Thomas R. Teehan
Senior Counsel

September 1, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: 2010 Gas Cost Recovery Filing
Docket No.________

Dear Ms Massaro:

Enclosed please find ten (10) copies of the pre-filed testimony and schedules of Elizabeth D. Arangio, John F. Nestor, III, and Stephen A. Mc Cauley in support of National Grid's[1] Annual Gas Cost Recovery ("GCR") filing. The proposed rates contained in this GCR filing reflect the customer class-specific factors necessary for the Company to collect sufficient revenues to recover projected gas costs for the period November 1, 2010 through October 31, 2011.

As described in this filing, the proposed GCR rate will result in an average residential heating customer using 922 therms per year experiencing an annual bill decrease of approximately $144 over the currently effective rates or 9.7%. That customer should also experience an additional increase of approximately $22 associated with the proposed Distribution Adjustment Charge rates found in Docket 4196 filed today under separate cover. Overall, the combined impact of the proposed GCR and DAC rates is an annual reduction of approximately $122 for the average residential heating customer or 8.2%.

This filing also contains a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I.G.L. § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain pricing terms contained in its FCS contract with Distrigas as well as forecast basis numbers, which are purchased subject to a contractual confidentiality agreement. Accordingly, National Grid requests that the Commission protect the price terms and basis information set forth in designated portions of Attachments EDA-2 and EDA-4. To that end, the Company has provided the Commission with the confidential materials for its review, and has included redacted copies of these attachments in the filing.

Thank you for your attention to this filing. If you have any questions, please do not hesitate to contact me at (401) 784-7667.

Sincerely,

Thomas R. Teehan

Enclosures

cc: Leo Wold, Esq.
Steve Scialabba
Bruce Oliver

[1] The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company").

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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Annual Gas Cost Recovery Filing 2010
Docket No. _______

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NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission ("Commission") provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(i)(B). National Grid also hereby requests that, pending entry of that finding, the Commission preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On September 1, 2009, National Grid filed with the Commission its Annual Gas Cost Recovery filing in this docket. This filing included information relative to the Company's Distrigas contract (Attachment EDA-2) and relative to forecasted basis numbers (Attachment EDA-4) for which National Grid is requesting confidential treatment.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(i)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; <u>or</u> (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. <u>Providence Journal Company v. Convention Center Authority</u>, 774 A.2d 40 (R.I.2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be

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[1] The Narragansett Electric Company d/b/a National Grid ("National Grid or "the Company").

released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company has redacted forecasts of basis numbers that appear at Attachment EDA-2, pages 3 through 6, 9, 11, 14, and 17 and Attachment EDA-4, pages 2 through 7, 10, 13, 14, 16, 17, and 19. The Company seeks protective treatment for its basis number information which provides price forecasts at specific points where gas is purchased. This information is assembled by a third-party and purchased by the Company subject to contractual agreement to maintain it as proprietary and confidential information.

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of its GCR filing.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorney,

Thomas R. Teehan

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Thomas R. Teehan, Esq. (RI Bar #4698)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7667

Dated: September 1, 2010

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

ELIZABETH D. ARANGIO

SEPTEMBER 1, 2010

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Elizabeth Danehy Arangio. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. WHAT IS YOUR POSITION WITH NATIONAL GRID?

A. I am the Director of Gas Supply Planning with responsibility for the gas-resource portfolio held by National Grid in Rhode Island. I am also responsible for gas supply planning for the National Grid resource portfolios in Massachusetts, New York, and New Hampshire. For purposes of this testimony, references to "National Grid" or the "Company" relate solely to The Narragansett Electric Company which is doing business in Rhode Island as National Grid.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Business Administration. In 1995, I graduated from Bentley College with a Master of Business Administration. From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services, with responsibility for managing all activities associated with the customer-choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services with responsibility for the administration of the Company's gas-resource portfolio and customer-choice program in Massachusetts and, as of 2000, the resource portfolio of EnergyNorth Natural Gas, Inc in New Hampshire. In February 2004, I assumed the additional responsibility of gas supply planning for the former KeySpan Corporation New York and Long Island resource portfolios. Following the acquisition of KeySpan Corporation by National Grid, plc, I was named to my current position with the added responsibility for the National Grid gas resource portfolios in upstate New York and in Rhode Island.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have recently testified before the Rhode Island Public Utility Commission in support of National Grid's Annual Gas Cost Recovery ("GCR") (Docket No. 4097), the Natural Gas Portfolio Management Plan ("NGPMP") (Docket No. 4038) and the Long Range Gas Supply plan. In the past, I have testified numerous times before the Massachusetts Department of Public Utilities, New York State Department of Public Service and the New Hampshire Public Utilities Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides support for the estimated gas costs, assignments of pipeline capacity to marketers and other issues relating to the Company's proposed Gas Cost Recovery ("GCR") factors.

Q. ARE YOU SPONSORING ATTACHMENTS TO YOUR TESTIMONY?

A. Yes. I am sponsoring the following attachments:

EDA-1 Summary of Projected Gas Costs
EDA-2 Gas Cost Details **- CONFIDENTIAL Information Redacted**
EDA-3 NYMEX Strip Comparison
EDA-4 Assignment of Pipeline Capacity – **CONFIDENTIAL Information Redacted**
EDA-5 FT-2 Operational Parameters
EDA-6 Default Transportation Service

II. ***<u>PROJECTED GAS COSTS</u>***

Q. WHAT COMMODITY PRICES WERE USED TO DEVELOP THE PROPOSED GCR FACTORS?

A. In terms of commodity prices, the proposed GCR factors are based on the following: (1) the NYMEX strip as of the close of trading on August 4, 2010 purchases; and (2) the difference between the futures contract purchases under the GPIP Plan as of July 31, 2010 and the August 4, 2010 NYMEX strip. The GCR factors also reflect storage and inventory costs as of July 31, 2010, as well as the projected cost of purchasing gas ratably through the remainder of the injection season, as provided for in the Natural Gas

Portfolio Management Plan ("NGPMP"). Attachment EDA-1 provides a summary of gas costs by major cost categories. Attachment EDA-2 shows the details of the calculations including the cost detail by supply source and the cost impact of financial hedges.

Q. OVERALL, WHAT ARE THE NYMEX PRICES FOR GAS SUPPLIES PROJECTED TO BE PURCHASED IN THE GCR YEAR AND HOW DO THEY COMPARE TO LAST YEAR'S PRICES?

A. Attachment EDA-3 is a graph that compares August 24, 2009 the previous NYMEX utilized in last years filing to NYMEX pricing of August 4, 2010 the date used in this filing.

Q. PLEASE DESCRIBE HOW GAS COSTS ARE CALCULATED.

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT model to perform a dispatch optimization of the entire Rhode Island portfolio of gas supply, pipeline transportation, underground storage and peaking supplies. The model uses commodity price, pipeline contract and storage information to determine the dispatch of supplies to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the prices in effect as of August 4, 2010. For Company purchases at locations other than the Henry Hub, the model uses the expected basis differential to the Henry Hub prices to determine the expected difference or "basis." Applying the basis to the NYMEX pricing creates a reasonable estimate of the expected cost of supply.

Q. HOW DID THE COMPANY CATEGORIZE THE PROJECTED GAS COST COMPONENTS?

A. Gas costs are disaggregated into five components: (1) Supply Fixed Costs; (2) Storage Fixed Costs; (3) Supply Variable Costs; (4) Storage Variable Product Costs; and (5) Storage Variable Non-Product Costs. Each is described below.

1. The Supply Fixed Cost component includes all fixed costs related to the purchase of firm gas, including pipeline demand charges and supplier (fixed) reservation costs.

2. The Storage Fixed Cost component includes all fixed costs related to the operation and maintenance of storage including fixed storage demand charges, fixed costs associated with delivery of storage gas to the Company's distribution system, and local production and storage costs.

3. The Supply Variable Cost component includes all variable costs of firm gas supplies, including the commodity costs and expenses incurred to transport gas. Commodity costs included in the Supply Variable Cost component reflect the sum of purchases made under the Gas Purchasing Program and projections of gas costs based on the NYMEX prices of wellhead futures contracts as of the close of regular trading on August 4, 2010 as well as the basis differentials between the point of purchase and Henry Hub.

4. The Storage Variable Product Cost component includes all variable costs related to the operation, maintenance and delivery of storage gas, including storage injection and withdrawal costs, delivery of storage gas to the Company's distribution system and the cost of LNG supplies. A summary of gas costs included in the GCR and disaggregated into these cost components by month for the period November 2010 through October 2011 is shown on Attachment EDA-1.

5. The Storage Variable Non-Product Cost component includes all variable costs related to the withdrawal, injection or delivery of storage gas to the Company's Distribution System.

Q. PLEASE DESCRIBE ATTACHMENT EDA-2, PAGES 1 THROUGH 17.

A. Attachment EDA-2 shows the supporting detail for gas costs included in the filing for the period November 2010 through October 2011. The first two pages show the optimized, forecasted sendout by supply source from the SENDOUT model and the detailed makeup of supply by pipeline source, storage contract and peaking facility. The next section, pages 3 through 6, show the calculation of the full commodity cost, the dispatch cost, for each unit delivered for each pipeline path based on the August 4th NYMEX strip. The prices shown are delivered prices which reflect both pipeline commodity charges and pipeline fuel losses. Pages 7 through 9 show the calculation of the delivered cost for each path (the cost times the quantity). Pages 10 through 14 show the detailed calculation of fixed costs including the unit rates, the billing quantities and the projected total invoice cost. All known changes to pipeline demand costs have been included.

The cost details for gas injected into and withdrawn from pipeline storage are shown on pages 15 and 16 while the costs for LNG are shown on page 17. The price the Company will be paying will mimic all storage related costs, including the various injection and withdrawal related charges shown in EDA-2. Charges for the Distrigas contracts have been redacted in the public version of the filing in order to comply with the confidentiality terms of the contracts.

Q. HOW DO YOU CALCULATE THE DELIVERED COST FOR A PARTICULAR GAS SUPPLY?

A. On Attachment EDA-2, page 3, the second supply source shown is gas purchased on Tennessee Pipeline in Zone 0, located in South Texas. The calculation for November begins with the $4.909 NYMEX price which is then adjusted for basis by, in this case, subtracting $0.0725. This reflects the forward basis strip for gas supply in South Texas delivered into Tennessee Pipeline. Next the price is adjusted to reflect the fuel retention percentage of the pipeline, 8.71%, to bring the price to $5.297. That adjustment is made by dividing the price by one minus the loss factor, .9129, effectively adjusting the commodity price to incorporate the fact that only 91.29% of the supply delivered to the pipeline in South Texas will be delivered to Rhode Island. The pipeline usage fee of

16.27 cents is then added to reflect the cost of transportation on the pipeline, resulting in a delivered cost of $5.4607 per Dth.

III. MARKETER CAPACITY ASSIGNMENT

Q. DID THE COMPANY RECEIVE INPUT FROM THE MARKETERS REGARDING BASIS PRICING?

A. Yes, as agreed in Docket No. 4097, the Company collaborated with the Marketers to address the issue regarding basis pricing calculated in EDA-4, in particular, the use of a three-year historical average pricing methodology versus a one-year forward looking forecast pricing methodology. The Company met with the Marketers on July 15, 2010 and presented them with two scenarios using the July 1, 2010 NYMEX; (1) one calculated based on using the three-year historical average basis pricing methodology and (2) a second based on using a one-year forward looking forecast of prices. After reviewing both methodologies, it was agreed to that the marketers would notify the Company by July 21, 2010 as to their preferred choice of the calculation going forward. It was a unanimous decision by the marketers to use the forward looking forecast in the calculation of EDA-4 for the 2010-2011 GCR filing, as well as future such filings.

Q. HOW IS PIPELINE CAPACITY ASSIGNED TO MARKETERS?

A. At the time a sales service customer switches to transportation service, the portion of the Company's interstate pipeline transportation capacity under contract to meet the customer's requirements are assigned to the marketer. Under RIPUC NG-GAS 101, Section 6, Schedule C, Sheets 10-13, sub-part 1.07.0 of the Company's Tariff, a pro-rata share of upstream pipeline capacity is assigned to marketers serving customers who convert to firm transportation service after October 1, 1997. The pro rata share equals the ratio of the customer's average normalized winter day usage to the average normalized winter day usage for the system as a whole. This share is multiplied by the amount of pipeline capacity in the Company's portfolio to determine the amount of capacity to be assigned.

The Company's tariff utilizes a path-specific assignment approach that allows marketers to select the path or paths upon which they prefer to acquire capacity. In order to reflect the differing values of various paths, sub-part1.07.0 provides in pertinent part that:

> The Company shall assess a surcharge/credit to marketers based on the difference between the charges of the upstream pipeline transportation capacity and the weighted average of the Company's upstream pipeline transportation capacity charges as calculated by the Company. To the extent that the charges of such released pipeline capacity are greater than the weighted average charges, the marketer shall receive credit for such difference in charges based on the total quantity of capacity released by the Company to the Marketer.

The weighted average charge and the surcharge/credit charges applicable to individual pipeline paths selected by the marketer are updated at Attachment EDA-4 of this filing.

Q. WHAT TRANSPORTATION PATHS WILL BE AVAILABLE FOR ASSIGNMENT TO MARKETERS?

A. Attachment EDA-4, page 1 shows the paths and corresponding quantities available for assignment to marketers. In total, the Company has made available 29,258 Dth per day of capacity on six different pipeline paths, an increase of 4,000 MMBtus from the 2009 GCR Filing. The capacity provides marketers with the flexibility to select paths that best compliment their individual resource portfolios and requirements.

Q. PLEASE EXPLAIN THE SURCHARGE/CREDIT CALCULATION FOR EACH ASSIGNED PIPELINE PATH?

A. The first step in calculating the adjustment charge for each path starts with calculating the system-average cost. The derivation of the weighted-average pipeline path cost of $.9630 per Dth is shown at Attachment EDA-4, Page 10. This cost is equal to the sum of the 100% load factor fixed-cost unit value and the system-average unit variable cost. The fixed costs are similar to reservation charges, which reserve space on the pipeline and ensure that there is a path available to transport gas to the Rhode Island area. The 100% load factor fixed-cost unit value is $.5227 per Dth. The variable costs include the pipeline fuel loss and the commodity charges on the pipelines. The system-average pipeline unit variable cost is $0.4403 per Dth. The sum of the $0.5227 (100% load factor) unit fixed-cost and $0.4403 system-average pipeline unit variable cost results in a weighted average pipeline cost of $.9630 per Dth.

Q. HOW ARE THE DELIVERED COSTS FOR EACH PATH DEVELOPED?

A. The calculations for delivered cost for each path are similar to those described for the system average. For illustration, the calculation for the first path (Tennessee Zone 1, shown on Attachment EDA-4, page 6) is comprised of a single contract originating in Zone 1 and terminating in Zone 6. Total fixed costs of $1,497,456 and total variable costs of $16,370,280 are shown near the bottom, right of page 6 of EDA-4. Commodity gas costs of $14,933,072 priced at the August 4, 2010 NYMEX prices used in this filing are subtracted from the variable costs to arrive at the non-gas variable costs, which include pipeline charges and any basis differential associated with the path. The cost of the path equals the sum of the fixed unit cost of $0.513 per Dth at 100% load factor plus the non-gas variable unit cost of $0.492 per Dth, or $1.005 per Dth. The unit cost of $1.005 per Dth represents the direct costs incurred by the marketer, which are paid to the transporter or other provider. Since these costs are $0.042 per Dth greater than the system-average, marketers electing this path would be credited $0.042 per Dth per day each month on their bill from the Company. A summary of the individual path costs and associated credits or surcharges, for which approval is sought, is shown on Page 1 of Schedule EDA-4.

IV. <u>GAS SUPPLY PORTFOLIO</u>

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S INTERSTATE PIPELINE CAPACITY?

A. Yes. The Company's next capacity change will occur November 1, 2010 with the addition of new Algonquin pipeline capacity from the East to West Project being added to serve a number of constrained areas. This project will provide an incremental 10,000 MMBtu/day of pipeline capacity from the interconnection with the Maritimes system at Beverly, Massachusetts to various delivery points on the E and G Systems to the Company's distribution system. In addition, this project will provide several benefits to the National Grid distribution system in Rhode Island. This project provides for incremental deliveries to four stations: Montville, Portsmouth, Tiverton, and Warren. Three of the four stations feed isolated and constrained areas with limited supply options. The project will improve reliability on two of these systems through reduced reliance on LNG facilities and trucking. In Westerly, RI the project will allow for elimination of a temporary LNG site and associated trucking which was previously established in the area to support winter operations. In Portsmouth, RI the project, coupled with an on-system distribution project in the Portsmouth area, will significantly reduce reliance on the LNG site in the Newport Navy Yard and limit the need for trucking to the site to under the very coldest conditions. Overall, this project will improve reliability on these systems, as well as enable continued customer growth on these isolated systems through expanded deliveries.

Q. WHAT OPTIONS ARE AVAILABLE TO SUPPLY THE EAST-TO-WEST PROJECT?

A. This project is perfectly situated to receive supply directly from "local" supply sources; Repsol's Canaport Project, Excelerate Energy Limited Partnership's Northeast Gateway Project and Suez LNG NA LLC's Neptune Project. These projects are all discussed in more detail below.

Q. ARE THERE ANY OTHER CONTRACT CHANGES AFFECTING THE SUPPLY PORTFOLIO AND GAS COSTS?

A. Yes. The 10,000 dekatherm per day LNG combination vapor/liquid supply contract (FCS) with Distrigas of Massachusetts will terminate on October 31, 2010. The FCS contract provided both gas supply delivered to the RI system and LNG liquid to the Companies LNG facilities. The Company utilized the liquid component provided in its FCS Agreement to refill LNG in the 2009 off-peak season. In addition, the Company contracted for an Interruptible Liquid Sales agreement. The liquid supply contract with Distrigas commenced in September 1, 2009 and expired on October 31, 2009. The Company retained the right to purchase a quantity of LNG up to the MDQ of 9,500 MMBtu/day with a total quantity during the term of up to 250,000 MMBtus. The contract was structured in a format that allowed the Company to fill its LNG facilities to 100% prior to November 1, 2009. This filing reflects an estimate assuming the need for a peak season liquid refill agreement. The Company is still in the process of determining the appropriate level of LNG liquid that it should contract for the 2010/11 peak season.

Q. WHAT CHANGES HAVE OCCURRED IN THE SUPPLY OF NATURAL GAS SINCE THE COMPANY'S FILING LAST YEAR?

A. The 2009 natural gas market demonstrated relatively abundant supply and low prices, with this dynamic continuing into 2010. Factors that have contributed to the decline in prices can be associated with reduced demand from warmer than normal weather and weak economic conditions, as well as higher than usual production and storage levels.

With respect to supply availability, the Rockies Express Pipeline delivering into Lebanon and Clarington, Ohio as well as the emerging Marcellus supplies, have been two factors contributing to lower natural gas prices. In addition, a number of other shale areas are in development as new drilling technology has made previously uneconomic formations profitable. While drilling has receded significantly from its record level, it is expected that the expansion of new supply basins outside of the traditional Gulf of Mexico producing area will result in intensification of gas on gas competition, likely causing a flattening of the basis differentials throughout the United States.

With its proximity to the Northeast market, among other attributes, the Marcellus Shale is expected to have a significant affect on the overall supply dynamic. The shale formation, which extends from West Virginia northeast through Pennsylvania into southern New York to the western boundary in Ohio and to the base of the Appalachian Mountains in

Pennsylvania, has a reserve base estimated somewhere between 200 Tcf to 500 Tcf. It is anticipated that the ramp up in supply from Marcellus will take place over the next 3 to 5 years. To date, there are a significant number of projects proposed to bring the Marcellus gas to market. Construction of gathering systems by producers is progressing, and once these are fully developed, the additional production will create more liquidity in the Marcellus shale basin. The RI portfolio is well situated to take advantage of opportunities with a good balance of economically priced existing market-area transportation on existing short-haul capacity, as well as the ability to segment long haul capacity. As the new supply side options develop, the Company will continue to evaluate the portfolio for opportunities to reduce costs.

Q. ARE THERE ANY "LOCAL" PROJECTS IN NEW ENGLAND AFFECTING THE OVERALL SUPPLY PICTURE?

A. Yes. There are several "local" projects in the Northeast that have gone into service during the 2009/2010 year. Some of these projects are: (1) Maritimes Phase IV which was built to facilitate delivery of an incremental 730,000 MMBtu/day from the Canaport LNG Terminal to markets in the Northeast and was completed with an in-service date of January 2009; (2) Repsol's LNG and Storage Project which received its first LNG shipment at the Canaport LNG Terminal in New Brunswick on June 27, 2009. The Canaport LNG Terminal has a firm sendout capacity of 1.2 billion cubic feet per day and storage capacity of nearly 10 BCF. Since coming on-line, the facility has received 27 cargoes and has delivered over 80 BCF into the market. Last winter the facility experienced a peak day of 770 MMcf with an average daily sendout of 220 MMcf; (3) owned and operated by Excelerate Energy, the offshore LNG facility, Northeast Gateway, began commercial operations in May 2008. It is located about 13 miles offshore Cape Ann, MA and has the capability of moving approximately 800 million cubic feet of gas per day into the offshore HubLine system of Spectra Energy. To date, the facility has received ten cargo deliveries and (4) lastly, the Neptune Project being developed by Suez LNG, which consists of a 13 mile lateral off the coast of Gloucester, Massachusetts that ties into Spectra's HubLine. The Neptune Project is expected to have an average sendout of 400 million cubic feet per day with a peak capability of 750 million cubic feet per day and is expected to be in-service in winter 2010. The combined effect of these projects has been quite significant on the overall availability of supply in the Northeast, particularly when coupled with volumes received from both the Rockies Express Pipeline as well as Marcellus Shale.

Q. ARE THERE ANY OTHER MAJOR UPCOMING ISSUES AFFECTING THE GAS SUPPLY PORTFOLIO?

A. Yes. The Company was notified by Tennessee Gas Pipeline of its likely plan to file a rate case with FERC by the end of this year. Assuming Tennessee files the rate case, it will mostly likely deal with major issues such as; pipeline rate design, cost allocation, capital and O&M expenses, pipeline tariff services, and much more. As one of the largest customers on Tennessee Gas Pipeline, the Company plans to be heavily involved in this proceeding. Approximately, forty percent of the supply serving Rhode Island is delivered via Tennessee Gas Pipeline, and thus, any rate redesign or cost re-allocation would certainly have an impact on the cost of the gas supply portfolio.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SUMMARY OF ESTIMATED GAS COSTS FOR 2010-2011 GCR Estimate

08/04/2010 NYMEX

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	GCR TOTAL
Variable Costs													
Total Pipeline Supply Costs	$16,627,592	$22,001,510	$23,997,111	$21,011,154	$22,138,394	$12,466,126	$6,807,779	$4,642,552	$4,334,014	$3,951,779	$4,156,962	$7,379,258	$149,514,232
Total Storage Product Costs	$0	$4,396,327	$8,703,454	$6,729,191	$1,173,912	$0	$0	$0	$0	$0	$0	$0	$21,002,885
Total Storage Delivery Costs	$0	$150,155	$298,646	$234,688	$32,156	$0	$0	$0	$0	$0	$0	$0	$715,645
Total LNG Costs	$126,411	$688,360	$130,829	$118,081	$130,829	$126,132	$129,483	$123,770	$128,056	$127,897	$123,174	$127,640	$2,080,662
Total All Variable Gas Costs	$16,754,003	$27,236,353	$33,130,039	$28,093,115	$23,475,291	$12,592,259	$6,937,262	$4,766,322	$4,462,071	$4,079,676	$4,280,135	$7,506,898	$173,313,424
Fixed Costs													
TOTAL PIPELINE DEMANDS	$2,747,993	$2,749,395	$2,748,152	$2,743,948	$2,748,152	$2,746,751	$2,748,152	$2,746,751	$2,748,152	$2,748,152	$2,746,751	$2,748,152	$32,970,500
TOTAL SUPPLIER DEMANDS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL STORAGE FACILITIES	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$393,833	$4,725,995
TOTAL STORAGE DELIVERY	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$560,704	$6,728,444
Total All Fixed Costs	$3,702,530	$3,703,931	$3,702,689	$3,698,484	$3,702,689	$3,701,287	$3,702,689	$3,701,287	$3,702,689	$3,702,689	$3,701,287	$3,702,689	$44,424,940
Capacity Release Credits	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$453,562	$5,442,749
NGPMP Credit	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$2,400,000
Net Fixed Costs	$3,048,967	$3,050,369	$3,049,126	$3,044,922	$3,049,126	$3,047,725	$3,049,126	$3,047,725	$3,049,126	$3,049,126	$3,047,725	$3,049,126	$36,582,190
Total All Gas Costs	$19,802,971	$30,286,722	$36,179,165	$31,138,036	$26,524,417	$15,639,984	$9,986,389	$7,814,047	$7,511,197	$7,128,802	$7,327,860	$10,556,024	$209,895,614

National Grid
2010 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 30-Aug-2010
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Natural Gas Supply VS. Requirements Units: MDT

	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	OCT 2011	Total/Average
Forecast Demand													
RI Sales GCR	2,421,900	3,845,700	4,610,300	3,931,200	3,481,200	1,990,000	998,400	735,000	697,000	620,700	646,300	1,127,200	25,104,900
Total Demand	2,421,900	3,845,700	4,610,300	3,931,200	3,481,200	1,990,000	998,400	735,000	697,000	620,700	646,300	1,127,200	25,104,900
Storage Injections													
TENN_501	0	0	0	0	0	119,300	123,300	119,300	123,300	120,300	0	0	605,500
GSS 300170	0	0	0	0	0	24,500	0	0	0	0	0	0	24,500
GSS 300168	0	0	0	0	0	25,000	25,900	25,000	25,900	25,900	0	0	127,700
GSS 300171	0	0	0	0	0	15,700	16,200	15,700	16,200	16,200	15,700	16,200	111,900
GSSTE 600045	0	0	0	0	0	223,500	231,000	223,500	0	0	0	0	678,000
TETCO_400515	0	0	0	0	0	8,600	8,900	8,600	8,900	8,900	8,600	0	52,500
TETCO_400221	0	0	0	0	0	180,900	186,900	180,900	186,900	186,900	161,300	0	1,083,800
TETCO 400185	0	0	0	0	0	7,900	8,200	7,900	8,200	3,000	0	0	35,200
GSS 300169	0	0	0	0	0	33,500	34,600	33,500	34,600	21,600	0	0	157,800
COL FSS 9630	0	0	0	0	0	60,100	78,800	65,100	0	0	0	0	204,000
TENN_62918	0	0	0	0	0	41,400	42,800	41,400	42,800	41,700	0	0	210,100
Total Underground Storage	0	0	0	0	0	740,400	756,600	720,900	446,800	424,500	185,600	16,200	3,291,000
LNG PROV	10,900	0	0	0	0	66,900	70,100	10,900	11,300	11,300	10,900	11,300	203,600
LNG VALLEY	3,000	0	0	0	0	0	17,300	16,300	3,100	3,100	3,000	3,100	48,900
LNG EXETER	4,900	0	0	0	0	23,100	5,600	6,100	5,100	5,100	4,900	5,100	59,900
Total LNG Injection	18,800	0	0	0	0	90,000	93,000	33,300	19,500	19,500	18,800	19,500	312,400
Total Injections	18,800	0	0	0	0	830,400	849,600	754,200	466,300	444,000	204,400	35,700	3,603,400

Delivered Firm Sales Supply

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENN_CONX	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	4,234,000
TENN_ZONE_0	81,183	187,459	171,829	172,645	185,730	75,538	56,939	41,146	38,438	32,141	0	0	1,043,049
TENN_ZONE_1	167,617	387,041	354,771	356,455	383,470	155,962	117,561	84,954	79,362	66,359	0	0	2,153,551
TENN_NIAGARA	0	3,200	3,400	1,100	21,800	0	0	0	0	0	0	0	29,500
TENN_DRACUT	0	45,000	120,400	60,100	0	425,900	2,300	0	0	75,000	62,400	4,300	795,400
COL_MAUMEE	689,325	883,650	883,650	798,075	883,650	662,250	482,250	180,000	250,950	0	11,700	443,025	6,168,525
COL_BROADRUN	229,775	294,550	294,550	266,025	294,550	220,750	160,750	60,000	83,650	0	3,900	147,675	2,056,175
TRANSCO Z2	3,915	4,013	4,013	3,621	4,013	2,740	1,468	0	4,013	0	0	0	27,796
TRANSCO Z3	85	87	87	79	87	60	32	0	87	0	0	0	604
TETCO_ELA	269,427	273,583	327,270	293,067	271,981	179,249	185,236	179,249	97,155	90,254	70,769	6,177	2,243,417
TETCO_ETX	80,713	81,958	98,041	87,795	81,478	53,698	55,492	53,698	29,105	27,038	21,201	1,850	672,068
TETCO_STX	120,301	122,157	146,128	130,857	121,442	80,036	82,709	80,036	43,380	40,299	31,599	2,758	1,001,701
TETCO_WLA	185,163	188,019	224,916	201,410	186,919	123,189	127,303	123,189	66,770	62,027	48,636	4,245	1,541,784
TETCO to B&W - SCT	29,958	30,421	36,390	32,587	30,243	19,931	20,597	19,931	10,803	10,036	7,869	687	249,453
TETCO - NF - TRANSCO	13,202	13,406	16,037	14,361	13,327	8,783	9,077	8,783	4,761	4,423	3,468	303	109,931
TETCO - DTI - TETCO	7,836	7,957	9,518	8,523	7,910	5,213	5,387	5,213	2,826	2,625	2,058	180	65,245
M3_DELIVERED	146,600	119,900	12,900	4,800	419,300	50,100	0	0	0	0	0	0	753,600
HUBLINE	0	72,600	271,000	184,700	200	270,200	37,700	222,800	22,200	225,000	171,400	122,000	1,599,800
COL_EAGLE	0	10,237	2,125	290	0	0	0	0	0	0	0	0	12,652
COL_DOWNINGTOWN	0	10,963	2,275	310	0	0	0	0	0	0	0	0	13,548
ANE II - AECO-TENN - CONOCO P	30,000	30,900	30,900	28,000	30,900	30,000	30,900	30,000	30,900	30,900	30,000	30,900	364,300
DISTRI FLS Winter	18,900	0	0	0	0	0	0	0	0	0	0	0	18,900
DISTRI FLS Summer	0	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	293,800
DIST FCS VAP	0	0	0	0	0	0	0	0	0	0	0	0	0
DIST FCS LIQ	0	0	0	0	0	0	0	0	0	0	0	0	0
NEWPORT_LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
SPOT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

National Grid
2010 Estimated GCR
Normal Weather Scenario

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
Non LNG Liquid take	2,403,100	3,126,700	3,369,800	2,969,600	3,296,600	2,711,600	1,735,300	1,437,000	1,124,000	1,025,700	813,000	1,123,700	25,136,100
LNG Liquid take	18,900	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	312,700
Total take	2,422,000	3,126,700	3,369,800	2,969,600	3,296,600	2,801,600	1,828,300	1,470,400	1,143,500	1,045,200	831,900	1,143,200	25,448,800
Storage Withdrawals													
TENN 501	0	141,700	240,800	171,000	9,100	0	0	0	0	0	0	0	562,600
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,200	42,500	38,400	18,300	0	0	0	0	0	0	0	117,400
GSS 300171	0	0	71,100	28,600	0	0	0	0	0	0	0	0	99,700
GSSTE 600045	0	141,500	165,700	149,600	134,400	0	0	0	0	0	0	0	591,200
TETCO_400515	0	2,400	24,800	19,500	0	0	0	0	0	0	0	0	46,700
TETCO_400221	0	224,100	404,200	346,100	0	0	0	0	0	0	0	0	974,400
TETCO 400185	0	0	17,700	13,300	0	0	0	0	0	0	0	0	31,000
GSS 300169	0	35,700	55,400	50,000	0	0	0	0	0	0	0	0	141,100
COL FSS 9630	0	43,400	76,200	67,100	400	0	0	0	0	0	0	0	187,100
TENN_62918	0	9,700	122,600	60,200	2,700	0	0	0	0	0	0	0	195,200
LNG PROV	10,900	82,000	11,300	10,200	11,300	10,900	11,300	10,900	11,300	11,300	10,900	11,300	203,600
LNG VALLEY	3,000	15,500	3,100	2,800	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	48,900
LNG EXETER	4,900	5,100	5,100	4,600	5,100	4,900	5,100	4,900	5,100	5,100	4,900	5,100	59,900
Total Withdrawal Delivered	18,800	719,300	1,240,500	961,400	184,400	18,800	19,500	18,800	19,500	19,500	18,800	19,500	3,258,800
Total Storage withdrawal	0	616,700	1,221,000	943,800	164,900	0	0	0	0	0	0	0	2,946,400
Total Peaking withdrawal	18,800	102,600	19,500	17,600	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,500	312,400
Total Supply	**2,421,900**	**3,846,000**	**4,610,300**	**3,931,000**	**3,481,000**	**2,730,400**	**1,754,800**	**1,455,800**	**1,143,500**	**1,045,200**	**831,800**	**1,143,200**	**28,394,900**
Storage withdrawals at Storage Facilty													
TENN 501	0	144,843	246,141	174,793	9,302	0	0	0	0	0	0	0	575,079
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,604	43,443	39,252	18,706	0	0	0	0	0	0	0	120,004
GSS 300171	0	0	73,015	29,370	0	0	0	0	0	0	0	0	102,385
GSSTE 600045	0	145,621	170,525	153,957	138,314	0	0	0	0	0	0	0	608,417
TETCO_400515	0	2,546	26,310	20,687	0	0	0	0	0	0	0	0	49,544
TETCO_400221	0	234,458	422,883	362,098	0	0	0	0	0	0	0	0	1,019,439
TETCO 400185	0	0	18,518	13,915	0	0	0	0	0	0	0	0	32,433
GSS 300169	0	37,250	57,806	52,171	0	0	0	0	0	0	0	0	147,227
COL FSS 9630	0	43,994	77,243	68,018	405	0	0	0	0	0	0	0	189,660
TENN_62918	0	9,915	125,319	61,535	2,760	0	0	0	0	0	0	0	199,530
	0	637,231	1,261,203	975,796	169,487	0	0	0	0	0	0	0	3,043,718

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
08/04/2010 NYMEX	**$4.909**	**$5.149**	**$5.285**	**$5.252**	**$5.152**	**$4.982**	**$4.997**	**$5.034**	**$5.088**	**$5.132**	**$5.155**	**$5.235**	
TENNESSEE CONNEXION													
Basis	[redacted]												
usage to Zn 6	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
fuel to Zn 6	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	
fuel	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE ZN 1													
Basis	[redacted]												
usage to Zn 6	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	
fuel to Zn 6	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	
Total Delivered	[redacted]												
TENNESSEE DRACUT													
Basis	[redacted]												
usage	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	
fuel	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.47%	7.29%	7.29%	7.29%	7.29%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO ETX													
Basis	[redacted]												
Usage to M3	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.47%	7.29%	7.29%	7.29%	7.29%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO STX													
Basis	[redacted]												
Usage to M3	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	7.46%	8.59%	8.59%	8.59%	8.59%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

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	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.78%	7.69%	7.69%	7.69%	7.69%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO -> NF -> TRANSCO													
Basis	[redacted]												
Usage to M2	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	
Usage on NF	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	
Usage on Transco	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	
Usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
Fuel to M2	5.72%	6.33%	6.33%	6.33%	6.33%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	
Fuel on NF	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	
Fuel on Transco	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Delivered to NF	[redacted]												
Delivered to Transco													
Delivered to Algonquin													
Total Delivered													
M3 DELIVERED													
Basis	[redacted]												
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA MAUMEE													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA BROADRUN													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

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	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
COLUMBIA EAGLE													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA DOWNINGTOWN													
Basis	[redacted]												
Usage on Columbia	$0.1979	$0.2440	$0.2467	$0.2297	$0.2438	$0.1792	$0.1422	$0.1570	$0.1530	$0.1453	$0.1265	$0.1226	
Usage on AGT	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO -> DTI -> TETCO													
Basis	[redacted]												
Usage to M2	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	
Usage on Dominion	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
Fuel to M2	5.72%	6.33%	6.33%	6.33%	6.33%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	
Fuel on Dominion	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Delivered to Dominion	[redacted]												
Delivered to Tetco													
Delivered to Algonquin													
Total Delivered													
TRANSCO ZONE 2													
Basis	[redacted]												
Usage on Transco	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Transco	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	
Fuel on Tetco	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TRANSCO ZONE 3													
Basis	[redacted]												
Usage on Transco	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Transco	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	
Fuel on Tetco	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

