratio	1.96
11. Threshold Benefit/Cost Ratio	1.00
12. Target lifetime MMBTU	736,594
13. Threshold MMBTU	478,786
14. Budget	$3,090,674
15. CE Percentage	4.00%
16. Lifetime MMBTU Percentage	4.00%
17. Target Residential Incentive	**$247,254**
18. Cap	**$370,881**
19. TOTAL TARGET INCENTIVE	**$501,236**

Line No. Notes:

1, 3, 5, 10, 12, and 14. See Exhibit B

2, 6, 7, 11, 15, and 16. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.

4. 65% of line 3.

8. 8% of line 5.

9. 12% of line 5.

13. 65% of line 12.

17. 8% of line 14.

18. 12% of line 14.

19. Line 8 plus line 17.

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual increase in rates	$0	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/09- sales and transportation	158,020,633	therms
Surcharge per therm	$0.0000	per therm
Total Environmental Surcharge	$0.0000	

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Concord Pond

internal order no. 500061 (formerly acc no. 1796)

	(thru 3/98) pool #1	(4/98 - 9/98) pool #2	(10/98 - 9/15/99) pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	subtotal
Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	6,250,410
Remediation costs (i.o. 500005)	-	-	-	-								-
A Subtotal - remediation costs	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	6,250,410
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(2,094,376)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-								(445,985)
Recovery costs (i.o. 500004)	623,784	-	-	-				-	-	-	-	623,784
Transfer Credit from Gas Restructuring												-
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(1,916,577)
A-B Total net expenses to recover	520,030	1,409,330	1,654,552	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	4,333,833
Surcharge revenue:												
actual June 1998 - October 1998	(54,889)	-	-	-								(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-								(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-								(760,871)
actual November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)								(640,539)
actual November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)								(625,114)
actual November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)								(607,874)
actual November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)								(305,907)
Actual November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)							(85,078)
Actual November 2005- October 2006	-	-	-	(6,875)	(6,875)							(13,750)
Actual November 2006- October 2007	-	-	-	-	-	-	(14,091)					(14,091)
Actual November 2007- October 2008												-
AES collections					(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(12,888)	(107,764)
Gas Street overcollection	-	(23,511)										(23,511)
Prior Period Pool under/overcollection		-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	
C Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,190	(12,888)	(12,888)	(3,777,530)
D Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,564	102,691	124,048	556,303
E Allocation of Litigated Recovery					-		-		(329,564)	-	-	(329,564)
Surcharge calculation 2007/2008												
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	102,691	124,048	226,739
remaining life	-	-	-	-	24	36	48	60	72	84	84	
one year	-	-	-	-	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-		-	14,670	17,721	
Required annual increase in rates 2007/2008: smaller of D or F	-	-	-	-	-	-	-		-	14,670	17,721	32,391
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0002

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000120

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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Laconia & Liberty Hill

		i.o. no. 500005 (through 9/15/99) pool #1	(9/99 - 9/00) pool #2	(9/00 - 9/01) pool #3	(9/04 - 9/05) pool #4	(9/05 - 9/06) pool #5	(9/06 - 9/07) pool #6	(9/07 - 9/08) pool #7 Incl. Audit Corr	(9/08 - 9/09) pool #8	(9/09 - 9/10) pool #9	subtotal
	Remediation costs (i.o. 500061)	-	-		-						-
	Remediation costs (i.o. 500005)	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	624,557	262,678	10,985,948
A	Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	624,557	262,678	10,985,948
	Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-	-		-
	Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-	-		-
	Recovery costs (i.o. 500004)	-	-	-			11,643	21,729	-	-	33,372
	Transfer Credit from Gas Restructuring						-	-	-		-
B	Subtotal - net recoveries	-	-	-	-	-	11,643	21,729	-	-	33,372
A-B	Total net expenses to recover	1,027,747	3,513,285	700,000	9,702	2,330,555	2,100,842	449,954	624,557	262,678	11,019,320
	Surcharge revenue:										
actual	June 1998 - October 1998	-	-	-	-	-		-	-	-	-
actual	November 1998 - October 1999	-	-	-	-	-		-	-	-	-
actual	November 1999 - October 2000	(151,933)	-	-	-	-		-	-	-	(151,933)
actual	November 2000 - October 2001	(153,172)	(543,065)	-	-	-		-	-	-	(696,237)
actual	November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-		-	-	-	(796,714)
actual	November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-		-	-	-	(805,434)
actual	November 2003 - October 2004	(131,103)	(466,143)	(101,969)							(699,215)
Actual	November 2004- October 2005	(127,617)	(439,570)	(85,078)							(652,264)
Actual	November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-		-	-	-	(691,159)
Actual	November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)					(958,171)
Actual	November 2007- October 2008										-
	AES collections										-
	Gas Street overcollection										-
	Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004		-	
C	Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	-	(5,451,127)
D	Net balance to be recovered (A-B+C)	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	4,680,958	624,557	262,678	5,568,193
E	Allocation of Litigated Recovery							(4,680,958)	-	-	(4,680,958)
	Surcharge calculation 2007/2008										
	Unrecovered costs (D+E)	-	-	-	-			-	624,557	262,678	887,235
	remaining life	-	-	-	36	48	60	72	84	84	
	one year	-	-	-	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	89,222	37,525	
	Required annual increase in rates 2007/2(										
	smaller of D or F	-	-	-	-	-		-	89,222	37,525	126,748
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0006	$0.0002	$0.0008

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000121

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Manchester

		(9/00 - 9/01) pool #1	(9/02 - 9/03) pool #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8 Incl. Audit Corr	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	subtotal
	Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	8,830,965
	Remediation costs (i.o. 500005)	495,106	329,986									825,092
A	Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	9,656,057
	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(1,933,688)
	Cash recoveries (i.o. 500004)	-	-									-
	Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-			1,244,872
	Transfer Credit from Gas Restructuring							-	-			-
B	Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(688,816)
A-B	Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	8,967,241
	Surcharge revenue:											
actual	June 1998 - October 1998	-	-	-	-							-
actual	November 1998 - October 1999	-	-	-	-							-
actual	November 1999 - October 2000	-	-	-	-							-
actual	November 2000 - October 2001	-	-	-	-							-
actual	November 2001 - October 2002	(73,543)	-	-	-							(73,543)
actual	November 2002 - October 2003	(75,984)	-	-	-							(75,984)
actual	November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-							(138,576)
Actual	November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	-	-	(326,132)
Actual	November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	-	-	(563,732)
Actual	November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)					(662,265)
Actual	November 2007- October 2008											-
	AES collections											-
	Gas Street overcollection											-
	Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	-	-	
C	Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	-	-	(1,840,233)
D	Net balance to be recovered (A-B+C)	76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	6,486,145	312,185	328,678	7,127,008
E	Allocation of Litigated Recovery			-	-	-			(6,486,145)	-	-	(6,486,145)
	Surcharge calculation 2007/2008											
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	312,185	328,678	640,863
	remaining life	-	-	-	24	36	48	60	70	84	84	
	one year	-	-	-	12	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	-	44,598	46,954	
	Required annual increase in rates 2007/2(											
	smaller of D or F	-	-	-	-	-	-		-	44,598	46,954	91,552
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	$0.0003	$0.0006

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000122

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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	Nashua										
							Corrected per 2/08 Audit				
	(9/00 - 9/01) pool #1	**(9/01 - 9/02) pool #2**	**(9/02 - 9/03) pool #3**	**(9/03 - 9/04) pool #4**	**(9/04 - 9/05) pool #5**	**(9/05 - 9/06) pool #6**	**(9/06 - 9/07) pool #7**	**(9/07 - 9/08) pool #8**	**(9/08 - 9/09) pool #9**	**(9/09 - 9/10) pool #9**	**subtotal**
Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	599,167
Remediation costs (i.o. 500005)	1,233,726	362,663	175,178								1,771,567
A Subtotal - remediation costs	1,233,726	362,663	175,178	10,841	206,367	23,354	9,737	107,605	78,535	162,729	2,370,734
											-
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(159,145)
Cash recoveries (i.o. 500004)	-	-	-								-
Recovery costs (i.o. 500004)	-	-	-			5,449	12,938	-	-		18,388
Transfer Credit from Gas Restructuring							-	-	-		-
B Subtotal - net recoveries	-	-	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(140,758)
											-
A-B Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	16,289	98,975	2,229,976
Surcharge revenue:											
actual June 1998 - October 1998	-	-	-	-							-
actual November 1998 - October 1999	-	-	-	-							-
actual November 1999 - October 2000	-	-	-	-							-
actual November 2000 - October 2001	-	-	-	-							-
actual November 2001 - October 2002	(183,857)	-	-	-							(183,857)
actual November 2002 - October 2003	(182,362)	(60,787)	-	-							(243,150)
actual November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-							(247,639)
Actual November 2004- October 2005	(170,156)	(42,539)	(28,359)	-							(241,054)
Actual November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	-	-	(274,991)
Actual November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-					(281,815)
Actual November 2007- October 2008											-
AES collections											-
Gas Street overcollection											-
Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	-	-	
C Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	-	(1,472,506)
D Net balance to be recovered (A-B+C)	188,463	292,737	354,741	365,582	516,269	526,492	545,015	642,206	16,289	98,975	757,470
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	-	-	(642,206)
Surcharge calculation 2007/2008											
Unrecovered costs (D+E)	-	-	-	-	-	-		-	16,289	98,975	115,264
remaining life	-	-	12	24	36	48	60	72	84	84	
one year	-	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	2,327	14,139	
Required annual increase in rates 2007/2(											
smaller of D or F	-	-	-	-	-	-		-	2,327	14,139	16,466
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000123

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Dover

		(9/02 - 9/03) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	subtotal
	Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	21,142
	Remediation costs (i.o. 500005)	181,066							181,066
A	Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	202,208
	Cash recoveries (i.o. 500061)	-					-	-	-
	Cash recoveries (i.o. 500004)	-							-
	Recovery costs (i.o. 500004)	-							-
	Transfer Credit from Gas Restructuring								-
B	Subtotal - net recoveries	-	-	-	-	-	-	-	-
A-B	Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	202,208
	Surcharge revenue:								
actual	June 1998 - October 1998	-							-
actual	November 1998 - October 1999	-							-
actual	November 1999 - October 2000	-							-
actual	November 2000 - October 2001	-							-
actual	November 2001 - October 2002	-							-
actual	November 2002 - October 2003	-							-
actual	November 2003 - October 2004	(29,134)							(29,134)
Actual	November 2004- October 2005	(28,359)							(28,359)
Actual	November 2005- October 2006	(27,499)	-			-	-	-	(27,499)
Actual	November 2006- October 2007	(28,181)	-	-					(28,181)
Actual	November 2007- October 2008								-
	AES collections								-
	Gas Street overcollection								-
	Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	
C	Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	(113,174)
D	Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	89,034
E	Allocation of Litigated Recovery		-		-	(89,034)	-	-	(89,034)
	Surcharge calculation 2007/2008								
	Unrecovered costs (D+E)	-	-	-		-	-	-	-
	remaining life	24	36	48	60	72	84	84	
	one year	12	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	-	-	
	Required annual increase in rates 2007/2(								
	smaller of D or F	-	-	-		-	-	-	-
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00001124

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		Keene							
		(9/03 - 9/04) pool #1	**(9/04 - 9/05) pool #2**	**(9/05 - 9/06) pool #3**	**(9/06 - 9/07) pool #4**	**(9/07 - 9/08) pool #5**	**(9/08 - 9/09) pool #6**	**(9/09 - 9/10) pool #7**	**subtotal**
	Remediation costs (i.o. 500061)	-							-
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	60,949
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	60,949
									-
	Cash recoveries (i.o. 500061)	-							-
	Cash recoveries (i.o. 500004)	-							-
	Recovery costs (i.o. 500004)			18,831	823	-	-		19,655
	Transfer Credit from Gas Restructuring				-	-	-		-
B	Subtotal - net recoveries	-		18,831	823	-	-	-	19,655
A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	80,604
									-
									-
	Surcharge revenue:								-
actual	June 1998 - October 1998	-							-
actual	November 1998 - October 1999	-							-
actual	November 1999 - October 2000	-							-
actual	November 2000 - October 2001	-							-
actual	November 2001 - October 2002	-							-
actual	November 2002 - October 2003	-							-
actual	November 2003 - October 2004	-							-
Actual	November 2004- October 2005	-	-				-	-	-
Actual	November 2005- October 2006	-	-				-	-	-
Actual	November 2006- October 2007	-	-	(14,091)					(14,091)
Actual	November 2007- October 2008								-
	AES collections								-
	Gas Street overcollection								-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	66,513
									-
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	-	-	(66,244)
									-
	Surcharge calculation 2007/2008								-
	Unrecovered costs (D+E)	-	-	-			269	-	269
	remaining life	24	36	48	60	72	84	84	
	one year	12	12	12	12	12	12	12	
F	amortization 2007/2008	-	-	-	-	-	38	-	
	Required annual increase in rates 2007/2(								
	smaller of D or F	-	-	-			38	-	38
	forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000125

