STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

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

Winter 2011-12 Cost of Gas

DG 11-______

Prefiled Testimony of Ann E. Leary

September 1, 2011

TABLE OF CONTENTS

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, Gas Pricing 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 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 2011/12 Winter (Peak) Period to be effective beginning November 1, 2011.

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 $0.7926 per therm for residential customers, $0.7929 per therm for commercial/industrial high winter use customers and $0.7911 per therm for commercial/industrial low winter use customers as shown on Proposed Twenty-eighth Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0000 per therm as shown on Proposed Third Revised Page 89.

Q. Would you please explain tariff page Proposed Fifth Revised Page 86 and Proposed Twenty-eighth Revised Page 87?

A. Proposed Fifth Revised Page 86 and Proposed Twenty-eighth Revised Page 87 contain the calculation of the 2011/12 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 2011/12 Average Cost of Gas of $0.7926 per therm is derived by adding the Direct Cost of Gas Rate of $0.7488 per therm to the Indirect Cost of Gas Rate of $0.0438 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $61,876,339. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $3,616,575. The Direct Cost of Gas Rate of $0.7488 and the Indirect Cost of Gas Rate of $0.0438 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 82,632,661 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 $2,193,271. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $59,683,067 to determine the Total Anticipated Direct Cost of Gas of $61,876,339.

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

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

1.	Purchased Gas Demand Costs	$11,669,833
2.	Purchased Gas Commodity Costs	$35,469,665
3.	Storage Demand and Capacity Costs	$1,247,501
4.	Storage Commodity Costs	$8,822,497
5.	Produced Gas Cost	$381,653
6.	Hedge Contract Loss/(Savings)	$2,091,917
	Total	$59,683,067

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

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

1.	Prior Period Under Collection	$3,735,297
2.	Interest	123,025
3.	Broker Revenues	(1,417,572)

4.	Fuel Financing	182,975
5.	Transportation COG Revenue	0
6.	Interruptible Sales Margin	0
7.	Capacity Release Margin	(471,144)
8.	Fixed Price Administrative Cost	40,691
	Total Adjustments	2,193,271

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 10-230 for the 2010/11 Winter Period?

The average cost of gas rate proposed in this filing is $0.0294 per therm lower than the initial rate of $0.8220 approved by the Commission in Order No. 25,161 dated October 28, 2010 in DG 10-230. This decrease in the rate reflects a decrease in the total cost of gas of approximately $2.8 million or 4% (a $3.5 million decrease in total direct gas costs offset by a $0.7 million increase in indirect gas costs). The $3.5 million decrease in the total direct cost of gas is a result of a $7.5 million decrease in commodity costs, offset by a $3.6 million increase in demand costs and a $0.4 million increase in adjustments.

The $7.5 million decrease in commodity costs is due to a $7.8 million decrease in pipeline commodity costs offset by a $0.3 million increase in supplemental costs (underground storage, LNG, and propane). The $7.8 million decrease in pipeline costs is due to a projected decrease in commodity price of $4.0 million and a projected decrease of $3.8 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are projected to be approximately $.06/therm lower than last year, resulting in a $4.0 million decrease, while pipeline throughput is projected to be down by 6 million therms, resulting in a decrease in commodity costs of $3.8 million. The $0.4 million increase in adjustments reflects an increase in Prior Period Under Collection.

Q. Please explain the variance in the Company's demand charges.

A. As indicated in Mr. Poe's testimony, the Company has updated its Tennessee demand charges to reflect the June 1, 2011 tariff rates as filed by Tennessee Gas Pipeline. As a result of this increase, the demand charges for the Peak 2011 season are approximately $3.5 million higher than Peak 2010-11.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2010/11 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0000 per therm. The rate approved in DG 10-230 was $0.0009. This decrease is largely due to the reduction in peaking costs as compared to the 2010/11 period and a decrease in the estimated percentage of the Company's peaking facilities that are used for pressure support purposes.

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. Yes, the Company has updated the percentage used for pressure support purposes from 12.4% to 9.9% based on the marginal cost study used for the rate design approved in the Settlement Agreement in DG 10-017. This change affects the allocation of costs associated with peaking capacity between sales and delivery customers, but not the overall costs that the Company is authorized to recover.

Q. What was the actual weighted average firm sales cost of gas rate for the 2010/11 winter period?

A. The weighted average cost of gas rate was approximately $0.8033 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2010 through April 2011 to the monthly therm usage of a typical residential heating customer using 796 therms per year, or 641 therms for the six winter period months, for heat, hot water and cooking.

Q. Has the Company made changes to the 2011-12 Peak COG to reflect the recent approval of the settlement agreement in Order No. 25,202 in DG 10-017?