National Grid
Rhode Island - Gas

National Grid
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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
AECO TO TENNESSEE - ANE II													
Basis	[redacted]												
Transcanada usage	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	
Transcanada pressure chg	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	
Fuel on TCPL	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	
Iroquois usage	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	
NETNE usage	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Iroquois	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel Tenn NET18	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Total Delivered	[redacted]												
NIAGARA TO TENNESSEE													
Basis	[redacted]												
Tenn usage	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	
Tenn Fuel	2.09%	2.09%	2.09%	2.09%	2.09%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	
Total Delivered	[redacted]												
Tetco to B&W - SCT													
Basis	[redacted]												
usage on Tetco	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	
usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
fuel to ZN 3	6.72%	7.62%	7.62%	7.62%	7.62%	6.72%	6.72%	6.72%	6.72%	6.72%	6.72%	6.72%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
DISTRIGAS FLS													
Total Delivered	[redacted]												
Hubline													
Basis	[redacted]												
usage	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
fuel	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
Total delivered to the City Gate Gas Supply Costs													
TENN CONNEXION													
Delivered Mmbtu	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	
NYMEX $/Mmbtu Del	$5.300	$5.461	$5.590	$5.528	$5.441	$5.238	$5.244	$5.266	$5.331	$5.386	$5.431	$5.521	
Total Delivered Cost	$1,844,348	$1,963,928	$2,010,291	$1,795,396	$1,956,562	$1,822,981	$1,885,767	$1,832,454	$1,917,113	$1,936,961	$1,890,003	$1,985,281	
Tennessee Zn 0													
Delivered Mmbtu	81,183	187,459	171,829	172,645	185,730	75,538	56,939	41,146	38,438	32,141	0	0	
NYMEX $/Mmbtu Del	$5.461	$5.622	$5.751	$5.688	$5.602	$5.399	$5.405	$5.426	$5.492	$5.547	$5.592	$5.682	
Total Delivered Cost	$443,314	$1,053,937	$988,217	$982,091	$1,040,410	$407,851	$307,749	$223,280	$211,103	$178,291	$0	$0	
TENN ZONE 1													
Delivered Mmbtu	167,617	387,041	354,771	356,455	383,470	155,962	117,561	84,954	79,362	66,359	0	0	
$/Mmbtu Del	$5.421	$5.674	$5.820	$5.788	$5.677	$5.426	$5.439	$5.472	$5.532	$5.581	$5.612	$5.699	
Total Delivered Cost	$908,581	$2,196,030	$2,064,696	$2,063,014	$2,176,894	$846,292	$639,366	$464,869	$439,033	$370,338	$0	$0	
TENN DRACUT													
Delivered Mmbtu	0	45,000	120,400	60,100	0	425,900	2,300	0	0	75,000	62,400	4,300	
$/Mmbtu Del	$5.98	$6.22	$6.36	$6.32	$6.22	$5.29	$5.37	$5.38	$5.49	$5.45	$5.45	$5.58	
Total Delivered Cost	$0	$279,894	$765,394	$380,060	$0	$2,253,270	$12,349	$0	$0	$408,588	$340,159	$23,999	
TETCO ELA													
Delivered Mmbtu	269,427	273,583	327,270	293,067	271,981	179,249	185,236	179,249	97,155	90,254	70,769	6,177	
$/Mmbtu Del	$5.3567	$5.6891	$5.8371	$5.8037	$5.6920	$5.4291	$5.4425	$5.4781	$5.5380	$5.5871	$5.6159	$5.7037	
Total Delivered Cost	$1,443,240	$1,556,431	$1,910,311	$1,700,861	$1,548,123	$973,154	$1,008,151	$981,948	$538,042	$504,259	$397,434	$35,232	
TETCO ETX													
Delivered Mmbtu	80,713	81,958	98,041	87,795	81,478	53,698	55,492	53,698	29,105	27,038	21,201	1,850	
NYMEX $/Mmbtu Del	$5.1535	$5.4686	$5.6133	$5.5931	$5.4640	$5.2063	$5.2089	$5.2238	$5.2913	$5.3487	$5.3995	$5.4913	
Total Delivered Cost	$415,952	$448,199	$550,335	$491,044	$445,202	$279,569	$289,050	$280,507	$154,003	$144,617	$114,473	$10,162	
TETCO STX													
Delivered Mmbtu	120,301	122,157	146,128	130,857	121,442	80,036	82,709	80,036	43,380	40,299	31,599	2,758	
NYMEX $/Mmbtu Del	$5.239	$5.578	$5.725	$5.704	$5.574	$5.322	$5.324	$5.338	$5.407	$5.465	$5.518	$5.611	
Total Delivered Cost	$630,294	$681,397	$836,568	$746,367	$676,883	$425,988	$440,368	$427,218	$234,541	$220,242	$174,369	$15,476	
TETCO WLA													
Delivered Mmbtu	185,163	188,019	224,916	201,410	186,919	123,189	127,303	123,189	66,770	62,027	48,636	4,245	
$/Mmbtu Del	$5.3332	$5.6741	$5.8231	$5.7881	$5.6772	$5.4050	$5.4187	$5.4545	$5.5144	$5.5637	$5.5925	$5.6806	
Total Delivered Cost	$987,512	$1,066,838	$1,309,707	$1,165,775	$1,061,167	$665,839	$689,812	$671,930	$368,196	$345,100	$271,998	$24,115	

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO -> NF -> TRANSCO													
Delivered Mmbtu	13,202	13,406	16,037	14,361	13,327	8,783	9,077	8,783	4,761	4,423	3,468	303	
Delivered $/Mmbtu	$6.0362	$6.3624	$6.5124	$6.4785	$6.3654	$6.1096	$6.1233	$6.1594	$6.2202	$6.2701	$6.2993	$6.3884	
Delivered Cost	$79,691	$85,294	$104,437	$93,036	$84,835	$53,664	$55,580	$54,101	$29,613	$27,730	$21,845	$1,934	
M3 DELIVERED													
Delivered Mmbtu	146,600	119,900	12,900	4,800	419,300	50,100	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.3772	$6.0326	$6.4929	$6.4213	$5.7268	$5.3735	$5.3891	$5.4651	$5.5083	$5.5360	$5.5202	$5.5908	
Delivered Cost	$788,291	$723,304	$83,758	$30,822	$2,401,262	$269,214	$0	$0	$0	$0	$0	$0	
COLUMBIA MAUMEE													
Delivered Mmbtu	689,325	883,650	883,650	798,075	883,650	662,250	482,250	180,000	250,950	0	11,700	443,025	
Delivered $/Mmbtu	$5.2213	$5.5220	$5.6670	$5.6217	$5.5299	$5.2853	$5.3082	$5.3597	$5.4113	$5.4488	$5.4591	$5.5382	
Total Delivered Cost	$3,599,197	$4,879,538	$5,007,674	$4,486,537	$4,886,489	$3,500,177	$2,559,900	$964,751	$1,357,970	$0	$63,871	$2,453,550	
COLUMBIA BROADRUN													
Delivered Mmbtu	229,775	294,550	294,550	266,025	294,550	220,750	160,750	60,000	83,650	0	3,900	147,675	
Delivered $/Mmbtu	$5.2964	$5.6198	$5.7634	$5.7116	$5.6227	$5.3523	$5.3297	$5.3830	$5.4345	$5.4719	$5.4762	$5.5545	
Total Delivered Cost	$1,216,981	$1,655,323	$1,697,608	$1,519,440	$1,656,176	$1,181,523	$856,743	$322,980	$454,595	$0	$21,357	$820,268	
COLUMBIA EAGLE													
Delivered Mmbtu	0	10,237	2,125	290	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.5148	$6.1841	$6.6541	$6.5811	$5.8720	$5.5111	$5.5270	$5.6046	$5.6487	$5.6770	$5.6608	$5.7329	
Delivered Cost	$0	$63,310	$14,138	$1,907	$0	$0	$0	$0	$0	$0	$0	$0	
COLUMBIA DOWNINGTOWN													
Delivered Mmbtu	0	10,963	2,275	310	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.7253	$6.4723	$6.9702	$6.8768	$6.1359	$5.6767	$5.6551	$5.7484	$5.7883	$5.8086	$5.7727	$5.8405	
Delivered Cost	$0	$70,953	$15,859	$2,134	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO -> DTI -> TETCO													
Delivered Mmbtu	7,836	7,957	9,518	8,523	7,910	5,213	5,387	5,213	2,826	2,625	2,058	180	
Delivered $/Mmbtu	$6.1571	$6.4896	$6.6424	$6.6079	$6.4926	$6.2319	$6.2459	$6.2827	$6.3446	$6.3955	$6.4252	$6.5160	
Delivered Cost	$48,245	$51,635	$63,222	$56,321	$51,357	$32,488	$33,648	$32,752	$17,927	$16,787	$13,224	$1,171	
TRANSCO ZONE 2													
Delivered Mmbtu	3,915	4,013	4,013	3,621	4,013	2,740	1,468	0	4,013	0	0	0	
Delivered $/Mmbtu	$5.2099	$5.4942	$5.6400	$5.6044	$5.4974	$5.3051	$5.3213	$5.3610	$5.4184	$5.4652	$5.4894	$5.5745	
Delivered Cost	$20,396	$22,047	$22,632	$20,295	$22,060	$14,538	$7,812	$0	$21,743	$0	$0	$0	

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TRANSCO ZONE 3													
Delivered Mmbtu	85	87	87	79	87	60	32	0	87	0	0	0	
Delivered $/Mmbtu	$5.2670	$5.5535	$5.6991	$5.6620	$5.5569	$5.3282	$5.3444	$5.3843	$5.4413	$5.4878	$5.5117	$5.5962	
Delivered Cost	$448	$484	$497	$446	$485	$317	$171	$0	$475	$0	$0	$0	
AECO TO TENNESSEE - ANE II													
Delivered Mmbtu	30,000	30,900	30,900	28,000	30,900	30,000	30,900	30,000	30,900	30,900	30,000	30,900	
Delivered $/Mmbtu	$6.0732	$6.3252	$6.4680	$6.4333	$6.3283	$6.1499	$6.1656	$6.2045	$6.2612	$6.3074	$6.3315	$6.4155	
Total Delivered Cost	$182,196	$195,449	$199,861	$180,134	$195,546	$184,496	$190,517	$186,134	$193,470	$194,897	$189,945	$198,239	
NIAGARA TO TENNESSEE													
Delivered Mmbtu	0	3,200	3,400	1,100	21,800	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.6467	$5.8111	$5.8230	$5.8182	$5.7342	$5.4792	$5.5038	$5.5545	$5.6033	$5.6382	$5.6449	$5.7257	
Total Delivered Cost	$0	$18,596	$19,798	$6,400	$125,006	$0	$0	$0	$0	$0	$0	$0	
Tetco to B&W - SCT													
Delivered Mmbtu	29,958	30,421	36,390	32,587	30,243	19,931	20,597	19,931	10,803	10,036	7,869	687	
Delivered $/Mmbtu	$6.0533	$6.3940	$6.5426	$6.5090	$6.3969	$6.1259	$6.1394	$6.1751	$6.2351	$6.2844	$6.3132	$6.4012	
Total Delivered Cost	$181,349	$194,509	$238,085	$212,109	$193,460	$122,097	$126,453	$123,077	$67,358	$63,068	$49,679	$4,397	
DISTRIGAS FLS													
Delivered Mmbtu	18,900	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	
Delivered $/Mmbtu	[redacted]												
Total Delivered Cost													
HUBLINE													
Total Delivered Vol	0	72,600	271,000	184,700	200	270,200	37,700	222,800	22,200	225,000	171,400	122,000	
Delivered $/Mmbtu	$5.9105	$6.1844	$6.3222	$6.2888	$6.1874	$5.2259	$5.3042	$5.3177	$5.4215	$5.3831	$5.3865	$5.5165	
Total Delivered Cost	$0	$448,985	$1,713,323	$1,161,536	$1,237	$1,412,033	$199,970	$1,184,773	$120,358	$1,211,198	$923,251	$673,016	

	NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	
	2010	2010	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	
Financial Hedges as of 7/31/2010													
Quantity	3,086,000	3,240,000	3,080,000	2,970,000	2,800,000	2,030,000	1,527,000	991,000	802,000	790,000	642,000	923,000	**22,881,000**
Average Price	$6.122	$6.490	$6.707	$6.570	$6.443	$5.992	$6.206	$6.234	$6.196	$6.312	$6.373	$6.466	
08/04/2010 NYMEX	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
Impact of Financial Hedges	**$3,744,776**	**$4,345,430**	**$4,380,700**	**$3,915,430**	**$3,615,240**	**$2,050,190**	**$1,845,816**	**$1,189,041**	**$888,704**	**$932,270**	**$781,690**	**$1,136,410**	**$28,825,697.00**
Total Pipeline Costs (Incl Inj)	**$16,627,592**	**$22,001,510**	**$23,997,111**	**$21,011,154**	**$22,138,394**	**$16,944,062**	**$11,613,943**	**$9,107,951**	**$7,113,457**	**$6,654,421**	**$5,350,729**	**$7,485,331**	**$170,045,655**
Total Delivered Pipeline Vol	**2,422,000**	**3,126,700**	**3,369,800**	**2,969,600**	**3,296,600**	**2,801,600**	**1,828,300**	**1,470,400**	**1,143,500**	**1,045,200**	**831,900**	**1,143,200**	**25,448,800**
WACOG (Cost/Volume)	$6.865	$7.037	$7.121	$7.075	$6.716	$6.048	$6.352	$6.194	$6.221	$6.367	$6.432	$6.548	$6.682
Injections	0	0	0	0	0	740,400	756,600	720,900	446,800	424,500	185,600	16,200	
Cost of Injections	$0	$0	$0	$0	$0	$4,477,935	$4,806,164	$4,465,398	$2,779,443	$2,702,642	$1,193,768	$106,073	**$20,531,423**
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	**$16,627,592**	**$22,001,510**	**$23,997,111**	**$21,011,154**	**$22,138,394**	**$12,466,126**	**$6,807,779**	**$4,642,552**	**$4,334,014**	**$3,951,779**	**$4,156,962**	**$7,379,258**	**$149,514,232**
Total Pipeline Purchase Volumes	**2,422,000**	**3,126,700**	**3,369,800**	**2,969,600**	**3,296,600**	**2,061,200**	**1,071,700**	**749,500**	**696,700**	**620,700**	**646,300**	**1,127,000**	**22,157,800**

2010 GCR estimate
FIXED COST ESTIMATES
Nov 2010 - Oct 2011

2010-2011 Gas Supply Fixed Costs
UNIT PRICES

		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST UNIT PRICES $/Dth													
ALGONQUIN AFT-E/AFT-1 DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391
TEXAS EASTERN STX CDS DEMAND Z3	$/Dth	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805
TEXAS EASTERN WLA CDS DEMAND Z3	$/Dth	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825
TEXAS EASTERN ELA CDS DEMAND Z3	$/Dth	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375
TEXAS EASTERN ETX CDS DEMAND Z3	$/Dth	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189
TETCO FTS DEMAND	$/Dth	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350
TETCO M1 TO M3 DEMAND Z3	$/Dth	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241
TETCO SCT STX DEMAND	$/Dth	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722
TETCO SCT WLA DEMAND	$/Dth	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130
TETCO SCT ELA DEMAND	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-3	$/Dth	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497
TETCO SCT STX DEMAND Z2	$/Dth	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722
TETCO SCT WLA DEMAND Z2	$/Dth	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130
TETCO SCT ELA DEMAND Z2	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND Z2	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-2	$/Dth	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CONI	$/Dth	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737
TENNESSEE DRACUT	$/Dth	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930
NETNE	$/Dth	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610
IROQUOIS	$/Dth	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597
NOVA	$/Dth	$4.515	$4.666	$4.666	$4.214	$4.666	$4.515	$4.666	$4.515	$4.666	$4.666	$4.515	$4.666
TRANSCANADA	$/Dth	$30.150	$31.155	$31.155	$28.140	$31.155	$30.150	$31.155	$30.150	$31.155	$31.155	$30.150	$31.155
DOMINION FTNN DEMAND	$/Dth	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462
TRANSCO DEMAND ZONE 3 TO 6.	$/Dth	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435
TRANSCO DEMAND ZONE 6	$/Dth	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119
NATIONAL FUEL DEMAND	$/Dth	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557
COLUMBIA FTS DEMAND	$/Dth	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075
HUBLINE	$/Dth	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558
HUBLINE	$/Dth	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996
HUBLINE	$/Dth	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992
EAST TO WEST	$/Dth	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS FCS	$/Dth	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
STORAGE FIXED COST UNIT PRICES													
TEXAS EASTERN SS-1 DEMAND	$/Dth	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592	$5.592
TEXAS EASTERN SS-1 CAPACITY	$/Dth	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129
TEXAS EASTERN FSS-1 DEMAND	$/Dth	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895	$0.895
TEXAS EASTERN FSS-1 CAPACITY	$/Dth	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129	$0.129
DOMINION GSS DEMAND	$/Dth	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877
DOMINION GSS CAPACITY	$/Dth	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015
DOMINION GSS-TE DEMAND	$/Dth	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877	$1.877
DOMINION GSS-TE CAPACITY	$/Dth	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015
TENNESSEE FSMA DEMAND	$/Dth	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150	$1.150
TENNESSEE FSMA CAPACITY	$/Dth	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019	$0.019
COLUMBIA FSS DEMAND	$/Dth	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506	$1.506
COLUMBIA FSS CAPACITY	$/Dth	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029	$0.029

STORAGE DELIVERY FIXED		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
UNIT RATES ($/Dth)													
PATH													
ALGONQUIN FOR TETCO SS-1	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN DELIVERY FOR FSS-1	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
TETCO DELIVERY FOR FSS-1	$/Dth	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359	$5.359
ALGONQUIN SCT FOR SS-1	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
ALGONQUIN SCT DELIVERY FOR GSS-TE	$/Dth	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909	$2.3909
ALGONQUIN DELIVERY FOR GSS CONV.	$/Dth	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785	$9.785
TENNESSEE DELIVERY FOR GSS	$/Dth	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900
TENNESSEE DELIVERY FOR FSMA	$/Dth	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900	$5.8900
TETCO DELIVERY FOR GSS	$/Dth	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576	$6.576
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864	$6.864
TETCO DELIVERY FOR GSS CONV.	$/Dth	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179	$5.179
DOMINION DELIVERY FOR GSS	$/Dth	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461
DOMINION DELIVERY FOR GSS CONV.	$/Dth	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461	$4.3461
ALGONQUIN DELIVERY FOR FSS	$/Dth	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771	$5.9771
COLUMBIA DELIVERY FOR FSS	$/Dth	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905	$5.905
DISTRIGAS FLS CALL PAYMENT Winter	$/Dth	[redacted]											
DISTRIGAS FLS CALL PAYMENT Summer	$/Dth												

BILLING UNITS

PIPELINE FIXED COST BILLING UNITS		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
ALGONQUIN AFT-E/AFT-1 DEMAND	Dth	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950
ALGONQUIN AFT-3 DEMAND	Dth	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	Dth	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414
TEXAS EASTERN STX CDS DEMAND Z3	Dth	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN WLA CDS DEMAND Z3	Dth	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN ELA CDS DEMAND Z3	Dth	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN ETX CDS DEMAND Z3	Dth	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TETCO M1 TO M3 DEMAND Z3	Dth	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TETCO FTS DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
TETCO SCT STX DEMAND	Dth	571	571	571	571	571	571	571	571	571	571	571	571
TETCO SCT WLA DEMAND	Dth	648	648	648	648	648	648	648	648	648	648	648	648
TETCO SCT ELA DEMAND	Dth	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TETCO SCT ETX DEMAND	Dth	329	329	329	329	329	329	329	329	329	329	329	329
TETCO SCT DEMAND 1-3	Dth	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TETCO SCT STX DEMAND Z2	Dth	401	401	401	401	401	401	401	401	401	401	401	401
TETCO SCT WLA DEMAND Z2	Dth	455	455	455	455	455	455	455	455	455	455	455	455
TETCO SCT ELA DEMAND Z2	Dth	831	831	831	831	831	831	831	831	831	831	831	831
TETCO SCT ETX DEMAND Z2	Dth	231	231	231	231	231	231	231	231	231	231	231	231
TETCO SCT DEMAND 1-2	Dth	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 (New)	Dth	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE DRACUT	Dth	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TENNESSEE FT-A DEMAND ZONE 5 TO 6	Dth	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
NETNE	Dth	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
IROQUOIS	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NOVA	Dth	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
TRANSCANADA	Dth	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
DOMINION FTNN DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
TRANSCO DEMAND ZONE 2 TO 6	Dth	4,140	4,278	4,278	3,864	4,278	4,140	4,278	4,140	4,278	4,278	4,140	4,278
TRANSCO DEMAND ZONE 3 TO 6.	Dth	90	93	93	84	93	90	93	90	93	93	90	93
TRANSCO DEMAND ZONE 6	Dth	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
NATIONAL FUEL DEMAND	Dth	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
COLUMBIA FTS DEMAND	Dth	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
HUBLINE	Dth	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
HUBLINE	Dth	500	500	500	500	500	500	500	500	500	500	500	500
HUBLINE	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
EAST TO WEST	Dth	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS FCS	Dth	0	0	0	0	0	0	0	0	0	0	0	0
STORAGE FIXED COST BILLING UNITS													
TEXAS EASTERN SS-1 DEMAND	Dth	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802
TEXAS EASTERN SS-1 CAPACITY	Dth	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336
TEXAS EASTERN FSS-1 DEMAND	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TEXAS EASTERN FSS-1 CAPACITY	Dth	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720
DOMINION GSS DEMAND	Dth	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403
DOMINION GSS CAPACITY	Dth	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304
DOMINION GSS-TE DEMAND	Dth	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337
DOMINION GSS-TE CAPACITY	Dth	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324
TENNESSEE FSMA DEMAND	Dth	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
TENNESSEE FSMA CAPACITY	Dth	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343
COLUMBIA FSS DEMAND	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA FSS CAPACITY	Dth	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957
STORAGE DELIVERY BILLING UNITS (DTH)													
ALGONQUIN FOR TETCO SS-1	Dth	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137
ALGONQUIN DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TETCO DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
ALGONQUIN SCT FOR SS-1	Dth	665	665	665	665	665	665	665	665	665	665	665	665
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	Dth	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739
ALGONQUIN SCT DELIVERY FOR GSS-TE	Dth	187	187	187	187	187	187	187	187	187	187	187	187
ALGONQUIN DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
TENNESSEE DELIVERY FOR GSS	Dth	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725
TENNESSEE DELIVERY FOR FSMA	Dth	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111
TETCO DELIVERY FOR GSS	Dth	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377
TETCO DELIVERY FOR GSS-TE	Dth	538	538	538	538	538	538	538	538	538	538	538	538
TETCO DELIVERY FOR GSS-TE	Dth	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011
TETCO DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
DOMINION DELIVERY FOR GSS	Dth	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324
DOMINION DELIVERY FOR GSS CONV	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
ALGONQUIN DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
DISTRIGAS FLS CALL PAYMENT Winter	Dth	3,000	3,000	3,000	3,000	3,000	0	0	0	0	0	0	0
DISTRIGAS FLS CALL PAYMENT Summer	Dth	0	0	0	0	0	3,000	3,000	3,000	3,000	3,000	3,000	3,000

		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
							TOTAL COST							
PIPELINE FIXED COST DOLLARS														
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	
ALGONQUIN AFT-3 DEMAND	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
ALGONQUIN AFT-ES/1S DEMAND	$	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	
TEXAS EASTERN STX CDS DEMAND Z3	$	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	
TEXAS EASTERN WLA CDS DEMAND Z3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
TEXAS EASTERN ELA CDS DEMAND Z3	$	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	
TEXAS EASTERN ETX CDS DEMAND Z3	$	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	
TETCO M1 TO M3 DEMAND Z3	$	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	
TETCO FTS DEMAND	$	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	
TETCO SCT STX DEMAND	$	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	
TETCO SCT WLA DEMAND	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
TETCO SCT ELA DEMAND	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TETCO SCT ETX DEMAND	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TETCO SCT DEMAND 1-3	$	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	
TETCO SCT STX DEMAND Z2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TETCO SCT WLA DEMAND Z2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TETCO SCT ELA DEMAND Z2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TETCO SCT ETX DEMAND Z2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TETCO SCT DEMAND 1-2	$	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 (New)	$	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	
TENNESSEE DRACUT	$	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	
NETNE	$	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	
IROQUOIS	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NOVA	$	$4,858	$5,020	$5,020	$4,534	$5,020	$4,858	$5,020	$4,858	$5,020	$5,020	$4,858	$5,020	
TRANSCANADA	$	$30,813	$31,840	$31,840	$28,759	$31,840	$30,813	$31,840	$30,813	$31,840	$31,840	$30,813	$31,840	
DOMINION FTNN DEMAND	$	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,911	$1,975	$1,975	$1,784	$1,975	$1,911	$1,975	$1,911	$1,975	$1,975	$1,911	$1,975	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$40	$40	$37	$40	$39	$40	$39	$40	$40	$39	$40	
TRANSCO DEMAND ZONE 6	$	$4,424	$4,571	$4,571	$4,129	$4,571	$4,424	$4,571	$4,424	$4,571	$4,571	$4,424	$4,571	
NATIONAL FUEL DEMAND	$	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	
COLUMBIA FTS DEMAND	$	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	
HUBLINE	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
HUBLINE	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
HUBLINE	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
EAST TO WEST	$	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	
WESTERLY LATERAL (Yankee)	$	$58,879	$58,879	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	
TOTAL PIPELINE DEMAND COSTS		**$2,747,993**	**$2,749,395**	**$2,748,152**	**$2,743,948**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$32,970,500**
SUPPLIER FIXED COST DOLLARS														
DISTRIGAS FCS - Vapor Portion	$	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TOTAL SUPPLIER DEMAND COSTS		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
STORAGE FIXED COST DOLLARS														
TEXAS EASTERN SS-1 DEMAND	$	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	$82,773	
TEXAS EASTERN SS-1 CAPACITY	$	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	
TEXAS EASTERN FSS-1 DEMAND	$	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	$845	
TEXAS EASTERN FSS-1 CAPACITY	$	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	
DOMINION GSS DEMAND	$	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	$21,407	
DOMINION GSS CAPACITY	$	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	
DOMINION GSS-TE DEMAND	$	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	$26,915	
DOMINION GSS-TE CAPACITY	$	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	
TENNESSEE FSMA DEMAND	$	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	$24,344	
TENNESSEE FSMA CAPACITY	$	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	$15,084	
COLUMBIA FSS DEMAND	$	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	$3,833	
COLUMBIA FSS CAPACITY	$	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	$5,894	
NATIONAL GRID LNG TANK LEASE PAYMENTS	$	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	**$1,964,880**
TOTAL STORAGE DEMAND COSTS	$	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$4,725,995**

STORAGE DELIVERY FIXED COSTS														
ALGONQUIN FOR TETCO SS-1	$	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	$84,498	
ALGONQUIN DELIVERY FOR FSS-1	$	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	$5,642	
TETCO DELIVERY FOR FSS-1	$	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	$5,059	
ALGONQUIN SCT FOR SS-1	$	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	$1,590	
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	$70,165	
ALGONQUIN SCT DELIVERY FOR GSS-TE	$	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	$447	
ALGONQUIN DELIVERY FOR GSS CONV	$	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	
TENNESSEE DELIVERY FOR GSS	$	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	$39,610	
TENNESSEE DELIVERY FOR FSMA	$	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	$24,214	
TETCO DELIVERY FOR GSS	$	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	
TETCO DELIVERY FOR GSS-TE	$	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	
TETCO DELIVERY FOR GSS-TE	$	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	
TETCO DELIVERY FOR GSS CONV	$	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	
DOMINION DELIVERY FOR GSS	$	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	$23,139	
DOMINION DELIVERY FOR GSS CONV	$	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	$8,957	
ALGONQUIN DELIVERY FOR FSS	$	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	$15,212	
COLUMBIA DELIVERY FOR FSS	$	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	$15,028	
DISTRIGAS FCS - LIQUID PORTION	$	[redacted]												
DISTRIGAS FLS CALL PAYMENT Winter	$													
DISTRIGAS FLS CALL PAYMENT Summer	$													
TOTAL STORAGE DELIVERY DEMAND CHARGES														
TOTAL ALL DEMAND COSTS	$	[redacted]												

		NOV	DEC	JAN-11	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
Marketer Demand Charge Credits														
Capacity Release Volumes as of August 1, 2010														
Tennessee	Dth	7,723	7,723	7,723	7,723	7,723	7,723	7,723	7,723	7,723	7,723	7,723	7,723	
Algonquin	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	
Tetco STX/AGT	Dth	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	
Tetco WLA/AGT	Dth	7,824	7,824	7,824	7,824	7,824	7,824	7,824	7,824	7,824	7,824	7,824	7,824	
Tetco ELA/AGT	Dth	5,476	5,476	5,476	5,476	5,476	5,476	5,476	5,476	5,476	5,476	5,476	5,476	
Columbia/Downington	Dth	764	764	764	764	764	764	764	764	764	764	764	764	
Total		**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	**28,528**	
System Weighted Average cost per MMBtu		**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	**$15.8989**	
Total Demand Charge Credit		**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$5,442,749**
Demand Costs Net of Releases to Marketers	**$**	**$3,248,967**	**$3,250,369**	**$3,249,126**	**$3,244,922**	**$3,249,126**	**$3,247,725**	**$3,249,126**	**$3,247,725**	**$3,249,126**	**$3,249,126**	**$3,247,725**	**$3,249,126**	**$38,982,190**
TOTAL PIPELINE DEMANDS	**$**	**$2,747,993**	**$2,749,395**	**$2,748,152**	**$2,743,948**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$32,970,500**
TOTAL SUPPLIER DEMANDS	**$**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
TOTAL STORAGE FACILITIES	**$**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$393,833**	**$4,725,995**
TOTAL STORAGE DELIVERY DEMANDS	**$**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$560,704**	**$6,728,444**
Total All Demands	**$**	**$3,702,530**	**$3,703,931**	**$3,702,689**	**$3,698,484**	**$3,702,689**	**$3,701,287**	**$3,702,689**	**$3,701,287**	**$3,702,689**	**$3,702,689**	**$3,701,287**	**$3,702,689**	**$44,424,940**
Marketer Release Credits	**$**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$453,562**	**$5,442,749**
NGPMP credit		**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$2,400,000**
Demand Net of Releases	**$**	**$3,048,967**	**$3,050,369**	**$3,049,126**	**$3,044,922**	**$3,049,126**	**$3,047,725**	**$3,049,126**	**$3,047,725**	**$3,049,126**	**$3,049,126**	**$3,047,725**	**$3,049,126**	**$36,582,190**

Storage Product Cost

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
WACOG INJECTIONS	$5.319	$5.647	$5.821	$5.757	$5.619	$5.316	$5.343	$5.386	$5.444	$5.475	$5.492	$5.554
Injection cost	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023	$0.023
Total injection cost	$5.342	$5.669	$5.844	$5.779	$5.641	$5.339	$5.365	$5.408	$5.466	$5.497	$5.515	$5.576

COMBINED STORAGE	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Beginning Inv Vol	4,495,011	4,495,011	3,857,780	2,596,576	1,620,780	1,451,293	2,191,693	2,948,293	3,669,193	4,115,993	4,540,493	4,726,093
Vol Withdrawn	0	637,231	1,261,203	975,796	169,487	0	0	0	0	0	0	0
Vol Injected	0	0	0	0	0	740,400	756,600	720,900	446,800	424,500	185,600	16,200
Begining Inv $ (virtual)	$23,678,819	$23,678,819	$20,322,012	$13,678,244	$8,537,946	$7,645,122	$11,597,943	$15,657,328	$19,556,035	$21,998,315	$24,331,900	$25,355,458
$ Withdrawn (1)	$0	$4,504,482	$8,915,238	$6,897,740	$1,198,076	$0	$0	$0	$0	$0	$0	$0
$ Injected	$0	$0	$0	$0	$0	$3,952,821	$4,059,386	$3,898,707	$2,442,280	$2,333,586	$1,023,557	$90,334
Ending Vol	4,495,011	3,857,780	2,596,576	1,620,780	1,451,293	2,191,693	2,948,293	3,669,193	4,115,993	4,540,493	4,726,093	4,742,293
Ending $	$23,678,819	$20,322,012	$13,678,244	$8,537,946	$7,645,122	$11,597,943	$15,657,328	$19,556,035	$21,998,315	$24,331,900	$25,355,458	$25,445,792
Avg $/Mmbtu	$5.268	$5.268	$5.268	$5.268	$5.268	$5.292	$5.311	$5.330	$5.345	$5.359	$5.365	$5.366
Withdrawal cost	**$0**	**$19,283**	**$36,674**	**$30,134**	**$3,394**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Transportation cost	**$0**	**$22,717**	**$50,188**	**$36,005**	**$4,598**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Costs allocated to fuel	**$0**	**$108,155**	**$211,784**	**$168,549**	**$24,164**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Storage value Less fuel	**$0**	**$4,396,327**	**$8,703,454**	**$6,729,191**	**$1,173,912**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Delivered Volumes	0	616,700	1,221,000	943,800	164,900	0	0	0	0	0	0	0
Hedge Amortization		**$1,147,675**	**$2,271,470**	**$1,757,442**	**$305,252**							
	0	20,531	40,203	31,996	4,587	0	0	0	0	0	0	0

- amortization of hedges on injection gas
$5,481,839

(1) Includes Hedge Amortization
3,043,718 Withdrawal

Storage Withdrawal variable costs
2010-2011 GCR Storage surcharge estimate

Storage Withdrawals at Facility Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	144,843	246,141	174,793	9,302	0	0	0	0	0	0	0	575,079
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,604	43,443	39,252	18,706	0	0	0	0	0	0	0	120,004
GSS 300171	0	0	73,015	29,370	0	0	0	0	0	0	0	0	102,385
GSS-TE 600045	0	145,621	170,525	153,957	138,314	0	0	0	0	0	0	0	608,417
TETCO_400515	0	2,546	26,310	20,687	0	0	0	0	0	0	0	0	49,544
TETCO_400221	0	234,458	422,883	362,098	0	0	0	0	0	0	0	0	1,019,439
TETCO 400185	0	0	18,518	13,915	0	0	0	0	0	0	0	0	32,433
GSS 300169	0	37,250	57,806	52,171	0	0	0	0	0	0	0	0	147,227
COL FSS 9630	0	43,994	77,243	68,018	405	0	0	0	0	0	0	0	189,660
TENN_62918	0	9,915	125,319	61,535	2,760	0	0	0	0	0	0	0	199,530
TOTAL	0	637,231	1,261,203	975,796	169,487	0	0	0	0	0	0	0	3,043,718

STORAGE WITHDRAWAL PRICES												
Tennessee Withdrawal	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102	$0.0102
Dominion GSS Withdrawal	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163	$0.0163
Dominion GSS-TE Withdrawal	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214	$0.0214
Tetco SS-1 Withdrawal	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551	$0.0551
Tetco FSS-1 Withdrawal	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339	$0.0339
Columbia Withdrawal	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153

GAS YEAR 2010 - 2011

Withdrawal Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Withdrawal	$0	$1,579	$3,789	$2,411	$123	$0	$0	$0	$0	$0	$0	$0	$7,901
Dominion GSS Withdrawal	$0	$910	$2,840	$1,969	$305	$0	$0	$0	$0	$0	$0	$0	$6,025
Dominion GSS-TE Withdrawal	$0	$3,116	$3,649	$3,295	$2,960	$0	$0	$0	$0	$0	$0	$0	$13,020
Tetco SS-1 Withdrawal	$0	$12,919	$24,321	$20,718	$0	$0	$0	$0	$0	$0	$0	$0	$57,958
Tetco FSS-1 Withdrawal	$0	$86	$892	$701	$0	$0	$0	$0	$0	$0	$0	$0	$1,680
Columbia Withdrawal	$0	$673	$1,182	$1,041	$6	$0	$0	$0	$0	$0	$0	$0	$2,902
Totals	$0	$19,283	$36,674	$30,134	$3,394	$0	$0	$0	$0	$0	$0	$0	$89,485

Storage Withdrawals at Gate Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_501	0	141,700	240,800	171,000	9,100	0	0	0	0	0	0	0	562,600
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,200	42,500	38,400	18,300	0	0	0	0	0	0	0	117,400
GSS 300171	0	0	71,100	28,600	0	0	0	0	0	0	0	0	99,700
GSS-TE 600045	0	141,500	165,700	149,600	134,400	0	0	0	0	0	0	0	591,200
TETCO_400515	0	2,400	24,800	19,500	0	0	0	0	0	0	0	0	46,700
TETCO_400221	0	224,100	404,200	346,100	0	0	0	0	0	0	0	0	974,400
TETCO 400185	0	0	17,700	13,300	0	0	0	0	0	0	0	0	31,000
GSS 300169	0	35,700	55,400	50,000	0	0	0	0	0	0	0	0	141,100
COL FSS 9630	0	43,400	76,200	67,100	400	0	0	0	0	0	0	0	187,100
TENN_62918	0	9,700	122,600	60,200	2,700	0	0	0	0	0	0	0	195,200
TOTAL	0	616,700	1,221,000	943,800	164,900	0	0	0	0	0	0	0	2,946,400

Storage Transportation Prices												
Tennessee Transportation	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853
Dominion Trans on Tetco/AGT	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150	$0.0150
Dominion Trans on DTI/Tetco/AGT	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401	$0.0401
Dominion Trans on Tennessee	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853	$0.0853
Dominion Trans on DTI/Tennessee	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104	$0.1104
Tetco SS-1 Trans	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131
Tetco FSS-1 Trans	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570	$0.0570
Columbia Trans	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374	$0.0374

Storage Transportation Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Transportation	$0	$12,914	$30,998	$19,721	$1,007	$0	$0	$0	$0	$0	$0	$0	$64,640
Dominion Trans on Tetco/AGT	$0	$2,123	$3,552	$2,673	$2,016	$0	$0	$0	$0	$0	$0	$0	$10,364
Dominion Trans on DTI/Tetco/AGT	$0	$1,432	$2,222	$2,005	$0	$0	$0	$0	$0	$0	$0	$0	$5,658
Dominion Trans on Tennseess	$0	$1,552	$3,625	$3,276	$1,561	$0	$0	$0	$0	$0	$0	$0	$10,014
Dominion Trans on DTI/Tennessee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tetco SS-1 Trans	$0	$2,936	$5,527	$4,708	$0	$0	$0	$0	$0	$0	$0	$0	$13,171
Tetco FSS-1 Trans	$0	$137	$1,415	$1,112	$0	$0	$0	$0	$0	$0	$0	$0	$2,664
Columbia Trans	$0	$1,623	$2,850	$2,510	$15	$0	$0	$0	$0	$0	$0	$0	$6,998
Total	$0	$22,717	$50,188	$36,005	$4,598	$0	$0	$0	$0	$0	$0	$0	$113,508
Total Variable	$0	$42,000	$86,862	$66,139	$7,993	$0	$0	$0	$0	$0	$0	$0	$202,994