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	Concord							
	(9/03 - 9/04) pool #1	**(9/04 - 9/05) pool #2**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #3**	Corrected per 2/08 Audit **(9/06 - 9/07) pool #4**	**(9/07 - 9/08) pool #5**	**(9/08 - 9/09) pool #6**	**(9/09 - 9/10) pool #7**	**subtotal**
Remediation costs (i.o. 500061)	-							-
Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	49,403	531,581
A Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	49,403	531,581
								-
Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(69,407)
Cash recoveries (i.o. 500004)	-							-
Recovery costs (i.o. 500004)					1,432	(1,007)		425
Transfer Credit from Gas Restructuring			-					-
B Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(68,982)
A-B Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	46,190	462,600
								-
								-
Surcharge revenue:								-
actual June 1998 - October 1998	-							-
actual November 1998 - October 1999	-							-
actual November 1999 - October 2000	-							-
actual November 2000 - October 2001	-							-
actual November 2001 - October 2002	-							-
actual November 2002 - October 2003	-							-
actual November 2003 - October 2004	-							-
Actual November 2004- October 2005								-
Actual November 2005- October 2006	-	(27,499)			-	-	-	(27,499)
Actual November 2006- October 2007	-	(28,181)	-					(28,181)
Actual November 2007- October 2008								-
AES collections								-
Gas Street overcollection								-
Prior Period Pool under/overcollection		22,191	187,442	209,549	271,214	-	-	
C Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	-	-	(55,681)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	406,919
								-
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	-	-	(268,051)
Surcharge calculation 2007/2008								-
								-
Unrecovered costs (D+E)	-	-	-		-	92,679	46,190	138,869
remaining life	36	48	60		72	84	84	
one year	12	12	12		12	12	12	
F amortization 2007/2008	-	-	-		-	13,240	6,599	
Required annual increase in rates 2007/2(								
smaller of D or F	-	-	-		-	13,240	6,599	19,838
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0001

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000126

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	General									
	(9/02 - 9/03) pool #1	**(9/03 - 9/04) pool #2**	**(9/04 - 9/05) pool #3**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #4**	**(9/06 - 9/07) pool #5**	**(9/07 - 9/08) pool #6**	**(9/08 - 9/09) pool #7**	**(9/09 - 9/10) pool #8**	**subtotal**	**2010 MGP Remediation subtotal**
Remediation costs (i.o. 500061)	-								-	15,701,685
Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	602,926	14,959,129
A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	602,926	30,660,813
Cash recoveries (i.o. 500061)	-				-	-	-		-	(4,256,616)
Cash recoveries (i.o. 500004)	-								-	(445,985)
Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953		361,946	2,302,441
Transfer Credit from Gas Restructuring	(3,331)			-					(3,331)	(3,331)
B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	-	358,615	(2,403,491)
A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	4,199	961,541	28,257,322
										28,257,322
										-
Surcharge revenue:										
actual June 1998 - October 1998	-	-							-	(54,889)
actual November 1998 - October 1999	-	-							-	(538,143)
actual November 1999 - October 2000	-	-							-	(912,804)
actual November 2000 - October 2001	-	-							-	(1,336,776)
actual November 2001 - October 2002	-	-							-	(1,679,228)
actual November 2002 - October 2003	-	-							-	(1,732,442)
actual November 2003 - October 2004	(8,265)	-							(8,265)	(1,428,735)
Actual November 2004- October 2005		(70,898)							(70,898)	(1,403,787)
Actual November 2005- October 2006		(68,748)	(27,499)			-	-	-	(96,247)	(1,694,877)
Actual November 2006- October 2007		(77,499)	(28,181)	(49,318)					(154,998)	(2,141,793)
Actual November 2007- October 2008									-	-
AES collections		-							-	(107,764)
Gas Street overcollection									-	(23,511)
Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	-	-	
C Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	-	-	(330,408)	(13,054,749)
D Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	(2,931)	4,199	631,133	15,202,573
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	-	-	(629,865)	(13,192,066)
Surcharge calculation 2007/2008										
Unrecovered costs (D+E)	-	-	-	-		-	(2,931)	4,199	1,268	
remaining life		36	48	60	72	84	84	84		
one year		12	12	12	12	12	12	12		
F amortization 2007/2008		-	-	-	-	-	(419)	600		
Required annual increase in rates 2007/2										
smaller of D or F	-	-	-	-		-	-	600	600	2,010,507
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	**155,445,404**
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	**$0.0129**

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000127

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Cash Recoveries[1]

e	(9/09 - 9/10) Concord Pond	(9/08 - 9/09) Concord Pond	(9/07 - 9/08) Concord Pond	(9/06 - 9/07) Concord Pond	(9/05 - 9/06) Concord Pond	(9/04- 9/05) Concord Pond	(9/03 - 9/04) Concord Pond	(9/09 - 9/10) Laconia	(9/08 - 9/09) Laconia	(9/07 - 9/08) Laconia	(9/06 - 9/07) Laconia	Corrected per 1/24/07 Audit (9/05 - 9/06) Laconia	(9/04 - 9/05) Laconia	(9/03 - 9/04) Laconia
Remediation costs (i.o. 500061)	-	-	-		-	-	-	-	-	-			-	-
Remediation costs (i.o. 500005)	-	-	-		-	-	-	-	-	-			-	-
A Subtotal - remediation costs	-	-	-		-	-	-	-	-	-			-	-
Cash recoveries (i.o. 500061)														
Cash recoveries (i.o. 500004)		-	568	-	-	-	(648,000)	-	-	-	-	-	(23,619)	(2,677,000)
Recovery costs (i.o. 500004)		-	-	-	73	-	658,508		-	-	45	22,240	486,894	1,492,967
Transfer Credit from Gas Restructuring		-	-	-	-	-	-							
B Subtotal - net recoveries	-	-	568	-	73	-	10,508	-	-	-	45	22,240	463,275	(1,184,033)
A-B Total net expenses to recover	-	-	568	-	73	-	10,508	-	-	-	45	22,240	463,275	(1,184,033)
Surcharge revenue:														
actual June 1998 - October 1998	-	-	-		-	-	-							
actual November 1998 - October 1999	-	-	-		-	-	-							
actual November 1999 - October 2000	-	-	-		-	-	-							
actual November 2000 - October 2001	-	-	-		-	-	-							
actual November 2001 - October 2002	-	-	-		-	-	-							
actual November 2002 - October 2003	-	-	-		-	-	-							
actual November 2003 - October 2004	-	-	-		-	-	-							
Actual November 2004- October 2005														
Actual November 2005- October 2006														
Actual November 2006- October 2007														
Actual November 2007- October 2008														
AES collections	-	-	-		-	-	-							
Gas Street overcollection	-	-	-		-	-	-							
Prior Period Pool under/overcollection														
C Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D Net balance to be recovered (A-B+C)	-	-	568	-	73	-	10,508	-	-	-	45	22,240	463,275	(1,184,033)
E Allocation of Litigated Recovery														
Surcharge calculation 2007/2008														
Unrecovered costs (D+E)														
remaining life														
one year														
F amortization 2007/2008														
Required annual increase in rates 2007/2(														
smaller of D or F														
forecasted therm sales														
surcharge per therm														

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000128

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		(9/09 - 9/10) Manchester	**(9/08 - 9/09) Manchester**	**(9/07 - 9/08) Manchester**	**(9/06 - 9/07) Manchester**	Corrected per 1/24/07 Audit **(9/05 - 9/06) Manchester**	**(9/04 - 9/05) Manchester**	**(9/03 - 9/04) Manchester**	**(9/09 - 9/10) Nashua**	**(9/08 - 9/09) Nashua**	**(9/07 - 9/08) Nashua**	**(9/06 - 9/07) Nashua**	**(9/05 - 9/06) Nashua**	**(9/04 - 9/05) Nashua**	**(9/03 - 9/04) Nashua**
	Remediation costs (i.o. 500061)								-	-	-			-	
	Remediation costs (i.o. 500005)								-	-	-			-	
A	Subtotal - remediation costs								-	-	-			-	
	Cash recoveries (i.o. 500061)														
	Cash recoveries (i.o. 500004)		9,679	-	(630,000)	(1,725,792)	(754,938)	-	-		(1,032,186)	(544,402)	(625,000)	(782,450)	(795,000)
	Recovery costs (i.o. 500004)	-	(2,008,365)	77,222	195,929	941,433	307,062	951,425			561,030	78,298	645,302	537,552	655,683
	Transfer Credit from Gas Restructuring														
B	Subtotal - net recoveries	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
A-B	Total net expenses to recover	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
	Surcharge revenue:														
actual	June 1998 - October 1998	-	-	-		-	-								
actual	November 1998 - October 1999	-	-	-	-	-	-								
actual	November 1999 - October 2000	-	-	-	-	-	-								
actual	November 2000 - October 2001	-	-	-	-	-	-								
actual	November 2001 - October 2002	-	-	-	-	-	-								
actual	November 2002 - October 2003	-	-	-	-	-	-								
actual	November 2003 - October 2004	-	-	-	-	-	-								
Actual	November 2004- October 2005														
Actual	November 2005- October 2006					-	-								
Actual	November 2006- October 2007														
Actual	November 2007- October 2008														
	AES collections	-	-	-	-										
	Gas Street overcollection	-	-	-	-										
	Prior Period Pool under/overcollection					-	-								
						-	-								
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
E	Allocation of Litigated Recovery														
	Surcharge calculation 2007/2008														
	Unrecovered costs (D+E)														
	remaining life														
	one year														
F	amortization 2007/2008														
	Required annual increase in rates 2007/2(														
	smaller of D or F														
	forecasted therm sales														
	surcharge per therm														

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000129

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		(9/09 - 9/10) Dover	(9/08 - 9/09) Dover	(9/07 - 9/08) Dover	(9/06 - 9/07) Dover	(9/05 - 9/06) Dover	(9/04 - 9/05) Dover	(9/03 - 9/04) Dover
	Remediation costs (i.o. 500061)	-	-	-		-	-	
	Remediation costs (i.o. 500005)	-	-	-		-	-	
A	Subtotal - remediation costs	-	-	-		-	-	
	Cash recoveries (i.o. 500061)							
	Cash recoveries (i.o. 500004)	-	-	(2,133)	-	(237,489)	(7,150)	(645,500)
	Recovery costs (i.o. 500004)		(92,947)	-	14,848	117,621	517,891	500,868
	Transfer Credit from Gas Restructuring							
B	Subtotal - net recoveries	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)
A-B	Total net expenses to recover	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)
	Surcharge revenue:							
actual	June 1998 - October 1998							
actual	November 1998 - October 1999							
actual	November 1999 - October 2000							
actual	November 2000 - October 2001							
actual	November 2001 - October 2002							
actual	November 2002 - October 2003							
actual	November 2003 - October 2004							
Actual	November 2004- October 2005							
Actual	November 2005- October 2006							
Actual	November 2006- October 2007							
Actual	November 2007- October 2008							
	AES collections							
	Gas Street overcollection							
	Prior Period Pool under/overcollection							
C	Surcharge Subtotal	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)
E	Allocation of Litigated Recovery							
	Surcharge calculation 2007/2008							
	Unrecovered costs (D+E)							
	remaining life							
	one year							
F	amortization 2007/2008							
	Required annual increase in rates 2007/2(							
	smaller of D or F							
	forecasted therm sales							
	surcharge per therm							

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

000001130

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	(9/09 - 9/10) Keene	(9/08 - 9/09) Keene	(9/07 - 9/08) Keene	(9/06 - 9/07) Keene	(9/05 - 9/06) Keene	(9/04 - 9/05) Keene	(9/03 - 9/04) Keene	(9/06 - 9/07) General	2010 subtotal	MGP TOTAL
Remediation costs (i.o. 500061)					-	-			-	15,701,685
Remediation costs (i.o. 500005)					-	-			-	14,959,129
A Subtotal - remediation costs					-	-			-	30,660,813
Cash recoveries (i.o. 500061)									-	(4,256,616)
Cash recoveries (i.o. 500004)	-	116			(700,000)	(211,213)	0	(10,760,900)	(22,792,408)	(23,238,393)
Recovery costs (i.o. 500004)			1,559	28,211	309,618	56,392	121,018		7,178,376	9,480,817
Transfer Credit from Gas Restructuring									-	(3,331)
B Subtotal - net recoveries	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(4,853,133)	(7,256,623)
									-	-
A-B Total net expenses to recover	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	12,643,290
Surcharge revenue:										
actual June 1998 - October 1998									-	(54,889)
actual November 1998 - October 1999									-	(538,143)
actual November 1999 - October 2000									-	(912,804)
actual November 2000 - October 2001									-	(1,336,776)
actual November 2001 - October 2002									-	(1,679,228)
actual November 2002 - October 2003									-	(1,732,442)
actual November 2003 - October 2004									-	(1,428,735)
Actual November 2004- October 2005									-	(1,403,787)
Actual November 2005- October 2006										(1,694,877)
Actual November 2006- October 2007										(2,141,793)
Actual November 2007- October 2008										-
AES collections									-	(107,764)
Gas Street overcollection									-	(23,511)
Prior Period Pool under/overcollection									-	
									-	
C Surcharge Subtotal				-	-	-	-		-	(13,054,749)
									-	
									-	
D Net balance to be recovered (A-B+C)	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	(411,459)
E Allocation of Litigated Recovery									13,192,066	
									(2,421,966)	