A. Yes, in accordance with Sections II. B. and C. of the approved Settlement Agreement, the Company has revised the indirect gas costs to reflect the amounts approved in that case. The Company made the following changes: (1) updated the working capital to reflect the net lag of 14.273 days divided by 365, which equated to a working capital percentage of 3.9104%; (2) revised the Miscellaneous Overhead to reflect the annual amount of $13,170, of which only $10,337 is being recovered during the Peak period; (3) revised its Production and Storage costs to $1,980,428; and (4) incorporated a Peak bad debt commodity percentage of 2.37%. The settlement allows the Company to recover its actual bad debt expense for the twelve month period ending April 2011 (the period included in this filing). In addition, because the Company has now lowered its bad debt percentage beyond the target level of 2.50%, it will continue to use its actual bad debt experience going forward.

<u>PRIOR PERIOD UNDER COLLECTION</u>

Q. Please explain the Prior Period Under Collection of $3,780,233.

The Prior Period Under Collection is detailed in the 2010/2011 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $3,780,233 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2011, including Peak Period costs recovered in May 2011 based on billings for April consumption. The under collection is the result of higher actual commodity gas prices in March and April 2011 than forecasted in the Company's April trigger filing, and a revision to the COG unbilled revenues for the period November 2010 through February

2011 that was reflected in the Company's April Trigger Filing. Specifically, the actual average commodity price for March and April was approximately $.07/therm higher than the amount reflected in the Company's April trigger filing, resulting in an increase of gas commodity costs of approximately $1.7 million. In the Trigger filings, the Company assumed gas prices based on the monthly settled NYMEX prices while actual gas costs reflect variations in daily prices. In addition, in preparing its Peak 2010-11 Gas Cost Reconciliation filing, the Company updated its November through February sendout volumes. This resulted in a change to the Company's unbilled COG revenues of approximately $2.2 million which had been used to calculate the April COG factor.

FIXED PRICE OPTION

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

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 ("FPO"). In accordance with the approved changes to the FPO, the FPO rates are set at $0.02 per therm higher than the initial proposed COG. Proposed Third Revised Page 88 contains the FPO rates for the 2011/12 Winter period, which are $0.8126 per therm for residential customers, $0.8111 per therm for commercial/industrial low winter use customers, and $0.8129 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2010/11 winter period of $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. This represents a $0.0294 per therm, or 3.5%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $7 or 0.8% compared to last winter. The bill impact reflects the implementation of the increase in base distribution rates associated with the final rates approved in DG 10-017 effective May 1, 2011 and in the increase approved in DG 11-106 effective July 1, 2011 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 would be approximately $13 or 1.5% 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 DG 05-127.

HEDGED SUPPLIES

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

A. Yes, it has. As shown in Tab 7, Schedule 7, Page 2, the Company thus far has hedged 2,750,000 Dekatherms (27.5 million therms) at a weighted average fixed price of $5.1608 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 640,000 Dekatherms will be hedged at an estimated price of $ 4.3989 per Dekatherm based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 3,390,000 Dekatherms at a cost of $17,007,491 or approximately $5.017 per Dth.

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

A. The Company has twenty three contracts that hedge the price of gas supplies for the 2011/12 Winter Period with prices ranging from $4.3500 to $6.2140 per Dekatherms. The contracts date as far back as June 11, 2010 and as recently as July 22, 2011. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

LOCAL DISTRIBUTION ADJUSTMENT CHARGE

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

A. The Company is submitting for approval an LDAC of $0.0697 for the residential non heating class and residential heating class, and $0.0497 for the commercial/industrial bundled sales classes and $0.0532 for unbundled transportation customers that will be billed from November 1, 2011 through October 31, 2012. 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, the Residential Low Income Assistance Program charge, and the Temporary Rate Reconciliation Amount per DG 10-017 as approved per (1) Order No. 24,109 in DG 02-

106, Energy Efficiency for Gas Utilities, (2) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, (3) Order No. 24,508 in DG 05-076, and (4) Order No. 25,202 in DG 10-017. The Company is also proposing to include in its LDAC a surcharge to unbundled transportation customers and a credit to bundled sales customers to reflect the reallocation of gas costs resulting from the updating of the Company Allowance percentage for the November 2010 through October 2011 time period. I will explain this reallocation in more detail later in my testimony.