National Grid
Rhode Island - Gas

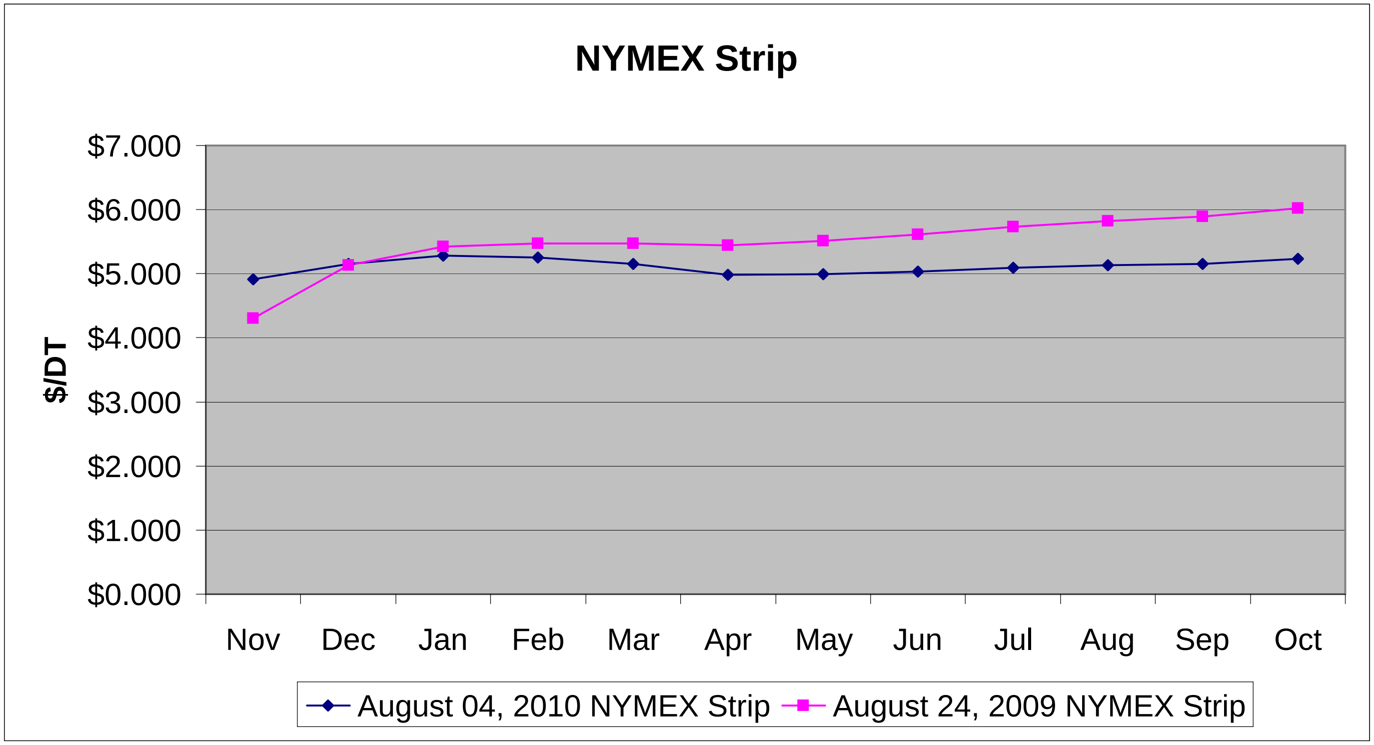
NATIONAL GRID - RI SERVICE AREA
NOVEMBER 2010 - OCTOBER 2011

LNG Estimate for 2010 - 2011

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
08/04/2010 NYMEX	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235
Trucking Delivered Cost - FLS contract	[redacted]											
Basis FLS contract TGP Zone 6 Delivered Cost - FLS contract	[redacted]											
Basis New England Spot LNG Delivered Cost - FCS contract	[redacted]											

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Combined LNG Inv												
Beginning Inv Vol	906,000	906,000	803,400	783,900	766,300	746,800	818,000	891,500	906,000	906,000	906,000	906,000
Vol Injected - FLS winter	18,800	0	0	0	0	0	0	0	0	0	0	0
Vol Injected - FLS summer	0	0	0	0	0	90,000	93,000	33,300	19,500	19,500	18,800	19,500
Vol Injected - Spot LNG	0	0	0	0	0	0	0	0	0	0	0	0
Vol Withdrawn	18,800	102,600	19,500	17,600	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,500
Begining Inv $ 8/2/10 = $6.724	$6,091,944	$6,078,502	$5,390,142	$5,259,313	$5,141,232	$5,010,403	$5,431,651	$5,869,189	$5,949,681	$5,942,291	$5,935,918	$5,930,339
$ Injected	$112,969	$0	$0	$0	$0	$547,380	$567,021	$204,262	$120,666	$121,524	$117,594	$123,533
$ Withdrawn	$126,411	$688,360	$130,829	$118,081	$130,829	$126,132	$129,483	$123,770	$128,056	$127,897	$123,174	$127,640
Ending Vol	906,000	803,400	783,900	766,300	746,800	818,000	891,500	906,000	906,000	906,000	906,000	906,000
Ending $	$6,078,502	$5,390,142	$5,259,313	$5,141,232	$5,010,403	$5,431,651	$5,869,189	$5,949,681	$5,942,291	$5,935,918	$5,930,339	$5,926,231
Avg $/Dth	[redacted]											
Newport												
Newport LNG Vol Vapor	0	0	0	0	0	0	0	0	0	0	0	0
Avg $/Dth	[redacted]											
Total cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total All LNG Costs	**$126,411**	**$688,360**	**$130,829**	**$118,081**	**$130,829**	**$126,132**	**$129,483**	**$123,770**	**$128,056**	**$127,897**	**$123,174**	**$127,640**

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 24, 2009 NYMEX Strip	**$4.307**	**$5.130**	**$5.422**	**$5.473**	**$5.473**	**$5.446**	**$5.509**	**$5.610**	**$5.730**	**$5.825**	**$5.896**	**$6.018**
August 04, 2010 NYMEX Strip	**$4.909**	**$5.149**	**$5.285**	**$5.252**	**$5.152**	**$4.982**	**$4.997**	**$5.034**	**$5.088**	**$5.132**	**$5.155**	**$5.235**



National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2010 - October 2011

12 Month Forward Pricing

Path to City Gate	As of 8/1/10 Existing Releases	Total Available	Remaining Available	Cost /Dth	New Credit/ Surcharge	Old Credit / Surcharge
Company Weighted Average				**$0.963**		
Tennessee Zone 1	7,723	8,000	277	$1.005	($0.042)	$0.018
Algonquin @ Lambertville, NJ	2,714	2,714	0	$0.782	$0.181	$0.279
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,027	4,044	17	$1.345	($0.382)	($0.237)
Texas Eastern - West La Algonquin @ Lambertville, NJ	7,824	8,000	176	$1.212	($0.249)	($0.193)
Texas Eastern - East La Algonquin @ Lambertville, NJ	5,476	5,500	24	$1.138	($0.175)	($0.186)
Columbia (Maumee/Downington) at 5:1 ratio**	764	1,000	236	$0.687	$0.276	$0.355
Totals	28,528	29,258	730			

** Note: Marketers selecting this path are assigned 5/6 of the amount selected at the Maumee, Ohio receipt point into Columbia and 1/6 at the Downington, Pa. Receipt into Columbia.

Gas Year 2010 - 2011
TEXAS EASTERN SOUTH TEXAS SUPPLY PATH COST MATRIX
CITY GATE DELIVERED MDQ = 4,044

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	$6.81	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO STX M1 TO M3 DEMAND	$/Dth	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE STX TO M3	$/Dth	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/04/2010 NYMEX	$/Dth	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													

BILLING UNITS

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$/Dth	4,078	4,099	4,099	4,099	4,099	4,078	4,078	4,078	4,078	4,078	4,078	4,078	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,078	4,099	4,099	4,099	4,099	4,078	4,078	4,078	4,078	4,078	4,078	4,078	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,078	4,099	4,099	4,099	4,099	4,078	4,078	4,078	4,078	4,078	4,078	4,078	
TETCO STX M1 TO M3 DEMAND	$/Dth	4,078	4,099	4,099	4,099	4,099	4,078	4,078	4,078	4,078	4,078	4,078	4,078	
ALGONQUIN AFT-E DEMAND	$/Dth	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	4,044	48,528
VARIABLE														
TETCO USAGE STX TO M3	Dth	132,211	139,022	139,022	125,568	139,022	132,211	136,618	132,211	136,618	136,618	132,211	136,618	1,617,946
ALGONQUIN USAGE	Dth	122,348	127,080	127,080	114,782	127,080	122,348	126,426	122,348	126,426	126,426	122,348	126,426	1,491,115
PURCHASE VOLUMES	Dth	132,211	139,022	139,022	125,568	139,022	132,211	136,618	132,211	136,618	136,618	132,211	136,618	1,617,946
DELIVERED VOLUMES	Dth	121,320	125,364	125,364	113,232	125,364	121,320	125,364	121,320	125,364	125,364	121,320	125,364	1,476,060
TETCO STX M1 TO M3 FUEL	%	7.46%	8.59%	8.59%	8.59%	8.59%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	
ALGONQUIN AFT-E FUEL	%	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$27,753	$27,896	$27,896	$27,896	$27,896	$27,753	$27,753	$27,753	$27,753	$27,753	$27,753	$27,753	$333,604
TECCO WLA SUPPLY ZONE DEMAND	$	$11,521	$11,581	$11,581	$11,581	$11,581	$11,521	$11,521	$11,521	$11,521	$11,521	$11,521	$11,521	$138,491
TETCO ELA SUPPLY ZONE DEMAND	$	$9,686	$9,736	$9,736	$9,736	$9,736	$9,686	$9,686	$9,686	$9,686	$9,686	$9,686	$9,686	$116,431
TETCO STX M1 TO M3	$	$45,844	$46,081	$46,081	$46,081	$46,081	$45,844	$45,844	$45,844	$45,844	$45,844	$45,844	$45,844	$551,072
ALGONQUIN AFT-E	$	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$24,171	$290,057
VARIABLE														
TETCO USAGE STX TO M3	$	$11,145	$11,720	$11,720	$10,585	$11,720	$11,145	$11,517	$11,145	$11,517	$11,517	$11,145	$11,517	$136,393
ALGONQUIN USAGE	$	$1,603	$1,665	$1,665	$1,504	$1,665	$1,603	$1,656	$1,603	$1,656	$1,656	$1,603	$1,656	$19,534
PURCHASE COST	$	$623,730	$686,933	$705,340	$634,683	$686,391	$633,818	$655,177	$635,682	$665,492	$672,842	$657,563	$691,149	$7,948,799
TOTAL FIXED	$	$118,975	$119,465	$119,465	$119,465	$119,465	$118,975	$118,975	$118,975	$118,975	$118,975	$118,975	$118,975	$1,429,655
TOTAL VARIABLE	$	$636,478	$700,317	$718,724	$646,772	$699,775	$646,566	$668,350	$648,430	$678,665	$686,015	$670,311	$704,322	$8,104,725
DELIVERED COST AT NYMEX	$	$595,560	$645,499	$662,549	$594,694	$645,875	$604,416	$626,444	$610,725	$637,852	$643,368	$625,405	$656,281	$7,548,668
NET NON-GAS VARIABLE COST	$	$40,918	$54,818	$56,175	$52,077	$53,900	$42,150	$41,906	$37,705	$40,813	$42,647	$44,906	$48,041	$556,057
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.337**	**$0.437**	**$0.448**	**$0.460**	**$0.430**	**$0.347**	**$0.334**	**$0.311**	**$0.326**	**$0.340**	**$0.370**	**$0.383**	**$0.377**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2010 - 2011
TEXAS EASTERN WEST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 8,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	$/Dth	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	$2.83	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO WLA M1 TO M3 DEMAND	$/Dth	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE WLA TO M3	$/Dth	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	$0.081	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/04/2010 NYMEX	$/Dth	$4.91	$5.15	$5.29	$5.25	$5.15	$4.98	$5.00	$5.03	$5.09	$5.13	$5.16	$5.24	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
						BILLING UNITS								
FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	8,068	8,109	8,109	8,109	8,109	8,068	8,068	8,068	8,068	8,068	8,068	8,068	
TETCO ELA SUPPLY ZONE DEMAND	Dth	8,068	8,109	8,109	8,109	8,109	8,068	8,068	8,068	8,068	8,068	8,068	8,068	
TETCO WLA M1 TO M3 DEMAND	Dth	8,068	8,109	8,109	8,109	8,109	8,068	8,068	8,068	8,068	8,068	8,068	8,068	
ALGONQUIN AFT-E DEMAND	Dth	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	96,000
VARIABLE														
TETCO USAGE WLA TO M3	Dth	259,636	272,336	272,336	245,981	272,336	259,636	268,291	259,636	268,291	268,291	259,636	268,291	3,174,700
ALGONQUIN USAGE	Dth	242,033	251,394	251,394	227,065	251,394	242,033	250,101	242,033	250,101	250,101	242,033	250,101	2,949,783
PURCHASE VOLUMES	Dth	259,636	272,336	272,336	245,981	272,336	259,636	268,291	259,636	268,291	268,291	259,636	268,291	3,174,700
DELIVERED VOLUMES	Dth	240,000	248,000	248,000	224,000	248,000	240,000	248,000	240,000	248,000	248,000	240,000	248,000	2,920,000
						FUEL USE %								
TETCO WLA M1 TO M3 FUEL	%	6.78%	7.69%	7.69%	7.69%	7.69%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	
ALGONQUIN AFT-E FUEL	%	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
FIXED														
TETCO WLA SUPPLY ZONE	$	$22,791	$22,909	$22,909	$22,909	$22,909	$22,791	$22,791	$22,791	$22,791	$22,791	$22,791	$22,791	$273,969
TETCO ELA SUPPLY ZONE DEMAND	$	$19,161	$19,260	$19,260	$19,260	$19,260	$19,161	$19,161	$19,161	$19,161	$19,161	$19,161	$19,161	$230,328
TETCO WLA M1 TO M3	$	$90,690	$91,159	$91,159	$91,159	$91,159	$90,690	$90,690	$90,690	$90,690	$90,690	$90,690	$90,690	$1,090,153
ALGONQUIN AFT-E	$	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$47,817	$573,802
VARIABLE														
TETCO USAGE WLA TO M3	$	$20,901	$21,923	$21,923	$19,801	$21,923	$20,901	$21,597	$20,901	$21,597	$21,597	$20,901	$21,597	$255,563
ALGONQUIN USAGE	$	$3,171	$3,293	$3,293	$2,975	$3,293	$3,171	$3,276	$3,171	$3,276	$3,276	$3,171	$3,276	$38,642
PURCHASE COST	$	$1,257,341	$1,383,687	$1,420,643	$1,275,315	$1,384,450	$1,274,581	$1,320,448	$1,286,447	$1,344,191	$1,356,426	$1,319,576	$1,385,401	$16,008,506
TOTAL FIXED	$	$180,459	$181,145	$181,145	$181,145	$181,145	$180,459	$180,459	$180,459	$180,459	$180,459	$180,459	$180,459	$2,168,251
TOTAL VARIABLE	$	$1,281,413	$1,408,904	$1,445,860	$1,298,091	$1,409,666	$1,298,653	$1,345,321	$1,310,518	$1,369,065	$1,381,299	$1,343,648	$1,410,275	$16,302,712
DELIVERED VOLUMES AT NYMEX	$	$1,178,160	$1,276,952	$1,310,680	$1,176,448	$1,277,696	$1,195,680	$1,239,256	$1,208,160	$1,261,824	$1,272,736	$1,237,200	$1,298,280	$14,933,072
NET NON-GAS VARIABLE COST	$	$103,253	$131,952	$135,180	$121,643	$131,970	$102,973	$106,065	$102,358	$107,241	$108,563	$106,448	$111,995	$1,369,640
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.43**	**$0.53**	**$0.55**	**$0.54**	**$0.53**	**$0.43**	**$0.43**	**$0.43**	**$0.43**	**$0.44**	**$0.44**	**$0.45**	**$0.47**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2010 - 2011
TEXAS EASTERN EAST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 5,500

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
						UNIT PRICING								
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	
TETCO ELA M1 TO M3 DEMAND	$/Dth	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	$11.24	
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
TETCO USAGE ELA TO M3	$/Dth	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	$0.079	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/04/2010 NYMEX	$/Dth	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth	[redacted]												
						BILLING UNITS								
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	5,547	5,575	5,575	5,575	5,575	5,547	5,547	5,547	5,547	5,547	5,547	5,547	
TETCO ELA M1 TO M3 DEMAND	Dth	5,547	5,575	5,575	5,575	5,575	5,547	5,547	5,547	5,547	5,547	5,547	5,547	
ALGONQUIN AFT-E DEMAND	Dth	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	66,000
VARIABLE														
TETCO USAGE ELA TO M3	Dth	177,908	186,424	186,424	168,383	186,424	177,908	183,839	177,908	183,839	183,839	177,908	183,839	2,174,642
ALGONQUIN USAGE	Dth	166,398	172,833	172,833	156,107	172,833	166,398	171,944	166,398	171,944	171,944	166,398	171,944	2,027,975
PURCHASE VOLUMES	Dth	177,908	186,424	186,424	168,383	186,424	177,908	183,839	177,908	183,839	183,839	177,908	183,839	2,174,642
DELIVERED VOLUMES	Dth	165,000	170,500	170,500	154,000	170,500	165,000	170,500	165,000	170,500	170,500	165,000	170,500	2,007,500
						FUEL USE %								
TETCO ELA M1 TO M3 FUEL	%	6.47%	7.29%	7.29%	7.29%	7.29%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	
ALGONQUIN AFT-E FUEL	%	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
FIXED														
TETCO ELA SUPPLY ZONE	$	$13,173	$13,241	$13,241	$13,241	$13,241	$13,173	$13,173	$13,173	$13,173	$13,173	$13,173	$13,173	$158,350
TETCO ELA M1 TO M3	$	$62,349	$62,672	$62,672	$62,672	$62,672	$62,349	$62,349	$62,349	$62,349	$62,349	$62,349	$62,349	$749,480
ALGONQUIN AFT-E	$	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$32,874	$394,489
VARIABLE														
TETCO USAGE ELA TO M3	$	$14,037	$14,709	$14,709	$13,285	$14,709	$14,037	$14,505	$14,037	$14,505	$14,505	$14,037	$14,505	$171,579
ALGONQUIN USAGE	$	$2,180	$2,264	$2,264	$2,045	$2,264	$2,180	$2,252	$2,180	$2,252	$2,252	$2,180	$2,252	$26,566
PURCHASE COST	$	$868,567	$954,116	$979,357	$879,428	$954,619	$880,504	$912,152	$888,599	$928,422	$936,805	$911,336	$956,678	$11,050,584
TOTAL FIXED	$	$108,396	$108,787	$108,787	$108,787	$108,787	$108,396	$108,396	$108,396	$108,396	$108,396	$108,396	$108,396	$1,302,319
TOTAL VARIABLE	$	$884,783	$971,089	$996,330	$894,759	$971,592	$896,721	$928,910	$904,816	$945,180	$953,563	$927,553	$973,436	$11,248,730
DELIVERED VOLUMES AT NYMEX	$	$809,985	$877,905	$901,093	$808,808	$878,416	$822,030	$851,989	$830,610	$867,504	$875,006	$850,575	$892,568	$10,266,487
NET NON-GAS VARIABLE COST	$	$74,798	$93,184	$95,238	$85,951	$93,176	$74,691	$76,921	$74,206	$77,676	$78,557	$76,978	$80,868	$982,243
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.453**	**$0.547**	**$0.559**	**$0.558**	**$0.546**	**$0.453**	**$0.451**	**$0.450**	**$0.456**	**$0.461**	**$0.467**	**$0.474**	**$0.489**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

National Grid
Rhode Island - Gas

Gas Year 2010 - 2011
MAUMEE/DOWNINGTON COLUMBIA PATH TO CITY GATE
CITY GATE DELIVERED MDQ = 1,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
					UNIT PRICING									
FIXED														
COLUMBIA FTS DEMAND	$/Dth	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	
ALGONQUIN DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
COLUMBIA USAGE	$/Dth	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	
ALGONQUIN USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/04/2010 NYMEX	$/Dth	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
SUPPLY BASIS MAUMEE	$/Dth	[redacted]												
SUPPLY BASIS DOWNINGTON	$/Dth	[redacted]												
NET COST AFTER BASIS MAUMEE	$/Dth	[redacted]												
NET COST AFTER BASIS DOWNINGTON	$/Dth	[redacted]												
					BILLING UNITS									
FIXED														
COLUMBIA FTS DEMAND	Dth	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	
ALGONQUIN DEMAND	Dth	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
VARIABLE														
COLUMBIA USAGE	Dth	30,254	31,424	31,424	28,383	31,424	30,254	31,263	30,254	31,263	31,263	30,254	31,263	
ALGONQUIN USAGE	Dth	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	
PURCHASE VOLUMES MAUMEE	Dth	25,212	26,187	26,187	23,653	26,187	25,212	26,052	25,212	26,052	26,052	25,212	26,052	
PURCHASE VOLUMES DOWNINGTON	Dth	5,042	5,237	5,237	4,731	5,237	5,042	5,210	5,042	5,210	5,210	5,042	5,210	
DELIVERED VOLUMES MAUMEE	Dth	25,000	25,833	25,833	23,333	25,833	25,000	25,833	25,000	25,833	25,833	25,000	25,833	304,167
DELIVERED VOLUMES DOWNINGTON	Dth	5,000	5,167	5,167	4,667	5,167	5,000	5,167	5,000	5,167	5,167	5,000	5,167	60,833
					FUEL USE %									
COLUMBIA FUEL	%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
ALGONQUIN AFT-E FUEL	%	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
FIXED														
COLUMBIA FTS DEMAND	$	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$6,203	$74,435
ALGONQUIN DEMAND	$	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$5,977	$71,725
VARIABLE														
COLUMBIA USAGE	$	$741	$770	$770	$695	$770	$741	$766	$741	$766	$766	$741	$766	$9,034
ALGONQUIN USAGE	$	$393	$406	$406	$367	$406	$393	$406	$393	$406	$406	$393	$406	$4,782
PURCHASE COST MAUMEE	$	$126,916	$138,751	$142,420	$127,601	$138,950	$128,482	$133,345	$130,305	$135,953	$136,902	$132,737	$139,163	$1,611,525
PURCHASE COST DOWNINGTON	$	$26,820	$31,101	$33,479	$29,905	$29,521	$26,802	$27,776	$27,260	$28,392	$28,535	$27,535	$28,818	$345,943
TOTAL FIXED	$	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$12,180	$146,160
TOTAL VARIABLE	$	$154,871	$171,028	$177,075	$158,568	$169,647	$156,418	$162,293	$158,699	$165,517	$166,609	$161,407	$169,153	$1,971,284
DELIVERED VOLUMES AT NYMEX	$	$147,270	$159,619	$163,835	$147,056	$159,712	$149,460	$154,907	$151,020	$157,728	$159,092	$154,650	$162,285	$1,866,634
NET NON-GAS VARIABLE COST	$	$7,601	$11,409	$13,240	$11,512	$9,935	$6,958	$7,386	$7,679	$7,789	$7,517	$6,757	$6,868	$104,650
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.253**	**$0.368**	**$0.427**	**$0.411**	**$0.320**	**$0.232**	**$0.238**	**$0.256**	**$0.251**	**$0.242**	**$0.225**	**$0.222**	**$0.287**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2010 - 2011
TENNESSEE ZONE 1 TO CITY GATE
CITY GATE DELIVERED MDQ = 8,000

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$/Dth	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	$0.152	
08/04/2010 NYMEX	$/Dth	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	Dth	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	96,000
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	Dth	260,360	269,039	269,039	243,003	269,039	257,152	265,724	257,152	265,724	265,724	257,152	265,724	3,144,831
PURCHASE VOLUMES	Dth	260,360	269,039	269,039	243,003	269,039	257,152	265,724	257,152	265,724	265,724	257,152	265,724	3,144,831
DELIVERED VOLUMES	Dth	240,000	248,000	248,000	224,000	248,000	240,000	248,000	240,000	248,000	248,000	240,000	248,000	2,920,000
TENNESSEE ZONE 1 TO 6 FUEL	%	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	
						TRANSPORTATION COST								
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	$	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$1,497,456
VARIABLE														
TENNESSEE ZONE 1 TO 6 USAGE	$	$39,627	$40,948	$40,948	$36,985	$40,948	$39,139	$40,443	$39,139	$40,443	$40,443	$39,139	$40,443	$478,643
PURCHASE COST	$	$1,264,413	$1,369,381	$1,405,567	$1,262,327	$1,370,107	$1,265,779	$1,311,028	$1,276,760	$1,334,199	$1,346,290	$1,310,241	$1,375,546	$15,891,637
TOTAL FIXED	$	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$124,788	$1,497,456
TOTAL VARIABLE	$	$1,304,040	$1,410,328	$1,446,514	$1,299,312	$1,411,055	$1,304,918	$1,351,471	$1,315,898	$1,374,642	$1,386,733	$1,349,380	$1,415,989	$16,370,280
DELIVERED VOLUMES AT NYMEX	$	$1,178,160	$1,276,952	$1,310,680	$1,176,448	$1,277,696	$1,195,680	$1,239,256	$1,208,160	$1,261,824	$1,272,736	$1,237,200	$1,298,280	$14,933,072
NET NON-GAS VARIABLE COST	$	$125,880	$133,376	$135,834	$122,864	$133,359	$109,238	$112,215	$107,738	$112,818	$113,997	$112,180	$117,709	$1,437,208
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.524**	**$0.538**	**$0.548**	**$0.548**	**$0.538**	**$0.455**	**$0.452**	**$0.449**	**$0.455**	**$0.460**	**$0.467**	**$0.475**	**$0.492**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2010 - 2011
ALGONQUIN LAMBERTVILLE TO CITY GATE
CITY GATE DELIVERED MDQ = 2,714

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
FIXED														
ALGONQUIN AFT-E DEMAND	$/Dth	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	$5.98	
VARIABLE														
ALGONQUIN AFT-E USAGE	$/Dth	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	
08/04/2010 NYMEX	$/Dth	$4.909	$5.149	$5.285	$5.252	$5.152	$4.982	$4.997	$5.034	$5.088	$5.132	$5.155	$5.235	
SUPPLY AREA BASIS	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													
						BILLING UNITS								
FIXED														
ALGONQUIN AFT-E DEMAND	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	32,568
VARIABLE														
ALGONQUIN AFT-E USAGE	Dth	82,110	85,285	85,285	77,032	85,285	82,110	84,847	82,110	84,847	84,847	82,110	84,847	1,000,714
PURCHASE VOLUMES	Dth	82,110	85,285	85,285	77,032	85,285	82,110	84,847	82,110	84,847	84,847	82,110	84,847	1,000,714
DELIVERED VOLUMES	Dth	81,420	84,134	84,134	75,992	84,134	81,420	84,134	81,420	84,134	84,134	81,420	84,134	990,610
ALGONQUIN AFT-E FUEL	%	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
						TRANSPORTATION COST								
FIXED														
ALGONQUIN AFT-E DEMAND	$	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$194,662
VARIABLE														
ALGONQUIN AFT-E USAGE	$	$1,076	$1,117	$1,117	$1,009	$1,117	$1,076	$1,111	$1,076	$1,111	$1,111	$1,076	$1,111	$13,109
PURCHASE COST	$	$436,742	$506,441	$545,170	$486,973	$480,719	$436,446	$452,301	$443,902	$462,330	$464,663	$448,385	$469,270	$5,633,341
TOTAL FIXED	$	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$16,222	$194,662
TOTAL VARIABLE	$	$437,817	$507,559	$546,287	$487,982	$481,837	$437,522	$453,412	$444,977	$463,441	$465,775	$449,460	$470,382	$5,646,450
DELIVERED VOLUMES AT NYMEX	$	$399,691	$433,206	$444,648	$399,110	$433,458	$405,634	$420,418	$409,868	$428,074	$431,776	$419,720	$440,441	$5,066,045
NET NON-GAS VARIABLE COST	$	$38,126	$74,353	$101,639	$88,872	$48,378	$31,887	$32,995	$35,109	$35,367	$33,999	$29,740	$29,940	$580,406
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.468**	**$0.884**	**$1.208**	**$1.169**	**$0.575**	**$0.392**	**$0.392**	**$0.431**	**$0.420**	**$0.404**	**$0.365**	**$0.356**	**$0.586**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2010 - 2011 GCR PROJECTED PRICES**

August 1, 2010 Update **UNIT PRICES**

		NOV 2010	DEC	JAN 2011	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST UNIT PRICES													
ALGONQUIN AFT-E/AFT-1 DEMAND	$/Dth	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977	$5.977
ALGONQUIN AFT-3 DEMAND	$/Dth	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755	$10.755
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391	$2.391
TEXAS EASTERN STX CDS DEMAND M3	$/Dth	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805	$6.805
TEXAS EASTERN WLA CDS DEMAND M3	$/Dth	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825	$2.825
TEXAS EASTERN ELA CDS DEMAND M3	$/Dth	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375	$2.375
TEXAS EASTERN ETX CDS DEMAND M3	$/Dth	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189	$2.189
TETCO FTS DEMAND	$/Dth	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350	$5.350
TETCO M1 TO M3 DEMAND M3	$/Dth	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241	$11.241
TETCO SCT STX DEMAND	$/Dth	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722
TETCO SCT WLA DEMAND	$/Dth	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130
TETCO SCT ELA DEMAND	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-3	$/Dth	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497	$4.497
TETCO SCT STX DEMAND M2	$/Dth	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722	$2.722
TETCO SCT WLA DEMAND M2	$/Dth	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130	$1.130
TETCO SCT ELA DEMAND M2	$/Dth	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950	$0.950
TETCO SCT ETX DEMAND M2	$/Dth	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876	$0.876
TETCO SCT DEMAND 1-2	$/Dth	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415	$3.415
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654	$15.654
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599	$15.599
TENNESSEE DRACUT	$/Dth	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160	$3.160
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930	$4.930
TENNESSEE CONNEXION	$/Dth	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737	$22.737
NETNE	$/Dth	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610	$10.610
IROQUOIS	$/Dth	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597	$6.597
NOVA	$/Dth	$4.515	$4.666	$4.666	$4.214	$4.666	$4.515	$4.666	$4.515	$4.666	$4.666	$4.515	$4.666
TRANSCANADA	$/Dth	$30.150	$31.155	$31.155	$28.140	$31.155	$30.150	$31.155	$30.150	$31.155	$31.155	$30.150	$31.155
DOMINION FTNN DEMAND	$/Dth	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346	$4.346
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462	$0.462
TRANSCO DEMAND ZONE 3 TO 6.	$/Dth	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435	$0.435
TRANSCO DEMAND ZONE 6	$/Dth	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119	$0.119
NATIONAL FUEL DEMAND	$/Dth	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557	$3.557
COLUMBIA FTS DEMAND	$/Dth	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075	$6.075
HUBLINE	$/Dth	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558	$11.558
HUBLINE	$/Dth	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996	$6.996
HUBLINE	$/Dth	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992	$6.992
EAST TO WEST	$/Dth	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446	$8.446
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS FCS	$/Dth	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2010 - 2011 GCR PROJECTED PRICES**

August 1, 2010 Update

UNIT PRICES

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	DTH	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950	86,950
ALGONQUIN AFT-3 DEMAND	DTH	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	DTH	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414	4,414
TEXAS EASTERN STX CDS DEMAND M3	DTH	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN WLA CDS DEMAND M3	DTH	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN ELA CDS DEMAND M3	DTH	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN ETX CDS DEMAND M3	DTH	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TETCO M1 TO M3 DEMAND M3	DTH	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TETCO FTS DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
TETCO SCT STX DEMAND	DTH	571	571	571	571	571	571	571	571	571	571	571	571
TETCO SCT WLA DEMAND	DTH	648	648	648	648	648	648	648	648	648	648	648	648
TETCO SCT ELA DEMAND	DTH	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TETCO SCT ETX DEMAND	DTH	329	329	329	329	329	329	329	329	329	329	329	329
TETCO SCT DEMAND 1-3	DTH	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TETCO SCT STX DEMAND M2	DTH	401	401	401	401	401	401	401	401	401	401	401	401
TETCO SCT WLA DEMAND M2	DTH	455	455	455	455	455	455	455	455	455	455	455	455
TETCO SCT ELA DEMAND M2	DTH	831	831	831	831	831	831	831	831	831	831	831	831
TETCO SCT ETX DEMAND M2	DTH	231	231	231	231	231	231	231	231	231	231	231	231
TETCO SCT DEMAND 1-2	DTH	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	DTH	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
TENNESSEE FT-A DEMAND ZONE 0 TO 6	DTH	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	DTH	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE DRACUT	DTH	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TENNESSEE FT-A DEMAND ZONE 5 TO 6	DTH	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
TENNESSEE CONNEXION	DTH	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
NETNE	DTH	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
IROQUOIS	DTH	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NOVA	DTH	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
TRANSCANADA	DTH	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
DOMINION FTNN DEMAND	DTH	537	537	537	537	537	537	537	537	537	537	537	537
TRANSCO DEMAND ZONE 2 TO 6	DTH	4,140	4,278	4,278	3,864	4,278	4,140	4,278	4,140	4,278	4,278	4,140	4,278
TRANSCO DEMAND ZONE 3 TO 6.	DTH	90	93	93	84	93	90	93	90	93	93	90	93
TRANSCO DEMAND ZONE 6	DTH	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
NATIONAL FUEL DEMAND	DTH	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
COLUMBIA FTS DEMAND	DTH	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
HUBLINE	DTH	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
HUBLINE	DTH	500	500	500	500	500	500	500	500	500	500	500	500
HUBLINE	DTH	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
EAST TO WEST	Dth	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS FCS	DTH	0	0	0	0	0	0	0	0	0	0	0	0

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2010 - 2011 GCR PROJECTED PRICES**

August 1, 2010 Update

		UNIT PRICES												
		NOV	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	
PIPELINE FIXED COST DOLLARS														
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	$519,709	
ALGONQUIN AFT-3 DEMAND	$	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	$118,987	
ALGONQUIN AFT-ES/1S DEMAND	$	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	$10,553	
TEXAS EASTERN STX CDS DEMAND M3	$	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	$94,208	
TEXAS EASTERN WLA CDS DEMAND M3	$	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	$44,398	
TEXAS EASTERN ELA CDS DEMAND M3	$	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	
TEXAS EASTERN ETX CDS DEMAND M3	$	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	
TETCO FTS DEMAND	$	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	
TETCO M1 TO M3 DEMAND M3	$	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	$516,344	
TETCO SCT STX DEMAND	$	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	
TETCO SCT WLA DEMAND	$	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	$732	
TETCO SCT ELA DEMAND	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TETCO SCT ETX DEMAND	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TETCO SCT DEMAND 1-3	$	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	$9,439	
TETCO SCT STX DEMAND M2	$	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	$1,092	
TETCO SCT WLA DEMAND M2	$	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	$514	
TETCO SCT ELA DEMAND M2	$	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	$789	
TETCO SCT ETX DEMAND M2	$	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	$202	
TETCO SCT DEMAND 1-2	$	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	$5,034	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	$54,789	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	$101,751	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	$93,934	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	$207,663	
TENNESSEE DRACUT	$	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	$47,400	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	$5,260	
TENNESSEE CONNEXION	$	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	$263,743	
NETNE	$	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	$10,610	
IROQUOIS	$	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	$6,676	
NOVA	$	$4,858	$5,020	$5,020	$4,534	$5,020	$4,858	$5,020	$4,858	$5,020	$5,020	$4,858	$5,020	
TRANSCANADA	$	$30,813	$31,840	$31,840	$28,759	$31,840	$30,813	$31,840	$30,813	$31,840	$31,840	$30,813	$31,840	
DOMINION FTNN DEMAND	$	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	$2,334	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,911	$1,975	$1,975	$1,784	$1,975	$1,911	$1,975	$1,911	$1,975	$1,975	$1,911	$1,975	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$40	$40	$37	$40	$39	$40	$39	$40	$40	$39	$40	
TRANSCO DEMAND ZONE 6	$	$4,424	$4,571	$4,571	$4,129	$4,571	$4,424	$4,571	$4,424	$4,571	$4,571	$4,424	$4,571	
NATIONAL FUEL DEMAND	$	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	$4,187	
COLUMBIA FTS DEMAND	$	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	$288,289	
HUBLINE	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
HUBLINE	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
HUBLINE	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
EAST TO WEST	$	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	$84,461	
WESTERLY LATERAL (Yankee)	$	$58,879	$58,879	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	$57,637	
	$	**$2,747,993**	**$2,749,395**	**$2,748,152**	**$2,743,948**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$32,970,500**
SUPPLIER FIXED COST DOLLARS														
DISTRIGAS FCS	$	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
TOTAL PIPELINE FIXED DEMAND CHARGES		**$2,747,993**	**$2,749,395**	**$2,748,152**	**$2,743,948**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$2,748,152**	**$2,746,751**	**$2,748,152**	**$32,970,500**
TOTAL DEMAND UNITS DTH		5,342,280	5,554,053	5,554,053	5,016,564	5,554,053	5,342,280	5,486,659	4,854,210	5,016,017	5,016,017	4,854,210	5,486,659	**63,077,055**
100% LOAD FACTOR UNIT VALUE $/DTH														[redacted]
Average rate per unit per month														
AVERAGE SYSTEM VARIABLE UNIT VALUE $/DTH														
TOTAL AVERAGE SYSTEM UNIT VALUE $/DTH														

National Grid
2010 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 30-Aug-2010
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Natural Gas Supply VS. Requirements Units: MDT