Surcharge calculation 2007/2008
Unrecovered costs (D+E)
remaining life
one year
F amortization 2007/2008

Required annual increase in rates 2007/2(
smaller of D or F

forecasted therm sales

surcharge per therm

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

000001131

filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

Expense and Collection Summary per Year

		(thru 3/98)	(4/98 - 9/98)	10/98 - 9/15/99	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	Total
	Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	15,701,685
	Remediation costs (i.o. 500005)	-	-	1,027,747	3,513,285	2,428,832	362,663	689,437	571,259	445,367	2,444,366	2,229,625	255,263	675,005	316,280	14,959,129
A	Subtotal - remediation costs	1,422,811	1,843,806	3,181,982	3,642,287	2,428,832	362,663	689,437	977,731	2,682,050	3,442,003	2,956,367	4,845,887	1,193,912	991,045	30,660,813
	Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(4,256,616)
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	(23,238,393)
	Recovery costs (i.o. 500004)	623,784	-	-	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	9,480,817
	Transfer Credit from Gas Restructuring	-	-	-	-	-	-	(3,331)	-	-	-	-	-	-	-	(3,331)
B	Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(3,331)	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(18,017,523)
A-B	Total net expenses to recover	520,030	1,409,330	2,682,299	3,609,083	2,428,832	362,663	686,106	1,835,026	2,808,471	1,903,772	(8,887,756)	3,340,669	(932,890)	877,655	12,643,290
	Surcharge revenue:															
actual	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
actual	November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
actual	November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	-	-	(912,804)
actual	November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	-	-	(1,336,776)
actual	November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	-	(1,679,228)
actual	November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	-	(1,732,442)
actual	November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	-	-	(1,428,735)
Actual	November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	-	-	(1,403,787)
Actual	November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	-	-	(1,694,877)
Actual	November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	-	-	(2,141,793)
Actual	November 2007- October 2008															
	AES collections	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(12,888)	(107,764)
	Gas Street overcollection	-	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
	Prior Period Pool under/overcollection															
C	Surcharge Subtotal	(520,030)	(1,388,292)	(2,653,355)	(3,615,454)	(2,062,596)	(258,389)	(440,504)	(902,092)	(721,725)	(441,669)	(12,271)	(12,597)	(12,888)	(12,888)	(13,054,749)
D	Net balance to be recovered (A-B+C)	-	21,038	28,944	(6,371)	366,236	104,274	245,602	932,934	2,086,746	1,462,103	(8,900,027)	3,328,072	(945,778)	864,767	(411,459)
E	Allocation of Litigated Recovery															

Surcharge calculation 2007/2008
Unrecovered costs (D+E)
remaining life
one year
F amortization 2007/2008

Required annual increase in rates 2007/2(
smaller of D or F

forecasted therm sales

surcharge per therm

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000132

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

LINE
NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI) received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September, 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003 and 2007, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit. These sample results will be evaluated over time to address the efficacy of the existing remedy, and determine if additional treatment may be necessary. **A groundwater sampling round for the MGP site will be conducted in August 2010 and will include monitoring wells located on the MGP site itself as well as a number of wells located offsite.**

   The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

   On July 15, 2003, NHDES issued a letter to KeySpan requesting submission of a schedule and scope of work for a site investigation of the gas plant by mid-September

LINE
NO.

2003. ENGI proposed a May 2005 date for submission of a site investigation report for the former manufactured gas plant on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. **The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the “Tar Pond” which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.**

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this workplan on August 3, 2010 and the work is scheduled to occur in September 2010.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the

LINE
NO.

pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase. **The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI will coordinate further discussions with the parties once all have reviewed the draft design plans.**

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. In May 2007, NHDES approved ENGI's April 2007 scope of work to conduct additional investigations around this well to determine the extent of the coal tar impacts and the feasibility of removing it from the subsurface. The issues associated with this well will be included in the overall site strategy.

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. A Site Investigation Report will be submitted for the river portion of the site, but based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In

addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI.

In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the gas plant. ENGI submitted the scope to NHDES in May 2004, and implemented it between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. **ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this workplan on August 3, 2010 and the work is scheduled to occur in September 2010.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into. *Insurance recovery efforts at the Concord Site are complete.*

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
KEYSPAN PROJECT DEF056

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	GEI Consultants	50385	5,335.70			5,335.70
	GEI Consultants	49607	2,048.19			2,048.19
	Anchor Environmental	17087	3,430.99			3,430.99
	Anchor Environmental	18409	30,659.10			30,659.10
	GEI Consultants	49711	3,730.36			3,730.36
	New Hampshire Department of Environmental Services		123.61			123.61
	Anchor Environmental	19146	10,726.25			10,726.25
	Anchor Environmental	18775	27,119.05			27,119.05
	GEI Consultants	49958	2,812.35			2,812.35
	GEI Consultants	50020	3,374.75			3,374.75
	GEI Consultants	50250	3,281.00			3,281.00
	Anchor Environmental	19919	28,435.04			28,435.04
	GEI Consultants	50543	6,494.57			6,494.57
	Clean Harbors	SB0945748	1,074.43			1,074.43
	GEI Consultants	50670	3,039.95			3,039.95
	GEI Consultants	50779	663.25			663.25
	GEI Consultants	50935	2,023.47			2,023.47
	GEI Consultants	51108	3,263.17			3,263.17
	New Hampshire Department of Environmental Services		112.25			112.25
	GEI Consultants	51280	5,252.57			5,252.57
	Total Pool Activity		**143,000.05**	**-**	**(6,063.97)**	**136,936.08**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
KEYSPAN PROJECT DEF077

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	GZA GeoEnvironmental	0612229	15,225.54			15,225 54
	GZA GeoEnvironmental	0618660	16,189.72			16,189.72
	McLane	2009080477	171.00			171 00
	GZA GeoEnvironmental	0620704	4,157.42			4,157.42
	McLane	2010010067	2,058.50			2,058 50
	GZA GeoEnvironmental	0622424	2,773.13			2,773.13
	McLane	2010030032	758.10			758.10
	McLane	2010040323	649.80			649 80
	Department of Environmental Services	198904063-04	4,187.15			4,187.15
	McLane	2010050382	3,232.40			3,232.40
	Total Pool Activity		**49,402.76**	**-**	**(3,213.24)**	**46,189.52**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD - LITIGATION
KEYSPAN PROJECT DEF051

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

	Total Pool Activity					

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Winnipesaukee River. The full nature and extent of contamination is unknown at this time. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

LINE
NO.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006 Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a RAP Addendum was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES 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.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter

LINE
NO.

deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice 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 submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modeling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. **ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. ENGI is awaiting a decision from NHDES on the RAP Addendum No. 2 and anticipates receiving the decision in the Summer of 2010.**

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2010, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; semi-annual groundwater and surface water sampling activities; and drinking water well sampling. Groundwater sampling is reported to the NHDES in semi-annual reports. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Please refer to Item 4.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was converted to propane. Half of the property is now owned by Robert Irwin and maintained as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

   The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

   Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that a “continuous injury-in-fact” trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.

   With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF086

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	McLane	2009080476	1,504.80			1,504.80
	McLane	2009070320	6,615.10			6,615.10
	Ostrow & Partners	07 09 01	1,670.00			1,670.00
	GEI Consultants	49605	41,821.26			41,821.26
	Public Service of New Hampshire		8.84			8.84
	Ostrow & Partners	08 09 01	310.00			310.00
	Ostrow & Partners	09 09 01	1,070.00			1,070.00
	GEI Consultants	49710	27,464.13			27,464.13
	Blue Chip Films	00861	725.00			725.00
	Departmental of Environmental Services	200411113-06	8,059.90			8,059.90
	McLane	2009090845	2,120.40			2,120.40
	Ostrow & Partners	10 09 01	1,726.00			1,726.00
	Public Service of New Hampshire		9.84			9.84
	Public Service of New Hampshire		19.95			19.95
	Public Service of New Hampshire		29.31			29.31
	GEI Consultants	49957	49,542.95			49,542.95
	Ostrow & Partners	11 09 01	310.00			310.00
	McLane	2009110669	444.60			444.60
	GEI Consultants	50019	28,441.30			28,441.30
	Ostrow & Partners	12 09 01	460.00			460.00
	GEI Consultants	50276	7,624.54			7,624.54
	Public Service of New Hampshire		9.87			9.87
	McLane	2009120992	171.00			171.00
	Ostrow & Partners	01 10 01	310.00			310.00
	GEI Consultants	50352	2,344.75			2,344.75
	Public Service of New Hampshire		7.57			7.57
	Public Service of New Hampshire		7.57			7.57
	GEI Consultants	50537	1,694.38			1,694.38
	Clean Harbors	SB0945743	1,137.97			1,137.97
	McLane	2010030031	108.30			108.30
	GEI Consultants	50679	7,024.25			7,024.25
	Public Service of New Hampshire		22.36			22.36
	Public Service of New Hampshire		48.44			48.44
	Ostrow & Partners	02 10 01	310.00			310.00
	GEI Consultants	50778	34,984.58			34,984.58
	Public Service of New Hampshire		28.09			28.09
	Clean Harbors	NH1015788	1,003.85			1,003.85
	Public Service of New Hampshire		20.06			20.06
	Public Service of New Hampshire		20.47			20.47
	Public Service of New Hampshire		32.45			32.45
	Public Service of New Hampshire		58.94			58.94
	GEI Consultants	50934	4,802.45			4,802.45
	McLane	2010050381	877.20			877.20
	Ostrow & Partners	04 10 01	479.50			479.50
	GEI Consultants	51107	2,741.65			2,741.65
	Ostrow & Partners	05 10 01	870.75			870.75
	GEI Consultants	51279	2,626.50			2,626.50
	Departmental of Environmental Services	2004111113-07	18,904.22			18,904.22
	Blue Chip Films	00916	700.00			700.00
	Ostrow & Partners	06 10 01	479.50			479.50
	Ostrow & Partners	07 10 01	636.00			636.00
	Blue Chip Films	00919	237.50			237.50
						-
	Total Pool Activity		**262,678.09**	**-**	**-**	**262,678.09**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LACONIA - LITIGATION
KEYSPAN PROJECT DEF050

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity					

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF087

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity					

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI) received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP from NHDES, which designated the site DES #200003011. It is understood that NHDES intended to solicit site investigation reports on all MGPs and then prioritize them for remedial action.

3. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

   - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

   - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

   - On August 31, 2000 an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE submitted a summary report to NHDES in January 2001 on behalf of ENGI documenting the response action.

   - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

   - NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

   - ENGI responded to NHDES' comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

LINE
NO.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments.

- In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage.

- In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence.

- NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization.

- ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers since April 2003, until they ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment are being addressed concurrently and that ENGI avoids incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, in portions of Singer Park at depth and in the Merrimack River sediment. Further investigations were recommended by ENGI to completely bound the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that a Remedial Action Plan for the upland and Merrimack River is required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAP began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

LINE
NO.