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. 25,189 dated December 30, 2010, in DE 10-188 for calendar year 2011 and 2012. In the calculation of the Energy efficiency Factor, the Company has also revised the approved 2011 Residential budget to include the 2010 Residential budget under spend of $380,888. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs during the period January–December 2010 that were filed in DG 09-049 on June 24, 2011. 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 $0.0092. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2011/12 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 $1,497,079, of which $1,788,548 is for the revenue shortfall resulting from 6,551 customers receiving a 60% discount off their base rates, $ 8,600 is for estimated administrative costs, and ($300,069) 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 2011-12 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2010 through October 31, 2011 is calculated to be $19,647,874 and the limit for non-fuel purposes is calculated to be $52,351,912.

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. 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 pre-filed 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 general settlement agreements between National Grid NH and various insurance companies covering more than one site, there is no basis to determine how much of the settlement amount is associated with a particular site. Page 13 provides the total remediation and recovery costs and collections by year and in total.

In total, the Company has incurred environmental remediation costs of $31,792,074, litigation costs of $9,480,817, and obtained third party cash recoveries of $27,808,566, for a net expense of $13,464,325. To date, the Company has collected $13,068,248 from its Environmental Surcharge factor.

The 2010-2011 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #11)	$217,032
Concord (Pool #8)	$168,638
Laconia (Pool #10)	$211,728
Manchester (Pool #11)	$137,633
Nashua (Pool #10)	$33,399
General (Pool #9)	$69,286
Total Remediation	$837,716
Litigation Recovery	0
Litigation Costs	0
Total 2010-2011	$837,716

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2010-11 costs that the Company is submitting. Consistent with past practice, the Company met with the Commission staff 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 temporary excess amounts recovered for 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 the 2010-11 time period, the Company has included a $74 credit in this account. As of September 2010, the Company no longer had any excess recoveries related to its environmental response costs, and therefore has stopped applying interest credits.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing?

A. The Company netted the environmental recoveries of $13,202 (which are recovered from Granite Ridge under the special contract for that customer) against the actual 2010/11 environmental expenditures of $837,716, resulting in a total of $824,514.

Q. Does the Company have any outstanding cash recoveries and if so, what does the Company plan on doing with these cash recoveries?

A. Yes, as of July 2011, the Company had a remaining balance of $428,437 in cash recoveries from prior periods. In this filing, the Company has continued the practice that it has employed during the prior few years and applied the cash recoveries of $428,437 against the total 2010/11 expenditure of $824,514, for a net amount of $396,077. The Company then amortized this net amount over a seven year period. The Settlement Agreement in DG 99-060 Section II. 2.c, allows the Company to apply any amounts received from third parties, net of the costs of obtaining such payments, to reduce any unamortized balance authorized to be recovered, thereby reducing the amortization period rather than reducing the per therm amount of the environmental surcharge. However, because the Company has been in an over recovered situation during the last few years as a result of the large amount of settlements and verdicts it has received, with the approval of the Commission these recoveries have instead been netted out against new remediation costs as they were incurred, thereby eliminating the need for an environmental surcharge during that period. After this year, the recoveries will have been fully credited to customers. On a going-forward basis, the Company expects to apply new cash recoveries to reduce any unamortized balances in accordance with the approved settlement agreement, thereby shortening the amortization period.

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

A. No, the Company has not provided any service under the classification over the past year and therefore has not earned any margins to credit back to sales customers.

Q. Is the Company proposing any changes to the Temporary Rate Reconciliation Adjustment approved in Order 25,217 in DG 11-046 relating to the reconciliation for temporary rates from the Company's last base rate case, DG 10-017?

A. Yes, as explained in the Company's 2011 Off Peak COG filing submitted on March 15, 2011, the reconciliation amount included in the approved 2011 Off Peak LDAC only included the base rate reconciliation through February 2011. However, since the final approved base rates were not implemented until April 1, 2011, the Company indicated it would need to update the temporary rate reconciliation amounts to include March 2011 and a portion of April 2011 billings. In this filing, the Company has updated Tariff Page 92 to reflect the Temporary Rate Reconciliation through April 2011.

Q. In addition to the temporary rate reconciliation, has the Company included the recovery of DG 10-017 rate case expense in this filing?

A. Yes, the Company has included an estimate of its rate case expenses based upon the rate case expense amount of $1,112,811 recommended by Staff. The Company will reconcile this estimated amount with the final approved rate case expense amount and will include any variance in its 2012 Off Peak Filing. The Company recognizes that the Office of Consumer Advocate ("OCA") has taken a different position on the amount of rate case expense that the Company should be authorized to recover, but the Company believes that it is in the public interest to begin collecting the expense now and adjust the amount once the Commission has made a final determination of the amount.

Q. In Order No. 25,217 in DG 11-046, the Commission ordered the Company to file a thorough analysis of the impact on both the bundled sales customers and unbundled transportation customers of using a fixed Company Gas Allowance of 1.2 percent, versus a Company Gas Allowance that is recalculated annually based on prior year actual data. Has the Company complied with this directive?