	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	OCT 2011	Total/Average
Forecast Demand													
RI Sales GCR	2,421,900	3,845,700	4,610,300	3,931,200	3,481,200	1,990,000	998,400	735,000	697,000	620,700	646,300	1,127,200	25,104,900
Total Demand	2,421,900	3,845,700	4,610,300	3,931,200	3,481,200	1,990,000	998,400	735,000	697,000	620,700	646,300	1,127,200	25,104,900
Storage Injections													
TENN_501	0	0	0	0	0	119,300	123,300	119,300	123,300	120,300	0	0	605,500
GSS 300170	0	0	0	0	0	24,500	0	0	0	0	0	0	24,500
GSS 300168	0	0	0	0	0	25,000	25,900	25,000	25,900	25,900	0	0	127,700
GSS 300171	0	0	0	0	0	15,700	16,200	15,700	16,200	16,200	15,700	16,200	111,900
GSSTE 600045	0	0	0	0	0	223,500	231,000	223,500	0	0	0	0	678,000
TETCO_400515	0	0	0	0	0	8,600	8,900	8,600	8,900	8,900	8,600	0	52,500
TETCO_400221	0	0	0	0	0	180,900	186,900	180,900	186,900	186,900	161,300	0	1,083,800
TETCO 400185	0	0	0	0	0	7,900	8,200	7,900	8,200	3,000	0	0	35,200
GSS 300169	0	0	0	0	0	33,500	34,600	33,500	34,600	21,600	0	0	157,800
COL FSS 9630	0	0	0	0	0	60,100	78,800	65,100	0	0	0	0	204,000
TENN_62918	0	0	0	0	0	41,400	42,800	41,400	42,800	41,700	0	0	210,100
Total Underground Storage	0	0	0	0	0	740,400	756,600	720,900	446,800	424,500	185,600	16,200	3,291,000
LNG PROV	10,900	0	0	0	0	66,900	70,100	10,900	11,300	11,300	10,900	11,300	203,600
LNG VALLEY	3,000	0	0	0	0	0	17,300	16,300	3,100	3,100	3,000	3,100	48,900
LNG EXETER	4,900	0	0	0	0	23,100	5,600	6,100	5,100	5,100	4,900	5,100	59,900
Total LNG Injection	18,800	0	0	0	0	90,000	93,000	33,300	19,500	19,500	18,800	19,500	312,400
Total Injections	18,800	0	0	0	0	830,400	849,600	754,200	466,300	444,000	204,400	35,700	3,603,400

Delivered Firm Sales Supply

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENN_CONX	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	4,234,000
TENN_ZONE_0	81,183	187,459	171,829	172,645	185,730	75,538	56,939	41,146	38,438	32,141	0	0	1,043,049
TENN_ZONE_1	167,617	387,041	354,771	356,455	383,470	155,962	117,561	84,954	79,362	66,359	0	0	2,153,551
TENN_NIAGARA	0	3,200	3,400	1,100	21,800	0	0	0	0	0	0	0	29,500
TENN_DRACUT	0	45,000	120,400	60,100	0	425,900	2,300	0	0	75,000	62,400	4,300	795,400
COL_MAUMEE	689,325	883,650	883,650	798,075	883,650	662,250	482,250	180,000	250,950	0	11,700	443,025	6,168,525
COL_BROADRUN	229,775	294,550	294,550	266,025	294,550	220,750	160,750	60,000	83,650	0	3,900	147,675	2,056,175
TRANSCO Z2	3,915	4,013	4,013	3,621	4,013	2,740	1,468	0	4,013	0	0	0	27,796
TRANSCO Z3	85	87	87	79	87	60	32	0	87	0	0	0	604
TETCO_ELA	269,427	273,583	327,270	293,067	271,981	179,249	185,236	179,249	97,155	90,254	70,769	6,177	2,243,417
TETCO_ETX	80,713	81,958	98,041	87,795	81,478	53,698	55,492	53,698	29,105	27,038	21,201	1,850	672,068
TETCO_STX	120,301	122,157	146,128	130,857	121,442	80,036	82,709	80,036	43,380	40,299	31,599	2,758	1,001,701
TETCO_WLA	185,163	188,019	224,916	201,410	186,919	123,189	127,303	123,189	66,770	62,027	48,636	4,245	1,541,784
TETCO to B&W - SCT	29,958	30,421	36,390	32,587	30,243	19,931	20,597	19,931	10,803	10,036	7,869	687	249,453
TETCO - NF - TRANSCO	13,202	13,406	16,037	14,361	13,327	8,783	9,077	8,783	4,761	4,423	3,468	303	109,931
TETCO - DTI - TETCO	7,836	7,957	9,518	8,523	7,910	5,213	5,387	5,213	2,826	2,625	2,058	180	65,245
M3_DELIVERED	146,600	119,900	12,900	4,800	419,300	50,100	0	0	0	0	0	0	753,600
HUBLINE	0	72,600	271,000	184,700	200	270,200	37,700	222,800	22,200	225,000	171,400	122,000	1,599,800
COL_EAGLE	0	10,237	2,125	290	0	0	0	0	0	0	0	0	12,652
COL_DOWNINGTOWN	0	10,963	2,275	310	0	0	0	0	0	0	0	0	13,548
ANE II - AECO-TENN - CONOCO P	30,000	30,900	30,900	28,000	30,900	30,000	30,900	30,000	30,900	30,900	30,000	30,900	364,300
DISTRI FLS Winter	18,900	0	0	0	0	0	0	0	0	0	0	0	18,900
DISTRI FLS Summer	0	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	293,800
DIST FCS VAP	0	0	0	0	0	0	0	0	0	0	0	0	0
DIST FCS LIQ	0	0	0	0	0	0	0	0	0	0	0	0	0
NEWPORT_LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
SPOT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
Non LNG Liquid take	2,403,100	3,126,700	3,369,800	2,969,600	3,296,600	2,711,600	1,735,300	1,437,000	1,124,000	1,025,700	813,000	1,123,700	25,136,100
LNG Liquid take	18,900	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	312,700
Total take	2,422,000	3,126,700	3,369,800	2,969,600	3,296,600	2,801,600	1,828,300	1,470,400	1,143,500	1,045,200	831,900	1,143,200	25,448,800
Storage Withdrawals													
TENN 501	0	141,700	240,800	171,000	9,100	0	0	0	0	0	0	0	562,600
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,200	42,500	38,400	18,300	0	0	0	0	0	0	0	117,400
GSS 300171	0	0	71,100	28,600	0	0	0	0	0	0	0	0	99,700
GSSTE 600045	0	141,500	165,700	149,600	134,400	0	0	0	0	0	0	0	591,200
TETCO_400515	0	2,400	24,800	19,500	0	0	0	0	0	0	0	0	46,700
TETCO_400221	0	224,100	404,200	346,100	0	0	0	0	0	0	0	0	974,400
TETCO 400185	0	0	17,700	13,300	0	0	0	0	0	0	0	0	31,000
GSS 300169	0	35,700	55,400	50,000	0	0	0	0	0	0	0	0	141,100
COL FSS 9630	0	43,400	76,200	67,100	400	0	0	0	0	0	0	0	187,100
TENN_62918	0	9,700	122,600	60,200	2,700	0	0	0	0	0	0	0	195,200
LNG PROV	10,900	82,000	11,300	10,200	11,300	10,900	11,300	10,900	11,300	11,300	10,900	11,300	203,600
LNG VALLEY	3,000	15,500	3,100	2,800	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	48,900
LNG EXETER	4,900	5,100	5,100	4,600	5,100	4,900	5,100	4,900	5,100	5,100	4,900	5,100	59,900
Total Withdrawal Delivered	18,800	719,300	1,240,500	961,400	184,400	18,800	19,500	18,800	19,500	19,500	18,800	19,500	3,258,800
Total Storage withdrawal	0	616,700	1,221,000	943,800	164,900	0	0	0	0	0	0	0	2,946,400
Total Peaking withdrawal	18,800	102,600	19,500	17,600	19,500	18,800	19,500	18,800	19,500	19,500	18,800	19,500	312,400
Total Supply	**2,421,900**	**3,846,000**	**4,610,300**	**3,931,000**	**3,481,000**	**2,730,400**	**1,754,800**	**1,455,800**	**1,143,500**	**1,045,200**	**831,800**	**1,143,200**	**28,394,900**
Storage withdrawals at Storage Facilty													
TENN 501	0	144,843	246,141	174,793	9,302	0	0	0	0	0	0	0	575,079
GSS 300170	0	0	0	0	0	0	0	0	0	0	0	0	0
GSS 300168	0	18,604	43,443	39,252	18,706	0	0	0	0	0	0	0	120,004
GSS 300171	0	0	73,015	29,370	0	0	0	0	0	0	0	0	102,385
GSSTE 600045	0	145,621	170,525	153,957	138,314	0	0	0	0	0	0	0	608,417
TETCO_400515	0	2,546	26,310	20,687	0	0	0	0	0	0	0	0	49,544
TETCO_400221	0	234,458	422,883	362,098	0	0	0	0	0	0	0	0	1,019,439
TETCO 400185	0	0	18,518	13,915	0	0	0	0	0	0	0	0	32,433
GSS 300169	0	37,250	57,806	52,171	0	0	0	0	0	0	0	0	147,227
COL FSS 9630	0	43,994	77,243	68,018	405	0	0	0	0	0	0	0	189,660
TENN_62918	0	9,915	125,319	61,535	2,760	0	0	0	0	0	0	0	199,530
	0	637,231	1,261,203	975,796	169,487	0	0	0	0	0	0	0	3,043,718

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Natural Gas Supply VS. Requirements | Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
08/04/2010 NYMEX	**$4.909**	**$5.149**	**$5.285**	**$5.252**	**$5.152**	**$4.982**	**$4.997**	**$5.034**	**$5.088**	**$5.132**	**$5.155**	**$5.235**	
TENNESSEE CONNEXION													
Basis	[redacted]												
usage to Zn 6	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
fuel to Zn 6	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	$0.1627	
fuel	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	
Total Delivered	[redacted]												
TENNESSEE ZN 1													
Basis	[redacted]												
usage to Zn 6	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	$0.1522	
fuel to Zn 6	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	
Total Delivered	[redacted]												
TENNESSEE DRACUT													
Basis	[redacted]												
usage	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	$0.0661	
fuel	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.47%	7.29%	7.29%	7.29%	7.29%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO ETX													
Basis	[redacted]												
Usage to M3	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	$0.0789	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.47%	7.29%	7.29%	7.29%	7.29%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	6.47%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO STX													
Basis	[redacted]												
Usage to M3	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	$0.0843	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	7.46%	8.59%	8.59%	8.59%	8.59%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	$0.0805	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel to M3	6.78%	7.69%	7.69%	7.69%	7.69%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	6.78%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TETCO -> NF -> TRANSCO													
Basis	[redacted]												
Usage to M2	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	
Usage on NF	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	$0.0088	
Usage on Transco	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	$0.0079	
Usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
Fuel to M2	5.72%	6.33%	6.33%	6.33%	6.33%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	
Fuel on NF	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	
Fuel on Transco	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Delivered to NF	[redacted]												
Delivered to Transco	[redacted]												
Delivered to Algonquin	[redacted]												
Total Delivered	[redacted]												
M3 DELIVERED													
Basis	[redacted]												
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA MAUMEE													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA BROADRUN													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA EAGLE													
Basis	[redacted]												
Usage on Columbia	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Usage on AGT	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	$0.0131	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
COLUMBIA DOWNINGTOWN													
Basis	[redacted]												
Usage on Columbia	$0.1979	$0.2440	$0.2467	$0.2297	$0.2438	$0.1792	$0.1422	$0.1570	$0.1530	$0.1453	$0.1265	$0.1226	
Usage on AGT	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	$0.0245	
Fuel on Columbia	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	2.06%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

National Grid
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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average

National Grid
2010 Estimated GCR
Normal Weather Scenario

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Natural Gas Supply VS. Requirements   Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO -> DTI -> TETCO													
Basis	[redacted]												
Usage to M2	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	$0.4324	
Usage on Dominion	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	$0.0251	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
Fuel to M2	5.72%	6.33%	6.33%	6.33%	6.33%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	
Fuel on Dominion	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	2.85%	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Delivered to Dominion	[redacted]												
Delivered to Tetco													
Delivered to Algonquin													
Total Delivered													
TRANSCO ZONE 2													
Basis	[redacted]												
Usage on Transco	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	$0.03696	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Transco	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	
Fuel on Tetco	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
TRANSCO ZONE 3													
Basis	[redacted]												
Usage on Transco	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	$0.03433	
Usage on Tetco	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Usage on AGT	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Transco	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	
Fuel on Tetco	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												
AECO TO TENNESSEE - ANE II													
Basis	[redacted]												
Transcanada usage	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	$0.0848	
Transcanada pressure chg	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	$0.0174	
Fuel on TCPL	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	3.550%	
Iroquois usage	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	$0.0052	
NETNE usage	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
Fuel on Iroquois	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel Tenn NET18	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Total Delivered	[redacted]												
NIAGARA TO TENNESSEE													
Basis	[redacted]												
Tenn usage	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	$0.0784	
Tenn Fuel	2.09%	2.09%	2.09%	2.09%	2.09%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	
Total Delivered	[redacted]												
Tetco to B&W - SCT													
Basis	[redacted]												
usage on Tetco	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	$0.5414	
usage on AGT	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	$0.2292	
fuel to ZN 3	6.72%	7.62%	7.62%	7.62%	7.62%	6.72%	6.72%	6.72%	6.72%	6.72%	6.72%	6.72%	
Fuel on AGT	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

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Natural Gas Supply VS. Requirements   Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
DISTRIGAS FLS													
Total Delivered	[redacted]												
Hubline													
Basis	[redacted]												
usage	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	$0.0019	
fuel	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	
Total Delivered	[redacted]												

Total delivered to the City Gate Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TENN CONNEXION													
Delivered Mmbtu	348,000	359,600	359,600	324,800	359,600	348,000	359,600	348,000	359,600	359,600	348,000	359,600	
NYMEX $/Mmbtu Del	$5.300	$5.461	$5.590	$5.528	$5.441	$5.238	$5.244	$5.266	$5.331	$5.386	$5.431	$5.521	
Total Delivered Cost	$1,844,348	$1,963,928	$2,010,291	$1,795,396	$1,956,562	$1,822,981	$1,885,767	$1,832,454	$1,917,113	$1,936,961	$1,890,003	$1,985,281	
Tennessee Zn 0													
Delivered Mmbtu	81,183	187,459	171,829	172,645	185,730	75,538	56,939	41,146	38,438	32,141	0	0	
NYMEX $/Mmbtu Del	$5.461	$5.622	$5.751	$5.688	$5.602	$5.399	$5.405	$5.426	$5.492	$5.547	$5.592	$5.682	
Total Delivered Cost	$443,314	$1,053,937	$988,217	$982,091	$1,040,410	$407,851	$307,749	$223,280	$211,103	$178,291	$0	$0	
TENN ZONE 1													
Delivered Mmbtu	167,617	387,041	354,771	356,455	383,470	155,962	117,561	84,954	79,362	66,359	0	0	
$/Mmbtu Del	$5.421	$5.674	$5.820	$5.788	$5.677	$5.426	$5.439	$5.472	$5.532	$5.581	$5.612	$5.699	
Total Delivered Cost	$908,581	$2,196,030	$2,064,696	$2,063,014	$2,176,894	$846,292	$639,366	$464,869	$439,033	$370,338	$0	$0	
TENN DRACUT													
Delivered Mmbtu	0	45,000	120,400	60,100	0	425,900	2,300	0	0	75,000	62,400	4,300	
$/Mmbtu Del	$5.98	$6.22	$6.36	$6.32	$6.22	$5.29	$5.37	$5.38	$5.49	$5.45	$5.45	$5.58	
Total Delivered Cost	$0	$279,894	$765,394	$380,060	$0	$2,253,270	$12,349	$0	$0	$408,588	$340,159	$23,999	
TETCO ELA													
Delivered Mmbtu	269,427	273,583	327,270	293,067	271,981	179,249	185,236	179,249	97,155	90,254	70,769	6,177	
$/Mmbtu Del	$5.3567	$5.6891	$5.8371	$5.8037	$5.6920	$5.4291	$5.4425	$5.4781	$5.5380	$5.5871	$5.6159	$5.7037	
Total Delivered Cost	$1,443,240	$1,556,431	$1,910,311	$1,700,861	$1,548,123	$973,154	$1,008,151	$981,948	$538,042	$504,259	$397,434	$35,232	
TETCO ETX													
Delivered Mmbtu	80,713	81,958	98,041	87,795	81,478	53,698	55,492	53,698	29,105	27,038	21,201	1,850	
NYMEX $/Mmbtu Del	$5.1535	$5.4686	$5.6133	$5.5931	$5.4640	$5.2063	$5.2089	$5.2238	$5.2913	$5.3487	$5.3995	$5.4913	
Total Delivered Cost	$415,952	$448,199	$550,335	$491,044	$445,202	$279,569	$289,050	$280,507	$154,003	$144,617	$114,473	$10,162	
TETCO STX													
Delivered Mmbtu	120,301	122,157	146,128	130,857	121,442	80,036	82,709	80,036	43,380	40,299	31,599	2,758	
NYMEX $/Mmbtu Del	$5.239	$5.578	$5.725	$5.704	$5.574	$5.322	$5.324	$5.338	$5.407	$5.465	$5.518	$5.611	
Total Delivered Cost	$630,294	$681,397	$836,568	$746,367	$676,883	$425,988	$440,368	$427,218	$234,541	$220,242	$174,369	$15,476	

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO WLA													
Delivered Mmbtu	185,163	188,019	224,916	201,410	186,919	123,189	127,303	123,189	66,770	62,027	48,636	4,245	
$/Mmbtu Del	$5.3332	$5.6741	$5.8231	$5.7881	$5.6772	$5.4050	$5.4187	$5.4545	$5.5144	$5.5637	$5.5925	$5.6806	
Total Delivered Cost	$987,512	$1,066,838	$1,309,707	$1,165,775	$1,061,167	$665,839	$689,812	$671,930	$368,196	$345,100	$271,998	$24,115	
TETCO -> NF -> TRANSCO													
Delivered Mmbtu	13,202	13,406	16,037	14,361	13,327	8,783	9,077	8,783	4,761	4,423	3,468	303	
Delivered $/Mmbtu	$6.0362	$6.3624	$6.5124	$6.4785	$6.3654	$6.1096	$6.1233	$6.1594	$6.2202	$6.2701	$6.2993	$6.3884	
Delivered Cost	$79,691	$85,294	$104,437	$93,036	$84,835	$53,664	$55,580	$54,101	$29,613	$27,730	$21,845	$1,934	
M3 DELIVERED													
Delivered Mmbtu	146,600	119,900	12,900	4,800	419,300	50,100	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.3772	$6.0326	$6.4929	$6.4213	$5.7268	$5.3735	$5.3891	$5.4651	$5.5083	$5.5360	$5.5202	$5.5908	
Delivered Cost	$788,291	$723,304	$83,758	$30,822	$2,401,262	$269,214	$0	$0	$0	$0	$0	$0	
COLUMBIA MAUMEE													
Delivered Mmbtu	689,325	883,650	883,650	798,075	883,650	662,250	482,250	180,000	250,950	0	11,700	443,025	
Delivered $/Mmbtu	$5.2213	$5.5220	$5.6670	$5.6217	$5.5299	$5.2853	$5.3082	$5.3597	$5.4113	$5.4488	$5.4591	$5.5382	
Total Delivered Cost	$3,599,197	$4,879,538	$5,007,674	$4,486,537	$4,886,489	$3,500,177	$2,559,900	$964,751	$1,357,970	$0	$63,871	$2,453,550	
COLUMBIA BROADRUN													
Delivered Mmbtu	229,775	294,550	294,550	266,025	294,550	220,750	160,750	60,000	83,650	0	3,900	147,675	
Delivered $/Mmbtu	$5.2964	$5.6198	$5.7634	$5.7116	$5.6227	$5.3523	$5.3297	$5.3830	$5.4345	$5.4719	$5.4762	$5.5545	
Total Delivered Cost	$1,216,981	$1,655,323	$1,697,608	$1,519,440	$1,656,176	$1,181,523	$856,743	$322,980	$454,595	$0	$21,357	$820,268	
COLUMBIA EAGLE													
Delivered Mmbtu	0	10,237	2,125	290	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.5148	$6.1841	$6.6541	$6.5811	$5.8720	$5.5111	$5.5270	$5.6046	$5.6487	$5.6770	$5.6608	$5.7329	
Delivered Cost	$0	$63,310	$14,138	$1,907	$0	$0	$0	$0	$0	$0	$0	$0	
COLUMBIA DOWNINGTOWN													
Delivered Mmbtu	0	10,963	2,275	310	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.7253	$6.4723	$6.9702	$6.8768	$6.1359	$5.6767	$5.6551	$5.7484	$5.7883	$5.8086	$5.7727	$5.8405	
Delivered Cost	$0	$70,953	$15,859	$2,134	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO -> DTI -> TETCO													
Delivered Mmbtu	7,836	7,957	9,518	8,523	7,910	5,213	5,387	5,213	2,826	2,625	2,058	180	
Delivered $/Mmbtu	$6.1571	$6.4896	$6.6424	$6.6079	$6.4926	$6.2319	$6.2459	$6.2827	$6.3446	$6.3955	$6.4252	$6.5160	
Delivered Cost	$48,245	$51,635	$63,222	$56,321	$51,357	$32,488	$33,648	$32,752	$17,927	$16,787	$13,224	$1,171	
TRANSCO ZONE 2													
Delivered Mmbtu	3,915	4,013	4,013	3,621	4,013	2,740	1,468	0	4,013	0	0	0	
Delivered $/Mmbtu	$5.2099	$5.4942	$5.6400	$5.6044	$5.4974	$5.3051	$5.3213	$5.3610	$5.4184	$5.4652	$5.4894	$5.5745	
Delivered Cost	$20,396	$22,047	$22,632	$20,295	$22,060	$14,538	$7,812	$0	$21,743	$0	$0	$0	
TRANSCO ZONE 3													
Delivered Mmbtu	85	87	87	79	87	60	32	0	87	0	0	0	
Delivered $/Mmbtu	$5.2670	$5.5535	$5.6991	$5.6620	$5.5569	$5.3282	$5.3444	$5.3843	$5.4413	$5.4878	$5.5117	$5.5962	
Delivered Cost	$448	$484	$497	$446	$485	$317	$171	$0	$475	$0	$0	$0	

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Natural Gas Supply VS. Requirements Units: MDT

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
AECO TO TENNESSEE - ANE II													
Delivered Mmbtu	30,000	30,900	30,900	28,000	30,900	30,000	30,900	30,000	30,900	30,900	30,000	30,900	
Delivered $/Mmbtu	$6.0732	$6.3252	$6.4680	$6.4333	$6.3283	$6.1499	$6.1656	$6.2045	$6.2612	$6.3074	$6.3315	$6.4155	
Total Delivered Cost	$182,196	$195,449	$199,861	$180,134	$195,546	$184,496	$190,517	$186,134	$193,470	$194,897	$189,945	$198,239	
NIAGARA TO TENNESSEE													
Delivered Mmbtu	0	3,200	3,400	1,100	21,800	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.6467	$5.8111	$5.8230	$5.8182	$5.7342	$5.4792	$5.5038	$5.5545	$5.6033	$5.6382	$5.6449	$5.7257	
Total Delivered Cost	$0	$18,596	$19,798	$6,400	$125,006	$0	$0	$0	$0	$0	$0	$0	
Tetco to B&W - SCT													
Delivered Mmbtu	29,958	30,421	36,390	32,587	30,243	19,931	20,597	19,931	10,803	10,036	7,869	687	
Delivered $/Mmbtu	$6.0533	$6.3940	$6.5426	$6.5090	$6.3969	$6.1259	$6.1394	$6.1751	$6.2351	$6.2844	$6.3132	$6.4012	
Total Delivered Cost	$181,349	$194,509	$238,085	$212,109	$193,460	$122,097	$126,453	$123,077	$67,358	$63,068	$49,679	$4,397	
DISTRIGAS FLS													
Delivered Mmbtu	18,900	0	0	0	0	90,000	93,000	33,400	19,500	19,500	18,900	19,500	
Delivered $/Mmbtu	[redacted]												
Total Delivered Cost													
HUBLINE													
Total Delivered Vol	0	72,600	271,000	184,700	200	270,200	37,700	222,800	22,200	225,000	171,400	122,000	
Delivered $/Mmbtu	$5.9105	$6.1844	$6.3222	$6.2888	$6.1874	$5.2259	$5.3042	$5.3177	$5.4215	$5.3831	$5.3865	$5.5165	
Total Delivered Cost	$0	$448,985	$1,713,323	$1,161,536	$1,237	$1,412,033	$199,970	$1,184,773	$120,358	$1,211,198	$923,251	$673,016	
	NOV	DEC	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	JUN	**JUL**	**AUG**	**SEP**	**OCT**	
Total Pipeline Costs	[redacted]												
Total Pipeline Volumes	2,422,000	3,126,700	3,369,800	2,969,600	3,296,600	2,801,600	1,828,300	1,470,400	1,143,500	1,045,200	831,900	1,143,200	25,448,800
WACOG	$5.319	$5.647	$5.821	$5.757	$5.619	$5.316	$5.343	$5.386	$5.444	$5.475	$5.492	$5.554	$5.549
Injections	0	0	0	0	0	740,400	756,600	720,900	446,800	424,500	185,600	16,200	3,291,000
Value at WACOG	$0	$0	$0	$0	$0	$3,936,116	$4,042,315	$3,882,441	$2,432,199	$2,324,008	$1,019,370	$89,969	$17,726,418
Pipeline Costs less Injections	$12,882,816	$17,656,080	$19,616,411	$17,095,724	$18,523,154	$10,957,756	$5,725,812	$4,036,468	$3,792,554	$3,398,143	$3,549,670	$6,258,952	$123,493,539
Pipeline Volumes less injections	2,422,000	3,126,700	3,369,800	2,969,600	3,296,600	2,061,200	1,071,700	749,500	696,700	620,700	646,300	1,127,000	22,157,800
NYMEX cost of Supplies	$11,889,598	$16,099,378	$17,809,393	$15,596,339	$16,984,083	$10,268,898	$5,355,285	$3,772,983	$3,544,810	$3,185,432	$3,331,677	$5,899,845	[redacted]
Non-gas cost of delivered supplies													

Operational Parameters
Non-Daily Metered FT-2 Storage and Peaking Resources

The following Operational Parameters are pursuant to RIPUC NG No. 101, Section 5, Schedule E:

Effective Period: November 1, 2010 through October 31, 2011

Underground Storage:

Maximum Inventory Level at any time is 100% of Aggregation Pool's MSQ-U

Minimum Inventory Levels:

November 1st	98%
December 1st	92%
January 1st	75%
February 1st	50%
March 1st	25%
April 1st	3%

Maximum Monthly Withdrawals expressed as percentage of MSQ-U:

November	10%
December	23%
January	25%
February	23%
March	22%

Maximum Daily Withdrawals:

Level of Storage Inventory Expressed as % of MSQ-U	Allowable Daily Withdrawal Expressed as % of MDQ-U
>35% to 100%	100%
>25% to 35%	85%
>10% to 25%	68%
>0% to 10%	50%

Maximum Daily Injections expressed as percentage of MDQ-U:

April - September	55%

Peaking Inventory:

Injections are not allowed.
Inventory Level allocated on November 1, 2010= MSQ-P

Minimum Inventory Levels:

	Minimum
November 1st	100%
January 1st	81%
February 1st	42%
March 1st	14%
April 1st	5%

Maximum Daily Withdrawals = MDQ-P

MSQ-U	Maximum Storage Quantity - Underground
MDQ-U	Maximum Daily Quantity - Underground
MSQ-P	Maximum Storage Quantity - Peaking
MDQ-P	Maximum Daily Quantity - Peaking

NATIONAL GRID – RHODE ISLAND
TRANSPORTATION DEFAULT SERVICE

Price Sheet

As indicated in Item 2.04.0 of Section 6, Schedule C of the Company's Transportation Terms and Conditions, two Default Transportation Services are available in the event that a marketer stops delivering gas on behalf of Large and Extra Large FT-1 customers who have elected to forgo the Company's assignment of pipeline capacity:

Short-Notice Service:

The commodity charge for Short-Notice service shall be the higher of:

a. The Company's applicable firm sales rate

OR

b. Winter (November – March) – 135% of the Daily Algonquin Citygates average price or 135% of the Daily Tennessee Zone 6 (delivered) average price published in Gas Daily. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

Summer (April – October) – 115% of the Daily Algonquin Citygates average price or 115% of the Daily Tennessee Zone 6 (delivered) average price published in Gas Daily. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

NATIONAL GRID – RHODE ISLAND
TRANSPORTATION DEFAULT SERVICE

Advance-Notice Service: The commodity charge for Advance-Notice service shall be the higher of:

a. The Company's applicable firm sales rate

OR

b. Winter (November – March) – 135% of the Algonquin Citygates Monthly Contract Index price or 135% of the Tennessee Zone 6 (delivered) Monthly Contract Index price published in the Gas Daily Price Guide. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

Summer (April – October) – 115% of the Algonquin Citygates Monthly Contract Index price or 115% of the Tennessee Zone 6 (delivered) Monthly Contract Index price published in the Gas Daily Price Guide. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

The Company and Default Transportation Service supplier shall review the pricing of these services annually and file any necessary revisions with the Commission concurrent with the Company's annual Gas Charge Clause filing.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

JOHN F. NESTOR, III

SEPTEMBER 1, 2010

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John F. Nestor, III. My business address is Reservoir Woods, 40 Sylvan Road, Waltham, Massachusetts 02451-1120.

Q. WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am a Lead Analyst in the Gas Regulatory & Pricing organization for National Grid – Gas ("National Grid" or the "Company"). My responsibilities include overseeing the design, implementation and administration of rates and tariffs by National Grid for natural gas service in Rhode Island.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Arts in American Studies from Merrimack College, a Masters in Business Administration from Northeastern University, and a Juris Doctorate from Suffolk University Law School. I have been employed by National Grid in my current position since November of 2008. Prior to joining National Grid, I was employed by Verizon Communications ("Verizon") and its predecessor companies for over 20 years as Vice President for Regulatory and State Government Relations, Director of Regulatory Affairs for Massachusetts and Director of Regulatory Planning & Support. I also have been employed as an attorney in private practice and by the Massachusetts

Department of Public Utilities ("MDPU") as a utility specialist, Director of Telecommunications and as regulatory counsel to the Commission. In addition, I served as a legislative assistant in the United States House of Representative where I had responsibility for matters before the Federal Communications Commission and Federal Power Commission (now FERC).

Q. HAVE YOU PREVIOUSLY TESTIFIED OR APPEARED BEFORE THIS COMMISSION?

A. Yes. I filed testimony in Docket No. 4077, the 2009 Distribution Adjustment Charge ("DAC") proceeding and I have submitted testimony in Docket No. 4196 the current 2010 DAC proceeding. I also have testified or appeared before this Commission and Staff in a number of proceedings and dockets during my time with Verizon and with the MDPU concerning rates, tariffs, rules and regulations, and telephone numbering issues.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to explain the calculation of the Gas Cost Recovery ("GCR") charges to be effective with consumption on and after November 1, 2010 for the following services: (1) firm sales service customers in the Residential Non-Heating and Heating rate classes as well as Commercial and Industrial ("C&I") customers in the Small, Medium, Large and Extra Large rate classes and (2) Gas

Marketer Charges and factors associated with transportation services billed to Gas Marketers and (3) the Natural Gas Vehicle ("NGV") rate.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is composed of six (6) general sections: (*I.)* the Introduction; (*II.)* a GCR Rate Development Overview; (*III.)*. GCR Rate Development Details; (*IV.)*. Bill Impacts;(*V.)* Natural Gas Vehicles ("NGV"); and (*VI.)* Marketer Factors.

Q. DO YOU HAVE ANY ATTACHMENTS INCLUDED WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following Attachments:

Attachment NG-JFN-1 Gas Cost Recovery Factors
Attachment NG-JFN-2 GCR Reconciliation Filing
Attachment NG-JFN-3 Projected Gas Cost Balances
Attachment NG-JFN-4 Bill Impacts
Attachment NG-JFN-5 NGV Tariff
Attachment NG-JFN-6 Marketer Transportation Factors

II. <u>GCR RATE DEVELOPMENT OVERVIEW</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE DEVELOPMENT OF THE PROPOSED GCR RATES.

A. The proposed GCR rates reflect the class-specific factors necessary for the Company to collect sufficient revenues to recover projected gas costs for the period November 1, 2010 through October 31, 2011. As shown in the testimony of Ms. Arangio on Attachment EDA-1, gas costs for the period are projected to be approximately $212 million for the twelve months ended October 2011.[1] In addition to these projected costs, the GCR factors also reflect Working Capital Costs of $1.4 million (Attachment NG-JFN-1, pages 10-12), Inventory Financing Costs of $2.4 million (Attachment NG-JFN-1, page 13), a prior period Deferred Balance of $6.7 million[2] (Attachment NG-JFN-1, pages 6-9; based on actual data through July 2010 and forecast data for the period August 2010 through October 2010), LNG Operation and Maintenance ("O&M") Costs of $1.0 million (Docket No. 3943), and a credit of $1.1 million associated with LNG Costs which will be collected via the Distribution Adjustment Clause ("DAC") factor. Thus, the GCR factors are intended to recover approximately $218 million in costs over the period November 2010 through October 2011. Attachment NG-JFN-1, page 1 provides a summary of the GCR factors by customer rate class.

[1] Before NGPMP Credits of $2.4M and Pipeline refunds of $1.6M

[2] The Deferred Balance of $6,727,553 includes a one-time adjustment for Storage Variable Product Costs-UG that will be made with the September 20th Deferred Report filing to account for a double-counting of these costs that had been included incorrectly in prior periods. This adjustment results in lowering the reported July Deferred Balance of $7,423,481 by $695,928 for purposes of calculating GCR rates.

III. GCR RATE DEVELOPMENT DETAILS

Q. ATTACHMENT NG-JFN-1, PAGE 1 SHOWS A GCR FACTOR OF $8.9288 PER DEKATHERM FOR RESIDENTIAL NON-HEAT AND BOTH LARGE AND EXTRA LARGE HIGH LOAD FACTOR. PLEASE EXPLAIN HOW THIS FACTOR WAS DERIVED.

A. The $8.9288 per dekatherm ("Dth") factor is applied to the sales classes where the customer uses gas at a high load factor. These classes use proportionately less of their gas for heating and thus place less demand on the supply portfolio under peak conditions. The $8.9288 GCR factor applicable to these customers consists of five gas cost components and an uncollectible component. The five gas-cost components are Supply Fixed Costs, Storage Fixed Costs, Supply Variable Costs, Storage Variable Product Costs and Storage Variable Non-Product Costs. The associated rate components are $0.6665 per Dth, $0.3527 per Dth, $6.6781 per Dth, $1.0382 per Dth, and ($0.0263) per Dth respectively, which are adjusted for the 2.46% uncollectible factor.

The derivation of the Supply Fixed Cost component is reflected on Attachment NG-JFN-1, page 2. As shown, Supply Fixed Costs total $27,527,751 (see also Attachment EDA-1; Pipeline Demand Costs of $32,970,500, Supplier Demand Costs of $0, and Marketer/Capacity Release Revenues of $5,442,749. Also, $2,400,00 is subtracted as an estimate of the credit to customers required under the Natural Gas Portfolio Management Plan ("NGPMP") and the Working Capital Costs (Attachment NG-JFN-1, page 10) associated with Supply Fixed Costs of $187,026 is added and the prior period Supply Fixed Gas Cost under-collection of $4,680,040 (Attachment NG-JFN-1, page 8) is subtracted, resulting in total Supply Fixed Gas Costs of $20,634,737 to be collected over the period November 2010 through October 2011. Because the Company's gas-supply resources are planned so that there is sufficient capacity to meet the needs of firm sales customers under severe (design) winter conditions, Supply Fixed Costs (as well as Storage Fixed Costs) are allocated to the various rate classes based on their proportion of design-winter use. As shown, the Residential Non-Heating, Large-HLF and Extra Large HLF design sales represents 3.47% of Design Winter Sales (Attachment NG-JFN-1, Page 2, High Load Factor Total, Line 14). Thus, 3.47% of total Supply Fixed Costs or $715,687 is allocated to the Residential and HLF classes. Dividing $715,687 by the November 2010 through October 2011 forecasted sales to those classes of 1,073,801 Dth, results in a Supply Fixed Cost rate component of $0.6605 per Dth.

Q. DID THE COMPANY DEVELOP ITS DESIGN WINTER CALCULATIONS CONSISTENT WITH LAST YEARS CALCULATION?

A. Yes. The Company developed its design winter calculation using calendar month degree days consistent with Commission's finding in Docket No. 4097.[3]

Q. HOW IS THE STORAGE FIXED COST FACTOR COMPONENT FOR THE RESIDENTIAL AND HIGH LOAD FACTOR CLASSES DERIVED?

A. The derivation of the Storage Fixed Cost factor is demonstrated on Attachment NG-JFN-1, page 3. As shown, Storage Fixed Costs total $11,454,439 (see also Attachment NG-JFN-1). Deducted from this amount are $661,228 of LNG demand costs that have been allocated to the DAC. Added to this amount are $618.591 of supply related LNG O&M costs and $77,533 of Working Capital Costs associated with Storage Fixed Costs (Attachment NG-JFN-1, page 10). The prior period under-collection associated with Storage Fixed Costs of $256,010 is added. Thus, Total Storage Fixed Costs to be collected over the period November 2010 through October 2011 amount to $11,745,346. As with Supply Fixed Costs, the Storage Fixed Costs are allocated on the basis of design winter throughput. Thus, 3.71%, or $436,176 of total Storage Fixed Costs is allocated to the Residential Non-Heating and HLF classes. Dividing $436,174 by forecasted period sales of 1,236,750 Dths results in the Storage Fixed Cost component of $0.3527 per Dth.