- Certain predesign investigations were completed on the upland portion of the former MGP site in 2008/2009. ENGI completed certain interim Phase I Corrective Actions at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale dense non-aqueous phase (DNAPL) recovery, and design for replacement of a portion of the site drainage system. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements. **Groundwater monitoring events to support this GMZ permit have been ongoing.**

- **ENGI submitted a Remedial Action Plan for the Site to NHDES for review on June 30, 2010. The remedial objectives for the Site include control of mobile DNAPL, reduction in contaminant mass (where practicable), and management of residual contamination through the use of administrative controls. The recommended remedial alternative includes removal of the contents of certain subsurface structures where removal is anticipated to provide a reduction in the potential for the further release of DNAPL to the subsurface; NAPL recovery from the subsurface; construction of a barrier wall proximate to the Merrimack River to mitigate potential DNAPL; and use of administrative controls to address potential human exposure to residual soil and groundwater contamination. Additional investigation activities were recommended to support the preparation of Design Plans and Construction Specifications following NHDES approval of the RAP and to confirm the appropriateness of certain remedial alternatives recommended in the RAP. ENGI has not received any formal NHDES review comments yet on the Remedial Action Plan.**

4. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. **A Remedial Action Plan (RAP) for the site was submitted to NHDES for review on June 30, 2010.**

5. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

LINE
NO.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity “operated” the Manchester Gas Plant, as defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as “CERCLA” or “Superfund”). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

   Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier willpaid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	URS	3947276	2,666.80			2,666.80
	URS	3976971	3,710.00			3,710.00
	Maxymillian Technologies		3,852.85			3,852.85
	Clean Harbors	NH0901797	152.64			152.64
	Clean Harbors	NH0906475	514.47			514.47
	URS	3995747	16,209.45			16,209.45
	Clean Harbors	NH0962661	721.02			721.02
	NH Department of Environmental Services	200003011-04	1,480.35			1,480.35
	URS	4038177	7,770.00			7,770.00
	URS	4038176	24,621.92			24,621.92
	Curry Printing	174596	470.81			470.81
	Clean Harbors	NH0985443	2,462.45			2,462.45
	Shaw Environmental	494198-R8-00501	805.00			805.00
	URS	4122632	1,019.77			1,019.77
	Shaw Environmental	491479-R8-00501	3,009.95			3,009.95
	URS	4107239	4,107.00			4,107.00
	Clean Harbors	NH0960987	1,581.41			1,581.41
	Clean Harbors	NH0944943	7,182.16			7,182.16
	Clean Harbors	NH0962838R	368.88			368.88
	Shaw Environmental	497590-R8-00501	1,163.75			1,163.75
	Shaw Environmental	495513-R8-00501	2,814.00			2,814.00
	GEI Consultants	50222	3,900.00			3,900.00
	Shaw Environmental	497586-R8-00501	10,363.13			10,363.13
	URS	4141174	2,328.52			2,328.52
	URS	4141179	3,630.00			3,630.00
	GZA Geo Environmental	0620705	552.00			552.00
	Shaw Environmental	502864-R8-00501	3,896.25			3,896.25
	URS	4175715	3,914.52			3,914.52
	URS	4141183	7,705.27			7,705.27
	Clean Harbors	NH0985320	326.48			326.48
	GZA Geo Environmental	0622427	9,279.88			9,279.88
	URS	4206129	5,663.53			5,663.53
	Shaw Environmental	503998-R8-00501	14,001.20			14,001.20
	Shaw Environmental	509352-R8-00501	25,813.25			25,813.25
	URS	4235574	2,087.85			2,087.85
	Clean Harbors	NH0926715	6,183.02			6,183.02
	Clean Harbors	NH1071878	2,541.98			2,541.98
	Clean Harbors	NH1070083	2,843.11			2,843.11
	GZA Geo Environmental	0624333	25,548.66			25,548.66
	Clean Harbors	NH1014297R	707.02			707.02
	Shaw Environmental	506112-R8-00501	26,379.77			26,379.77
	Shaw Environmental	511642-R8-00501	9,774.75			9,774.75
	Clean Harbors	NH1039917	191.86			191.86
	Clean Harbors	NH1027866	217.04			217.04
	Clean Harbors	NH1039934	1,418.58			1,418.58
	Clean Harbors	NH1027449	1,740.41			1,740.41
	NH Department of Environmental Services		100.00			100.00
	Shaw Environmental	514982-R8-00501	37,584.83			37,584.83
	Clean Harbors	NH1070656	1,013.46			1,013.46
	NH Department of Environmental Services	200003011-05	808.23			808.23
	Shaw Environmental	517751-R8-00501	22,107.00			22,107.00
	URS	4359632	1,298.53			1,298.53
	GZA Geo Environmental	0628303	48,432.23			48,432.23
	Century Indemnity				(23,538.97)	(23,538.97)
	UGI Insurance		-		(16,820.48)	(16,820.48)
	Total Pool Activity		**369,037.04**	**-**	**(40,359.45)**	**328,677.59**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - LITIGATION
KEYSPAN PROJECT DEF058

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

	Total Pool Activity					

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua manufactured gas plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England (ENGI), and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at a former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and later Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

   - In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.

LINE
NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.

- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.

- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.

- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.

- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.

- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.

- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.

- ENGI and ESE developed a letter discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and from PSNH/NU and submitted the document in August 2000 along with a proposed schedule for implementation.

- NHDES approved the Revised Phase II Work Plan for the 38 Bridge Street Site at the end of August 2000.

- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

LINE
NO.

- Harding ESE submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH/NU reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000-2001. Work entailed a comprehensive field program that included river borings and sediment samples as well as borings and monitoring wells completed on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI and Harding ESE submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and NHDES met in early June 2001 to discuss draft site conceptual model and the overall site objectives and approach.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

LINE
NO.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was made, and verbal approval obtained, on November 19, 2001.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the

LINE
NO.

capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004. The capping and re-armoring was completed in October 2004 and Remedial Completion Report submitted to NHDES in January 2005, and subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered that additional data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008 and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

- In Spring 2009, ENGI began trenching and final system installation activities for the DNAPL recovery pilot testing. The trenching, pump installations and system electrical work was completed in July 2009. Electrical service was installed in late August 2009. **The system was started up in November 2009 and has been operational since that time. The system has recovered 109 gallons of DNAPL through July 2010. ENGI is currently evaluating the effectiveness of the pilot DNAPL recovery system, and expects to submit the Installation Summary and Progress Report on DNAPL Recovery Pilot Test to NHDES in September 2010.**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the Fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. Pilot testing of the DNAPL recovery system in the approved RAP is on-going.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA’s claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

   ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

   Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered

LINE
NO.

into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling and guidance on the proper manner in which costs are to be allocated among insurers (discussed in more detail in the Manchester MGP summary) will be used in the calculation of that figure.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
KEYSPAN PROJECT DEF054

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
	Innovative Engineering Solutions, Inc.	7778	10,272.17			10,272.17
	Environmental Soil Management	1006425	6,816.27			6,816.27
	Department of Environmental Services	199810022-06	351.26			351.26
	Innovative Engineering Solutions, Inc.	7991	1,483.92			1,483.92
	Innovative Engineering Solutions, Inc.	8050	4,459.96			4,459.96
	Innovative Engineering Solutions, Inc.	7851	44,060.74			44,060.74
	Innovative Engineering Solutions, Inc.	7920	53,323.53			53,323.53
	Innovative Engineering Solutions, Inc.	8105	5,934.41			5,934.41
	Clean Harbors	NH0913109	4,271.48			4,271.48
	Innovative Engineering Solutions, Inc.	8165	5,711.71			5,711.71
	Innovative Engineering Solutions, Inc.	8211	1,562.40			1,562.40
	Innovative Engineering Solutions, Inc.	8276	4,680.60			4,680.60
	Innovative Engineering Solutions, Inc.	8357	2,188.72			2,188.72
	Innovative Engineering Solutions, Inc.	8430	2,317.89			2,317.89
	Innovative Engineering Solutions, Inc.	8507	1,015.70			1,015.70
	Innovative Engineering Solutions, Inc.	8563	14,277.78			14,277.78
	Total Pool Activity		**$162,728.54**	**$0.00**	**($63,753.10)**	**$98,975.44**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - LITIGATION
KEYSPAN PROJECT DEF049

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
	Total Pool Activity					

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

DOVER FORMER MGP

LINE
NO.

1. SITE LOCATION: Intersection of Cocheco Street and Portland Street, Dover, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: In 1999, NHDES sent notice letters to current and former site owners and operators including: Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities (NU).; EnergyNorth Natural Gas, Inc. (ENGI); Northern Utilities, Inc.; and Central Vermont Public Service Company (CVPS). It is the company's understanding that NHDES sent a notice to the current site owner, Estelle Maglaras, earlier. NHDES designated the site DES #198401047.

3. NATURE AND SCOPE OF SITE CONTAMINATION: According to the August 2002 Supplemental Site Investigation Report, the evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - During late 1999 and early 2000, PSNH/NU took the lead on preparation of a Site Investigation Report. PSNH/NU submitted the report to NHDES and the other potentially responsible parties (PRPs) in February 2000.

   - The PRPs held meetings and discussions during 2000 regarding site responsibility and liability.

   - Following an October meeting between NHDES and PSNH/NU, ENGI, and CVPS, Metcalf & Eddy, Inc. (M&E), in December 2000, submitted a Supplemental Site Investigation Work Plan on behalf of PSNH/NU, ENGI, and CVPS to NHDES.

   - NHDES provided written comments on the Supplemental Site Investigation Work Plan in April, 2001.

   - M&E submitted a letter response to NHDES comments on the Work Plan to NHDES in early June 2001.

   - NHDES approved the Supplemental Site Investigation Work Plan and letter addendum in late June 2001.

LINE
NO.

- PSNH/NU, in conjunction with CVPS and ENGI, submitted the M&E Supplemental Site Investigation Report to the DES on August 9, 2002.

- Since 2002, PSNH has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Supplemental Site Investigation completed. Please contact PSNH or NHDES for current status.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Dover MGP, which began operation in 1850, was included in that transaction. GSI operated the Dover MGP until 1956, when it was sold to Allied New Hampshire Gas Company (Allied). Approximately 10 months after that sale, the MGP was shut down when natural gas arrived in Dover. Allied merged into Northern Utilities in 1969, and Northern Utilities continued to own the property until 1978. At that time, the property was sold to Estelle Maglaras, the current owner. The majority of the property is used by the Maglaras family as a marina and boatyard. Northern Utilities, Inc. maintains a regulator station on a small portion of the former MGP property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Mediation between PSNH, ENGI, CVPS and Northern Utilities for allocation was undertaken in the fall of 2001 but was not successful. Since that time, PSNH reached a confidential settlement and allocation with CVPS, and has taken the lead on site investigation and remediation activities. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments. PSNH and ENGI have attempted to negotiate an allocation but thus far have been unsuccessful.

   Insurance recovery efforts are complete, and resulted in several confidential settlements as well as a judgment in favor of coverage. Trial was conducted in the United States District Court in February, 2005. At the close of the defendant's case, the court directed a verdict in ENGI's favor on the issue of coverage determining that the defendant is liable for environmental costs related to the site. In May, 2005, the court ordered Century Indemnity to reimburse ENGI's attorneys' fees and costs associated with the litigation. In June 2005, the Court issued an Amended Judgment awarding fees to ENGI. Century appealed the Amended Judgment and oral argument was heard in January 2006. Century's appeal was denied by the Court in June 2006, and ENGI was ultimately awarded its attorneys fees associated with that appeal.

LINE
NO.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
SITE NAME: DOVER - REMEDIATION
KEYSPAN PROJECT DEF059

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

Total Pool Activity	

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
DOVER - LITIGATION
KEYSPAN PROJECT DEF060

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

	Total Pool Activity					

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

KEENE FORMER MGP

LINE
NO.