A. Yes, in Schedule 25 the Company has included a thorough analysis of the impact on bundled sales and unbundled transportation customers.

Q. Please explain how the Company calculated the impact on both bundled sales and transportation customers of using a fixed Company Gas Allowance of 1.2 percent versus a Company Gas Allowance that is recalculated each year?

A. First the Company calculated the actual Company Allowance percentage that would have been in effect each year from November 2001 through October 2011 had the percentage been updated annually. The Company calculated this percentage by dividing the variance between the total billing throughput and monthly calendar sendout volumes for the twelve month period ending June of each year by the total annual sendout volume. The Company then calculated the incremental gas volume that the suppliers should have delivered on behalf of transportation customers by multiplying the annual firm transportation throughput during the period November through October by the variance between the updated and 1.2 % fixed Company Allowance. The Company then determined the gas cost associated with this incremental volume by multiplying the incremental volume by the average annual commodity cost of gas. The Company used an average annual commodity cost based on monthly settled NYMEX prices with an adder for transportation and fuel costs. Based on these calculations, the Company determined the incremental gas costs that were allocated to bundled sales customers instead of unbundled transportation customers averaged $265,000 per year over the ten year period. This impacted residential heating customers by approximately $0.27 per month which resulted in a 0.2% impact on their total bills.

Q. Is the Company proposing any adjustment in its Peak 2011-12 LDAC filing to incorporate the reallocation of gas costs between the bundled sales and transportation customers resulting from the application of a fixed Company allowance of 1.2 percent?

A. Yes, the Company is proposing an adjustment to reconcile the impact of this allocation issued relating to the period November 2010-October 2011 because the Commission has not yet approved the Company's 2010-11 Peak and 2011 Off Peak gas cost reconciliation filings. The adjustment is shown in Schedule 25. During the period November 2010 – October 2011, the Company Allowance percentage should have been 1.7%. To reconcile the allocation for this period, the Company is proposing to include a one time adjustment factor in its LDAC which will credit bundled sales customers and surcharge unbundled transportation customers for $132,266. This reallocation factor will reflect the gas costs associated with the variance between the actual 1.7% and the fixed 1.2% Company Allowance. Since this amount is based on an estimated throughput and commodity cost for the 2011 Off Peak period, the Company will update and reconcile this amount in its 2012 Off Peak LDAC filing.

Q. Has the Company also updated its Company Allowance percentage for the period November 2011-October 2012 in accordance with Section 8.1 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 the Company has recalculated its Company Allowance for the period November 2011 – October 2012. On August 4, 2011 the Company met with the Commission Staff and OCA and indicated that it planned to calculate the Company Allowance based on a twelve month period ending June of each year. Accordingly, in the current filing, the Company calculated the Company Allowance of 1.4% based on sendout and throughput data for the twelve month period ending June 2011. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2011.

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 & 8A of this filing. Please note that these bill impacts include the base distribution rates approved in Order No. 25,244 in Docket DG 11-106 relating to the cast iron/bare steel main replacement program. The total bill impact for a typical residential heating customer is an increase of approximately $5, or 0.7%, of which $3, or -0.6%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2010/11 winter season, offset by an increase of $8, or 3.3%, resulting from the implementation of final rates in DG 10-017 and the base rate adjustment in DG 11-106. The total bill impact for a typical commercial/industrial G-41 customer is a decrease of approximately $14, or -0.6%, of which $9, or 0.6 %, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2010/11 winter season and a decrease of $4, or 0.6%, resulting from the implementation of final rates in DG 10-017 and the base rate adjustment in DG 11-106. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

Q. Did the Company review the annual usage used to calculate its bill impacts for a typical customer?

A. Yes, during the 2011 Off peak COG proceeding, the Staff questioned the derivation of the usage levels associated with the Company’s typical customer bill impacts. In this filing the Company has recalculated the usage associated with a so-called typical customer to represent the normalized usage per customer class based on customer’s usage during 2010/11 period. For comparison purposes, the Company has included bill impacts using both the updated annual usage factors as well as the usage levels used in previous COG filings.

OTHER TARIFF CHANGES

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

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

Q. Please describe the changes to Page 155.

A. In Proposed Third Revised Page 155, the Company is updating the Peaking Demand Charge from $18.48 per MMBtu of Peak MDQ to $18.96 per MMBtu of Peak MDQ, a $0.48 increase and its Supplier Balancing Charges from $0.11 per MMBtu to $0.22 per MMBtu.

This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions Third Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to Page 156.

A. Proposed Third 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.