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[3] Docket No 4097 (Order 19832) at 20.

Q. THE PERCENT OF RESIDENTIAL NON-HEATING AND LARGE HLF AND EXTRA LARGE HLF USED FOR ALLOCATED SUPPLY FIXED COSTS WAS 3.47%. WHY IS THE COMPANY USING 3.71% FOR ALLOCATING STORAGE FIXED COSTS?

A. A portion of the Storage Fixed Costs is required to meet the needs of FT-2 transportation customers. Thus, the projected throughput has been adjusted to incorporate the consumption of this class of customers. Attachment NG-JFN-6, page 2, reflects the development of the FT-2 Marketer Charge and the allocation of Storage Fixed Costs to this class of customers.

Q. WHY DOES THE COMPANY ASSIGN A PORTION OF STORAGE FIXED COSTS TO FT-2 CUSTOMERS?

A. Consistent with the methodology established and approved by the Commission in Docket No. 2552, the FT-2 rate is based on the development of the storage and peaking costs as described in the Company's GCR tariff, RI-PUC NG-GAS No. 101 Section 2, Schedule A, Sheets 5-7.. The fixed and variable costs related to the operations, maintenance, and delivery of the Company's storage resources, along with requirements for purchased gas working capital, are components of this rate.

Q. HOW IS THE SUPPLY VARIABLE COST COMPONENT FOR THE RESIDENTIAL AND HLF CLASSES DERIVED?

A. The Supply Variable Cost component is $6.6781 per Dth for all customer classes, including the Residential and HLF classes as shown on Attachment NG-JFN-1, page 4. Projected Variable Supply Costs are $149,514,232 (see Attachment EDA-1). Deducted from this amount is Fuel Costs Allocated to Storage of $323,191 and refunds from the Tennessee Pipeline PCB Settlement of $1,627,056, resulting in total deductions of $1,950,246. These costs have been transferred to the Storage Variable Non-Product Cost bucket. Added to this amount are Working Capital Costs associated with Supply Variable Costs of $1,013,618 (Attachment NG-JFN-1, page 11) and the prior period under-collection associated with Supply Variable Costs of $13,406,402. Thus, total Supply Variable Costs for the period November 2010 through October 2011 are $161,984,006. Dividing $161,984,006 by projected period sales of 24,256,162 Dths results in the Supply Variable Cost factor of $6.6781 per Dth.

Q. WHY AREN'T THESE COSTS ALLOCATED ON THE BASIS OF DESIGN THOUGHPUT, AS WITH THE SUPPLY FIXED AND STORAGE FIXED COMPONENTS?

A. Supply Variable Costs vary with the amount of gas actually used, and accordingly, are allocated to the various rate classes based on projected consumption whereas Supply and Storage Fixed Costs are incurred to ensure the Company is able to meet customer requirements during design-winter conditions.

Q. HOW IS THE STORAGE VARIABLE PRODUCT COST FACTOR ASSOCIATED WITH THE RESIDENTIAL AND HLF CLASSES DERIVED?

A. The derivation of the Storage Variable Product Cost factor is shown on Attachment NG-JFN-1, page 5. As shown, projected Storage Variable Product Costs are $23,083,547. Deducted from this amount are $349,551 of Balancing Related LNG costs that have been transferred to the DAC for collection. Added to this amount are $430,129 of Supply Related LNG O&M Costs (Docket No. 3943), $157,379 of Working Capital Costs (Attachment NG-JFN-1, page 11), Inventory Financing Costs of $478,213, and $1,844,679 for LNG and Underground Storage, respectively (Attachment NG-JFN-1, page 13). The prior period under collection of $460,482 is subtracted. Thus, Total Storage Variable Costs to be collected over the period November 2010 through October 2011 are $25,183,914. Dividing $25,183,914 by forecasted period sales of 24,256,162 Dths results in the $1.0382 per Dth Storage Variable Product Cost factor.

Q. HOW IS THE STORAGE VARIABLE NON-PRODUCT COST FACTOR ASSOCIATED WITH THE RESIDENTIAL AND THE HLF CLASSES DERIVED?

A. The derivation of the Storage Variable Non-Product Cost factor is shown in Attachment NG-JFN-1, page 5. As shown, projected Storage Variable Non-Product Costs are $715,645. Added to this amount are Variable Injection Costs of $74,252, and Fuel Costs Allocated to Storage of $323,191. Also, Working Capital Costs of $4,862 are added to the calculation and the prior period over-collection of $1,794,337 is subtracted, resulting in total Storage Variable Non-Product Costs of ($676,387) to be refunded over the period November 2010 through October 2011. Dividing ($676,387) by forecasted period throughput of 25,698,884 Dths results in the ($0.0263) per Dth Storage Variable Non-Product Cost factor.

Q. WHY WAS THE STORAGE VARIABLE NON-PRODUCT COSTS DIVIDED BY FORECASTED THROUGHPUT WHILE STORAGE VARIABLE PRODUCT COSTS AND SUPPLY VARIABLE COSTS WERE DIVIDED BY FORECASTED SALES?

A. Similar to the derivation of the Storage Fixed Cost factor, a portion of Storage Variable Non-Product Costs are associated with the delivery of underground storage for FT-2 Marketers. Thus, a portion of the Storage Variable Non-Product Costs is assigned to FT-2 Marketers (see Attachment NG-JFN-6).

In summary, the $$8.9288 per Dth GCR factor applicable to the Residential Non-Heating and HLF classes consists of a $0.6665 per Dth Supply Fixed Cost component, $0.3527 Storage Fixed Cost component, $6.6781 Supply Variable Cost component, $1.0382 Storage Variable Product Cost component and ($0.0263) Storage Variable Non-Product Cost component. The sum total of these gas cost components is $8.7092 per Dth. Adjusting this rate by the 2.46 uncollectible percent results in the proposed

Residential, Large HLF and Extra Large HLF Class GCR factor of $8.9288 per Dth or $0.8929 per therm.

Q. HOW ARE THE GCR FACTORS FOR THE OTHER CUSTOMER CLASSES DERIVED?

A. The GCR factors for the remaining customer classes are calculated in a manner that is identical to the calculation for the Residential and HLF customer classes.

Q. WHAT IS THE COMPANY'S ESTIMATE OF THE DEFERRED GAS COST BALANCE AT THE END OF THE CURRENT GCR PERIOD?

A. The Company's current estimate is an under collection of approximately $6.7 million in the deferred gas cost account at the end of October 2010. This estimate is based on the actual deferred balance at the end of June as reflected in the Company's annual GCR reconciliation filed with the Division and Commission on August 2, 2010, actual data for July 2010, and our latest August 2010 through October 2010 projection using the current GCR factors and the estimate of gas costs included in the Company's August 20, 2010 deferred gas cost filing. A copy of the annual GCR reconciliation filing is attached here as Attachment NG-JFN-2 and the updated deferred gas cost balance projections for July 2010 through October 2011 are provided in Attachment NG-JFN-1 at pages 6-9.

Q. WHAT IS THE TOTAL DEFERRED BALANCE REFLECTED IN THE GCR FACTORS?

A. Based on actual data through July 2010, and forecasted data for the period August 2010 through October 2011, the total estimated deferred balance at October 31, 2010 is $6.7 million. The projected gas cost balances for the period November 2010 through October 31, 2011 are shown on Attachment NG-JFN-3.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE FORECAST THROUGHPUT REQUIREMENTS.

A. The forecast of throughput requirements incorporated in this GCR filing were developed utilizing regression analyses of daily send out and degree days over the April 2009 – May 2010 time period. This analysis determined the relationship between degree days and sendout and was used as the base for the forecast. To this initial base period throughput level, the Company then added its forecast of annual net incremental load growth developed using statistical forecast models for the residential heating, residential non-heating, commercial/industrial heating and commercial/industrial non-heating classes. Statistical models were developed for the numbers of customers and the use per customer utilizing various weather, economic and demographic data such as degree days, GDP, population, employment and the price of natural gas as independent variables. In addition, the load forecasts were adjusted to reflect projected load reductions from the Company's energy efficiency programs based on the goals of the program. With the modeling of the throughput completed for the revenue classes, the revenue class results are split between sales and transportation.

IV. BILL IMPACTS

Q. WHAT IS THE BILL IMPACT OF THE PROPOSED CHANGES?

A. An average residential heating customer using 922 therms per year will experience a decrease of approximately $144 or an annual 9.7% percent decrease over the currently effective rates. A summary of annual bill impacts for customers with various levels of usage is provided on Attachment NG-JFN-4. In addition to the proposed GCR factors, the bill impact analysis also incorporates the proposed decrease in DAC factors that is filed today under separate cover in Docket No. 4196. Overall, the average residential heating customer will experience an annual decrease of $122 or 8.2%.

V. NATURAL GAS VEHICLES

Q. IS THE COMPANY PROPOSING A CHANGE TO THE NGV RATE?

A. Yes. The commodity charge component of the NGV rates is based on the Supply Fixed Costs and the Supply Variable Costs identified in the Company's GCR filing. Accordingly, the NGV commodity charge is being updated to reflect the Supply Fixed Costs and Supply Variable Costs included in this filing. This new rate is $7.5298 Dth. A revised NGV tariff is provided as Attachment NG-JFN-5.

VI. MARKETER FACTORS

Q. WHAT ARE THE VARIOUS GAS MARKETER CHARGES AND FACTORS INCLUDED IN THIS GCR FILING?

A. The gas marketer charges and factors covered under the Company's GCR tariff and included in this GCR filing are: (1) the FT-2 firm transportation marketer gas charges; (2) Pool Balancing Service charges; and (3) the Company's weighted average pipeline cost and the associated credits/surcharges applied to marketers for pipeline capacity assignments. A summary of the proposed charges that would take effect concurrent with the updating of transportation factors and capacity releases on November 1, 2010 are shown on Attachment NG-JFN-6, page 1.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE FT-2 FIRM TRANSPORTATION RATE FOR STORAGE AND PEAKING RESOURCES.

A. Consistent with the methodology established and approved by the Commission in Docket No. 2552, the FT-2 rate is based on the development of the storage and peaking costs as described in the GCR tariff. The fixed and variable costs related to the operations, maintenance and delivery of the Company's storage resources were totaled, along with requirements for purchased gas working capital. The result was then divided by the forecasted firm throughput to arrive at a per therm cost. Attachment NG-JFN-6, page 2 shows the calculation of the $0.0430 per therm FT-2 Marketer Charge.

Q. PLEASE DESCRIBE THE UPDATE OF THE POOL BALANCING SERVICE CHARGE.

A. Pursuant to Item 5.04.1 of the Transportation Terms and Conditions and consistent with the methodology established in Item 4.2 of the GCR tariff, the Pool Balancing Charge is being updated to reflect the relevant Fixed and Storage Cost components. As shown on Attachment NG-JFN-6, page 3, the proposed balancing charge is $0.0024 per percentage of balancing elected per therm of throughput in the Marketer pool.

Q. HAS THE COMPANY UPDATED THE TRANSPORATION SERVICE CHARGES ASSOCIATED WITH PIPELINE CAPACITY ASSIGNMENT?

A. Yes, the updated Company weighted average pipeline cost is shown on Attachment NG-JFN-6, page 1. The testimony of Company witness Ms. Elizabeth Arangio describes its calculation as well as the calculation of the associated credits/surcharges applied to marketers for pipeline capacity assignments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Gas Cost Recovery (GCR)
Factors Effective November 1, 2010

($ per Dth)

Line No.	Description (a)	Reference (b)	Residential Non-Heat (c)	Residential Heat (d)	Small C&I (e)	Medium C&I (f)	Large LLF (g)	Large HLF (h)	Extra Large LLF (i)	Extra Large HLF (j)	FT-2 Mkter (k)	NGV (l)
1	Supply Fixed Cost Factor	pg. 2	$0.6665	$0.8592	$0.8592	$0.8592	$0.8592	$0.6665	$0.8592	$0.6665	n/a	$0.6665
2	Storage Fixed Cost Factor	pg. 3	$0.3527	$0.4623	$0.4623	$0.4623	$0.4623	$0.3527	$0.4623	$0.3527	$0.4454	
3	Supply Variable Cost Factor	pg. 4	$6.6781	$6.6781	$6.6781	$6.6781	$6.6781	$6.6781	$6.6781	$6.6781	n/a	$6.6781
4a	Storage Variable Product Cost Factor	pg. 5	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	n/a	
4b	Storage Variable Non-product Cost Factor	pg. 5	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	($0.0263)	
5	Total Gas Cost Recovery Charge	(1)+(2)+(3)+(4)	$8.7092	$9.0115	$9.0115	$9.0115	$9.0115	$8.7092	$9.0115	$8.7092	$0.4191	$7.3446
6	Uncollectible %	Docket 3943	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
7	Total GCR Charge adjusted for Uncollectibles	(5) / [(1 - (6)]	$8.9288	$9.2388	$9.2388	$9.2388	$9.2388	$8.9288	$9.2388	$8.9288	$0.4297	$7.5298
8	**GCR Charge on a per therm basis**	(7) / 10	**$0.8929**	**$0.9239**	**$0.9239**	**$0.9239**	**$0.9239**	**$0.8929**	**$0.9239**	**$0.8929**	**$0.0430**	**$0.7530**
	Current rate effective 11/01/09		$1.0338	$1.0801	$1.0801	$1.0801	$1.0801	$1.0338	$1.0801	$1.0338	$0.0337	$0.9091
	difference		($0.1409)	($0.1562)	($0.1562)	($0.1562)	($0.1562)	($0.1409)	($0.1562)	($0.1409)	$0.0093	($0.1561)
			-13.6%	-14.5%	-14.5%	-14.5%	-14.5%	-13.6%	-14.5%	-13.6%	27.6%	-17.2%

Gas Cost Recovery (GCR)
Fixed Cost Calculation ($ per Dth)

Line No.	Description (a)	Reference (b)	Amount (c)	Residential Heating (d)	Small C&I (e)	Medium C&I (f)	Large LLF (g)	Extra Large LLF (h)	Low Load Factor Total (i)	Residential Non-Heat (j)	Large HLF (k)	Extra Large HLF (l)	High Load Factor Total (m)	Line No.
1	Supply Fixed Costs (net of Cap Rel to marketers)	EDA-1	$27,527,751											1
2	Less:													2
3	NGPMP Customer Benefit	EDA-1	$2,400,000							`				3
4	Interruptible Costs		$0											4
5	Non-Firm Sales Costs		$0											5
6	Off-System Sales Margin		$0											6
7	Refunds		$0											7
8	Total Credits	sum[(3):(7)]	$2,400,000											8
9	Plus:													9
10	Working Capital Requirement	pg 10	$187,026											10
11	Reconciliation Amount	pg 8	($4,680,040)											11
12	Total Additions	(10) + (11)	($4,493,014)											12
13	Total Supply Fixed Costs	(1) - (8) + (12)	$20,634,737											13
14	Design Winter Sales Percentage	pg 15		69.86%	8.65%	12.98%	3.75%	1.29%	96.53%	2.18%	0.78%	0.51%	3.47%	14
15	Allocated Supply Fixed Costs	(13) x (14)		$14,416,418	$1,784,663	$2,677,569	$774,525	$265,875	$19,919,050	$449,518	$160,185	$105,984	$715,687	15
16	Sales (Dt) Nov 2010 - Oct 2011	pg 14	24,256,162	16,815,263	1,987,380	3,252,891	862,458	264,369	23,182,361	698,210	235,719	139,872	1,073,801	16
17	**Supply Fixed Factor**	(15) / (16)							**$0.8592**				**$0.6665**	17

Gas Cost Recovery (GCR)
Fixed Cost Calculation ($ per Dth)

Line No.	Description (a)	Reference (b)	Amount (c)	Residential Heating (d)	Small C&I (e)	Medium C&I (f)	Large LLF (g)	Extra Large LLF (h)	Low Load Factor Total (i)	Residential Non-Heat (j)	Large HLF (k)	Extra Large HLF (l)	High Load Factor Total (m)	Line No.
1	Storage Fixed Costs	EDA-1	$11,454,439											1
2	Less:													2
3	LNG Demand to DAC	EDA-2/Dkt 3943	$661,228											3
4	Credits		$0											4
5	Refunds		$0											5
6	Total Credits	sum [(3):(5)]	$661,228											6
7	Plus:													7
8	Supply Related LNG O&M Costs	Rate Case	$618,591											8
9	Working Capital Requirement	pg 10	$77,533											9
10	Reconciliation Amount	pg 8	$256,010											10
11	Total Additions	sum [(8):(10)]	$952,134											11
12	Total Storage Fixed Costs	(1) - (6) + (11)	$11,745,346											12
13	Design Winter Throughput Percentage	pg 15		66.23%	8.20%	14.60%	5.93%	1.32%	96.29%	2.07%	1.11%	0.54%	3.71%	13
14	Allocated Storage Fixed Costs	(12) x (13)		$7,779,034	$962,996	$1,715,216	$696,533	$155,393	$11,309,172	$242,558	$130,575	$63,041	$436,174	14
15	Throughput (Dt) Nov 10 - Oct 11	pg 14	25,698,884	16,815,263	1,987,380	3,902,893	1,469,433	287,165	24,462,133	698,210	380,465	158,075	1,236,750	15
16	**Storage Fixed Factor**	(14) / (15)							**$0.4623**				**$0.3527**	16

Gas Cost Recovery (GCR)
Variable Cost Calculation ($ per Dth)

Line No.	Description	Reference	Amount	Line No.
1	**Variable Supply Costs**	EDA-1	$149,514,232	1
2	Less:			2
3	Non-Firm Sales		$0	3
4	Variable Delivery Storage Costs	EDA-2 pg 16	$0	4
5	Variable Injection Storage Costs	EDA Storage Inj	$0	5
6	Fuel Costs Allocated to Storage	EDA-2	$323,191	6
7	Refunds (Tennessee Pipeline PCB)		$1,627,056	7
8	Total Credits	sum [(3):(7)]	$1,950,246	8
9	Plus:			9
10	Working Capital	pg 11	$1,013,618	10
11	Reconciliation Amount	pg 8	$13,406,402	11
12	Total Additions	(10)+(11)	$14,420,020	12
13	Total Variable Supply Costs	(1)-(8)+(12)	$161,984,006	13
14	Sales (Dt) Nov 2010 - Oct 2011	pg 14	24,256,162	14
15	**Supply Variable Cost Factor**	(13)/(14)	**$6.6781**	15

Gas Cost Recovery (GCR)
Variable Cost Calculation ($ per Dth)

Line No.	Description	Reference	Amount	Line No.
1	**Storage Variable Product Costs**	EDA 1	$23,083,547	1
2	Less:			2
3	Balancing Related LNG Costs (to DAC)	EDA 2/Dkt 3943	$349,551	3
4	Refunds		$0	4
5	Total Credits	(3)+(4)	$349,551	5
6	Plus:			6
7	Supply Related LNG O&M	Docket 3943	$430,129	7
8	Working Capital	pg 11	$157,379	8
9	Inventory Financing - LNG (Supply)	pg 13	$478,213	9
10	Inventory Financing - Storage	pg 13	$1,844,679	10
11	Reconciliation Amount	pg 9	($460,482)	11
12	Total Additions	sum[(7):(12)]	$2,449,919	12
13	Total Storage Variable Costs	(1)-(5)+(13)	$25,183,914	13
14	Sales (Dt) Nov 2010 - Oct 2011	pg 14	24,256,162	14
15	**Storage Variable Product Cost Factor**	(14) / (15)	**$1.0382**	15
16	**Storage Variable Non-Product Costs**	EDA-1	$715,645	16
17	Less:			17
18	Refunds		$0	18
19	Total Credits		$0	19
20	Plus:			20
21	Variable Delivery Storage Costs	pg 5	$0	21
22	Variable Injection Storage Costs	pg 5	$74,252	22
23	Fuel Costs Allocated to Storage - Injection	pg 5	$323,191	23
24	Working Capital	pg 12	$4,862	24
25	Inventory Financing - Storage	pg 13	$0	25
26	Reconciliation Amount	pg 9	($1,794,337)	26
27	Total Additions	sum[(22):(27)]	($1,392,032)	27
28	Total Storage Variable Costs	(17)-(20)+(28)	($676,387)	28
29	Throughput (Dt)	pg 12	25,698,884	29
30	**Storage Variable Non-Product Cost Factor**	(29) / (30)	**($0.0263)**	30

Line No.		Mar-10 31 actual	Apr-10 30 actual	May-10 31 actual	Jun-10 30 actual	Jul-10 31 actual
	I. Supply Fixed Cost Deferred					
1	Beginning Balance	($8,740,364)	($10,167,336)	($12,045,905)	($11,723,134)	($10,947,773)
2	Supply Fixed Costs (net of cap rel)	$2,443,223	$1,096,842	$1,813,964	$1,780,218	$2,620,430
3	Capacity Release	$0	$0	$0	$0	$0
4	Working Capital	$18,170	$8,157	$13,490	$13,239	$19,488
5	Total Supply Fixed Costs	$2,461,393	$1,104,999	$1,827,454	$1,793,457	$2,639,918
6	Supply Fixed - Collections	$3,723,869	$2,203,081	$1,292,179	$806,558	$653,159
7	Prelim. Ending Balance	($10,002,841)	($11,265,418)	($11,510,630)	($10,736,235)	($8,961,014)
8	Month's Average Balance	($9,371,603)	($10,716,377)	($11,778,267)	($11,229,685)	($9,954,393)
9	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
10	Interest Applied	($9,949)	($11,010)	($12,504)	($11,537)	($10,568)
11	Natural Gas Portfolio Management Plan	$154,545	$769,477	$200,000	$200,000	$200,000
12	Supply Fixed Ending Balance	($10,167,336)	($12,045,905)	($11,723,134)	($10,947,773)	($9,171,582)
	II. Storage Fixed Cost Deferred					
13	Beginning Balance	($661,406)	($1,481,605)	($1,862,153)	($1,622,104)	($1,137,242)
14	Storage Fixed Costs	$800,927	$549,607	$815,928	$853,488	$19,866
15	LNG Demand to DAC	($51,506)	($13,671)	($58,303)	($64,296)	$75,414
16	Supply Related LNG O & M	$51,549	$51,549	$51,549	$51,549	$51,549
17	Working Capital	$5,957	$4,369	$6,018	$6,252	$1,092
18	Total Storage Fixed Costs	$806,927	$591,855	$815,192	$846,994	$147,922
19	TSS Peaking Collections	$0	$0	$0	$0	$0
20	Storage Fixed - Collections	$1,625,989	$970,686	$573,295	$360,715	$286,431
21	Prelim. Ending Balance	($1,480,468)	($1,860,436)	($1,620,256)	($1,135,825)	($1,275,751)
22	Month's Average Balance	($1,070,937)	($1,671,021)	($1,741,204)	($1,378,965)	($1,206,497)
23	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
24	Interest Applied	($1,137)	($1,717)	($1,849)	($1,417)	($1,281)
25	Storage Fixed Ending Balance	($1,481,605)	($1,862,153)	($1,622,104)	($1,137,242)	($1,277,032)
	III. Variable Supply Cost Deferred					
26	Beginning Balance	$34,931,612	$24,325,204	$22,125,549	$17,535,102	$14,983,728
27	Variable Supply Costs	$21,711,082	$17,039,931	$6,791,156	$4,668,653	$2,978,384
28	Variable Delivery Storage	($23,075)	$0	$0	$0	$0
29	Variable Injections Storage	($1,472)	($16,828)	($17,350)	($13,932)	($8,143)
30	Fuel Cost Allocated to Storage	($130,763)	($88,698)	($92,134)	($74,192)	($39,785)
31	Working Capital	$160,307	$125,939	$49,691	$34,065	$21,793
32	Total Supply Variable Costs	$21,716,079	$17,060,343	$6,731,362	$4,614,594	$2,952,250
33	Supply Variable - Collections	$32,336,891	$19,284,258	$11,349,178	$7,191,128	$5,836,080
34	Customer Deferred Responsibility	$17,035	($410)	($6,327)	($8,464)	($11,123)
35	Prelim. Ending Balance	$24,293,766	$22,101,699	$17,514,061	$14,967,032	$12,111,021
36	Month's Average Balance	$29,612,689	$23,213,451	$19,819,805	$16,251,067	$13,547,374
37	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
38	Interest Applied	$31,438	$23,849	$21,042	$16,696	$14,382
39	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0
40	Supply Variable Ending Balance	$24,325,204	$22,125,549	$17,535,102	$14,983,728	$12,125,403

Line No.		Mar-10 31 actual	Apr-10 30 actual	May-10 31 actual	Jun-10 30 actual	Jul-10 31 actual
	IVa. Storage Variable Product Cost Deferred					
41	Beginning Balance	($4,815,097)	($2,018,864)	($2,171,969)	($1,778,549)	($1,502,844)
42	Storage Variable Prod. Costs - LNG	($86,720)	$205,101	$157,300	$152,156	$125,679
43	Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0
44	Storage Variable Prod. Costs - UG	$3,807,808	$70,513	$374,116	$86,591	$170,997
45	Supply Related LNG to DAC	$14,569	($34,457)	($26,426)	($25,562)	($101,011)
46	Supply Related LNG O & M	$35,844	$35,844	$35,844	$35,844	$35,844
47	Inventory Financing - LNG	$42,932	$42,951	$43,624	$44,153	$44,244
48	Inventory Financing - UG	$92,455	$148,334	$178,811	$216,366	$226,970
49	Inventory Financing - LP	$0	$0	$0	$0	$0
50	Working Capital	$28,048	$2,060	$4,022	$1,852	$1,722
51	Total Storage Variable Product Costs	$3,843,690	$468,763	$760,743	$508,844	$496,285
52	Storage Variable Product Collections	$1,043,832	$619,716	$365,227	$231,454	$187,835
53	Prelim. Ending Balance	($2,015,239)	($2,169,817)	($1,776,453)	($1,501,159)	($1,194,394)
54	Month's Average Balance	($3,415,168)	($2,094,341)	($1,974,211)	($1,639,854)	($1,348,619)
55	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
56	Interest Applied	($3,626)	($2,152)	($2,096)	($1,685)	($1,432)
57	Storage Variable Product Ending Bal.	($2,018,864)	($2,171,969)	($1,778,549)	($1,502,844)	($1,195,826)
	IVb. Stor Var Non-Prod Cost Deferred					
58	Beginning Balance	($3,081,318)	($2,677,290)	($2,445,835)	($2,277,627)	($2,159,310)
59	Storage Variable Non-prod. Costs	$91,247	$1,583	$6,548	$2,557	$8,161
60	Variable Delivery Storage Costs	$21,958	$405	$1,725	$687	$2,201
61	Variable Injection Storage Costs	$1,270	$12,972	$11,998	$10,301	$3,844
62	Fuel Costs Allocated to Storage	$5,743	$47,348	$48,294	$41,793	$17,253
63	Working Capital	$894	$463	$510	$412	$234
64	Total Storage Var Non-product Costs	$121,112	$62,771	$69,075	$55,749	$31,693
65	Storage Var Non-Product Collections	($285,971)	($171,314)	($101,639)	($64,846)	($51,587)
66	Prelim. Ending Balance	($2,674,235)	($2,443,205)	($2,275,121)	($2,157,032)	($2,076,031)
67	Month's Average Balance	($2,877,777)	($2,560,248)	($2,360,478)	($2,217,330)	($2,117,671)
68	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
69	Interest Applied	($3,055)	($2,630)	($2,506)	($2,278)	($2,248)
70	Storage Var Non-Product Ending Bal.	($2,677,290)	($2,445,835)	($2,277,627)	($2,159,310)	($2,078,279)
	GCR Deferred Summary					
71	Beginning Balance	$18,213,744	$8,651,672	$4,272,834	$813,383	($81,189)
72	Gas Costs	$28,827,072	$19,149,327	$10,136,644	$7,766,374	$6,231,899
73	Working Capital	$213,376	$140,988	$73,730	$55,820	$44,329
74	Total Costs	$29,040,448	$19,290,315	$10,210,374	$7,822,194	$6,276,228
75	Collections	$38,461,645	$22,906,017	$13,471,913	$8,516,545	$6,900,795
76	Prelim. Ending Balance	$8,792,547	$5,035,971	$1,011,296	$119,031	($705,756)
77	Month's Average Balance	$13,503,145	$6,843,822	$2,642,065	$466,207	($393,473)
78	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
79	Interest Applied	$13,671	$6,341	$2,087	($221)	($1,146)
80	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0
81	NGPMP Credit	$154,545	$769,477	$200,000	$200,000	$200,000
82	**Ending Bal. W/ Interest**	$8,651,672	$4,272,834	$813,383	($81,189)	($906,903)
83	Under/(Over)-collection	($9,421,197)	($3,615,702)	($3,261,538)	($694,351)	($624,567)

Line No.		Aug-10 31 fcst	Sep-10 30 fcst	Oct-10 31 fcst	Line No.
	I. Supply Fixed Cost Deferred				
1	Beginning Balance	($9,171,582)	($7,552,571)	($5,992,424)	1
2	Supply Fixed Costs (net of cap rel)	$2,477,975	$2,477,914	$2,477,975	2
3	Capacity Release	$0	$0	$0	3
4	Working Capital	$18,428	$18,428	$18,428	4
5	Total Supply Fixed Costs	$2,496,403	$2,496,342	$2,496,403	5
6	Supply Fixed - Collections	$668,625	$729,343	$978,464	6
7	Prelim. Ending Balance	($7,343,804)	($5,785,572)	($4,474,484)	7
8	Month's Average Balance	($8,257,693)	($6,669,071)	($5,233,454)	8
9	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	9
10	Interest Applied	($8,767)	($6,852)	($5,556)	10
11	Natural Gas Portfolio Management Plan	$200,000	$200,000	$200,000	
12	Supply Fixed Ending Balance	($7,552,571)	($5,992,424)	($4,680,040)	12
	II. Storage Fixed Cost Deferred				
13	Beginning Balance	($1,277,032)	($713,885)	($175,056)	13
14	Storage Fixed Costs	$823,721	$822,521	$823,721	14
15	LNG Demand to DAC	($26,460)	($26,460)	($26,460)	15
16	Supply Related LNG O & M	$51,549	$51,549	$51,549	16
17	Working Capital	$6,312	$6,304	$6,312	17
18	Total Storage Fixed Costs	$855,123	$853,914	$855,123	18
19	TSS Peaking Collections	$0	$0	$0	19
20	Storage Fixed - Collections	$290,919	$314,628	$424,099	20
21	Prelim. Ending Balance	($712,829)	($174,599)	$255,968	21
22	Month's Average Balance	($994,930)	($444,242)	$40,456	22
23	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	23
24	Interest Applied	($1,056)	($456)	$43	24
25	Storage Fixed Ending Balance	($713,885)	($175,056)	$256,010	25
	III. Variable Supply Cost Deferred				
26	Beginning Balance	$12,125,403	$11,369,138	$10,761,502	26
27	Variable Supply Costs	$5,196,861	$5,843,800	$11,250,462	27
28	Variable Delivery Storage	$0	$0	$0	28
29	Variable Injections Storage	($7,185)	($361)	($9,372)	29
30	Fuel Cost Allocated to Storage	($31,783)	($2,757)	($52,733)	30
31	Working Capital	$38,358	$43,436	$83,206	31
32	Total Supply Variable Costs	$5,196,251	$5,884,119	$11,271,562	32
33	Supply Variable - Collections	$5,964,982	$6,503,117	$8,639,485	33
34	Customer Deferred Responsibility	$0	$0	$0	34
35	Prelim. Ending Balance	$11,356,673	$10,750,140	$13,393,580	35
36	Month's Average Balance	$11,741,038	$11,059,639	$12,077,541	36
37	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	37
38	Interest Applied	$12,465	$11,363	$12,822	38
39	Gas Procurement Incentive/(penalty)	$0	$0	$0	
40	Supply Variable Ending Balance	$11,369,138	$10,761,502	$13,406,402	40

Gas Cost Recovery (GCR)
Gas Cost Account Balances

Line No.		Aug-10 31 fcst	Sep-10 30 fcst	Oct-10 31 fcst	Line No.
	IVa. Storage Variable Product Cost Deferre				
41	Beginning Balance	($1,195,826)	($919,339)	($656,882)	41
42	Storage Variable Prod. Costs - LNG	$112,034	$107,700	$111,215	42
43	Storage Variable Prod. Costs - LP	$0	$0	$0	43
44	Storage Variable Prod. Costs - UG	($690,413)	$0	$0	44
45	Supply Related LNG to DAC	($18,822)	($18,094)	($18,684)	45
46	Supply Related LNG O & M	$35,844	$35,844	$35,844	46
47	Inventory Financing - LNG	$39,286	$39,116	$38,942	47
48	Inventory Financing - UG	$306,594	$307,945	$307,945	48
49	Inventory Financing - LP	$0	$0	$0	49
50	Working Capital	($4,175)	$933	$955	50
51	Total Storage Variable Product Costs	($219,652)	$473,444	$476,216	51
52	Storage Variable Product Collections	$192,785	$210,178	$279,224	52
53	Prelim. Ending Balance	($1,608,263)	($656,072)	($459,890)	53
54	Month's Average Balance	($1,402,044)	($787,706)	($558,386)	54
55	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	55
56	Interest Applied	($1,488)	($809)	($593)	56
57	Storage Variable Product Ending Bal.	($919,339)	($656,882)	($460,482)	57
	IVb. Stor Var Non-Prod Cost Deferred				
58	Beginning Balance	($2,078,279)	($1,988,658)	($1,930,757)	58
59	Storage Variable Non-prod. Costs	$0	$0	$0	59
60	Variable Delivery Storage Costs	$0	$0	$0	60
61	Variable Injection Storage Costs	$7,185	$361	$9,372	61
62	Fuel Costs Allocated to Storage	$31,783	$2,757	$52,733	62
63	Working Capital	$290	$23	$462	63
64	Total Storage Var Non-product Costs	$39,258	$3,141	$62,568	64
65	Storage Var Non-Product Collections	($52,521)	($56,772)	($75,829)	65
66	Prelim. Ending Balance	($1,986,500)	($1,928,745)	($1,792,361)	66
67	Month's Average Balance	($2,032,389)	($1,958,701)	($1,861,559)	67
68	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	68
69	Interest Applied	($2,158)	($2,012)	($1,976)	69
70	Storage Var Non-Product Ending Bal.	($1,988,658)	($1,930,757)	($1,794,337)	70
	GCR Deferred Summary				
71	Beginning Balance	($906,903)	$194,686	$2,006,384	71
72	Gas Costs	$8,308,169	$9,641,835	$15,052,509	72
73	Working Capital	$59,214	$69,124	$109,363	73
74	Total Costs	$8,367,384	$9,710,959	$15,161,873	74
75	Collections	$7,064,790	$7,700,494	$10,245,443	75
76	Prelim. Ending Balance	$395,691	$2,205,151	$6,922,813	76
77	Month's Average Balance	($255,606)	$1,199,919	$4,464,599	77
78	Interest Rate (BOA Prime minus 200 bps	1.25%	1.25%	1.25%	78
79	Interest Applied	($1,004)	$1,233	$4,740	79
80	Gas Purchase Plan Incentives/(Penalties	$0	$0	$0	80
81	NGPMP Credit	$200,000	$200,000	$200,000	
82	**Ending Bal. W/ Interest**	$194,686	$2,006,384	**$6,727,553**	82
83	Under/(Over)-collection	$1,302,593	$2,010,465	$4,916,429	83

Gas Cost Recovery (GCR)
Working Capital Calculation

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Supply Fixed Costs (net of Cap Rel)**	EDA-1	$27,527,751	1
2	Capacity Release Revenue		$0	2
3	Allowable Working Capital Costs	(1) - (2)	$27,527,751	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$1,840,211	5
6	Cost of Capital	Docket 4196	7.47%	6
7	Return on Working Capital Requirement	(5) x (6)	$137,387	7
8	Weighted Cost of Debt	Docket 4196	2.46%	8
9	Interest Expense	(5) x (8)	$45,201	9
10	Taxable Income	(7) - (9)	$92,186	10
11	1 - Combined Tax Rate	Docket 3943	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$141,825	12
13	**Supply Fixed Working Capital Requirement**	(9) + (12)	**$187,026**	13
14	**Storage Fixed Costs**	EDA-1	$11,454,439	14
15	Less: LNG Demand to DAC		($661,228)	15
16	Less: Credits		$0	16
17	Plus: Supply Related LNG O&M Costs		$618,591	17
18	Allowable Working Capital Costs	(14)-(15)+(16)+(17)	$11,411,802	18
19	Number of Days Lag	Docket 3943	24.40	19
20	Working Capital Requirement	[(18) x (19)] / 365	$762,871	20
21	Cost of Capital	Docket 4196	7.47%	21
22	Return on Working Capital Requirement	(20) x (21)	$56,955	22
23	Weighted Cost of Debt	Docket 4196	2.46%	23
24	Interest Expense	(20) x (23)	$18,738	24
25	Taxable Income	(22) - (24)	$38,216	25
26	1 - Combined Tax Rate	Docket 3943	0.6500	26
27	Return and Tax Requirement	(25) / (26)	$58,794	27
28	**Storage Fixed Working Capital Requirement**	(24) + (27)	**$77,533**	28