1. SITE LOCATION: 207 and 227 Emerald Street, Keene, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: Information on site investigation activities comes from reports prepared by Public Service Company of New Hampshire (PSNH). It is apparent the New Hampshire Department of Environmental Services (NHDES) first investigated Mill Creek adjacent to the former Keene Manufactured Gas Plant (MGP) in 1986. PSNH, a former owner and operator, and its parent company, Northeast Utilities Service Company (NU), conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES, which designated the site DES # 199412009. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. Although it does not appear to have been actively involved in the site study, Keene Gas Corporation (KGC) received a notice letter from NHDES in January 1999. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Natural Gas, Inc. (ENGI) in April 2001. ENGI responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI entered into a confidential agreement with PSNH relative to the development and execution of a Remedial Action Plan (RAP) for the aquatic portion of the site in January 2005. Subsequently, in March 2005, ENGI and PSNH/NU submitted a Scope of Work for the ecological evaluation of the Ashuelot River Sediments to NHDES, and met with NHDES on April 25, 2005 to discuss the conceptual RAP (consisting of sediment removal and stream bed restoration) for Mill Creek/Ashuelot River. NHDES approved the scope of the ecological evaluation, and it was conducted in 2005. In February 2006, PSNH submitted a scope of work for a supplemental investigation of the Ashuelot River, which was approved by NHDES in April 2006. This work was completed and in response in February 2007 NHDES requested a Remedial Action Plan (RAP) for Mill Creek and a portion of the Ashuelot River. **NHDES files indicate that PSNH submitted the RAP in 2008 and completed permitting and obtaining access from private property owners for the Mill Creek and Ashuelot River remediation activities in 2010. Subsequently, a remedial contractor was a selected, and Phase II RAP implementation is underway.**

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Remediation of the terrestrial portion of the site was completed by PSNH/NU in 2004/2005. An ecological risk assessment in support of a Remedial Action Plan for the Ashuelot River and Mill Creek portions of the site was conducted jointly by ENGI and PSNH/NU in 2005. A supplemental investigation of the Ashuelot River to support the preparation of a Remedial Action Plan (RAP) was completed in 2007 and NHDES has requested PSNH/NU submit the RAP for Mill Creek and portions of the Ashuelot River in 2007. NHDES files indicate that the RAP was submitted by PSNH in 2008 and that NHDES commented and approved the Phase II RAP. NHDES and other public information sources indicate that remedial and wetland permitting is complete, necessary approvals and site access agreements with impacted landowners are complete, a remedial contractor has been selected, and Phase II RAP implementation is on-going. PSNH has taken the lead on investigation at this Site, and so has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: Given its status at the site, ENGI has not yet conducted a thorough evaluation of its history. It is known that the plant became operational in approximately 1860 and operated as a manufactured gas plant until 1952, after which it was converted to butane and later to propane. Gas Service, Inc., a predecessor of ENGI, owned the former MGP between October 1945 and its closure in 1952. Gas Service continued to own the property until it was sold to KGC in 1979. KGC continues to operate a propane-air plant at the site. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on site history, use and ownership.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS:

Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. The case is currently stayed. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court. The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In that case, EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007), the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums"

LINE
NO.

allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

ENGI intervened in Docket DE 98-123, the proceeding in which the Commission considered the proposed transfer of operating assets from Keene Gas Corporation (KGC) to New Hampshire Gas Corporation (NHGC). ENGI opposed the proposed transfer because it was concerned that the transfer was likely to create a significant, and possibly insurmountable, obstacle to the potential for KGC customers to share in responsibility for any costs associated with environmental liabilities at the Keene MGP site. At the time, ENGI had not been named as a potentially responsible party for the Keene MGP site, nor had it been notified by any PRP of any claimed liability for the site. Nevertheless, ENGI was aware of the possibility that it would receive such a notice at some point in the future. In the KGC/NHGC proceeding, ENGI proposed that the Commission condition any approval of the proposed transfer on NHGC's willingness to assume responsibility for KGC's liability with regard to the site. The Commission ultimately approved the transfer of assets without imposing such a condition, finding among other things that liability for environmental contamination at the Keene MGP site remained speculative at that time and that assignment of any such liability to various parties was not appropriate for determination by the Commission.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - REMEDIATION
KEYSPAN PROJECT DEF055

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

	Total Pool Activity					

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - LITIGATION
KEYSPAN PROJECT DEF071

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity					

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
KEYSPAN PROJECT DEF064

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	McLane	2009080475	513.00			513.00
	McLane	2009090869	2,428.20			2,428.20
	McLane	2009110668	307.80			307.80
	GZA Geo Environmental	0619733	7,200.00			7,200.00
	Curry Printing	173216	1,271.36			1,271.36
	Departmental of Environmental Services		800.00			800.00
	Curry Printing	180080	604.63			604.63
	McLane	2010050380	361.00			361.00
	McLane	2010060340	108.30			108.30
	Interest on Over Recovery Balance Aug 09-July 10		(9,395.63)			(9,395.63)
	Total Pool Activity		**4,198.66**	**-**	**-**	**4,198.66**

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.11 per MMBtu of Daily Imbalance Volumes*
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.
III.	Peaking Demand Charge	$18.48 MMBTU of Peak MDQ.

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

Rate: **$0.11 /MMBtu**

	Rate	Volume	Total	
Injection Cost	$0.0102	**664,014**	$6,773	
Withdrawal Cost	$0.0102	**308,811**	$3,150	
Delivery Rate	$0.0378	308,811	$11,676	
FTA Demand Charge	$0.1936	308,811	$59,799	
FTA Commodity Charge	$0.0834	308,811	$25,755	
		Total Cost	$107,153	
	Absolute Value of the	Sendout Error	**972,826**	MMBtu
		Rate	$ 0.11	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	$0.0102	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0102	/ MMBtu
TGP FSMA Deliverability Charge	$1.15	/ MMBtu per month
	$0.0378	/ MMBtu per day
TGP Z4-6 Demand Charge	$5.89	/ MMBtu per month
	$0.1936	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.0834	/ MMBtu

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

Calculation of Supplier Balancing Charge

Estimated Monthly Imbalances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	644	605	39	1,092,809	1,040,650	52,159	127,053	89,606	37,447
Dec	1,152	1,125	27	2,139,485	2,088,603	50,883	179,032	114,957	64,075
Jan	1,248	1,206	42	2,320,402	2,241,251	79,151	177,147	128,149	48,998
Feb	1,018	960	58	1,890,006	1,780,702	109,304	150,764	130,034	20,730
Mar	719	700	19	1,328,274	1,298,222	30,051	131,278	80,665	50,613
Apr	475	464	11	882,433	868,117	14,316	58,567	36,442	22,125
May	203	212	-9	450,972	456,503	-5,531	41,173	17,821	23,352
Jun	48	66	-18	331,227	337,601	-6,374	14,872	4,249	10,623
Jul	14	28	-14	305,687	305,687	0	0	0	0
Aug	9	17	-8	284,882	284,882	0	0	0	0
Sep	141	144	-3	351,741	352,838	-1,097	12,794	5,849	6,945
Oct	526	503	23	847,625	815,285	32,340	80,147	56,244	23,904
Total	**6,197**	**6,030**	**167**	**12,225,543**	**11,870,341**	**355,203**	**972,826**	**664,014**	**308,811**

EnergyNorth Natural Gas Inc.
d/b/a National Grid New Hampshire

Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 09	23	24	-1	38,742	40,043	-1,301	1,301	0	1,301
Apr 2, 09	17	13	4	30,933	25,727	5,206	5,206	5,206	0
Apr 3, 09	18	16	2	32,234	29,631	2,603	2,603	2,603	0
Apr 4, 09	22	23	-1	37,440	38,742	-1,301	1,301	0	1,301
Apr 5, 09	20	20	0	34,837	34,837	0	0	0	0
Apr 6, 09	20	23	-3	34,837	38,742	-3,904	3,904	0	3,904
Apr 7, 09	24	26	-2	40,043	42,646	-2,603	2,603	0	2,603
Apr 8, 09	25	26	-1	41,345	42,646	-1,301	1,301	0	1,301
Apr 9, 09	19	18	1	33,536	32,234	1,301	1,301	1,301	0
Apr 10, 09	18	14	4	32,234	27,028	5,206	5,206	5,206	0
Apr 11, 09	26	26	0	42,646	42,646	0	0	0	0
Apr 12, 09	28	30	-2	45,249	47,852	-2,603	2,603	0	2,603
Apr 13, 09	24	21	3	40,043	36,139	3,904	3,904	3,904	0
Apr 14, 09	20	19	1	34,837	33,536	1,301	1,301	1,301	0
Apr 15, 09	20	20	0	34,837	34,837	0	0	0	0
Apr 16, 09	19	19	0	33,536	33,536	0	0	0	0
Apr 17, 09	9	7	2	20,521	17,918	2,603	2,603	2,603	0
Apr 18, 09	15	14	1	28,330	27,028	1,301	1,301	1,301	0
Apr 19, 09	23	20	3	38,742	34,837	3,904	3,904	3,904	0
Apr 20, 09	21	19	2	36,139	33,536	2,603	2,603	2,603	0
Apr 21, 09	14	15	-1	27,028	28,330	-1,301	1,301	0	1,301
Apr 22, 09	10	15	-5	21,822	28,330	-6,507	6,507	0	6,507
Apr 23, 09	15	16	-1	28,330	29,631	-1,301	1,301	0	1,301
Apr 24, 09	5	4	1	15,315	14,014	1,301	1,301	1,301	0
Apr 25, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 26, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 27, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 28, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 29, 09	13	12	1	25,727	24,425	1,301	1,301	1,301	0
Apr 30, 09	7	4	3	17,918	14,014	3,904	3,904	3,904	0
May 1, 09	2	2	0	11,752	11,752	0	0	0	0
May 2, 09	10	9	1	16,669	16,054	615	615	615	0
May 3, 09	11	9	2	17,283	16,054	1,229	1,229	1,229	0
May 4, 09	11	4	7	17,283	12,981	4,302	4,302	4,302	0
May 5, 09	17	17	0	20,970	20,970	0	0	0	0
May 6, 09	7	8	-1	14,825	15,440	-615	615	0	615
May 7, 09	6	9	-3	14,211	16,054	-1,844	1,844	0	1,844
May 8, 09	4	0	4	12,981	10,523	2,458	2,458	2,458	0
May 9, 09	0	1	-1	10,523	11,138	-615	615	0	615
May 10, 09	11	11	0	17,283	17,283	0	0	0	0
May 11, 09	16	10	6	20,356	16,669	3,687	3,687	3,687	0
May 12, 09	11	10	1	17,283	16,669	615	615	615	0
May 13, 09	6	5	1	14,211	13,596	615	615	615	0
May 14, 09	6	6	0	14,211	14,211	0	0	0	0
May 15, 09	1	0	1	11,138	10,523	615	615	615	0
May 16, 09	2	3	-1	11,752	12,367	-615	615	0	615
May 17, 09	14	12	2	19,127	17,898	1,229	1,229	1,229	0
May 18, 09	13	15	-2	18,512	19,741	-1,229	1,229	0	1,229
May 19, 09	5	3	2	13,596	12,367	1,229	1,229	1,229	0
May 20, 09	0	0	0	10,523	10,523	0	0	0	0
May 21, 09	0	0	0	10,523	10,523	0	0	0	0
May 22, 09	0	0	0	10,523	10,523	0	0	0	0
May 23, 09	3	8	-5	12,367	15,440	-3,073	3,073	0	3,073
May 24, 09	2	0	2	11,752	10,523	1,229	1,229	1,229	0
May 25, 09	3	5	-2	12,367	13,596	-1,229	1,229	0	1,229
May 26, 09	5	10	-5	13,596	16,669	-3,073	3,073	0	3,073
May 27, 09	14	18	-4	19,127	21,585	-2,458	2,458	0	2,458
May 28, 09	10	17	-7	16,669	20,970	-4,302	4,302	0	4,302
May 29, 09	5	5	0	13,596	13,596	0	0	0	0
May 30, 09	2	2	0	11,752	11,752	0	0	0	0
May 31, 09	6	13	-7	14,211	18,512	-4,302	4,302	0	4,302
Jun 1, 09	0	2	-2	10,474	11,183	-708	708	0	708
Jun 2, 09	1	0	1	10,828	10,474	354	354	354	0
Jun 3, 09	0	1	-1	10,474	10,828	-354	354	0	354
Jun 4, 09	2	1	1	11,183	10,828	354	354	354	0
Jun 5, 09	5	6	-1	12,245	12,599	-354	354	0	354
Jun 6, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 7, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 8, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 9, 09	10	11	-1	14,015	14,369	-354	354	0	354
Jun 10, 09	7	8	-1	12,953	13,307	-354	354	0	354
Jun 11, 09	2	8	-6	11,183	13,307	-2,125	2,125	0	2,125
Jun 12, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 13, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 14, 09	0	7	-7	10,474	12,953	-2,479	2,479	0	2,479
Jun 15, 09	3	8	-5	11,537	13,307	-1,770	1,770	0	1,770
Jun 16, 09	4	6	-2	11,891	12,599	-708	708	0	708
Jun 17, 09	1	1	0	10,828	10,828	0	0	0	0
Jun 18, 09	2	3	-1	11,183	11,537	-354	354	0	354
Jun 19, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 20, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 21, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 22, 09	2	1	1	11,183	10,828	354	354	354	0
Jun 23, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 24, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 25, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 26, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 27, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 28, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 29, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 30, 09	0	3	-3	10,474	11,537	-1,062	1,062	0	1,062
Jul 1, 09	2	6	-4	9,861	9,861	0	0	0	0
Jul 2, 09	1	6	-5	9,861	9,861	0	0	0	0
Jul 3, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 4, 09	0	0	0	9,861	9,861	0	0	0	0

EnergyNorth Natural Gas Inc.
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Calculation of Supplier Balancing Charge

Estimated Daily Imbalances

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Jul 5, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 6, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 7, 09	2	4	-2	9,861	9,861	0	0	0	0
Jul 8, 09	4	6	-2	9,861	9,861	0	0	0	0
Jul 9, 09	2	3	-1	9,861	9,861	0	0	0	0
Jul 10, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 11, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 12, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 13, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 14, 09	1	0	1	9,861	9,861	0	0	0	0
Jul 15, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 16, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 17, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 18, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 19, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 20, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 21, 09	0	2	-2	9,861	9,861	0	0	0	0
Jul 22, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 23, 09	1	1	0	9,861	9,861	0	0	0	0
Jul 24, 09	1	0	1	9,861	9,861	0	0	0	0
Jul 25, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 26, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 27, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 28, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 29, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 30, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 31, 09	0	0	0	9,861	9,861	0	0	0	0
Aug 1, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 2, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 3, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 4, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 5, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 6, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 7, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 8, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 9, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 10, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 11, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 12, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 13, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 14, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 15, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 16, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 17, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 18, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 19, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 20, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 21, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 22, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 23, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 24, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 25, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 26, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 27, 09	3	0	3	9,190	9,190	0	0	0	0
Aug 28, 09	1	3	-2	9,190	9,190	0	0	0	0
Aug 29, 09	3	9	-6	9,190	9,190	0	0	0	0
Aug 30, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 31, 09	2	5	-3	9,190	9,190	0	0	0	0
Sep 1, 09	3	3	0	11,103	11,103	0	0	0	0
Sep 2, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 3, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 4, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 5, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 6, 09	3	9	-6	11,103	13,297	-2,193	2,193	0	2,193
Sep 7, 09	0	3	-3	10,007	11,103	-1,097	1,097	0	1,097
Sep 8, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 9, 09	3	6	-3	11,103	12,200	-1,097	1,097	0	1,097
Sep 10, 09	7	8	-1	12,565	12,931	-366	366	0	366
Sep 11, 09	5	6	-1	11,834	12,200	-366	366	0	366
Sep 12, 09	2	2	0	10,738	10,738	0	0	0	0
Sep 13, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 14, 09	0	1	-1	10,007	10,372	-366	366	0	366
Sep 15, 09	3	1	2	11,103	10,372	731	731	731	0
Sep 16, 09	12	10	2	14,393	13,662	731	731	731	0
Sep 17, 09	11	11	0	14,028	14,028	0	0	0	0
Sep 18, 09	8	6	2	12,931	12,200	731	731	731	0
Sep 19, 09	13	13	0	14,759	14,759	0	0	0	0
Sep 20, 09	6	7	-1	12,200	12,565	-366	366	0	366
Sep 21, 09	1	4	-3	10,372	11,469	-1,097	1,097	0	1,097
Sep 22, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 23, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 24, 09	4	2	2	11,469	10,738	731	731	731	0
Sep 25, 09	13	13	0	14,759	14,759	0	0	0	0
Sep 26, 09	12	11	1	14,393	14,028	366	366	366	0
Sep 27, 09	7	3	4	12,565	11,103	1,462	1,462	1,462	0
Sep 28, 09	4	1	3	11,469	10,372	1,097	1,097	1,097	0
Sep 29, 09	7	7	0	12,565	12,565	0	0	0	0
Sep 30, 09	17	17	0	16,221	16,221	0	0	0	0
Oct 1, 09	18	18	0	28,794	28,794	0	0	0	0
Oct 2, 09	9	11	-2	16,139	18,952	-2,812	2,812	0	2,812
Oct 3, 09	9	5	4	16,139	10,515	5,624	5,624	5,624	0
Oct 4, 09	6	6	0	11,921	11,921	0	0	0	0
Oct 5, 09	10	11	-1	17,545	18,952	-1,406	1,406	0	1,406
Oct 6, 09	11	9	2	18,952	16,139	2,812	2,812	2,812	0
Oct 7, 09	13	9	4	21,764	16,139	5,624	5,624	5,624	0
Oct 8, 09	14	12	2	23,170	20,358	2,812	2,812	2,812	0

EnergyNorth Natural Gas Inc.
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Oct 9, 09	8	8	0	14,733	14,733	0	0	0	0
Oct 10, 09	18	18	0	28,794	28,794	0	0	0	0
Oct 11, 09	17	19	-2	27,388	30,200	-2,812	2,812	0	2,812
Oct 12, 09	21	18	3	33,012	28,794	4,218	4,218	4,218	0
Oct 13, 09	24	23	1	37,231	35,825	1,406	1,406	1,406	0
Oct 14, 09	27	26	1	41,449	40,043	1,406	1,406	1,406	0
Oct 15, 09	26	26	0	40,043	40,043	0	0	0	0
Oct 16, 09	27	28	-1	41,449	42,855	-1,406	1,406	0	1,406
Oct 17, 09	24	22	2	37,231	34,419	2,812	2,812	2,812	0
Oct 18, 09	27	28	-1	41,449	42,855	-1,406	1,406	0	1,406
Oct 19, 09	23	25	-2	35,825	38,637	-2,812	2,812	0	2,812
Oct 20, 09	15	14	1	24,576	23,170	1,406	1,406	1,406	0
Oct 21, 09	13	9	4	21,764	16,139	5,624	5,624	5,624	0
Oct 22, 09	11	17	-6	18,952	27,388	-8,437	8,437	0	8,437
Oct 23, 09	22	21	1	34,419	33,012	1,406	1,406	1,406	0
Oct 24, 09	9	11	-2	16,139	18,952	-2,812	2,812	0	2,812
Oct 25, 09	18	16	2	28,794	25,982	2,812	2,812	2,812	0
Oct 26, 09	20	19	1	31,606	30,200	1,406	1,406	1,406	0
Oct 27, 09	19	17	2	30,200	27,388	2,812	2,812	2,812	0
Oct 28, 09	22	21	1	34,419	33,012	1,406	1,406	1,406	0
Oct 29, 09	20	17	3	31,606	27,388	4,218	4,218	4,218	0
Oct 30, 09	14	14	0	23,170	23,170	0	0	0	0
Oct 31, 09	11	5	6	18,952	10,515	8,437	8,437	8,437	0
Nov 1, 09	18	20	-2	31,791	34,465	-2,675	2,675	0	2,675
Nov 2, 09	22	23	-1	37,140	38,478	-1,337	1,337	0	1,337
Nov 3, 09	23	19	4	38,478	33,128	5,350	5,350	5,350	0
Nov 4, 09	26	23	3	42,490	38,478	4,012	4,012	4,012	0
Nov 5, 09	26	28	-2	42,490	45,165	-2,675	2,675	0	2,675
Nov 6, 09	27	29	-2	43,827	46,502	-2,675	2,675	0	2,675
Nov 7, 09	24	20	4	39,815	34,465	5,350	5,350	5,350	0
Nov 8, 09	17	19	-2	30,453	33,128	-2,675	2,675	0	2,675
Nov 9, 09	16	4	12	29,116	13,067	16,049	16,049	16,049	0
Nov 10, 09	16	13	3	29,116	25,104	4,012	4,012	4,012	0
Nov 11, 09	23	26	-3	38,478	42,490	-4,012	4,012	0	4,012
Nov 12, 09	23	24	-1	38,478	39,815	-1,337	1,337	0	1,337
Nov 13, 09	19	17	2	33,128	30,453	2,675	2,675	2,675	0
Nov 14, 09	19	14	5	33,128	26,441	6,687	6,687	6,687	0
Nov 15, 09	14	11	3	26,441	22,429	4,012	4,012	4,012	0
Nov 16, 09	21	20	1	35,803	34,465	1,337	1,337	1,337	0
Nov 17, 09	26	28	-2	42,490	45,165	-2,675	2,675	0	2,675
Nov 18, 09	24	29	-5	39,815	46,502	-6,687	6,687	0	6,687
Nov 19, 09	18	12	6	31,791	23,766	8,024	8,024	8,024	0
Nov 20, 09	19	16	3	33,128	29,116	4,012	4,012	4,012	0
Nov 21, 09	21	20	1	35,803	34,465	1,337	1,337	1,337	0
Nov 22, 09	22	23	-1	37,140	38,478	-1,337	1,337	0	1,337
Nov 23, 09	20	21	-1	34,465	35,803	-1,337	1,337	0	1,337
Nov 24, 09	22	18	4	37,140	31,791	5,350	5,350	5,350	0
Nov 25, 09	18	19	-1	31,791	33,128	-1,337	1,337	0	1,337
Nov 26, 09	17	19	-2	30,453	33,128	-2,675	2,675	0	2,675
Nov 27, 09	23	22	1	38,478	37,140	1,337	1,337	1,337	0
Nov 28, 09	29	20	9	46,502	34,465	12,037	12,037	12,037	0
Nov 29, 09	27	21	6	43,827	35,803	8,024	8,024	8,024	0
Nov 30, 09	24	27	-3	39,815	43,827	-4,012	4,012	0	4,012
Dec 1, 09	31	29	2	57,404	53,635	3,769	3,769	3,769	0
Dec 2, 09	19	15	4	34,790	27,252	7,538	7,538	7,538	0
Dec 3, 09	19	12	7	34,790	21,598	13,192	13,192	13,192	0
Dec 4, 09	26	23	3	47,982	42,328	5,654	5,654	5,654	0
Dec 5, 09	31	32	-1	57,404	59,289	-1,885	1,885	0	1,885
Dec 6, 09	34	37	-3	63,058	68,712	-5,654	5,654	0	5,654
Dec 7, 09	33	36	-3	61,174	66,827	-5,654	5,654	0	5,654
Dec 8, 09	27	34	-7	49,866	63,058	-13,192	13,192	0	13,192
Dec 9, 09	30	30	0	55,520	55,520	0	0	0	0
Dec 10, 09	38	36	2	70,596	66,827	3,769	3,769	3,769	0
Dec 11, 09	42	43	-1	78,134	80,019	-1,885	1,885	0	1,885
Dec 12, 09	40	43	-3	74,365	80,019	-5,654	5,654	0	5,654
Dec 13, 09	32	32	0	59,289	59,289	0	0	0	0
Dec 14, 09	30	27	3	55,520	49,866	5,654	5,654	5,654	0
Dec 15, 09	32	29	3	59,289	53,635	5,654	5,654	5,654	0
Dec 16, 09	45	44	1	83,788	81,904	1,885	1,885	1,885	0
Dec 17, 09	53	55	-2	98,864	102,634	-3,769	3,769	0	3,769
Dec 18, 09	47	48	-1	87,557	89,442	-1,885	1,885	0	1,885
Dec 19, 09	40	43	-3	74,365	80,019	-5,654	5,654	0	5,654
Dec 20, 09	43	44	-1	80,019	81,904	-1,885	1,885	0	1,885
Dec 21, 09	46	41	5	85,673	76,250	9,423	9,423	9,423	0
Dec 22, 09	46	45	1	85,673	83,788	1,885	1,885	1,885	0
Dec 23, 09	47	43	4	87,557	80,019	7,538	7,538	7,538	0
Dec 24, 09	36	37	-1	66,827	68,712	-1,885	1,885	0	1,885
Dec 25, 09	37	35	2	68,712	64,943	3,769	3,769	3,769	0
Dec 26, 09	33	27	6	61,174	49,866	11,307	11,307	11,307	0
Dec 27, 09	34	28	6	63,058	51,751	11,307	11,307	11,307	0
Dec 28, 09	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Dec 29, 09	61	55	6	113,941	102,634	11,307	11,307	11,307	0
Dec 30, 09	43	44	-1	80,019	81,904	-1,885	1,885	0	1,885
Dec 31, 09	34	41	-7	63,058	76,250	-13,192	13,192	0	13,192
Jan 1, 10	34	36	-2	63,058	66,827	-3,769	3,769	0	3,769
Jan 2, 10	40	43	-3	74,365	80,019	-5,654	5,654	0	5,654
Jan 3, 10	43	38	5	80,019	70,596	9,423	9,423	9,423	0
Jan 4, 10	39	39	0	72,481	72,481	0	0	0	0
Jan 5, 10	40	38	2	74,365	70,596	3,769	3,769	3,769	0
Jan 6, 10	43	38	5	80,019	70,596	9,423	9,423	9,423	0
Jan 7, 10	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Jan 8, 10	43	45	-2	80,019	83,788	-3,769	3,769	0	3,769
Jan 9, 10	51	51	0	95,095	95,095	0	0	0	0
Jan 10, 10	47	49	-2	87,557	91,326	-3,769	3,769	0	3,769
Jan 11, 10	42	37	5	78,134	68,712	9,423	9,423	9,423	0
Jan 12, 10	45	47	-2	83,788	87,557	-3,769	3,769	0	3,769