Gas Cost Recovery (GCR)
Working Capital Calculation

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Supply Variable Costs**	EDA-1	$149,514,232	1
2	Credits		$323,191	2
3	Allowable Working Capital Costs	(1) - (2)	$149,191,041	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$9,973,319	5
6	Cost of Capital	Docket 4196	7.47%	6
7	Return on Working Capital Requirement	(5) x (6)	$744,592	7
8	Weighted Cost of Debt	Docket 4196	2.46%	8
9	Interest Expense	(5) x (8)	$244,974	9
10	Taxable Income	(7) - (9)	$499,618	10
11	1 - Combined Tax Rate	Rate Case	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$768,644	12
13	**Supply Variable Working Capital Requirement**	(9) + (12)	**$1,013,618**	13
14	**Storage Variable Product Costs**	EDA-1	$23,083,547	14
15	Less: Balancing Related LNG Commodity (to DAC)		($349,551)	15
16	Plus: Supply Related LNG O&M Costs		$430,129	16
17	Allowable Working Capital Costs	(14) + (15) + (16)	$23,164,124	17
18	Number of Days Lag	Docket 3943	24.40	18
19	Working Capital Requirement	[(17) * (18)] / 365	$1,548,506	19
20	Cost of Capital	Docket 4196	7.47%	20
21	Return on Working Capital Requirement	(19) x (20)	$115,609	21
22	Weighted Cost of Debt	Docket 4196	2.46%	22
23	Interest Expense	(19) x (22)	$38,036	23
24	Taxable Income	(21) - (23)	$77,573	24
25	1 - Combined Tax Rate	Rate Case	0.6500	25
26	Return and Tax Requirement	(24) / (25)	$119,343	26
27	**Storage Var. Product Working Capital Requir.**	(23) + (26)	**$157,379**	27

Gas Cost Recovery (GCR)
Working Capital Calculation

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Storage Variable Non-Product Costs**	EDA-1	$715,645	1
2	Credits		$0	2
3	Allowable Working Capital Costs	(1) - (2)	$715,645	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$47,840	5
6	Cost of Capital	Docket 4196	7.47%	6
7	Return on Working Capital Requirement	(5) x (6)	$3,572	7
8	Weighted Cost of Debt	Docket 4196	2.46%	8
9	Interest Expense	(5) x (8)	$1,175	9
10	Taxable Income	(7) - (9)	$2,397	10
11	1 - Combined Tax Rate	Docket 3943	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$3,687	12
13	**Storage Variable Non-product WC Requir.**	(9) + (12)	**$4,862**	13
	Working Capital Factor		0.68%	

Gas Cost Recovery (GCR)
Inventory Finance Cost Calculation

Line No.	Description (a)	Nov-10 (c)	Dec-10 (d)	Jan-11 (e)	Feb-11 (f)	Mar-11 (g)	Apr-11 (h)	May-11 (i)	Jun-11 (j)	Jul-11 (k)	Aug-11 (l)	Sep-11 (m)	Oct-11 (n)	Total (p)	Line No.
1	**Storage Inventory Balance**	$23,678,819	$20,322,012	$13,678,244	$8,537,946	$7,645,122	$11,597,943	$15,657,328	$19,556,035	$21,998,315	$24,331,900	$25,355,458	$25,445,792		1
2	Hedging														
3	Subtotal	$23,678,819	$20,322,012	$13,678,244	$8,537,946	$7,645,122	$11,597,943	$15,657,328	$19,556,035	$21,998,315	$24,331,900	$25,355,458	$25,445,792		
4	Cost of Capital	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%		2
5	Return on Working Capital Requirement	$1,767,824	$1,517,210	$1,021,196	$637,430	$570,773	$865,884	$1,168,952	$1,460,023	$1,642,360	$1,816,582	$1,892,999	$1,899,743	$16,260,973	3
6	Weighted Cost of Debt	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%		4
7	Interest Charges Financed	$581,621	$499,168	$335,978	$209,717	$187,787	$284,879	$384,590	$480,354	$540,343	$597,663	$622,804	$625,023	$5,349,927	5
8	Taxable Income	$1,186,202	$1,018,041	$685,218	$427,713	$382,986	$581,005	$784,362	$979,669	$1,102,017	$1,218,919	$1,270,194	$1,274,720		6
9	1 - Combined Tax Rate	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500		7
10	Return and Tax Requirement	$1,824,927	$1,566,217	$1,054,182	$658,019	$589,210	$893,853	$1,206,710	$1,507,184	$1,695,410	$1,875,260	$1,954,145	$1,961,107	$16,786,225	8
11	Working Capital Requirement	$2,406,548	$2,065,386	$1,390,160	$867,736	$776,996	$1,178,733	$1,591,300	$1,987,537	$2,235,753	$2,472,922	$2,576,950	$2,586,130	$22,136,152	9
12	Monthly Average	$200,546	$172,115	$115,847	$72,311	$64,750	$98,228	$132,608	$165,628	$186,313	$206,077	$214,746	$215,511	$1,844,679	10
13	**LNG Inventory Balance**	$6,078,502	$5,390,142	$5,259,313	$5,141,232	$5,010,403	$5,431,651	$5,869,189	$5,949,681	$5,942,291	$5,935,918	$5,930,339	$5,926,231		11
14	Cost of Capital	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%		12
15	Return on Working Capital Requirement	$453,811	$402,420	$392,652	$383,836	$374,069	$405,519	$438,184	$444,194	$443,642	$443,166	$442,750	$442,443	$5,066,687	13
16	Weighted Cost of Debt	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%		14
17	Interest Charges Financed	$149,306	$132,398	$129,184	$126,284	$123,070	$133,417	$144,164	$146,142	$145,960	$145,804	$145,667	$145,566	$1,666,961	15
18	Taxable Income	$304,506	$270,022	$263,468	$257,553	$250,999	$272,101	$294,020	$298,052	$297,682	$297,363	$297,083	$296,878		16
19	1 - Combined Tax Rate	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500		17
20	Return and Tax Requirement	$468,470	$415,418	$405,335	$396,235	$386,152	$418,617	$452,338	$458,542	$457,972	$457,481	$457,051	$456,735	$5,230,347	18
21	Working Capital Requirement	$617,776	$547,816	$534,519	$522,518	$509,222	$552,035	$596,503	$604,684	$603,932	$603,285	$602,718	$602,300	$6,897,308	19
22	Monthly Average	$51,481	$45,651	$44,543	$43,543	$42,435	$46,003	$49,709	$50,390	$50,328	$50,274	$50,226	$50,192	$574,776	20
23	System Balancing Factor	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%		21
24	Balancing Related Inventory Costs	$8,649	$7,669	$7,483	$7,315	$7,129	$7,728	$8,351	$8,466	$8,455	$8,446	$8,438	$8,432	$96,562	22
25	Supply Related Inventory Costs	$42,832	$37,982	$37,060	$36,228	$35,306	$38,274	$41,358	$41,925	$41,873	$41,828	$41,788	$41,759	$478,213	23

Gas Cost Recovery (GCR)
Forecasted Throughput (Dth)

Line No.	Rate Class (a)	Nov-10 (b)	Dec-10 (c)	Jan-11 (d)	Feb-11 (e)	Mar-11 (f)	Apr-11 (g)	May-11 (h)	Jun-11 (i)	Jul-11 (j)	Aug-11 (k)	Sep-11 (l)	Oct-11 (m)	Total Dec-Oct (o)	Line No.
1	**SALES (dth)**														1
2	Residential Non-Heating	54,674	70,653	82,003	87,827	78,867	70,493	60,870	46,251	39,370	33,934	33,888	39,380	698,210	2
3	Residential Heating	1,104,878	2,046,100	2,750,982	2,917,818	2,636,773	1,990,787	1,114,772	639,475	404,535	324,025	378,664	506,454	16,815,263	3
4	Small C&I	117,722	232,014	356,865	380,511	326,979	224,643	116,333	61,244	58,320	40,721	20,031	51,998	1,987,380	4
5	Medium C&I	245,065	316,147	531,317	549,856	504,006	338,204	214,722	138,440	103,872	90,017	92,049	129,197	3,252,891	5
6	Large LLF	62,795	97,937	153,717	158,224	137,892	107,709	55,345	26,984	14,905	11,792	11,419	23,738	862,458	6
7	Large HLF	18,732	23,835	29,934	30,628	28,931	23,651	20,009	14,777	8,634	7,369	16,900	12,321	235,719	7
8	Extra Large LLF	17,718	28,155	82,505	39,855	38,476	24,008	11,344	15,383	(3,544)	1,762	2,395	6,312	264,369	8
9	Extra Large HLF	23,499	15,430	17,613	16,990	13,647	10,833	8,847	7,313	5,294	8,524	7,107	4,774	139,872	9
10	**Total Sales**	1,645,083	2,830,271	4,004,935	4,181,709	3,765,571	2,790,327	1,602,241	949,867	631,387	518,143	562,453	774,174	24,256,162	10
11	**FT-2 TRANSPORTATION**														11
12	FT-2 Medium	56,696	65,953	92,049	107,202	85,850	58,377	51,880	35,711	23,967	22,905	32,724	16,688	650,002	12
13	FT-2 Large LLF	33,737	73,676	101,154	104,509	93,242	92,535	45,113	26,009	4,313	5,355	12,706	14,626	606,975	13
14	FT-2 Large HLF	9,542	13,532	16,043	14,213	16,201	16,958	11,920	10,748	7,608	8,756	9,494	9,731	144,746	14
15	FT-2 Extra Large LLF	1,972	5,872	3,321	3,179	2,858	1,781	2,912	595	63	32	24	187	22,796	15
16	FT-2 Extra Large HLF	1,261	1,442	2,068	2,104	2,242	1,830	1,595	1,425	499	1,401	1,085	1,251	18,203	16
17	**Total Transportation**	103,208	160,475	214,635	231,207	200,393	171,481	113,420	74,488	36,450	38,449	56,033	42,483	1,442,722	17
18	**Sales & FT-2 THROUGHPUT**														18
19	Residential Non-Heating	54,674	70,653	82,003	87,827	78,867	70,493	60,870	46,251	39,370	33,934	33,888	39,380	698,210	19
20	Residential Heating	1,104,878	2,046,100	2,750,982	2,917,818	2,636,773	1,990,787	1,114,772	639,475	404,535	324,025	378,664	506,454	16,815,263	20
21	Small C&I	117,722	232,014	356,865	380,511	326,979	224,643	116,333	61,244	58,320	40,721	20,031	51,998	1,987,380	21
22	Medium C&I	301,761	382,100	623,366	657,058	589,856	396,581	266,602	174,151	127,839	112,922	124,773	145,885	3,902,893	22
23	Large LLF	96,532	171,613	254,872	262,733	231,133	200,243	100,457	52,993	19,218	17,147	24,125	38,365	1,469,433	23
24	Large HLF	28,274	37,367	45,977	44,841	45,132	40,609	31,929	25,525	16,242	16,125	26,394	22,052	380,465	24
25	Extra Large LLF	19,690	34,027	85,826	43,034	41,334	25,789	14,256	15,978	(3,481)	1,794	2,419	6,499	287,165	25
26	Extra Large HLF	24,760	16,872	19,681	19,094	15,889	12,663	10,442	8,738	5,793	9,925	8,192	6,025	158,075	26
27	**Total Throughput**	1,748,292	2,990,746	4,219,570	4,412,916	3,965,964	2,961,808	1,715,661	1,024,355	667,837	556,592	618,486	816,658	25,698,884	27
28	**FT-1 TRANSPORTATION**														28
29	FT-1 Medium	59,346	89,198	95,487	101,298	73,714	50,252	27,811	27,885	22,319	26,981	4,746	40,243	619,282	29
30	FT-1 Large LLF	83,765	146,780	152,325	163,599	162,854	102,833	39,999	20,683	17,286	20,056	9,919	40,136	960,238	30
31	FT-1 Large HLF	52,628	62,622	68,796	60,289	62,716	60,582	39,871	42,971	33,143	42,469	43,218	53,217	622,524	31
32	FT-1 Extra Large LLF	44,775	68,688	88,230	102,397	77,283	58,306	19,835	31,650	12,580	14,403	(3,525)	23,828	538,450	32
33	FT-1 Extra Large HLF	385,003	435,867	498,904	502,143	486,468	496,349	363,223	362,348	342,107	365,961	407,901	375,662	5,021,935	33
34	**Total Transportation**	625,518	803,156	903,743	929,727	863,035	768,323	490,739	485,537	427,435	469,870	462,260	533,086	7,762,429	34
35	**Total THROUGHPUT**														35
36	Residential Non-Heating	54,674	70,653	82,003	87,827	78,867	70,493	60,870	46,251	39,370	33,934	33,888	39,380	698,210	36
37	Residential Heating	1,104,878	2,046,100	2,750,982	2,917,818	2,636,773	1,990,787	1,114,772	639,475	404,535	324,025	378,664	506,454	16,815,263	37
38	Small C&I	117,722	232,014	356,865	380,511	326,979	224,643	116,333	61,244	58,320	40,721	20,031	51,998	1,987,380	38
39	Medium C&I	361,107	471,298	718,853	758,356	663,571	446,833	294,413	202,036	150,158	139,903	129,519	186,128	4,522,174	39
40	Large LLF	180,298	318,394	407,197	426,332	393,987	303,077	140,456	73,677	36,505	37,203	34,045	78,501	2,429,671	40
41	Large HLF	80,902	99,989	114,773	105,130	107,849	101,191	71,799	68,496	49,385	58,594	69,612	75,269	1,002,988	41
42	Extra Large LLF	64,465	102,715	174,056	145,431	118,617	84,095	34,091	47,628	9,099	16,197	(1,106)	30,327	825,615	42
43	Extra Large HLF	409,764	452,739	518,585	521,237	502,357	509,012	373,665	371,086	347,900	375,886	416,094	381,687	5,180,010	43
44	**Total Throughput**	2,408,713	3,793,902	5,123,313	5,342,642	4,828,999	3,730,130	2,206,399	1,509,892	1,095,272	1,026,462	1,080,746	1,349,744	$\boxed{\textbf{33,461,312}}$	44

Gas Cost Recovery (GCR)
Design Winter Period Throughput (Dth)

Line No.	Rate Class (a)	Nov-10 (b)	Dec-10 (c)	Jan-11 (d)	Feb-11 (e)	Mar-11 (f)	Total (h)	% (i)	Line No.
1	**SALES (dth)**								1
2	Residential Non-Heating	62,142	87,267	92,619	86,727	77,017	405,772	2.18%	2
3	Residential Heating	1,679,470	2,865,969	3,128,414	2,976,258	2,363,319	13,013,430	69.86%	3
4	Small C&I	205,487	355,308	388,499	369,947	291,741	1,610,982	8.65%	4
5	Medium C&I	322,729	529,981	575,597	546,068	442,616	2,416,991	12.98%	5
6	Large LLF	87,355	154,591	169,524	161,687	125,992	699,149	3.75%	6
7	Large HLF	21,432	31,250	33,364	31,348	27,203	144,596	0.78%	7
8	Extra Large LLF	28,309	53,427	59,039	56,546	42,679	240,000	1.29%	8
9	Extra Large HLF	14,067	20,701	22,132	20,811	17,959	95,670	0.51%	9
10	Total Sales	2,420,992	4,098,495	4,469,187	4,249,392	3,388,525	18,626,590	100.00%	10
11	**FT-2 TRANSPORTATION**								11
12	FT-2 Medium	63,910	98,440	105,961	100,022	84,034	452,368		12
13	FT-2 Large LLF	57,825	103,142	113,215	108,039	83,850	466,071		13
14	FT-2 Large HLF	12,163	15,697	16,423	15,251	14,306	73,840		14
15	FT-2 Extra Large LLF	2,363	4,440	4,904	4,696	3,552	19,954		15
16	FT-2 Extra Large HLF	1,553	2,094	2,208	2,059	1,877	9,791		16
17	Total Transportation	137,814	223,813	242,711	230,067	187,619	1,022,024		17
18	**Sales & FT-2 THROUGHPUT**								18
19	Residential Non-Heating	62,142	87,267	92,619	86,727	77,017	405,772	2.07%	19
20	Residential Heating	1,679,470	2,865,969	3,128,414	2,976,258	2,363,319	13,013,430	66.23%	20
21	Small C&I	205,487	355,308	388,499	369,947	291,741	1,610,982	8.20%	21
22	Medium C&I	386,640	628,421	681,558	646,091	526,650	2,869,359	14.60%	22
23	Large LLF	145,181	257,733	282,739	269,725	209,842	1,165,220	5.93%	23
24	Large HLF	33,595	46,947	49,787	46,599	41,508	218,436	1.11%	24
25	Extra Large LLF	30,672	57,867	63,943	61,241	46,230	259,954	1.32%	25
26	Extra Large HLF	15,620	22,795	24,340	22,870	19,836	105,460	0.54%	26
27	Total Throughput	2,558,806	4,322,308	4,711,898	4,479,459	3,576,144	19,648,614	100.00%	27

nationalgrid

Thomas R. Teehan
Senior Counsel
Rhode Island

August 2, 2010

VIA HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: <u>Annual Gas Cost Recovery Reconciliation</u>

Dear Ms. Massaro:

In accordance with the provisions of the Gas Cost Recovery ("GCR") Clause Tariff, RIPUC NG No. 101, Section 2, Schedule A, Item 1.2, enclosed please find ten (10) copies of National Grid's[1] annual GCR reconciliation filing. The filing contains actual data for the twelve months ending June 30, 2010 and consists of seven schedules.

Schedule 1 presents the monthly gas cost-specific ending deferred balances for the period July 2009 through June 2010, resulting in an end-of-period over-collection balance of $81,189, as shown on the bottom of page 2. The $81,189 over-collection is comprised of five distinct cost components: Supply Fixed, Storage Fixed, Supply Variable, Storage Variable Product, and Storage Variable Non-Product. The monthly balances for each of the components are contained in Schedule 1.

Schedule 2 summarizes monthly gas costs according to the five components described above. Schedule 3 summarizes Gas Cost Collections for the period of July to October 2009. Schedule 4 summarizes Gas Cost Collections for the period of November 2009 to June 2010 which reflects the new structure approved in Docket No.4097. Schedule 5 presents the calculation of inventory financing costs. Working Capital costs are calculated in Schedule 6 and include the inventory financing and working capital cost calculations which are consistent with the methodology approved in Docket No. 3401. Finally, monthly firm throughput is summarized in Schedule 7. This schedule indicates that for the twelve month period that total firm throughput was 33,765,821 dths, which was comprised of firm sales, including Transitional Sales Service of 24,376,731 dths, FT-1 throughput of 7,508,379 dths and FT-2 throughput of 1,880,711 dths.

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[1] Submitted on behalf of The Narragansett Electric Company, d/b/a National Grid ("Company").

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If you have any questions related to this filing, please do not hesitate to contact me at (401) 784-7667 or Gary Beland at (781) 907-2129.

Very truly yours,

Thomas R. Teehan

cc: Leo Wold, Esq.
Steve Scialabba, Division
Bruce Oliver, Division

Docket No. 4097 – National Grid – Annual Gas Cost Recovery Filing ("GCR") - Service List as of 10/5/09

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File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Lmassaro@puc.state.ri.us Plucarelli@puc.state.ri.us Sccamara@puc.state.ri.us	401-780-2107 401-941-1691

National Grid
Rhode Island Service Area
Deferred Gas Cost Balance

Schedule 1
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	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	July-June
	31	31	30	31	30	31	31	28	31	30	31	30	365
	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	
I. Supply Fixed Cost Deferred													
Beginning Balance	($5,471,703)	($4,298,338)	($3,199,776)	($1,830,945)	($802,683)	($2,008,988)	($2,919,408)	($6,153,880)	($8,740,364)	($10,167,336)	($12,045,905)	($11,723,134)	
Supply Fixed Costs (net of cap rel)	$1,778,133	$1,669,816	$1,744,440	$1,701,127	$1,841,268	$1,804,066	$2,016,419	$2,007,574	$2,443,223	$1,096,842	$1,813,964	$1,780,218	$21,697,088
Capacity Release	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$13,563	$12,737	$13,306	$12,976	$13,693	$13,417	$14,996	$14,930	$18,170	$8,157	$13,490	$13,239	$162,674
Total Supply Fixed Costs	$1,791,696	$1,682,553	$1,757,746	$1,714,103	$1,854,961	$1,817,483	$2,031,415	$2,022,504	$2,461,393	$1,104,999	$1,827,454	$1,793,457	$21,859,762
Supply Fixed - Collections	$613,147	$580,013	$386,332	$684,444	$1,747,051	$2,570,825	$5,106,609	$4,447,380	$3,723,869	$2,203,081	$1,292,179	$806,558	$24,161,488
Prelim. Ending Balance	($4,293,154)	($3,195,798)	($1,828,362)	($801,286)	($694,774)	($2,762,330)	($5,994,602)	($8,578,755)	($10,002,841)	($11,265,418)	($11,510,630)	($10,736,235)	
Month's Average Balance	($4,882,429)	($3,747,068)	($2,514,069)	($1,316,115)	($748,728)	($2,385,659)	($4,457,005)	($7,366,318)	($9,371,603)	($10,716,377)	($11,778,267)	($11,229,685)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($5,183)	($3,978)	($2,583)	($1,397)	($769)	($2,533)	($4,732)	($7,064)	($9,949)	($11,010)	($12,504)	($11,537)	($73,240)
Gas Procurement Incentive/(penalty)					$0	$0	$0	$0	$0	$0	$0	$0	$0
NGPMP Credit	$0	$0	$0	$0	$1,313,445	$154,545	$154,545	$154,545	$154,545	$769,477	$200,000	$200,000	$3,101,104
Supply Fixed Ending Balance	($4,298,338)	($3,199,776)	($1,830,945)	($802,683)	$617,902	($2,919,408)	($6,153,880)	($8,740,364)	($10,167,336)	($12,045,905)	($11,723,134)	($10,947,773)	
II. Storage Fixed Cost Deferred													
Beginning Balance	($1,057,907)	($395,492)	$286,466	$1,039,672	$1,674,812	$1,850,028	$1,670,455	$206,359	($661,406)	($1,481,605)	($1,862,153)	($1,622,104)	
Storage Fixed Costs	$946,348	$947,287	$943,341	$947,694	$943,967	$952,357	$721,613	$1,086,439	$800,927	$549,607	$815,928	$853,488	$10,508,997
LNG Demand to DAC	($77,196)	($77,196)	($77,196)	($77,196)	($77,196)	($77,196)	($39,815)	($84,534)	($51,506)	($13,671)	($58,303)	($64,296)	($775,301)
Supply Related LNG O & M	$47,253	$47,253	$47,253	$47,253	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$601,408
Working Capital	$6,990	$6,997	$6,967	$7,000	$6,829	$6,892	$5,454	$7,834	$5,957	$4,369	$6,018	$6,252	$77,560
Total Storage Fixed Costs	$923,396	$924,342	$920,366	$924,752	$925,149	$933,602	$738,802	$1,061,289	$806,927	$591,855	$815,192	$846,994	$10,412,665
TSS Peaking Collections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Storage Fixed - Collections	$260,209	$242,327	$167,840	$291,053	$751,743	$1,115,042	$2,203,893	$1,928,836	$1,625,989	$970,686	$573,295	$360,715	$10,491,628
Prelim. Ending Balance	($394,721)	$286,524	$1,038,991	$1,673,371	$1,848,218	$1,668,587	$205,364	($661,188)	($1,480,468)	($1,860,436)	($1,620,256)	($1,135,825)	
Month's Average Balance	($726,314)	($54,484)	$662,729	$1,356,522	$1,761,515	$1,759,307	$937,909	($227,414)	($1,070,937)	($1,671,021)	($1,741,204)	($1,378,965)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($771)	($58)	$681	$1,440	$1,810	$1,868	$996	($218)	($1,137)	($1,717)	($1,849)	($1,417)	($372)
Storage Fixed Ending Balance	($395,492)	$286,466	$1,039,672	$1,674,812	$1,850,028	$1,670,455	$206,359	($661,406)	($1,481,605)	($1,862,153)	($1,622,104)	($1,137,242)	
III. Variable Supply Cost Deferred													
Beginning Balance	$43,804,405	$42,250,882	$41,402,569	$43,677,832	$44,286,232	$46,972,599	$56,312,439	$45,371,861	$34,931,612	$24,325,204	$22,125,549	$17,535,102	
Variable Supply Costs	$5,032,342	$5,404,592	$6,473,233	$6,851,509	$18,065,386	$31,739,269	$33,753,812	$28,292,074	$21,711,082	$17,039,931	$6,791,156	$4,668,653	$185,823,039
Variable Delivery Storage	$0	$0	$0	$0	$0	($29,074)	($89,361)	($69,473)	($23,075)	$0	$0	$0	($210,983)
Variable Injections Storage	$10,712	$9,924	$9,781	$8,830	($5,163)	($488)	$0	$0	($1,472)	($16,828)	($17,350)	($13,932)	($15,985)
Fuel Cost Allocated to Storage	$58,527	$50,336	$43,713	$50,892	($33,017)	($125,895)	($380,174)	($291,966)	($130,763)	($88,698)	($92,134)	($74,192)	($1,013,371)
Working Capital	$38,914	$41,685	$49,785	$52,718	$134,066	$234,884	$247,530	$207,716	$160,307	$125,939	$49,691	$34,065	$1,377,297
Total Supply Variable Costs	$5,140,495	$5,506,538	$6,576,511	$6,963,948	$18,161,271	$31,818,695	$33,531,807	$28,138,351	$21,716,079	$17,060,343	$6,731,362	$4,614,594	$185,959,997
Supply Variable - Collections	$6,672,963	$6,399,233	$4,344,932	$7,401,685	$15,520,233	$22,531,906	$44,516,981	$38,605,179	$32,336,891	$19,284,258	$11,349,178	$7,191,128	$216,154,567
Deferred Responsibility	$66,711	$0	$0	$0	$1,527	$1,746	$9,352	$11,904	$17,035	($410)	($6,327)	($8,464)	
Prelim. Ending Balance	$42,205,226	$41,358,187	$43,634,148	$43,240,094	$46,925,744	$56,257,643	$45,317,914	$34,893,129	$24,293,766	$22,101,699	$17,514,061	$14,967,032	
Month's Average Balance	$43,004,815	$41,804,535	$42,518,359	$43,458,963	$45,605,988	$51,615,121	$50,815,177	$40,132,495	$29,612,689	$23,213,451	$19,819,805	$16,251,067	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	$45,656	$44,382	$43,683	$46,138	$46,855	$54,797	$53,948	$38,483	$31,438	$23,849	$21,042	$16,696	$466,967
Gas Procurement Incentive/(penalty)	$0	$0	$0	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,000,000
Supply Variable Ending Balance	$42,250,882	$41,402,569	$43,677,832	$44,286,232	$46,972,599	$56,312,439	$45,371,861	$34,931,612	$24,325,204	$22,125,549	$17,535,102	$14,983,728	

National Grid
Rhode Island Service Area
Deferred Gas Cost Balance

	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	July-June
	31	31	30	31	30	31	31	28	31	30	31	30	365
	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	
IVa. Storage Variable Product Cost Deferred													
Beginning Balance	($29,697,766)	($30,294,688)	($30,671,149)	($30,614,921)	($30,418,752)	($29,547,847)	($25,329,368)	($13,137,611)	($4,815,097)	($2,018,864)	($2,171,969)	($1,778,549)	
Storage Variable Prod. Costs - LNG	$126,042	$102,723	$166,255	$259,580	$31,545	$743,101	$820,931	$1,161,436	($86,720)	$205,101	$157,300	$152,156	$3,839,450
Storage Variable Prod. Costs - UG	$4,445	$170,483	$190,794	$731,945	$933,168	$4,102,105	$12,782,776	$8,449,142	$3,807,808	$70,513	$374,116	$86,591	$31,703,886
Supply Related LNG to DAC	($21,175)	($17,258)	($27,931)	($43,609)	($5,299)	($124,841)	($137,916)	($195,121)	$14,569	($34,457)	($26,426)	($25,562)	($645,028)
Supply Related LNG O & M	$32,857	$32,857	$32,857	$32,857	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$418,181
Inventory Financing - LNG	$44,813	$39,435	$42,407	$47,872	$48,072	$44,219	$41,050	$34,733	$42,932	$42,951	$43,624	$44,153	$516,261
Inventory Financing - UG	$319,576	$343,406	$368,099	$379,460	$385,002	$331,274	$222,978	$143,100	$92,455	$148,334	$178,811	$216,366	$3,128,860
Working Capital	$1,084	$2,203	$2,761	$7,481	$7,402	$35,371	$100,410	$70,288	$28,048	$2,060	$4,022	$1,852	$262,982
Total Storage Variable Product Costs	$507,643	$673,850	$775,241	$1,415,585	$1,395,758	$4,971,320	$13,644,500	$9,576,405	$3,843,690	$468,763	$760,743	$508,844	$38,542,341
Storage Variable Product Collections	$1,072,736	$1,017,966	$687,546	$1,187,036	$494,064	$723,726	$1,432,335	$1,245,287	$1,043,832	$619,716	$365,227	$231,454	$10,120,925
Prelim. Ending Balance	($30,262,860)	($30,638,804)	($30,583,454)	($30,386,371)	($29,517,058)	($25,300,253)	($13,117,203)	($4,806,493)	($2,015,239)	($2,169,817)	($1,776,453)	($1,501,159)	
Month's Average Balance	($29,980,313)	($30,466,746)	($30,627,302)	($30,500,646)	($29,967,905)	($27,424,050)	($19,223,285)	($8,972,052)	($3,415,168)	($2,094,341)	($1,974,211)	($1,639,854)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($31,828)	($32,345)	($31,466)	($32,381)	($30,789)	($29,115)	($20,408)	($8,603)	($3,626)	($2,152)	($2,096)	($1,685)	($226,494)
Storage Variable Product Ending Bal.	($30,294,688)	($30,671,149)	($30,614,921)	($30,418,752)	($29,547,847)	($25,329,368)	($13,137,611)	($4,815,097)	($2,018,864)	($2,171,969)	($1,778,549)	($1,502,844)	
IVb. Stor Var Non-Prod Cost Deferred													
Beginning Balance	($4,255,144)	($4,426,026)	($4,582,079)	($4,703,734)	($4,875,985)	($4,687,669)	($4,242,572)	($3,578,583)	($3,081,318)	($2,677,290)	($2,445,835)	($2,277,627)	
Storage Variable Non-prod. Costs	$0	$0	$0	$0	$39,974	$195,754	$221,572	$123,017	$91,247	$1,583	$6,548	$2,557	$682,252
Variable Delivery Storage Costs	$0	$0	$0	$0	$9,610	$47,211	$53,219	$29,511	$21,958	$405	$1,725	$687	$164,326
Variable Injection Storage Costs	($10,712)	($9,924)	($9,781)	($8,830)	$2,094	$1,472	$523	$1,291	$1,270	$12,972	$11,998	$10,301	$2,673
Fuel Costs Allocated to Storage	($58,527)	($50,336)	($43,713)	($50,892)	$7,844	$6,675	$3,041	$6,619	$5,743	$47,348	$48,294	$41,793	($36,112)
Working Capital	($528)	($460)	($408)	($456)	$443	$1,867	$2,070	$1,193	$894	$463	$510	$412	$6,001
Total Storage Var Non-product Costs	($69,768)	($60,720)	($53,902)	($60,177)	$59,965	$252,979	$280,425	$161,631	$121,112	$62,771	$69,075	$55,749	$819,140
Storage Var Non-Product Collections	$96,509	$90,553	$62,985	$106,992	($133,262)	($196,856)	($387,713)	($338,825)	($285,971)	($171,314)	($101,639)	($64,846)	($1,323,387)
Prelim. Ending Balance	($4,421,421)	($4,577,300)	($4,698,966)	($4,870,903)	($4,682,759)	($4,237,834)	($3,574,434)	($3,078,127)	($2,674,235)	($2,443,205)	($2,275,121)	($2,157,032)	
Month's Average Balance	($4,338,282)	($4,501,663)	($4,640,522)	($4,787,318)	($4,779,372)	($4,462,751)	($3,908,503)	($3,328,355)	($2,877,777)	($2,560,248)	($2,360,478)	($2,217,330)	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($4,606)	($4,779)	($4,768)	($5,082)	($4,910)	($4,738)	($4,149)	($3,192)	($3,055)	($2,630)	($2,506)	($2,278)	($46,694)
Storage Var Non-Product Ending Bal.	($4,426,026)	($4,582,079)	($4,703,734)	($4,875,985)	($4,687,669)	($4,242,572)	($3,578,583)	($3,081,318)	($2,677,290)	($2,445,835)	($2,277,627)	($2,159,310)	
GCR Deferred Summary													
Beginning Balance	$3,321,883	$2,836,338	$3,236,031	$7,567,905	$9,863,623	$15,244,987	$25,727,275	$23,165,448	$18,213,744	$8,651,672	$4,272,834	$813,383	
Gas Costs	$8,233,439	$8,663,400	$9,903,551	$10,878,492	$22,274,646	$39,697,402	$50,078,061	$40,781,235	$28,827,072	$19,149,327	$10,136,644	$7,766,374	$256,389,643
Working Capital	$60,024	$63,163	$72,411	$79,720	$162,432	$292,431	$370,459	$301,961	$213,376	$140,988	$73,730	$55,820	$1,886,515
Total Costs	$8,293,462	$8,726,563	$9,975,962	$10,958,211	$22,437,078	$39,989,833	$50,448,521	$41,083,197	$29,040,448	$19,290,315	$10,210,374	$7,822,194	$258,276,158
Collections	$8,782,275	$8,330,092	$5,649,635	$9,671,210	$18,381,356	$26,746,389	$52,881,457	$45,899,761	$38,461,645	$22,906,017	$13,471,913	$8,516,545	$259,698,295
Prelim. Ending Balance	$2,833,071	$3,232,809	$7,562,358	$8,854,906	$13,919,345	$28,488,431	$23,294,339	$18,348,883	$8,792,547	$5,035,971	$1,011,296	$119,031	
Month's Average Balance	$3,077,477	$3,034,573	$5,399,194	$8,211,405	$11,891,484	$21,866,709	$24,510,807	$20,757,165	$13,503,145	$6,843,822	$2,642,065	$466,207	
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	$3,267	$3,222	$5,547	$8,718	$12,197	$20,279	$25,654	$19,407	$13,671	$6,341	$2,087	($221)	$120,168
Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$1,000,000	$1,313,445	($1,313,445)	$0	$0	$0	$0	$0	$0	
NGPMP Credit						$1,467,990	$154,545	$154,545	$154,545	$769,477	$200,000	$200,000	$3,101,104
Ending Bal. W/ Interest	$2,836,338	$3,236,031	$7,567,905	$9,863,623	$15,244,987	$25,727,275	$23,165,448	$18,213,744	$8,651,672	$4,272,834	$813,383	($81,189)	
Under/(Over)-collection	($488,813)	$396,471	$4,326,327	$1,287,001	$4,055,722	$13,243,444	($2,432,936)	($4,816,565)	($9,421,197)	($3,615,702)	($3,261,538)	($694,351)	