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Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 10	44	46	-2	81,904	85,673	-3,769	3,769	0	3,769
Jan 14, 10	39	34	5	72,481	63,058	9,423	9,423	9,423	0
Jan 15, 10	35	28	7	64,943	51,751	13,192	13,192	13,192	0
Jan 16, 10	35	30	5	64,943	55,520	9,423	9,423	9,423	0
Jan 17, 10	35	32	3	64,943	59,289	5,654	5,654	5,654	0
Jan 18, 10	39	34	5	72,481	63,058	9,423	9,423	9,423	0
Jan 19, 10	37	34	3	68,712	63,058	5,654	5,654	5,654	0
Jan 20, 10	37	36	1	68,712	66,827	1,885	1,885	1,885	0
Jan 21, 10	40	40	0	74,365	74,365	0	0	0	0
Jan 22, 10	42	43	-1	78,134	80,019	-1,885	1,885	0	1,885
Jan 23, 10	44	43	1	81,904	80,019	1,885	1,885	1,885	0
Jan 24, 10	27	30	-3	49,866	55,520	-5,654	5,654	0	5,654
Jan 25, 10	26	19	7	47,982	34,790	13,192	13,192	13,192	0
Jan 26, 10	34	30	4	63,058	55,520	7,538	7,538	7,538	0
Jan 27, 10	35	34	1	64,943	63,058	1,885	1,885	1,885	0
Jan 28, 10	39	44	-5	72,481	81,904	-9,423	9,423	0	9,423
Jan 29, 10	54	57	-3	100,749	106,403	-5,654	5,654	0	5,654
Jan 30, 10	51	52	-1	95,095	96,980	-1,885	1,885	0	1,885
Jan 31, 10	45	42	3	83,788	78,134	5,654	5,654	5,654	0
Feb 1, 10	51	42	9	95,095	78,134	16,961	16,961	16,961	0
Feb 2, 10	40	40	0	74,365	74,365	0	0	0	0
Feb 3, 10	37	39	-2	68,712	72,481	-3,769	3,769	0	3,769
Feb 4, 10	45	42	3	83,788	78,134	5,654	5,654	5,654	0
Feb 5, 10	42	42	0	78,134	78,134	0	0	0	0
Feb 6, 10	46	47	-1	85,673	87,557	-1,885	1,885	0	1,885
Feb 7, 10	44	42	2	81,904	78,134	3,769	3,769	3,769	0
Feb 8, 10	42	40	2	78,134	74,365	3,769	3,769	3,769	0
Feb 9, 10	38	33	5	70,596	61,174	9,423	9,423	9,423	0
Feb 10, 10	41	34	7	76,250	63,058	13,192	13,192	13,192	0
Feb 11, 10	41	36	5	76,250	66,827	9,423	9,423	9,423	0
Feb 12, 10	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Feb 13, 10	37	35	2	68,712	64,943	3,769	3,769	3,769	0
Feb 14, 10	37	31	6	68,712	57,404	11,307	11,307	11,307	0
Feb 15, 10	36	34	2	66,827	63,058	3,769	3,769	3,769	0
Feb 16, 10	36	36	0	66,827	66,827	0	0	0	0
Feb 17, 10	32	32	0	59,289	59,289	0	0	0	0
Feb 18, 10	31	28	3	57,404	51,751	5,654	5,654	5,654	0
Feb 19, 10	32	30	2	59,289	55,520	3,769	3,769	3,769	0
Feb 20, 10	32	27	5	59,289	49,866	9,423	9,423	9,423	0
Feb 21, 10	34	33	1	63,058	61,174	1,885	1,885	1,885	0
Feb 22, 10	31	27	4	57,404	49,866	7,538	7,538	7,538	0
Feb 23, 10	29	30	-1	53,635	55,520	-1,885	1,885	0	1,885
Feb 24, 10	29	26	3	53,635	47,982	5,654	5,654	5,654	0
Feb 25, 10	27	25	2	49,866	46,097	3,769	3,769	3,769	0
Feb 26, 10	28	30	-2	51,751	55,520	-3,769	3,769	0	3,769
Feb 27, 10	29	33	-4	53,635	61,174	-7,538	7,538	0	7,538
Feb 28, 10	28	29	-1	51,751	53,635	-1,885	1,885	0	1,885
Mar 1, 10	29	25	4	52,031	45,705	6,327	6,327	6,327	0
Mar 2, 10	28	27	1	50,450	48,868	1,582	1,582	1,582	0
Mar 3, 10	30	29	1	53,613	52,031	1,582	1,582	1,582	0
Mar 4, 10	31	28	3	55,195	50,450	4,745	4,745	4,745	0
Mar 5, 10	31	28	3	55,195	50,450	4,745	4,745	4,745	0
Mar 6, 10	27	22	5	48,868	40,960	7,908	7,908	7,908	0
Mar 7, 10	26	19	7	47,286	36,215	11,072	11,072	11,072	0
Mar 8, 10	27	19	8	48,868	36,215	12,653	12,653	12,653	0
Mar 9, 10	27	28	-1	48,868	50,450	-1,582	1,582	0	1,582
Mar 10, 10	24	25	-1	44,123	45,705	-1,582	1,582	0	1,582
Mar 11, 10	21	26	-5	39,378	47,286	-7,908	7,908	0	7,908
Mar 12, 10	25	28	-3	45,705	50,450	-4,745	4,745	0	4,745
Mar 13, 10	23	27	-4	42,541	48,868	-6,327	6,327	0	6,327
Mar 14, 10	26	25	1	47,286	45,705	1,582	1,582	1,582	0
Mar 15, 10	23	26	-3	42,541	47,286	-4,745	4,745	0	4,745
Mar 16, 10	23	21	2	42,541	39,378	3,163	3,163	3,163	0
Mar 17, 10	18	13	5	34,633	26,725	7,908	7,908	7,908	0
Mar 18, 10	16	15	1	31,470	29,888	1,582	1,582	1,582	0
Mar 19, 10	14	12	2	28,307	25,143	3,163	3,163	3,163	0
Mar 20, 10	10	8	2	21,980	18,817	3,163	3,163	3,163	0
Mar 21, 10	18	22	-4	34,633	40,960	-6,327	6,327	0	6,327
Mar 22, 10	16	23	-7	31,470	42,541	-11,072	11,072	0	11,072
Mar 23, 10	21	23	-2	39,378	42,541	-3,163	3,163	0	3,163
Mar 24, 10	24	23	1	44,123	42,541	1,582	1,582	1,582	0
Mar 25, 10	16	17	-1	31,470	33,051	-1,582	1,582	0	1,582
Mar 26, 10	35	35	0	61,521	61,521	0	0	0	0
Mar 27, 10	31	32	-1	55,195	56,776	-1,582	1,582	0	1,582
Mar 28, 10	21	21	0	39,378	39,378	0	0	0	0
Mar 29, 10	21	16	5	39,378	31,470	7,908	7,908	7,908	0
Mar 30, 10	19	19	0	36,215	36,215	0	0	0	0
Mar 31, 10	18	18	0	34,633	34,633	0	0	0	0
Apr 1, 10	0	0	0	0	0	0	0	0	0
Apr	475	464	11	882,433	868,117	14,316	58,567	36,442	22,125
May	203	212	-9	450,972	456,503	-5,531	41,173	17,821	23,352
Jun	48	66	-18	331,227	337,601	-6,374	14,872	4,249	10,623
Jul	14	28	-14	305,687	305,687	0	0	0	0
Aug	9	17	-8	284,882	284,882	0	0	0	0
Sep	141	144	-3	351,741	352,838	-1,097	12,794	5,849	6,945
Oct	526	503	23	847,625	815,285	32,340	80,147	56,244	23,904
Nov	644	605	39	1,092,809	1,040,650	52,159	127,053	89,606	37,447
Dec	1,152	1,125	27	2,139,485	2,088,603	50,883	179,032	114,957	64,075
Jan	1,248	1,206	42	2,320,402	2,241,251	79,151	177,147	128,149	48,998
Feb	1,018	960	58	1,890,006	1,780,702	109,304	150,764	130,034	20,730
Mar	719	700	19	1,328,274	1,298,222	30,051	131,278	80,665	50,613
Total	6,197	6,030	167	12,225,543	11,870,341	355,203	972,826	664,014	308,811
Datacheck	0	0	0	0	0	0	0	0	0

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

Line	Description	Contract	Amount	Unit	Source:
1	Peak Day		137,400	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 33371	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 72694	4,000		
10			53,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		55,567	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,165,430		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,749,387		Attachment B: Order No. 23,675 (page 15), Docket DG 00-063,
26	Granite Ridge		$247,522		Attachment B Page 3 Line 1
27	Total		$6,162,340		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$110.90		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$18.48**	**/Dekatherm**	Line 29 divided by 6 month

ENERGY NORTH NATURAL GAS

Tennessee Allocations

Resource Type	High Load Factor	Low Load Factor
Pipeline	50 00%	38 00%
Storage	17 00%	21 00%
Peaking	33 00%	41 00%
TOTAL:	100 00%	100 00%

Capacity Resources effective November 1, 2009

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE II*	Supply at Waddington		4,000		$11.8810		10/31/2017	X
	Iroquois	RTS to Wright	470-01	4,047		$6 5971		11/01/2017	
	TGP	NET-NE	33371	4,000		$10 6100		10/31/2011	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		03/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$4 9300		10/31/2015	
	TGP	FT-A (Z0-Z6)	8587	7,035		$16 5900		10/31/2015	
	TGP	FT-A (Z1-Z6)	8587	14,561		$15 1500		10/31/2015	
	TGP	FT-A (Z6-Z6)	42076	20,000		$3 1600		10/31/2015	
	TGP	FT-A (Z6-Z6)	72694	4,000		$12 1700		09/30/2029	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.1500	$0.0185	10/31/2015	
	TGP	FT-A (Z4-Z6)	632	15,265		$5.8900		10/31/2015	
	TGP	FT-A (Z4-Z6)	8587	3,811		$5.8900		10/31/2015	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.1556	$0.0432	03/31/2011	
	National Fuel	FST (Transport)	N02358	6,098		$3.3612		03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	6,150		$5.8900		10/31/2011	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	04/01/2011	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$4.9300		10/31/2011	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8773	$0.0145	03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	932		$5.8900		10/31/2011	
Peaking									
	Energy North	LNG/Propane****		29,567	-	$18.4800	$0 0000		X
	TGP	FT-A (Z6-Z6)	72694	26,000	-	$12.1700	$0 0000	09/30/2029	X

* Volumes and Demand Charges are based on MMBtu at the border
**BP commodity price is based on Inside FERC at Niagara plus $ 01 per Dth
***All gas transferred for storage contracts will be based on LDC's monthly WACOG
****All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention   Demand charge applicable for 6 months

Note **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/08. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the Energy North Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $27.4017/dth.

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ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

			Volume	Rate	Monthly Cost	Months/Year	Annual Cost	
1	Granite Ridge - 30 days @ 15,000/dt							
2								
3								
4	Concord Lateral							
5	DOMAC *	FLS 160						
6								
7	Subtotal						**$4,165,430**	*
8								
9	**Total**						**$4,412,953**	
10								

* Contract currently being negotiated for an effective date of November 1, 2010.

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	Low Annual /Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-42	Medium Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-52	High Annual / Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-43	High Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-53	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%
G-54	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	Storage	Peaking	Total
G-41	**LAHW**	Low Annual C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	50.0%	17.0%	33.0%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	50.0%	17.0%	33.0%	100.0%

HLF	High Load Factor	50%	17%	33%	100%
LLF	Low Load Factor	38%	21%	41%	100%
	Total	39%	20%	40%	99%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		Base load	72 Heat load	Total
HLF	R-1 RNSH	156	495	651
LLF	R-3 RSH	3,993	60,343	64,336
LLF	G-41 SL	851	22,911	23,761
HLF	G-51 SH	627	1,978	2,605
LLF	G-42 ML	1,653	31,424	33,077
HLF	G-52 MH	1,247	3,064	4,311
LLF	G-43 LL	463	4,152	4,615
HLF	G-53 LLL90	297	1,298	1,595
HLF	G-54 LLG90	384	2,064	2,449
	TOTAL	9,671	127,729	137,400

HLF	2,712	8,899	11,611
LLF	6,959	118,830	125,789
Total	9,671	127,729	137,400

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	156	171	326	109	215	651
R-3 RSH	3,993	20,809	24,802	13,282	26,252	64,336
G-41 SL	851	7,901	8,751	5,043	9,967	23,761
G-51 SH	627	682	1,309	435	861	2,605
G-42 ML	1,653	10,837	12,489	6,917	13,671	33,077
G-52 MH	1,247	1,057	2,304	674	1,333	4,311
G-43 LL	463	1,432	1,895	914	1,806	4,615
G-53 LLL90	297	448	745	286	565	1,595
G-54 LLG90	384	712	1,096	454	898	2,449
TOTAL	9,671	44,047	53,718	28,115	55,567	137,400

HLF	2,712	3,069	5,781	1,959	3,872	11,611
LLF	6,959	40,978	47,937	26,156	51,695	125,789
Total	9,671	44,047	53,718	28,115	55,567	137,400