	Jul-09 actual	Aug-09 actual	Sep-09 actual	Oct-09 actual	Nov-09 actual	Dec-09 actual	Jan-10 actual	Feb-10 actual	Mar-10 actual	Apr-10 actual	May-10 actual	Jun-10 actual	July-June
SUPPLY FIXED COSTS - Pipeline & Supplier													
Merrill Lynch													
Algonquin	$636,746	$648,477	$650,475	$640,028	$646,473	$618,604	$615,021	$435,710	$657,677	$634,403	$644,043	$645,943	$7,473,601
TETCO/Texas Eastern	$517,240	$516,568	$535,814	$496,704	$500,954	$538,562	$594,551	$440,315	$500,043	$511,238	$512,362	$490,411	$6,154,762
Tennessee	$721,128	$639,779	$683,253	$694,735	$694,705	$684,131	$679,313	$675,601	$677,495	$674,132	$669,161	$660,233	$8,153,665
Dominion	$3,170	$2,340	$2,340	$2,340									
Columbia	$305,525	$302,358	$302,358	$309,792	$308,698	$310,895	$249,120	$274,112	$285,016	$302,632	$287,945	$314,369	$3,552,820
Westerly Lateral	$63,103	$60,153	$60,149	$60,153	$60,149	$60,153	$58,883	$58,879	$58,879	$58,879	$58,879	$58,879	$717,139
Others	$57,746	$60,724	$57,783	$55,659	$88,971	$95,457	$309,129	$122,956	$264,113	$467,853	$198,746	$158,668	$1,937,806
Less Credits from Insourcing	$83,333	$83,333	$83,333	$83,333									$0
Less Credits from Mkter Releases	$443,193	$477,250	$464,398	$474,950	$458,683	$503,735	$489,599	$0	$0	$1,552,294	$557,172	$548,285	$5,969,558
TOTAL SUPPLY FIXED COSTS - Pipeline & Supplier	$1,778,133	$1,669,816	$1,744,440	$1,701,127	$1,841,268	$1,804,066	$2,016,419	$2,007,574	$2,443,223	$1,096,842	$1,813,964	$1,780,218	$21,697,088
STORAGE FIXED COSTS - Facilities													
Texas Eastern SS-1 Demand	$87,781	$88,193	$87,459	$88,641	$88,743	$89,527	$86,713	$88,612	$88,599	$88,465	$88,192	$89,201	$1,060,126
Dominion GSS Demand	$83,456	$83,456	$83,456	$83,456	$83,348	$83,348	$83,348	$83,348	$83,348	$83,348	$83,348	$83,348	$1,000,612
Tennessee FSMA Demand	$39,428	$39,428	$39,428	$39,428	$39,428	$39,428	$40,627	$39,426	$39,424	$39,426	$39,428	$39,428	$474,330
Columbia FSS Demand	$0	$0	$0	$0	$0	$0	$0	$38,899	$9,727	$3	$0	$0	$48,629
Keyspan LNG Tank Lease Payment	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$201,180	$163,740	$163,740	$163,740	$163,740	$1,958,640
TOTAL FIXED STORAGE COSTS	$368,166	$368,578	$367,844	$369,025	$369,019	$369,804	$368,188	$451,466	$384,839	$374,983	$374,709	$375,717	$4,542,337
STORAGE FIXED COSTS - Delivery													
STORAGE DELIVERY FIXED COST $	$578,182	$578,710	$575,497	$578,669	$574,948	$582,553	$353,425	$634,973	$416,088	$174,625	$441,219	$477,771	$5,966,660
TOTAL STORAGE FIXED	$946,348	$947,287	$943,341	$947,694	$943,967	$952,357	$721,613	$1,086,439	$800,927	$549,607	$815,928	$853,488	$10,508,997
TOTAL FIXED COSTS	$2,724,481	$2,617,103	$2,687,781	$2,648,821	$2,785,234	$2,756,423	$2,738,032	$3,094,013	$3,244,150	$1,646,449	$2,629,892	$2,633,706	$32,206,086
VARIABLE SUPPLY COSTS (Includes Injections)													
Total Pipeline Commodity Charges	$2,697,630	$2,242,130	$2,227,056	$2,350,752	$8,974,179	$19,219,155	$28,569,254	$20,002,697	$12,003,958	$12,129,028	$4,247,259	$3,096,371	$117,759,470
Hedging	$2,657,578	$3,213,256	$3,807,884	$4,752,118	$9,053,170	$13,942,299	$6,955,611	$8,908,621	$8,983,081	$4,890,493	$2,236,083	$1,722,863	$71,123,057
Costs of Injections													$0
Tennessee PCB Refunds						($594,636)				($194,663)			($789,299)
TOTAL VARIABLE SUPPLY COSTS	$5,355,208	$5,455,386	$6,034,940	$7,102,871	$18,027,350	$33,161,453	$35,524,865	$28,911,319	$20,987,039	$17,019,521	$6,483,343	$4,819,235	$188,882,527
VARIABLE STORAGE COSTS													
Underground Storage	$4,445	$170,483	$190,794	$731,945	$933,168	$4,102,105	$12,782,776	$8,449,142	$3,807,808	70,513	374,116	86,591	$31,703,886
LNG Withdrawals/Westerly Trucking	$126,042	$102,723	$166,255	$259,580	$31,545	$743,101	$820,931	$1,161,436	($86,720)	$205,101	$157,300	$152,156	$3,839,450
TOTAL VARIABLE STORAGE COSTS	$130,487	$273,207	$357,048	$991,525	$964,712	$4,845,206	$13,603,707	$9,610,578	$3,721,088	$275,615	$531,416	$238,748	$35,543,336
TOTAL VARIABLE COSTS	$5,485,695	$5,728,592	$6,391,988	$8,094,396	$18,992,062	$38,006,659	$49,128,572	$38,521,897	$24,708,127	$17,295,136	$7,014,758	$5,057,982	$224,425,864
TOTAL SUPPLY COSTS AFTER CREDITS	$8,210,176	$8,345,696	$9,079,769	$10,743,217	$21,777,296	$40,763,082	$51,866,604	$41,615,910	$27,952,277	$18,941,585	$9,644,650	$7,691,688	$256,631,949
Storage Costs for FT-2 Calculation													
Storage Fixed Costs - Facilities	$368,166	$368,578	$367,844	$369,025	$369,019	$369,804	$368,188	$451,466	$384,839	$374,983	$374,709	$375,717	$4,542,337
Storage Fixed Costs - Deliveries	$578,182	$578,710	$575,497	$578,669	$574,948	$582,553	$353,425	$634,973	$416,088	$174,625	$441,219	$477,771	$5,966,660
Variable Delivery Costs	$0	$0	$0	$0	$0	$29,074	$89,361	$69,473	$23,075	$0	$0	$0	$210,983
Variable Injection Costs	$10,712	$9,924	$9,781	$8,830	$5,163	$488	$0	$0	$1,472	$16,828	$17,350	$13,932	$94,480
Fuel Costs Allocated to Storage	$58,527	$50,336	$43,713	$50,892	$33,017	$125,895	$380,174	$291,966	$130,763	$88,698	$92,134	$74,192	$1,420,309
Total Storage Costs	$1,015,588	$1,007,548	$996,835	$1,007,416	$982,146	$1,107,814	$1,191,149	$1,447,878	$956,237	$655,133	$925,413	$941,612	$12,234,770
Pipeline Variable	$5,355,208	$5,455,386	$6,034,940	$7,102,871	$18,027,350	$33,161,453	$35,524,865	$28,911,319	$20,987,039	$17,019,521	$6,483,343	$4,819,235	
Less Non-firm Gas Costs	$99,348	$83,407	$93,393	$216,675	$181,276	$338,069	$95,540	$115,082	$225,141	$257,847	$12,824	$76,395	
Less Company Use	$185,146	$214,622	$40,467	$62,091	$122,766	$122,766	$556,038	$51,731	$151,278	$68,408	$77,871	$171,674	
Less Manchester St Balancing	$28,981	$9,133	$7,615	$8,643	$9,339	$9,339	$14,405	$14,123	($193,039)	$0	$10,016	$0	
Plus Cashout													
Less Mkter Over-takes	($4,856)	$27,462	$51,925	$73,217	$136,755	$68,890	$229,565	$158,493	$53,746	$10,945	$13,761	$6,988	
Less Mkter W/drawals	$121,467	($166,507)	($462,691)	$73,232	$158,988	$1,071,261	$1,082,834	$414,038	($712,204)	($155,628)	($58,954)	$21,544	
Plus Mkter Undertakes	($61,560)	($57,952)	($9,465)	$9,378	$468,531	$112,153	$122,972	$48,442	$169,310	$112,075	$277,357	$38,381	
Plus Mkter Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Storage Service Charge													
Plus Pipeline Srchg/Credit	$168,779	$175,275	$178,467	$173,118	$178,630	$75,987	$84,357	$85,781	$79,654	$89,906	$85,975	$87,638	
TOTAL FIRM COMMODITY COSTS	$5,032,342	$5,404,592	$6,473,233	$6,851,509	$18,065,386	$31,739,269	$33,753,812	$28,292,074	$21,711,082	$17,039,931	$6,791,156	$4,668,653	

National Grid
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GCR Gas Cost Collections

	Jul-09 actual	Aug-09 actual	Sep-09 actual	Oct-09 actual	Total July-Oct
I. Supply Fixed Cost Collections --					
(a) RH, SM, Med C & I dth	680,539	649,380	427,032	794,805	2,551,757
Supply Fixed Cost Factor	$0.7783	$0.7780	$0.7841	$0.7770	
Res & Small C & I collections	$529,659	$505,213	$334,820	$617,533	$1,987,225
(b) Res Non-Heat dth	43,168	33,686	32,573	40,239	149,666
Supply Fixed Cost Factor	$0.5510	$0.5503	$0.5501	$0.5528	
Res Non-heat collections	$23,786	$18,539	$17,917	$22,244	$82,486
(c) C & I Large LLF dth	11,686	23,220	(2,199)	32,693	65,400
Supply Fixed Cost Factor	$0.9219	$0.7970	$0.7496	$0.7835	
C & I Large LLF collections	$10,774	$18,507	($1,648)	$25,615	$53,248
(d) C & I Large HLF dth	22,295	23,007	32,896	15,163	93,360
Supply Fixed Cost Factor	$0.5595	$0.8007	$0.5639	$0.3121	
C & I Large HLF collections	$12,475	$18,421	$18,551	$4,733	$54,180
(e) C & I Extra Large LLF dth	(53,429)	4,522	3,983	5,216	(39,707)
Supply Fixed Cost Factor	($0.4818)	$0.7784	$0.7782	$0.7782	
C & I XL LLF collections	$25,744	$3,520	$3,100	$4,059	$36,423
(f) C & I Extra Large HLF dth	16,519	23,265	19,997	15,096	74,876
Supply Fixed Cost Factor	$0.6483	$0.6797	$0.6797	$0.6797	
C & I XL HLF collections	$10,709	$15,813	$13,592	$10,260	$50,374
sub-total Dth	720,779	757,080	514,282	903,211	2,895,351
sub-total Supply Fixed Collections	**$613,147**	**$580,013**	**$386,332**	**$684,444**	**$2,263,936**
II. Storage Fixed Cost Collections --					
(a) RH, SM, Med C & I dth	680,539	649,380	427,032	794,805	2,551,757
Storage Fixed Cost Factor	$0.3082	$0.3081	$0.3105	$0.3077	
Res & Small C & I collections	$209,740	$200,059	$132,586	$244,538	$786,923
(b) Res Non-Heat dth	43,168	33,686	32,573	40,239	149,666
Storage Fixed Cost Factor	$0.2188	$0.2185	$0.2184	$0.2195	
Res Non-heat collections	$9,446	$7,362	$7,115	$8,834	$32,757
(c) C & I Large LLF dth	11,686	23,220	(2,199)	32,693	65,400
Storage Fixed Cost Factor	$0.3651	$0.3156	$0.2966	$0.3103	
C & I Large LLF collections	$4,267	$7,329	($652)	$10,144	$21,088
(d) C & I Large HLF dth	22,295	23,007	32,896	15,163	93,360
Storage Fixed Cost Factor	$0.2222	$0.3180	$0.2240	$0.1240	
C & I Large HLF collections	$4,954	$7,316	$7,367	$1,880	$21,517
(e) C & I XL LLF dth	(53,429)	4,522	3,983	5,216	(39,707)
Storage Fixed Cost Factor	($0.1908)	$0.3083	$0.3083	$0.3081	
C & I XL LLF collections	$10,194	$1,394	$1,228	$1,607	$14,423
(f) C & I XL HLF dth	16,519	23,265	19,997	15,096	74,876
Storage Fixed Cost Factor	$0.2283	$0.2394	$0.2393	$0.2393	
C & I XL HLF collections	$3,771	$5,569	$4,786	$3,613	$17,739

	Jul-09 actual	Aug-09 actual	Sep-09 actual	Oct-09 actual	Total July-Oct
(g) FT-2 dth	56,597	42,195	48,898	64,848	212,537
Storage Fixed Cost Factor	$0.3152	$0.3152	$0.3151	$0.3152	
FT-2 collection	$17,837	$13,298	$15,410	$20,437	$66,982
sub-total Dth	777,375	799,275	563,180	968,059	3,107,888
sub-total Storage Fixed Collections	**$260,209**	**$242,327**	**$167,840**	**$291,053**	**$961,429**
III. Variable Supply Cost Collections --					
(a) Firm Sales dth	724,500	769,226	516,268	897,817	2,907,811
Variable Supply Cost Factor	$9.1468	$8.1751	$8.2270	$8.1675	
Variable Supply collections	**$6,626,855**	**$6,288,512**	**$4,247,330**	**$7,332,933**	**$24,495,630**
(b) TSS Sales dth	5,346	13,917	1,072	(5,042)	15,293
TSS Variable Supply Cost F.	$0.0000	$0.0000	$0.0000	$0.0000	
TSS Surcharge collections	**$0**	**$0**	**$0**	**$0**	**$0**
(c) NGV Sales dth	676	1,607	1,607	1,547	5,437
Variable Supply Cost Factor	$8.1815	$8.1815	$7.9273	$8.1815	
Variable Supply collections	**$5,534**	**$13,145**	**$12,737**	**$12,661**	**$44,077**
(d) Default Sales dth	3,697	8,891	7,733	5,111	25,431
Variable Supply Cost Factor	$10.9750	$10.9750	$10.9750	$10.9750	
Variable Supply collections	**$40,574**	**$97,575**	**$84,865**	**$56,091**	**$279,106**
TOTAL Variable Supply Collections	**$6,672,963**	**$6,399,233**	**$4,344,932**	**$7,401,685**	**$24,818,813**
IVa. Storage Variable Product Cost Collections --					
(a) Firm Sales dth	724,500	769,226	516,268	897,817	2,907,811
Variable Supply Cost Factor	$1.4807	$1.3234	$1.3318	$1.3221	
Stor Var Product collections	**$1,072,736**	**$1,017,966**	**$687,546**	**$1,187,036**	**$3,965,284**
IVb. Storage Variable Non-product Cost Collections --					
(a) Firm Sales dth	720,779	757,080	514,282	903,211	2,895,351
Variable Supply Cost Factor	$0.1269	$0.1146	$0.1140	$0.1120	
Stor Var Non-Product collec	$91,446	$86,779	$58,611	$101,191	$338,027
(b) FT-2 dth	56,597	42,195	48,898	64,848	212,537
Variable Supply Cost Factor	$0.0895	$0.0894	$0.0895	$0.0895	
Stor Var Non-Product collec	$5,063	$3,774	$4,374	$5,801	**$19,012**
Total Firm Sales/FT-2 dth	777,375	799,275	563,180	968,059	3,107,888
Stor Var Non-Product collec	**$96,509**	**$90,553**	**$62,985**	**$106,992**	**$357,039**
Total Gas Cost Collections	**$8,715,564**	**$8,330,092**	**$5,649,635**	**$9,671,210**	**$32,366,501**

National Grid
Rhode Island Service Area
GCR Gas Cost Collections

	Nov-09 actual	Dec-09 actual	Jan-10 actual	Feb-10 actual	Mar-10 actual	Apr-10 actual	May-10 actual	Jun-10 actual	Total Nov-June
I. Supply Fixed Cost Collections --									
(a) Low Load dth	1,599,798	2,394,199	4,798,717	4,196,088	3,502,394	2,066,076	1,195,701	716,684	20,469,658
Supply Fixed Cost Factor	$1.0416	$1.0352	$1.0347	$1.0347	$1.0353	$1.0299	$1.0321	$1.0357	
Low Load collections	$1,666,284	$2,478,486	$4,965,365	$4,341,584	$3,626,189	$2,127,856	$1,234,044	$742,293	$21,182,101
(b) High Load dth	110,848	129,380	197,908	148,327	136,864	105,406	81,283	89,247	999,262
Supply Fixed Cost Factor	$0.7286	$0.7137	$0.7137	$0.7133	$0.7137	$0.7137	$0.7152	$0.7201	
High Load collections	$80,767	$92,339	$141,244	$105,796	$97,680	$75,225	$58,135	$64,265	$715,451
sub-total Dth	1,710,647	2,523,579	4,996,625	4,344,415	3,639,258	2,171,482	1,276,984	805,931	21,468,920
TOTAL Supply Fixed Collections	**$1,747,051**	**$2,570,825**	**$5,106,609**	**$4,447,380**	**$3,723,869**	**$2,203,081**	**$1,292,179**	**$806,558**	**$21,897,552**
II. Storage Fixed Cost Collections --									
(a) Low Load dth	1,599,798	2,394,199	4,798,717	4,196,088	3,502,394	2,066,076	1,195,701	716,684	20,469,658
Storage Fixed Cost Factor	$0.4215	$0.4189	$0.4187	$0.4187	$0.4189	$0.4167	$0.4176	$0.4191	
Low Load collections	$674,245	$1,002,893	$2,009,186	$1,756,779	$1,467,300	$861,015	$499,342	$300,361	$8,571,121
(b) High Load dth	110,848	129,380	197,908	148,327	136,864	105,406	81,283	89,247	999,262
Storage Fixed Cost Factor	$0.2946	$0.2886	$0.2886	$0.2884	$0.2886	$0.2886	$0.2892	$0.2912	
High Load collections	$32,660	$37,339	$57,114	$42,782	$39,498	$30,419	$23,509	$25,986	$289,307
(c) FT-2 dth	111,676	186,325	342,697	321,980	296,865	197,390	125,640	85,600	1,668,174
Storage Fixed Cost Factor	$0.4015	$0.4015	$0.4015	$0.4015	$0.4015	$0.4015	$0.4015	$0.4015	
FT-2 collection	$44,838	$74,810	$137,593	$129,275	$119,191	$79,252	$50,444	$34,368	$669,771
sub-total Dth	1,822,323	2,709,904	5,339,321	4,666,395	3,936,123	2,368,872	1,402,624	891,531	$23,137,094
TOTAL Storage Fixed Collections	**$751,743**	**$1,115,042**	**$2,203,893**	**$1,928,836**	**$1,625,989**	**$970,686**	**$573,295**	**$360,715**	**$9,530,199**
III. Variable Supply Cost Collections --									
(a) Firm Sales dth	1,710,647	2,523,579	4,996,625	4,344,415	3,639,258	2,171,482	1,276,984	805,931	21,468,920
Variable Supply Cost Factor	$8.9363	$8.8734	$8.8696	$8.8690	$8.8747	$8.8302	$8.8494	$8.8859	
Variable Supply collections	$15,286,855	$22,392,807	$44,317,917	$38,530,442	$32,297,215	$19,174,597	$11,300,486	$7,161,410	$190,461,729
(b) TSS Sales dth	16,977	5,119	12,462	9,844	9,896	9,028	2,026	27	
TSS Variable Supply Cost F.	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
TSS Surcharge collections	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
(c) NGV Sales dth	1,515	1,374	832	504	186	304	622	177	5,515
Variable Supply Cost Factor	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	
Variable Supply collections	**$13,431**	**$12,188**	**$7,376**	**$4,471**	**$1,652**	**$2,698**	**$5,519**	**$1,568**	**48,902**
(d) Default Sales dth	20,878	12,047	18,196	6,670	3,609	10,153	4,098	2,672	
Variable Supply Cost Factor	$10.5348	$10.5348	$10.5348	$10.5348	$10.5348	$10.5348	$10.5348	$10.5348	
Variable Supply collections	**$219,947**	**$126,911**	**$191,688**	**$70,267**	**$38,024**	**$106,962**	**$43,173**	**$28,151**	
TOTAL Variable Supply Collections	**$15,520,233**	**$22,531,906**	**$44,516,981**	**$38,605,179**	**$32,336,891**	**$19,284,258**	**$11,349,178**	**$7,191,128**	**$191,335,754**

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GCR Gas Cost Collections

	Nov-09 actual	Dec-09 actual	Jan-10 actual	Feb-10 actual	Mar-10 actual	Apr-10 actual	May-10 actual	Jun-10 actual	Total Nov-June
IVa. Storage Variable Product Cost Collections --									
(a) Firm Sales dth	1,710,647	2,523,579	4,996,625	4,344,415	3,639,258	2,171,482	1,276,984	805,931	21,468,920
Variable Supply Cost Factor	$0.2888	$0.2868	$0.2867	$0.2866	$0.2868	$0.2854	$0.2860	$0.2872	
TOTAL Stor Var Product collections	**$494,064**	**$723,726**	**$1,432,335**	**$1,245,287**	**$1,043,832**	**$619,716**	**$365,227**	**$231,454**	**$6,155,641**
IVb. Storage Variable Non-product Cost Collections --									
(a) Firm Sales dth	1,710,647	2,523,579	4,996,625	4,344,415	3,639,258	2,171,482	1,276,984	805,931	21,468,920
Variable Supply Cost Factor	($0.0732)	($0.0726)	($0.0726)	($0.0726)	($0.0727)	($0.0723)	($0.0725)	($0.0727)	
Stor Var Non-Product collec	($125,154)	($183,329)	($362,833)	($315,449)	($264,419)	($156,983)	($92,518)	($58,631)	($1,559,316)
(b) FT-2 dth	111,676	186,325	342,697	321,980	296,865	197,390	125,640	85,600	
Variable Supply Cost Factor	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	
Stor Var Non-Product collec	($8,108)	($13,527)	($24,880)	($23,376)	($21,552)	($14,331)	($9,121)	($6,215)	**($121,110)**
Total Firm Sales/FT-2 dth	1,822,323	2,709,904	5,339,321	4,666,395	3,936,123	2,368,872	1,402,624	891,531	
TOTAL Stor Var Non-Product collec	**($133,262)**	**($196,856)**	**($387,713)**	**($338,825)**	**($285,971)**	**($171,314)**	**($101,639)**	**($64,846)**	**($1,680,426)**
Total Gas Cost Collections	**$18,379,829**	**$26,744,643**	**$52,872,105**	**$45,887,857**	**$38,444,610**	**$22,906,427**	**$13,478,240**	**$8,525,009**	**$227,238,720**

National Grid
Rhode Island Service Area
Gas Cost Inventory Financing Calculation

Line No.	Description	Reference	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(p)
1	**Storage Inventory Balance**		$26,191,729	$26,643,436	$27,003,938	$26,778,572	$26,229,386	$22,683,959	$17,794,092	$14,536,590	$10,860,219	$15,163,967	$17,119,647	$19,826,506	
2	Hedging		$7,416,995	$9,471,372	$11,707,748	$13,127,938	$13,127,938	$11,197,325	$5,369,649	$771,545	($761,361)	$836,372	$2,168,208	$3,512,326	
	Hedge Collateral Carrying Average Balance						$70,499,148	$45,422,510	$35,210,069	$40,364,683	$53,935,675	$53,003,803	$47,840,092	$40,860,280	
	NE Money Pool Rate						0.21%	0.20%	0.20%	0.20%	0.21%	0.22%	0.30%	0.35%	
	Hedge Collateral Carrying Costs						$12,337	$6,924	$5,168	$5,155	$8,499	$8,387	$10,619	$10,681	
3	Subtotal	(1) + (2)	$33,608,725	$36,114,807	$38,711,686	$39,906,509	$39,357,324	$33,881,284	$23,163,742	$15,308,136	$10,098,858	$16,000,339	$19,287,855	$23,338,832	
4	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
5	Return on Working Capital Requirement	(3) * (4)	$2,928,332	$3,146,687	$3,372,954	$3,477,059	$3,316,776	$2,855,292	$1,952,088	$1,290,069	$851,065	$1,348,403	$1,625,453	$1,966,843	$28,131,022
6	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
7	Interest Charges Financed	(1) * (6)	$1,244,686	$1,337,498	$1,433,673	$1,477,922	$896,466	$775,291	$608,165	$496,830	$371,180	$546,858	$659,219	$797,673	$10,645,461
8	Taxable Income	(5) - (7)	$1,683,646	$1,809,189	$1,939,281	$1,999,137	$2,420,310	$2,080,001	$1,343,923	$793,239	$479,886	$801,545	$966,235	$1,169,170	
9	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
10	Return and Tax Requirement	(8) / (9)	$2,590,224	$2,783,368	$2,983,510	$3,075,595	$3,723,555	$3,200,002	$2,067,573	$1,220,367	$738,286	$1,233,146	$1,486,515	$1,798,724	$26,900,864
11	Working Capital Requirement	(7) + (10)	$3,834,911	$4,120,866	$4,417,182	$4,553,517	$4,620,020	$3,975,292	$2,675,738	$1,717,197	$1,109,465	$1,780,004	$2,145,734	$2,596,397	$37,546,324
12	Monthly Average	(11) / 12	$319,576	$343,406	$368,099	$379,460	$385,002	$331,274	$222,978	$143,100	$92,455	$148,334	$178,811	$216,366	$3,128,860
13	**LNG Inventory Balance**		$5,664,521	$4,984,704	$5,360,299	$6,051,082	$6,232,424	$5,732,970	$5,322,061	$4,503,043	$5,566,058	$5,568,519	$5,655,766	$5,724,336	
14	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
15	Return on Working Capital Requirement	(13) * (14)	$493,550	$434,318	$467,044	$527,231	$525,228	$483,137	$448,508	$379,487	$469,071	$469,278	$476,631	$482,409	$5,655,892
16	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
17	Interest Charges Financed	(13) * (16)	$209,783	$184,607	$198,517	$224,100	$213,011	$195,941	$181,897	$153,905	$190,236	$190,320	$193,302	$195,646	$2,331,265
18	Taxable Income	(15) - (17)	$283,767	$249,711	$268,527	$303,132	$312,216	$287,196	$266,611	$225,582	$278,834	$278,958	$283,328	$286,763	
19	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
20	Return and Tax Requirement	(18) / (19)	$436,565	$384,171	$413,118	$466,357	$480,333	$441,840	$410,171	$347,050	$428,976	$429,166	$435,890	$441,175	$5,114,811
21	Working Capital Requirement	(17) + (20)	$646,348	$568,778	$611,635	$690,456	$693,344	$637,781	$592,068	$500,954	$619,212	$619,486	$629,192	$636,820	$7,446,076
22	Monthly Average	(21) / 12	$53,862	$47,398	$50,970	$57,538	$57,779	$53,148	$49,339	$41,746	$51,601	$51,624	$52,433	$53,068	$620,506
23	System Balancing Factor	Rate Case	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	
24	Balancing Related Inventory Costs	(22) * (23)	$9,049	$7,963	$8,563	$9,666	$9,707	$8,929	$8,289	$7,013	$8,669	$8,673	$8,809	$8,915	$104,245
25	Supply Related Inventory Costs	(22) - (24)	$44,813	$39,435	$42,407	$47,872	$48,072	$44,219	$41,050	$34,733	$42,932	$42,951	$43,624	$44,153	$516,261

National Grid
Rhode Island Service Area
Gas Cost Working Capital Calculation

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Line No.	Description	Reference	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1	**Supply Fixed Costs**		$1,778,133	$1,669,816	$1,744,440	$1,701,127	$1,841,268	$1,804,066	$2,016,419	$2,007,574	$2,443,223	$1,096,842	$1,813,964	$1,780,218	$21,697,088
2	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	$1,778,133	$1,669,816	$1,744,440	$1,701,127	$1,841,268	$1,804,066	$2,016,419	$2,007,574	$2,443,223	$1,096,842	$1,813,964	$1,780,218	$21,697,088
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$118,867	$111,626	$116,615	$113,719	$123,087	$120,601	$134,796	$134,205	$163,328	$73,323	$121,262	$119,006	
6	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
7	Return on Working Capital Requirement	(5) * (6)	$10,357	$9,726	$10,161	$9,908	$10,373	$10,163	$11,360	$11,310	$13,764	$6,179	$10,219	$10,029	
8	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
9	Interest Expense	(5) * (8)	$4,402	$4,134	$4,319	$4,212	$4,207	$4,122	$4,607	$4,587	$5,582	$2,506	$4,144	$4,067	
10	Taxable Income	(7) - (9)	$5,955	$5,592	$5,842	$5,697	$6,166	$6,042	$6,753	$6,723	$8,182	$3,673	$6,075	$5,962	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	$9,161	$8,603	$8,987	$8,764	$9,486	$9,295	$10,389	$10,343	$12,588	$5,651	$9,346	$9,172	
13	**Supply Fixed Working Capital Requirement**	(9) + (12)	$13,563	$12,737	$13,306	$12,976	$13,693	$13,417	$14,996	$14,930	$18,170	$8,157	$13,490	$13,239	$162,674
14	**Storage Fixed Costs**		$946,348	$947,287	$943,341	$947,694	$943,967	$952,357	$721,613	$1,086,439	$800,927	$549,607	$815,928	$853,488	$10,508,997
15	Less: LNG Demand to DAC		$77,196	$77,196	$77,196	$77,196	$77,196	$77,196	$39,815	$84,534	$51,506	$13,671	$58,303	$64,296	$775,301
16	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Plus: Supply Related LNG O&M Costs		$47,253	$47,253	$47,253	$47,253	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$601,408
18	Allowable Working Capital Costs	(14) - (15) + (16)	$916,406	$917,345	$913,399	$917,752	$918,320	$926,710	$733,348	$1,053,454	$800,970	$587,486	$809,174	$840,741	$10,335,105
19	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
20	Working Capital Requirement	[(17) * (18)] / 365	$61,261	$61,324	$61,060	$61,351	$61,389	$61,950	$49,024	$70,423	$53,544	$39,273	$54,093	$56,203	
21	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
22	Return on Working Capital Requirement	(19) * (20)	$5,338	$5,343	$5,320	$5,346	$5,173	$5,221	$4,131	$5,935	$4,512	$3,310	$4,559	$4,736	
23	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
24	Interest Expense	(19) * (22)	$2,269	$2,271	$2,261	$2,272	$2,098	$2,117	$1,676	$2,407	$1,830	$1,342	$1,849	$1,921	
25	Taxable Income	(19) - (23)	$3,069	$3,072	$3,059	$3,073	$3,075	$3,103	$2,456	$3,528	$2,682	$1,967	$2,710	$2,816	
26	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
27	Return and Tax Requirement	(24) / (25)	$4,721	$4,726	$4,706	$4,728	$4,731	$4,774	$3,778	$5,427	$4,127	$3,027	$4,169	$4,332	
28	**Storage Fixed Working Capital Requirement**	(23) + (26)	$6,990	$6,997	$6,967	$7,000	$6,829	$6,892	$5,454	$7,834	$5,957	$4,369	$6,018	$6,252	$77,560
1	**Supply Variable Costs**		$5,032,342	$5,404,592	$6,473,233	$6,851,509	$18,065,386	$31,739,269	$33,753,812	$28,292,074	$21,711,082	$17,039,931	$6,791,156	$4,668,653	$185,823,039
2a	Less: Non-firm Sales														$0
2b	Less: Variable Delivery Storage Costs		$0	$0	$0	$0	$0	$29,074	$89,361	$69,473	$23,075	$0	$0	$0	$210,983
2c	Less: Variable Injection Storage Costs		($10,712)	($9,924)	($9,781)	($8,830)	$5,163	$488	$0	$0	$1,472	$16,828	$17,350	$13,932	$15,985
2d	Less: Fuel Costs Allocated to Storage		($58,527)	($50,336)	($43,713)	($50,892)	$33,017	$125,895	$380,174	$291,966	$130,763	$88,698	$92,134	$74,192	$1,013,371
2e	Less: Supply Refunds														$0
2	Total Credits		($69,240)	($60,261)	($53,494)	($59,722)	$38,180	$155,458	$469,535	$361,439	$155,310	$105,526	$109,484	$88,124	$1,240,340
3	Allowable Working Capital Costs	(1) - (2)	$5,101,582	$5,464,853	$6,526,727	$6,911,231	$18,027,206	$31,583,811	$33,284,277	$27,930,635	$21,555,772	$16,934,405	$6,681,672	$4,580,529	$184,582,699
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$341,037	$365,322	$436,307	$462,011	$1,205,106	$2,111,356	$2,225,031	$1,867,144	$1,440,989	$1,132,053	$446,665	$306,205	
6	Cost of Capital	Rate Case	$0	$0	$0	$0	$0	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
7	Return on Working Capital Requirement	(5) * (6)	$29,715	$31,831	$38,015	$40,255	$101,558	$177,931	$187,511	$157,351	$121,437	$95,402	$37,642	$25,805	
8	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
9	Interest Expense	(5) * (8)	$12,630	$13,530	$16,158	$17,110	$41,188	$72,162	$76,047	$63,815	$49,250	$38,691	$15,266	$10,465	
10	Taxable Income	(7) - (9)	$17,084	$18,301	$21,857	$23,145	$60,370	$105,769	$111,464	$93,536	$72,187	$56,711	$22,376	$15,340	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	$26,284	$28,155	$33,626	$35,607	$92,878	$162,722	$171,483	$143,901	$111,057	$87,247	$34,424	$23,599	
13	**Supply Variable Working Capital Requirement**	(9) + (12)	$38,914	$41,685	$49,785	$52,718	$134,066	$234,884	$247,530	$207,716	$160,307	$125,939	$49,691	$34,065	$1,377,297

National Grid
Rhode Island Service Area
Gas Cost Working Capital Calculation

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Line No.	Description (a)	Reference (b)	Jul-09 (c)	Aug-09 (d)	Sep-09 (e)	Oct-09 (f)	Nov-09 (g)	Dec-09 (h)	Jan-10 (i)	Feb-10 (j)	Mar-10 (k)	Apr-10 (l)	May-10 (m)	Jun-10 (n)	Total
14	**Storage Variable Product Costs**		$130,487	$273,207	$357,048	$991,525	$964,712	$4,845,206	$13,603,707	$9,610,578	$3,721,088	$275,615	$531,416	$238,748	$35,543,336
15	Less: Balancing Related LNG Commodity (to DAC)		($21,175)	($17,258)	($27,931)	($43,609)	($5,299)	($124,841)	($137,916)	($195,121)	$14,569	($34,457)	($26,426)	($25,562)	($645,028)
16	Plus: Supply Related LNG O&M Costs		$32,857	$32,857	$32,857	$32,857	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$418,181
17	Allowable Working Capital Costs	(14) + (15) + (16)	$142,169	$288,806	$361,975	$980,773	$995,257	$4,756,209	$13,501,634	$9,451,301	$3,771,501	$277,002	$540,833	$249,030	$35,316,490
18	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
19	Working Capital Requirement	[(17) * (18)] / 365	$9,504	$19,306	$24,198	$65,564	$66,532	$317,949	$902,575	$631,813	$252,122	$18,517	$36,154	$16,647	
20	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
21	Return on Working Capital Requirement	(19) * (20)	$828	$1,682	$2,108	$5,713	$5,607	$26,795	$76,063	$53,245	$21,247	$1,561	$3,047	$1,403	
22	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
23	Interest Expense	(19) * (22)	$352	$715	$896	$2,428	$2,274	$10,867	$30,848	$21,594	$8,617	$633	$1,236	$569	
24	Taxable Income	(19) - (23)	$476	$967	$1,212	$3,284	$3,333	$15,928	$45,215	$31,651	$12,630	$928	$1,811	$834	
25	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
26	Return and Tax Requirement	(24) / (25)	$732	$1,488	$1,865	$5,053	$5,128	$24,504	$69,561	$48,694	$19,431	$1,427	$2,786	$1,283	
27	**Storage Var. Product Working Capital Requir.**	(23) + (26)	$1,084	$2,203	$2,761	$7,481	$7,402	$35,371	$100,410	$70,288	$28,048	$2,060	$4,022	$1,852	$262,982
1	**Storage Variable Non-Product Costs**		($69,240)	($60,261)	($53,494)	($59,722)	$59,522	$251,112	$278,355	$160,438	$120,218	$62,308	$68,565	$55,337	$813,139
2	Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	($69,240)	($60,261)	($53,494)	($59,722)	$59,522	$251,112	$278,355	$160,438	$120,218	$62,308	$68,565	$55,337	$813,139
4	Number of Days Lag	Rate Case	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	($4,629)	($4,028)	($3,576)	($3,992)	$3,979	$16,787	$18,608	$10,725	$8,037	$4,165	$4,584	$3,699	
6	Cost of Capital	Rate Case	8.71%	8.71%	8.71%	8.71%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	
7	Return on Working Capital Requirement	(5) * (6)	($403)	($351)	($312)	($348)	$335	$1,415	$1,568	$904	$677	$351	$386	$312	
8	Weighted Cost of Debt	Rate Case	3.70%	3.70%	3.70%	3.70%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	
9	Interest Expense	(5) * (8)	($171)	($149)	($132)	($148)	$136	$574	$636	$367	$275	$142	$157	$126	
10	Taxable Income	(7) - (9)	($232)	($202)	($179)	($200)	$199	$841	$932	$537	$403	$209	$230	$185	
11	1 - Combined Tax Rate	Rate Case	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	0.6500	
12	Return and Tax Requirement	(10) / (11)	($357)	($310)	($276)	($308)	$307	$1,294	$1,434	$827	$619	$321	$353	$285	
13	**Storage Variable Non-product WC Requir.**	(9) + (12)	($528)	($460)	($408)	($456)	$443	$1,867	$2,070	$1,193	$894	$463	$510	$412	$6,001

National Grid
Rhode Island Service Area
Actual Throughput (Dth)