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	50.2%	16.7%	33.1%	100 0%
R-3 RSH	38.6%	20 6%	40.8%	100 0%
G-41 SL	36.8%	21 2%	41.9%	100 0%
G-51 SH	50.3%	16.7%	33.0%	100 0%
G-42 ML	37.8%	20 9%	41.3%	100 0%
G-52 MH	53.4%	15 6%	30.9%	100 0%
G-43 LL	41.1%	19 8%	39.1%	100 0%
G-53 LLL90	46.7%	17 9%	35.4%	100 0%
G-54 LLG90	44.8%	18 6%	36.7%	100 0%
TOTAL	39.1%	20 5%	40.4%	100 0%

High Load Factor	50%	17%	33%	100%
Low Load Factor	38%	21%	41%	100%
Total	39%	20%	40%	100%

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Allocate Design Day Sendout to Rate Classes

Design DD **72**

	Daily Baseload * 1000	February Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	156	6.440	464	619	25%	0.387%	156	495	651
R-3 RSH	3,993	785.433	56,551	60,544	7%	47.243%	3,993	60,343	64,336
G-41 SL	851	298.209	21,471	22,322	4%	17.937%	851	22,911	23,761
G-51 SH	627	25.748	1,854	2,481	25%	1.549%	627	1,978	2,605
G-42 ML	1,653	409.017	29,449	31,102	5%	24.602%	1,653	31,424	33,077
G-52 MH	1,247	39.884	2,872	4,119	30%	2.399%	1,247	3,064	4,311
G-43 LL	463	54.041	3,891	4,354	11%	3.250%	463	4,152	4,615
G-53 LLL90	297	16.892	1,216	1,514	20%	1.016%	297	1,298	1,595
G-54 LLG90	384	26.872	1,935	2,319	17%	1.616%	384	2,064	2,449
TOTAL	9,671	1,637.058	119,703	129,373		100.000%	9,671	127,729	137,400

HLF	2,712	116	8,340	11,052
LLF	6,959	1,521	111,362	118,321
Total	9,671	1,637	119,703	129,373

Design Day from 2009-2010 Resource Plan		**137,400**
Design Day from Billing Calculation		129,373
Variance		8,027

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Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	7	9	13	11	10	8	7	6	5	5	4	6	91	4 830	0 156
LLF	R-3 RSH	388	575	1,118	975	734	464	295	171	129	118	120	224	5,312	123 771	3 993
LLF	G-41 SL	110	174	403	352	261	147	80	41	28	25	24	53	1,697	26 367	0 851
HLF	G-51 SH	25	32	55	46	39	30	24	21	20	19	19	23	354	19 440	0 627
LLF	G-42 ML	200	287	565	496	389	250	148	82	51	51	53	105	2,676	51 229	1 653
HLF	G-52 MH	49	60	88	79	68	57	48	42	39	39	39	44	651	38 662	1 247
LLF	G-43 LL	26	35	55	72	60	49	33	23	17	11	8	4	394	14 360	0 463
HLF	G-53 LLL90	13	(4)	14	27	16	27	13	12	15	4	4	(1)	138	9 221	0 297
HLF	G-54 LLL110	8	1	22	40	(18)	26	5	9	8	16	(1)	2	117	11 911	0 384
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0 000	0 000
	TOTAL	826	1,169	2,332	2,098	1,560	1,058	654	406	312	288	270	459	11,432	299 791	9 671
	HLF	102	98	192	203	116	147	97	90	86	82	66	73	1,352	84 065	2 712
	LLF	725	1,071	2,140	1,895	1,444	911	557	316	225	206	205	386	10,079	215 726	6 959

Baseload (= the lesser of actual volumes or the average of July and August volumes)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	5	5	5	4	5	5	5	5	5	5	4	5	57
LLF	R-3 RSH	120	124	124	112	124	120	124	120	129	118	120	124	1,457
LLF	G-41 SL	26	26	26	24	26	26	26	26	28	25	24	26	310
HLF	G-51 SH	19	19	19	18	19	19	19	19	20	19	19	19	229
LLF	G-42 ML	50	51	51	46	51	50	51	50	51	51	50	51	603
HLF	G-52 MH	37	39	39	35	39	37	39	37	39	39	37	39	455
LLF	G-43 LL	14	14	14	13	14	14	14	14	17	11	8	4	169
HLF	G-53 LLL90	9	(4)	9	8	9	9	9	9	15	4	4	(1)	109
HLF	G-54 LLL110	8	1	12	11	(18)	12	5	9	8	16	(1)	2	117
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	316	306	331	299	301	320	324	318	343	319	295	300	3,530
	HLF	77	59	84	76	55	81	77	79	86	82	64	63	967
	LLF	209	216	216	195	216	209	216	209	225	206	202	206	2,540

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Heating Volumes (= Actual Volumes - Baseload)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	2	4	9	7	5	3	2	1	0	0	0	1	34
LLF	R-3 RSH	269	451	994	863	610	345	172	51	0	0	0	100	3,855
LLF	G-41 SL	84	148	376	328	234	122	54	15	0	0	0	26	1,386
HLF	G-51 SH	6	13	35	28	20	11	5	2	0	0	0	3	125
LLF	G-42 ML	151	236	513	450	337	201	97	33	0	0	3	53	2,073
HLF	G-52 MH	12	22	49	44	30	19	10	4	0	0	2	5	196
LLF	G-43 LL	12	21	41	59	46	35	19	9	0	0	0	0	225
HLF	G-53 LLL90	4	0	4	19	7	18	4	3	0	0	0	0	30
HLF	G-54 LLL110	0	0	10	30	0	14	0	0	0	0	0	0	0
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	510	863	2,001	1,799	1,259	738	330	88	(31)	(31)	(25)	159	7,902

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	24	39	108	127	62	66	20	11	0	0	2	10	385
LLF	516	856	1,924	1,700	1,228	702	341	107	0	0	3	180	7,539
Actual BDD	553.5	866.0	1167.0	1099.0	846.0	545.5	269.0	92.0	19.0	22.5	81.0	324.0	5884 5

Heat Factors

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	0 0044	0 0048	0 0074	0 0064	0 0060	0 0062	0 0062	0 0105	0 0000	0 0000	0 0000	0 0039	
LLF	R-3 RSH	0 4853	0 5212	0 8516	0 7854	0 7213	0 6318	0 6381	0 5523	0 0000	0 0000	0 0000	0 3101	
LLF	G-41 SL	0 1525	0 1706	0 3223	0 2982	0 2771	0 2227	0 2000	0 1652	0 0000	0 0000	0 0000	0 0812	
HLF	G-51 SH	0 0117	0 0149	0 0303	0 0257	0 0235	0 0207	0 0183	0 0219	0 0000	0 0000	0 0048	0 0103	
LLF	G-42 ML	0 2720	0 2721	0 4400	0 4090	0 3989	0 3681	0 3593	0 3549	0 0000	0 0000	0 0373	0 1646	
HLF	G-52 MH	0 0213	0 0248	0 0422	0 0399	0 0350	0 0353	0 0356	0 0473	0 0000	0 0000	0 0225	0 0161	
LLF	G-43 LL	0 0221	0 0241	0 0349	0 0540	0 0541	0 0640	0 0694	0 0946	0 0000	0 0000	0 0000	0 0000	
HLF	G-53 LLL90	0 0067	0 0000	0 0038	0 0169	0 0085	0 0323	0 0149	0 0369	0 0000	0 0000	0 0000	0 0000	
HLF	G-54 LLL110	0 0000	0 0000	0 0087	0 0269	0 0000	0 0261	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	
HLF	G-63 LLG110	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	
	TOTAL	0 9219	0 9968	1 7145	1 6371	1 4876	1 3523	1 2266	0 9576	-1 6316	-1 3778	-0 3058	0 4906	

Energy North Natural Gas, Inc
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Actual BillingDD	**553.5**	**866.0**	**1167.0**	**1099.0**	**846.0**	**545.5**	**269.0**	**92.0**	**19.0**	**22.5**	**81.0**	**324.0**	**5884.5**
Norm Billing DD	**561.7**	**889.5**	**1144.4**	**1131.9**	**973.4**	**712.3**	**384.4**	**149.1**	**28.1**	**8.2**	**63.0**	**263.4**	**6309.3**

Normal Volumes (= Heating Volumes * Normal EDD/Actual EDD + Baseload)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	**R-1 RNSH**	7	9	13	12	11	9	7	6	5	5	4	6	94
LLF	**R-3 RSH**	392	587	1,098	1,001	826	570	369	202	129	118	120	205	5,618
LLF	**G-41 SL**	111	178	395	361	296	184	103	50	28	25	24	48	1,804
HLF	**G-51 SH**	25	33	54	47	42	34	26	22	20	19	19	22	363
LLF	**G-42 ML**	202	293	555	509	440	312	189	102	51	51	52	95	2,852
HLF	**G-52 MH**	49	61	87	80	73	63	52	44	39	39	39	43	668
LLF	**G-43 LL**	26	36	54	74	67	59	41	28	17	11	8	4	427
HLF	**G-53 LLL90**	13	(4)	14	27	17	32	15	14	15	4	4	(1)	149
HLF	**G-54 LLL110**	8	1	22	41	(18)	30	5	9	8	16	(1)	2	122
HLF	**G-63 LLG110**	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	834	1,193	2,293	2,152	1,749	1,283	795	461	297	308	276	429	12,069

HLF	102	99	190	207	126	167	106	97	86	82	65	71	1,398
LLF	732	1,095	2,103	1,946	1,628	1,125	703	383	225	206	204	352	10,702

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6%				$0.3927	$0.3722	$ 943 37	$ 926.93	$ 16.44	1.77%	$0 3927	$0.3736	$ 1,570.86	$ 1,546 08	$ 24.79	1 60%
2	Nov 99 - Mar 00	9%				$0.4724	$0.4628	$ 679 85	$ 672.22	$ 7 63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20%				$0.6408	$0.7656	$ 816 25	$ 916.09	$ (99 84)	-10.90%	$0 6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10 22%
4	Nov 01 - Apr 02	24%				$0.5141	$0.4818	$ 790 65	$ 760.55	$ 30.10	3.96%	$0 5238	$0.4928	$ 1,301.07	$ 1,256 88	$ 44.19	3 52%
5	Nov 02 - Apr 03	24%	$0 0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821 32	$ 840.44	$ (19.11)	-2.27%	$0 5658	$0.5860	$ 1,344.02	$ 1,372 86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23%	$0 0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115 55	$ 1,080.46	$ 35 09	3.25%	$0 8759	$0.8352	$ 1,798.38	$ 1,740 30	$ 58.08	3 34%
7	Nov 04 - Apr 05	30%	$0 0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142 96	$ 1,189.55	$ (46 60)	-3.92%	$0 9092	$0.9562	$ 1,844.75	$ 1,911 86	$ (67.10)	-3 51%
8	Nov 05 - Apr 06	30%	$0 0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526 01	$ 1,376.01	$ 150 00	10.90%	$1 3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9 61%
9	Nov 06 - Apr 07	15%	$0 0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93 99	6.64%	$1 2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6 68%
10	Nov 07 - Apr 08	16%	$0 0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433 09	$ 1,405.40	$ 27 69	1.97%	$1 2044	$1.1725	$ 2,232.39	$2,186 92	$ 45.47	2 08%
11	Nov 08 - Apr 09	15%	$0 0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555 31	$ 1,373.85	$ 181.46	13.21%	$1 2836	$1.0958	$ 2,467.49	$2,199 54	$ 267.95	12.18%
12	Nov 09 - Apr 10	11%	$0 0200	8,405,413	$ 168,108	$0.9863	$0.9416	$1,250 80	$1,209.12	$ 41 69	3.45%	$0 9865	$0.9408	$1,984.29	$1,919 03	$ 65.26	3.40%
13	Nov 10 - Apr 11 1/					$0.8403	$0.8203	$1,169 53	$1,150 89	$ 18 64	1.62%	$0 8418	$0.8218	$1,874.98	$1,846.44	$ 28.54	1 55%
14																	
15	Total									$ 437.16						$ 654.55	

1/ The total bill calculation reflects the increase in base distribution rates as approved in Order 25,104 in DG 10-017 (Temporary Rates)

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Short Term Debt Limitations

	For Purposes of Fuel Financing
Total Direct Gas Costs	$ 65,369,088
Total Indirect Gas Costs	2,914,492
Total Gas Costs	$ 68,283,580
% of Debt to Total Gas Costs	30%
Short Term Debt	$ 20,485,074

	For Purposes Other Than Fuel Financing
12/1/2011 Projected Net Plant	$ 262,642,601
% of Debt to Net Plant	20%
Short Term Debt	$ 52,528,520