Line No.	Rate Class (a)	Jul-09 (b) actual	Aug-09 (c) actual	Sep-09 (d) actual	Oct-09 (e) actual	Nov-09 (f) actual	Dec-09 (g) actual	Jan-10 (h) actual	Feb-10 (i) actual	Mar-10 (j) actual	Apr-10 (k) actual	May-10 (l) actual	Jun-10 (m) actual	July-June (n)
1	**SALES (dth)**													
2	Residential Non-Heating	43,168	33,686	32,573	40,239	53,856	72,115	106,210	85,485	75,061	56,075	43,806	34,773	677,048
3	Residential Non-Heating Low Incom	770	574	505	799	1,228	1,917	3,920	3,982	3,696	2,198	1,465	866	21,920
4	Residential Heating	450,719	353,365	343,477	521,159	976,902	1,638,849	3,063,886	2,797,453	2,247,579	1,308,570	766,843	457,783	14,926,585
5	Residential Heating Low Income	54,251	38,489	36,910	56,558	109,132	175,730	337,180	316,550	289,312	165,907	107,144	65,672	1,752,836
6	Small C&I	50,311	132,518	(47,006)	59,806	124,663	230,236	615,969	359,350	354,709	183,324	102,574	58,577	2,225,030
7	Medium C&I	122,865	122,663	94,060	156,131	311,911	268,199	628,550	572,428	459,034	290,497	189,139	121,103	3,336,581
8	Large LLF	11,686	23,220	(2,199)	32,693	51,738	76,229	133,444	131,821	131,876	104,359	24,389	10,448	729,706
9	Large HLF	22,295	23,007	32,896	15,163	27,350	29,269	48,741	33,444	31,949	27,524	25,781	12,714	330,131
10	Extra Large LLF	(53,429)	4,522	3,983	5,216	15,382	2,660	12,861	12,411	15,061	6,666	5,441	3,074	33,849
11	Extra Large HLF	16,519	23,265	19,997	15,096	21,508	23,255	33,402	21,646	21,085	17,333	8,375	40,894	262,374
	Total Sales	719,154	755,309	515,196	902,859	1,693,670	2,518,460	4,984,162	4,334,571	3,629,362	2,162,453	1,274,958	805,904	24,296,059
12	**TSS**													
13	Medium	2,394	2,345	(409)	1,152	2,525	2,511	6,387	6,033	4,764	6,749	4,461	27	38,938
14	Large LLF	2,183	521	80	219	7,545	(215)	441	41	59	3	(4,291)	0	6,585
15	Large HLF	769	11,051	1,401	(6,412)	6,907	2,823	5,634	3,770	5,073	2,276	1,856	0	35,149
16	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
18	**Total TSS**	5,346	13,917	1,072	(5,042)	16,977	5,119	12,462	9,844	9,896	9,028	2,026	27	80,672
19	**FT-2 TRANSPORTATION**													
20	FT-2 Medium	27,023	20,236	20,545	30,160	55,472	86,571	164,596	154,653	134,338	91,851	60,355	45,505	891,306
21	FT-2 Large LLF	14,170	8,581	11,535	15,000	39,873	69,264	139,157	125,796	120,286	74,016	38,392	18,410	674,479
22	FT-2 Large HLF	7,601	6,978	9,060	11,241	11,014	17,953	21,969	22,532	24,213	18,749	14,450	13,165	178,924
23	FT-2 Extra Large LLF	20	1,387	416	559	1,075	9,076	12,561	9,369	10,636	5,005	2,988	(265)	52,826
24	FT-2 Extra Large HLF	7,782	5,013	7,342	7,888	4,243	3,461	4,414	9,631	7,392	7,770	9,454	8,785	83,176
25	**Total FT-2 Transportation**	56,597	42,195	48,898	64,848	111,676	186,325	342,697	321,980	296,865	197,390	125,640	85,600	1,880,711
26	**Sales & FT-2 THROUGHPUT**													
27	Residential Non-Heating	43,168	33,686	32,573	40,239	53,856	72,115	106,210	85,485	75,061	56,075	43,806	34,773	677,048
28	Residential Non-Heating Low Incom	770	574	505	799	1,228	1,917	3,920	3,982	3,696	2,198	1,465	866	21,920
29	Residential Heating	450,719	353,365	343,477	521,159	976,902	1,638,849	3,063,886	2,797,453	2,247,579	1,308,570	766,843	457,783	14,926,585
30	Residential Heating Low Income	54,251	38,489	36,910	56,558	109,132	175,730	337,180	316,550	289,312	165,907	107,144	65,672	1,752,836
31	Small C&I	50,311	132,518	(47,006)	59,806	124,663	230,236	615,969	359,350	354,709	183,324	102,574	58,577	2,225,030
32	Medium C&I	152,282	145,244	114,195	187,443	369,907	357,281	799,533	733,114	598,136	389,097	253,956	166,635	4,266,825
33	Large LLF	28,039	32,322	9,416	47,911	99,156	145,278	273,042	257,658	252,221	178,378	58,490	28,859	1,410,770
34	Large HLF	30,665	41,035	43,357	19,992	45,271	50,045	76,344	59,745	61,235	48,549	42,087	25,879	544,203
35	Extra Large LLF	(53,408)	5,909	4,400	5,774	16,457	11,735	25,422	21,780	25,697	11,671	8,429	2,809	86,675
36	Extra Large HLF	24,301	28,278	27,339	22,984	25,751	26,716	37,816	31,277	28,476	25,103	17,829	49,679	345,550
37	**Total Sales & FT-2 Throughput**	781,097	811,421	565,166	962,665	1,822,323	2,709,904	5,339,321	4,666,395	3,936,123	2,368,872	1,402,624	891,531	26,257,442
38	**FT-1 TRANSPORTATION**													
39	FT-1 Medium	28,666	59,723	4,856	53,988	55,583	92,625	131,042	102,284	73,803	50,005	41,460	30,070	724,106
40	FT-1 Large LLF	31,113	18,242	35,748	63,739	81,308	145,299	217,037	168,901	113,089	66,066	41,815	16,754	999,111
41	FT-1 Large HLF	30,852	30,865	40,833	55,386	41,419	59,542	78,382	64,417	53,517	43,217	44,174	38,318	580,922
42	FT-1 Extra Large LLF	11,104	11,737	14,575	31,613	34,778	71,391	98,247	101,582	59,774	36,255	30,365	14,642	516,063
43	FT-1 Extra Large HLF	354,007	353,635	339,394	352,303	307,500	399,910	570,169	439,547	410,200	361,432	322,490	373,837	4,584,423
44	Default	3,697	8,891	7,733	5,111	20,878	12,047	18,196	6,670	3,609	10,153	4,098	2,672	103,755
45	**Total FT-1 Transportation**	459,439	483,094	443,139	562,139	541,466	780,815	1,113,072	883,401	713,993	567,127	484,402	476,292	7,508,379
46	**Total THROUGHPUT**													
47	Residential Non-Heating	43,168	33,686	32,573	40,239	53,856	72,115	106,210	85,485	75,061	56,075	43,806	34,773	677,048
48	Residential Non-Heating Low Incom	770	574	505	799	1,228	1,917	3,920	3,982	3,696	2,198	1,465	866	21,920
49	Residential Heating	450,719	353,365	343,477	521,159	976,902	1,638,849	3,063,886	2,797,453	2,247,579	1,308,570	766,843	457,783	14,926,585
50	Residential Heating Low Income	54,251	38,489	36,910	56,558	109,132	175,730	337,180	316,550	289,312	165,907	107,144	65,672	1,752,836
51	Small C&I	50,311	132,518	(47,006)	59,806	124,663	230,236	615,969	359,350	354,709	183,324	102,574	58,577	2,225,030
52	Medium C&I	180,948	204,967	119,052	241,430	425,491	449,907	930,575	835,398	671,940	439,102	295,416	196,705	4,990,931
53	Large LLF	59,152	50,564	45,164	111,650	180,464	290,578	490,080	426,559	365,310	244,444	100,305	45,612	2,409,881
53	Large HLF	61,517	71,900	84,189	75,378	86,690	109,587	154,726	124,162	114,752	91,765	86,261	64,197	1,125,125
54	Extra Large LLF	(42,304)	17,646	18,975	37,387	51,235	83,127	123,668	123,362	85,471	47,925	38,794	17,451	602,738
55	Extra Large HLF	378,308	381,913	366,733	375,287	333,251	426,626	607,985	470,824	438,676	386,535	340,319	423,516	4,929,973
56	Default	3,697	8,891	7,733	5,111	20,878	12,047	18,196	6,670	3,609	10,153	4,098	2,672	103,755
57	**Total Throughput**	1,240,536	1,294,514	1,008,305	1,524,804	2,363,789	3,490,719	6,452,394	5,549,796	4,650,116	2,935,998	1,887,027	1,367,824	33,765,821

Gas Cost Recovery (GCR) Filing
Projected Gas Cost Balances

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
	30	31	31	28	31	30	31	30	31	31	30	31
	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast
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I. Supply Fixed Cost Deferred												
Beginning Balance	($4,680,040)	($3,969,141)	($4,272,565)	($5,583,585)	($7,050,421)	($8,160,183)	($8,437,054)	($7,694,683)	($6,396,003)	($4,823,888)	($3,153,422)	($1,519,053)
Supply Fixed Costs (net of cap rel)	$2,294,431	$2,295,832	$2,294,590	$2,290,385	$2,294,590	$2,293,188	$2,294,590	$2,293,188	$2,294,590	$2,294,590	$2,293,188	$2,294,590
Capacity Release	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$15,589	$15,598	$15,590	$15,561	$15,590	$15,580	$15,590	$15,580	$15,590	$15,590	$15,580	$15,590
Total Supply Fixed Costs	$2,310,019	$2,311,430	$2,310,179	$2,305,946	$2,310,179	$2,308,768	$2,310,179	$2,308,768	$2,310,179	$2,310,179	$2,308,768	$2,310,179
Supply Fixed - Collections	$1,394,782	$2,410,588	$3,416,076	$3,566,824	$3,211,978	$2,377,220	$1,359,356	$802,956	$532,218	$435,587	$472,103	$654,288
Prelim. Ending Balance	($3,764,803)	($4,068,299)	($5,378,462)	($6,844,462)	($7,952,220)	($8,228,635)	($7,486,231)	($6,188,871)	($4,618,041)	($2,949,295)	($1,316,756)	$136,839
Month's Average Balance	($4,222,422)	($4,018,720)	($4,825,513)	($6,214,024)	($7,501,320)	($8,194,409)	($7,961,642)	($6,941,777)	($5,507,022)	($3,886,592)	($2,235,089)	($691,107)
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	($4,338)	($4,266)	($5,123)	($5,959)	($7,964)	($8,419)	($8,452)	($7,132)	($5,846)	($4,126)	($2,296)	($734)
GPIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NGPMP Credits	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Supply Fixed Ending Balance	($3,969,141)	($4,272,565)	($5,583,585)	($7,050,421)	($8,160,183)	($8,437,054)	($7,694,683)	($6,396,003)	($4,823,888)	($3,153,422)	($1,519,053)	($63,895)
II. Storage Fixed Cost Deferred												
Beginning Balance	$256,010	$417,928	$7,733	($968,219)	($2,033,559)	($2,895,505)	($3,296,089)	($3,123,457)	($2,633,788)	($1,981,084)	($1,276,579)	($598,743)
Storage Fixed Costs	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537	$954,537
LNG Demand to DAC	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)	($55,102)
Supply Related LNG O & M	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549	$51,549
Working Capital	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461	$6,461
Total Storage Fixed Costs	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445	$957,445
TSS Peaking Collections	$0	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10
Storage Fixed - Collections	$795,873	$1,367,866	$1,932,886	$2,021,344	$1,816,772	$1,354,846	$781,402	$464,813	$302,285	$251,204	$278,636	$370,634
Prelim. Ending Balance	$417,582	$7,507	($967,710)	($2,032,121)	($2,892,890)	($3,292,910)	($3,120,052)	($2,630,832)	($1,978,635)	($1,274,851)	($597,780)	($11,942)
Month's Average Balance	$336,796	$212,717	($479,989)	($1,500,170)	($2,463,225)	($3,094,208)	($3,208,070)	($2,877,145)	($2,306,211)	($1,627,967)	($937,179)	($305,342)
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	$346	$226	($510)	($1,439)	($2,615)	($3,179)	($3,406)	($2,956)	($2,448)	($1,728)	($963)	($324)
Storage Fixed Ending Balance	$417,928	$7,733	($968,219)	($2,033,559)	($2,895,505)	($3,296,089)	($3,123,457)	($2,633,788)	($1,981,084)	($1,276,579)	($598,743)	($12,266)
III. Variable Supply Cost Deferred												
Beginning Balance	$13,406,402	$19,177,661	$22,449,904	$19,477,413	$12,720,880	$9,874,810	$3,311,900	($612,049)	($2,357,670)	($2,662,930)	($2,185,247)	($1,771,355)
Variable Supply Costs	$16,627,592	$22,001,510	$23,590,347	$21,011,154	$22,138,394	$11,982,989	$6,728,829	$4,568,171	$3,887,457	$3,913,878	$4,143,886	$6,969,779
Variable Delivery Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variable Injections Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost Allocated to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$112,969	$149,480	$160,275	$142,752	$150,410	$81,414	$45,716	$31,037	$26,412	$26,591	$28,154	$47,353
Total Supply Variable Costs	$16,740,562	$22,150,991	$23,750,622	$21,153,906	$22,288,804	$12,064,402	$6,774,545	$4,599,207	$3,913,869	$3,940,469	$4,172,040	$7,017,132
Supply Variable - Collections	$10,986,032	$18,900,833	$26,745,357	$27,925,869	$25,146,862	$18,634,083	$10,699,926	$6,343,304	$4,216,465	$3,460,214	$3,756,117	$5,170,014
Deferred Responsibility	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Prelim. Ending Balance	$19,160,932	$22,427,819	$19,455,169	$12,705,450	$9,862,822	$3,305,129	($613,481)	($2,356,146)	($2,660,266)	($2,182,675)	($1,769,324)	$75,763
Month's Average Balance	$16,283,667	$20,802,740	$20,952,537	$16,091,431	$11,291,851	$6,589,969	$1,349,209	($1,484,097)	($2,508,968)	($2,422,802)	($1,977,285)	($847,796)
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	$16,730	$22,085	$22,244	$15,430	$11,988	$6,771	$1,432	($1,525)	($2,664)	($2,572)	($2,031)	($900)
Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Supply Variable Ending Balance	$19,177,661	$22,449,904	$19,477,413	$12,720,880	$9,874,810	$3,311,900	($612,049)	($2,357,670)	($2,662,930)	($2,185,247)	($1,771,355)	$74,863

Gas Cost Recovery (GCR) Filing
Projected Gas Cost Balances

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
	30	31	31	28	31	30	31	30	31	31	30	31
	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast
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IVa. Storage Variable Product Cost Deferred												
Beginning Balance	($460,482)	($1,784,206)	$525,727	$5,432,133	$8,115,624	$5,641,127	$3,026,904	$1,684,472	$1,047,040	$764,034	$617,956	$430,354
Storage Variable Prod. Costs - LNG	$126,411	$688,360	$130,829	$118,081	$130,829	$126,132	$129,483	$123,770	$128,056	$127,897	$123,174	$127,640
Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Variable Prod. Costs - UG	$0	$4,396,327	$8,703,454	$6,729,191	$1,173,912	$0	$0	$0	$0	$0	$0	$0
Supply Related LNG to DAC	($21,237)	($115,645)	($21,979)	($19,838)	($21,979)	($21,190)	($21,753)	($20,793)	($21,513)	($21,487)	($20,693)	($21,443)
Supply Related LNG O & M	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844	$35,844
Inventory Financing - LNG	$42,832	$37,982	$37,060	$36,228	$35,306	$38,274	$41,358	$41,925	$41,873	$41,828	$41,788	$41,759
Inventory Financing - UG	$200,546	$172,115	$115,847	$72,311	$64,750	$98,228	$132,608	$165,628	$186,313	$206,077	$214,746	$215,511
Inventory Financing - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$958	$34,004	$60,115	$46,630	$8,959	$957	$975	$943	$967	$966	$940	$965
Total Storage Variable Product Costs	$385,354	$5,248,988	$9,061,169	$7,018,448	$1,427,620	$278,245	$318,515	$347,317	$371,540	$391,125	$395,799	$400,276
Storage Variable Product Collections	$1,707,926	$2,938,387	$4,157,924	$4,341,450	$3,909,416	$2,896,918	$1,663,447	$986,151	$655,506	$537,937	$583,939	$803,748
Prelim. Ending Balance	($1,783,054)	$526,395	$5,428,973	$8,109,132	$5,633,828	$3,022,453	$1,681,972	$1,045,637	$763,073	$617,223	$429,815	$26,881
Month's Average Balance	($1,121,768)	($628,906)	$2,977,350	$6,770,633	$6,874,726	$4,331,790	$2,354,438	$1,365,055	$905,057	$690,628	$523,886	$228,618
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	($1,153)	($668)	$3,161	$6,492	$7,299	$4,450	$2,500	$1,402	$961	$733	$538	$243
Storage Variable Product Ending Bal.	($1,784,206)	$525,727	$5,432,133	$8,115,624	$5,641,127	$3,026,904	$1,684,472	$1,047,040	$764,034	$617,956	$430,354	$27,124
IVb. Stor Var Non-Prod Cost Deferred												
Beginning Balance	($1,794,337)	($1,750,177)	($1,522,082)	($1,111,829)	($760,384)	($624,439)	($454,079)	($313,489)	($196,240)	($128,494)	($66,006)	($30,493)
Storage Variable Non-prod. Costs	$0	$150,155	$298,646	$234,688	$32,156	$0	$0	$0	$0	$0	$0	$0
Variable Delivery Storage Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variable Injection Storage Costs	$0	$0	$0	$0	$0	$16,017	$16,277	$15,579	$10,221	$9,729	$6,089	$340
Fuel Costs Allocated to Storage	$0	$0	$0	$0	$0	$76,374	$78,950	$74,381	$39,793	$37,901	$13,076	$2,715
Working Capital	$0	$1,020	$2,029	$1,594	$218	$628	$647	$611	$340	$324	$130	$21
Total Storage Var Non-product Costs	$0	$151,175	$300,675	$236,283	$32,375	$93,018	$95,875	$90,571	$50,353	$47,954	$19,295	$3,076
Storage Var Non-Product Collections	($45,980)	($78,656)	($110,975)	($116,060)	($104,305)	($77,896)	($45,122)	($26,940)	($17,564)	($14,638)	($16,267)	($21,478)
Prelim. Ending Balance	($1,748,357)	($1,520,346)	($1,110,432)	($759,487)	($623,704)	($453,525)	($313,082)	($195,978)	($128,322)	($65,903)	($30,444)	($5,939)
Month's Average Balance	($1,771,347)	($1,635,261)	($1,316,257)	($935,658)	($692,044)	($538,982)	($383,580)	($254,734)	($162,281)	($97,199)	($48,225)	($18,216)
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	($1,820)	($1,736)	($1,397)	($897)	($735)	($554)	($407)	($262)	($172)	($103)	($50)	($19)
Storage Var Non-Product Ending Bal.	($1,750,177)	($1,522,082)	($1,111,829)	($760,384)	($624,439)	($454,079)	($313,489)	($196,240)	($128,494)	($66,006)	($30,493)	($5,958)
GCR Deferred Summary												
Beginning Balance	$6,727,553	$12,092,065	$17,188,717	$17,245,914	$10,992,142	$3,835,815	($5,848,408)	($10,059,192)	($10,536,640)	($8,832,333)	($6,063,262)	($3,489,245)
Gas Costs	$20,257,403	$30,613,466	$36,135,620	$31,459,029	$26,834,785	$15,596,839	$10,387,170	$8,248,676	$7,553,616	$7,597,240	$7,802,081	$10,617,719
Working Capital	$135,977	$206,563	$244,470	$212,998	$181,638	$105,039	$69,389	$54,632	$49,770	$49,932	$51,265	$70,390
Total Costs	$20,393,380	$30,820,029	$36,380,090	$31,672,027	$27,016,423	$15,701,878	$10,456,559	$8,303,308	$7,603,386	$7,647,172	$7,853,347	$10,688,108
Collections	$14,838,633	$25,539,018	$36,141,268	$37,739,427	$33,980,723	$25,185,171	$14,459,009	$8,570,284	$5,688,910	$4,670,304	$5,074,528	$6,977,206
Prelim. Ending Balance	$12,282,300	$17,373,076	$17,427,539	$11,178,514	$4,027,842	($5,647,478)	($9,850,858)	($10,326,168)	($8,622,164)	($5,855,465)	($3,284,443)	$221,657
Month's Average Balance	$9,504,926	$14,732,571	$17,308,128	$14,212,214	$7,509,992	($905,831)	($7,849,633)	($10,192,680)	($9,579,402)	($7,343,899)	($4,673,852)	($1,633,794)
Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Interest Applied	$9,765	$15,641	$18,375	$13,628	$7,973	($931)	($8,334)	($10,472)	($10,170)	($7,797)	($4,802)	($1,735)
Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NGPMP Credits	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Ending Bal. W/ Interest	$12,092,065	$17,188,717	$17,245,914	$10,992,142	$3,835,815	($5,848,408)	($10,059,192)	($10,536,640)	($8,832,333)	($6,063,262)	($3,489,245)	**$19,923**
Under/(Over)-collection	$5,554,747	$5,281,011	$238,822	($6,067,400)	($6,964,300)	($9,483,293)	($4,002,450)	($266,976)	$1,914,476	$2,976,868	$2,778,819	$3,710,902

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2010-2011 Proposed GCR and DAC

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$946	$1,026	($79)	-7.7%	$0	($93.72)	$14.37	$0.00
	664	$1,031	$1,119	($88)	-7.8%	$0	($103.71)	$15.87	$0.00
	730	$1,119	$1,216	($97)	-7.9%	$0	($114.02)	$17.47	$0.00
	794	$1,202	$1,307	($105)	-8.0%	$0	($124.01)	$18.95	$0.00
	857	$1,282	$1,396	($113)	-8.1%	$0	($133.87)	$20.46	$0.00
Average Customer	**922**	**$1,364**	**$1,486**	**($122)**	**-8.2%**	**$0**	**($144.03)**	**$22.03**	**$0.00**
	987	$1,446	$1,576	($131)	-8.3%	$0	($154.19)	$23.58	$0.00
	1,051	$1,526	$1,665	($139)	-8.4%	$0	($164.20)	$25.11	$0.00
	1,114	$1,603	$1,750	($147)	-8.4%	$0	($174.01)	$26.65	$0.00
	1,180	$1,683	$1,839	($156)	-8.5%	$0	($184.32)	$28.20	$0.00
	1,247	$1,764	$1,929	($165)	-8.6%	$0	($194.78)	$29.77	$0.00

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$909	$988	($79)	-8.0%	$0	($93.72)	$14.37	$0.00
	664	$991	$1,079	($88)	-8.1%	$0	($103.71)	$15.87	$0.00
	730	$1,077	$1,173	($97)	-8.2%	$0	($114.02)	$17.47	$0.00
	794	$1,158	$1,263	($105)	-8.3%	$0	($124.01)	$18.95	$0.00
	857	$1,236	$1,349	($113)	-8.4%	$0	($133.87)	$20.46	$0.00
Average Customer	**922**	**$1,315**	**$1,437**	**($122)**	**-8.5%**	**$0**	**($144.03)**	**$22.03**	**$0.00**
	987	$1,395	$1,526	($131)	-8.6%	$0	($154.19)	$23.58	$0.00
	1,051	$1,473	$1,612	($139)	-8.6%	$0	($164.20)	$25.11	$0.00
	1,114	$1,548	$1,696	($147)	-8.7%	$0	($174.01)	$26.65	$0.00
	1,180	$1,627	$1,783	($156)	-8.8%	$0	($184.32)	$28.20	$0.00
	1,247	$1,706	$1,871	($165)	-8.8%	$0	($194.78)	$29.77	$0.00

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2010-2011 Proposed GCR and DAC

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$283	$297	($14)	-4.9%	$0	($17.37)	$2.95	$0
	137	$301	$317	($16)	-5.0%	$0	($19.27)	$3.26	$0
	147	$315	$332	($17)	-5.2%	$0	($20.70)	$3.49	$0
	161	$333	$352	($19)	-5.4%	$0	($22.68)	$3.85	$0
	176	$353	$373	($21)	-5.5%	$0	($24.80)	$4.23	$0
Average Customer	**189**	**$370**	**$392**	**($22)**	**-5.6%**	**$0**	**($26.67)**	**$4.52**	**$0**
	202	$387	$411	($24)	-5.7%	$0	($28.46)	$4.84	$0
	217	$407	$433	($25)	-5.9%	$0	($30.58)	$5.18	$0
	231	$426	$453	($27)	-6.0%	$0	($32.57)	$5.51	$0
	241	$439	$467	($28)	-6.0%	$0	($33.97)	$5.74	$0
	256	$459	$489	($30)	-6.1%	$0	($36.04)	$6.14	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$266	$280	($14)	-5.1%	$0	($17.37)	$2.95	$0
	137	$284	$300	($16)	-5.3%	$0	($19.27)	$3.26	$0
	147	$297	$314	($17)	-5.5%	$0	($20.70)	$3.49	$0
	161	$315	$333	($19)	-5.6%	$0	($22.68)	$3.85	$0
	176	$334	$354	($21)	-5.8%	$0	($24.80)	$4.23	$0
Average Customer	**189**	**$350**	**$373**	**($22)**	**-5.9%**	**$0**	**($26.67)**	**$4.52**	**$0**
	202	$367	$391	($24)	-6.0%	$0	($28.46)	$4.84	$0
	217	$386	$412	($25)	-6.2%	$0	($30.58)	$5.18	$0
	231	$404	$431	($27)	-6.3%	$0	($32.57)	$5.51	$0
	241	$417	$445	($28)	-6.3%	$0	($33.97)	$5.74	$0
	256	$436	$466	($30)	-6.4%	$0	($36.04)	$6.14	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2010-2011 Proposed GCR and DAC

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	824	$1,594	$1,703	($109)	-6.4%	$0	($129)	$20	$0
	916	$1,709	$1,830	($121)	-6.6%	$0	($143)	$22	$0
	1,003	$1,817	$1,950	($133)	-6.8%	$0	($157)	$24	$0
	1,092	$1,927	$2,071	($145)	-7.0%	$0	($171)	$26	$0
	1,179	$2,031	$2,187	($156)	-7.1%	$0	($184)	$28	$0
Average Customer	**1,269**	**$2,136**	**$2,304**	**($168)**	**-7.3%**	**$0**	**($198)**	**$30**	**$0**
	1,359	$2,241	$2,421	($180)	-7.4%	$0	($212)	$32	$0
	1,447	$2,344	$2,536	($191)	-7.5%	$0	($226)	$35	$0
	1,535	$2,447	$2,650	($203)	-7.7%	$0	($240)	$37	$0
	1,622	$2,548	$2,763	($215)	-7.8%	$0	($253)	$39	$0
	1,715	$2,657	$2,884	($227)	-7.9%	$0	($268)	$41	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	7,117	$9,220	$10,162	($942)	-9.3%	$0	($1,112)	$170	$0
	7,884	$10,136	$11,179	($1,043)	-9.3%	$0	($1,232)	$188	$0
	8,649	$11,050	$12,194	($1,144)	-9.4%	$0	($1,351)	$207	$0
	9,416	$11,965	$13,211	($1,246)	-9.4%	$0	($1,471)	$225	$0
	10,185	$12,884	$14,232	($1,348)	-9.5%	$0	($1,591)	$243	$0
Average Customer	**10,950**	**$13,797**	**$15,246**	**($1,449)**	**-9.5%**	**$0**	**($1,711)**	**$262**	**$0**
	11,715	$14,711	$16,261	($1,550)	-9.5%	$0	($1,830)	$280	$0
	12,484	$15,629	$17,281	($1,652)	-9.6%	$0	($1,950)	$298	$0
	13,251	$16,545	$18,299	($1,753)	-9.6%	$0	($2,070)	$317	$0
	14,016	$17,459	$19,314	($1,855)	-9.6%	$0	($2,190)	$335	$0
	14,783	$18,375	$20,331	($1,956)	-9.6%	$0	($2,309)	$353	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2010-2011 Proposed GCR and DAC

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,532	$46,744	$51,711	($4,966)	-9.6%	$0	($5,863)	$897	$0
	41,573	$51,622	$57,123	($5,501)	-9.6%	$0	($6,495)	$994	$0
	45,616	$56,503	$62,539	($6,036)	-9.7%	$0	($7,126)	$1,090	$0
	49,660	$61,384	$67,955	($6,571)	-9.7%	$0	($7,758)	$1,187	$0
	53,699	$66,260	$73,365	($7,106)	-9.7%	$0	($8,389)	$1,283	$0
Average Customer	**57,742**	**$71,140**	**$78,780**	**($7,641)**	**-9.7%**	**$0**	($9,021)	$1,380	**$0**
	61,785	$76,020	$84,196	($8,176)	-9.7%	$0	($9,652)	$1,477	$0
	65,824	$80,896	$89,606	($8,710)	-9.7%	$0	($10,283)	$1,573	$0
	69,868	$85,777	$95,022	($9,245)	-9.7%	$0	($10,915)	$1,670	$0
	73,911	$90,657	$100,437	($9,780)	-9.7%	$0	($11,547)	$1,766	$0
	77,952	$95,535	$105,850	($10,315)	-9.7%	$0	($12,178)	$1,863	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,970	$42,571	$47,014	($4,443)	-9.5%	$0	($5,351)	$907	$0
	42,061	$47,003	$51,924	($4,922)	-9.5%	$0	($5,927)	$1,005	$0
	46,151	$51,433	$56,834	($5,400)	-9.5%	$0	($6,503)	$1,103	$0
	50,240	$55,862	$61,741	($5,879)	-9.5%	$0	($7,080)	$1,201	$0
	54,329	$60,292	$66,649	($6,357)	-9.5%	$0	($7,656)	$1,298	$0
Average Customer	**58,418**	**$64,721**	**$71,557**	**($6,836)**	**-9.6%**	**$0**	**($8,232)**	**$1,396**	**$0**
	62,508	$69,152	$76,466	($7,314)	-9.6%	$0	($8,808)	$1,494	$0
	66,596	$73,580	$81,373	($7,793)	-9.6%	$0	($9,384)	$1,592	$0
	70,686	$78,010	$86,282	($8,271)	-9.6%	$0	($9,961)	$1,689	$0
	74,775	$82,440	$91,190	($8,750)	-9.6%	$0	($10,537)	$1,787	$0
	78,867	$86,873	$96,101	($9,229)	-9.6%	$0	($11,114)	$1,885	$0

Bill Impact Analysis with Various Levels of Consumption:
Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2010-2011 Proposed GCR and DAC

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	189,450	$205,756	$230,824	($25,069)	-10.9%	$0	($29,596)	$4,528	$0
	209,855	$227,529	$255,298	($27,769)	-10.9%	$0	($32,784)	$5,016	$0
	230,255	$249,297	$279,765	($30,468)	-10.9%	$0	($35,971)	$5,503	$0
	250,655	$271,066	$304,233	($33,167)	-10.9%	$0	($39,158)	$5,991	$0
	271,059	$292,838	$328,705	($35,867)	-10.9%	$0	($42,346)	$6,478	$0
Average Customer	**291,462**	**$314,610**	**$353,177**	**($38,567)**	**-10.9%**	**$0**	**($45,533)**	**$6,966**	**$0**
	311,865	$336,381	$377,648	($41,267)	-10.9%	$0	($48,720)	$7,454	$0
	332,269	$358,153	$402,120	($43,967)	-10.9%	$0	($51,908)	$7,941	$0
	352,669	$379,922	$426,588	($46,666)	-10.9%	$0	($55,095)	$8,429	$0
	373,069	$401,690	$451,055	($49,365)	-10.9%	$0	($58,282)	$8,916	$0
	393,474	$423,463	$475,529	($52,066)	-10.9%	$0	($61,470)	$9,404	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-10	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	184,661	$196,057	$217,665	($21,608)	-9.9%	$0	($26,022)	$4,413	$0
	204,549	$216,784	$240,720	($23,935)	-9.9%	$0	($28,824)	$4,889	$0
	224,435	$237,510	$263,772	($26,262)	-10.0%	$0	($31,626)	$5,364	$0
	244,321	$258,236	$286,825	($28,589)	-10.0%	$0	($34,429)	$5,839	$0
	264,206	$278,960	$309,876	($30,916)	-10.0%	$0	($37,231)	$6,315	$0
Average Customer	**284,094**	**$299,688**	**$332,931**	**($33,243)**	**-10.0%**	**$0**	($40,033)	$6,790	**$0**
	303,982	$320,415	$355,986	($35,570)	-10.0%	$0	($42,836)	$7,265	$0
	323,867	$341,140	$379,037	($37,897)	-10.0%	$0	($45,638)	$7,740	$0
	343,753	$361,865	$402,090	($40,224)	-10.0%	$0	($48,440)	$8,216	$0
	363,639	$382,591	$425,142	($42,551)	-10.0%	$0	($51,242)	$8,691	$0
	383,527	$403,318	$448,197	($44,878)	-10.0%	$0	($54,045)	$9,166	$0

NATURAL GAS VEHICLE SERVICE
RATE 70

1.0 NATURAL GAS VEHICLE SERVICE

1.1 AVAILABILITY: This rate is available for compressed natural gas dispensed at Company-owned fueling stations for the purpose of fueling natural gas vehicles.

No other use of gas will be included in this rate for billing purposes.

1.2 RATES:

Customer Charge:	$5.00 per month
Energy Charge:	
Distribution Charge:	$0.1958 per Therm
Commodity Charge:	$0.7530 Therm

1.3 MINIMUM RATE: Customer Charge

1.4 GENERAL RULES AND REGULATIONS: The Company's General Rules and Regulations in Section 1 of RIPUC NG-GAS No. 101, as in effect from time-to-time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

1.5 RHODE ISLAND GROSS EARNINGS TAX: The application of the above rates are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule D.

1.6 GAS ENERGY EFFICIENCY: The application of the above rate is subject to Gas Energy Efficiency provisions in Section 1, Schedule C.

Summary of Marketer Transportation Factors

Item	Reference	Proposed	Billing Units
FT-2 Firm Transportation Marketer Gas Charge	pg 15	**$0.0430**	Therms throughput of Marketer Pool
Pool Balancing Charge	pg 16	**$0.0024**	Per % of balancing elected per Therm throughput of Marketer Pool
Weighted Average Upstream Pipeline Transportation Cost	EDA - 4	**$0.9630**	Per Therm of capacity

Calculation of FT-2 Marketer Gas Charge

I. Determination of FT-2 Storage Fixed Cost Factor

1	Allocated Storage Fixed Costs	reference	
2	C & I Medium	JFN-1, pg 3	$1,715,216
3	C & I Large LLF	JFN-1, pg 3	$696,533
4	C & I Large HLF	JFN-1, pg 3	$130,575
5	C & I Extra Large LLF	JFN-1, pg 3	$155,393
6	C & I Extra Large HLF	JFN-1, pg 3	$63,041
7	sub-total	sum ([1]:[6])	$2,760,757
8	Through-put (dth)	JFN-1, pg 14	6,198,030
9	Storage Fixed Factor	[7] / [8]	$0.4454

II. Storage Variable Non-product Cost Factor	JFN-1, pg 1	($0.0263)
TOTAL FT-2 Gas Marketer Charge (per Dth)		$0.4191
Uncollectible %	Dkt 3943	2.46%
TOTAL FT-2 Gas Marketer Charge adj for uncollectible ($/dth)		**$0.4297**

Calculation of Pool Balancing Charge

		reference	Medium C&I	Large LLF	Large HLF	Extra Large LLF	Extra Large HLF	Total
1	Throughput (dth)	JFN-1, pg 14	3,902,893	1,469,433	380,465	287,165	158,075	6,198,030
2	% allocation		62.97%	23.71%	6.14%	4.63%	2.55%	100.00%
3	Supply Fixed Cost Factor	JFN-1, pg 1	$0.8592	$0.8592	$0.6665	$0.8592	$0.6665	
4	Storage Fixed Cost Factor	JFN-1, pg 1	$0.4623	$0.4623	$0.3527	$0.4623	$0.3527	
5	Storage Variable Cost Factor	JFN-1, pg 1	$1.0382	$1.0382	$1.0382	$1.0382	$1.0382	
6	Class Specific Pool Balancing Charge	([3]+[4]+[5]) x 1%	$0.0236	$0.0236	$0.0206	$0.0236	$0.0206	
7	Class Specific Weighted Average ($/dth)	[6] x [2]	$0.0149	$0.0056	$0.0013	$0.0011	$0.0005	$0.0233
8	Uncollectible %	Docket 3943	2.46%	2.46%	2.46%	2.46%	2.46%	
9	Pool Balancing Charge adjusted for Uncollectible	([7] / (1-[8])	$0.0152	$0.0057	$0.0013	$0.0011	$0.0005	$0.0238
10	Per Therm Pool Balancing Charge	[9] / 10						**$0.0024**

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY

OF

STEPHEN A. MC CAULEY

SEPTEMBER 1, 2010

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen A Mc Cauley**.** My business address is 100 E. Old Country Road, Hicksville, NY 11801**.**

Q. WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am Director of Origination and Hedging in the Energy Portfolio Management organization. As Director, I am responsible for all financial hedging activity for the eight National Grid regulated natural gas utilities. I am also responsible for structuring and optimizing the natural gas assets to help return the most value to the regulated entities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the United States Merchant Marine Academy in 1984 with a Bachelor of Science degree in Marine Engineering Systems.

Q. PLEASE DESCRIBE YOUR PROFESSION EXPERIENCE.

A. I joined the Company in 1992 as an engineer for the gas peak-shaving plants and the gas-regulator and telemetering stations. In 1996, I joined the gas supply group as a trader responsible for purchasing the natural gas supply requirements for both the firm gas customers and the LILCO generation facilities. In 1999, my responsibilities were changed to managing the emissions-allowance portfolio and the financial-hedging activities of the regulated utilities. In 2002, I was promoted to my current position as Director.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the results of the Gas Procurement Incentive Plan ("GPIP") for the period July 1, 2009 through June 30, 2010, the recommended changes to the GPIP to be effective July 1, 2010, and the results of the Natural Gas Portfolio Management Plan ("NGPMP") for the period April 1, 2009 through March 31, 2010.

II GAS PROCUREMENT INCENTIVE PLAN

Q. PLEASE DESCRIBE THE INCENTIVE PORTION OF THE GAS PROCUREMENT INCENTIVE PLAN (GPIP)?

A. The GPIP encourages the Company to purchase supply in a way designed to stabilize prices and reduce the risk that commodity costs will escalate dramatically. An outline of the proposed GPIP with revisions contained in the report filed with the Commission in February 2010 is provided in Attachment SAM-1 and the relined version with the recommended changes to the existing Plan shown in SAM-1a.

The gas procurement portion of the GPIP is based on the Company's gas purchasing program under which the Company fixes the price of commodity purchases through purchases or financial hedges over a 24-month horizon. The minimum amount fixed or financially hedged is 60% of the expected purchases for April and October, and 70% for all other months. The hedged volume is based on the five-year firm-sales forecast filed each year in the Gas Cost Recovery docket. These mandatory hedges are required to be made ratably over the period beginning 24 months prior to the start of each month and ending four months before the month begins. These mandatory hedges also form the benchmark for the incentive calculation. For each month, the average unit cost of the mandatory hedges is compared to the average unit cost of discretionary purchases to determine the savings or loss per dekatherm resulting from the discretionary purchases. This difference, multiplied by the discretionary volumes, determines the total savings or cost. To determine the incentive or penalty for the month, this total is multiplied by 10% except for those discretionary purchases made at least 8 months prior to the month of gas flow where the unit cost savings is greater than 50 cents per dekatherm, in which case the incentive applicable to those purchases is 20%.

Q. WHAT IS THE GPIP GAS PROCUREMENT INCENTIVE FOR THE PAST YEAR?

A. Attachment SAM-2 shows the results for the period July 1, 2009 through June 30, 2010 by month. As shown, the Company purchased discretionary supply of 4,381,000 Dth during the period resulting in a net calculated incentive of $1,606,937. The average cost of discretionary purchases was $ 2.494 per Dth less than the mandatory locks.

The calculation of the savings and incentive is shown for each month. For example, in July 2009 the average purchase cost per Dth for mandatory purchases was $8.219 and discretionary purchases were made at an average cost of $6.718, which equates to a savings of $1.501 per Dth on discretionary purchases of 200,000 Dth, resulting in a savings for the month of $300,111.

Q. WHAT IS THE GAS PROCUREMENT INCENTIVE THE COMPANY IS FILING?

A. As directed by the Commission, after the conclusion of last year's GCR proceeding (Docket 4097), the Company and the Division engaged in further discussions to evaluate the GPIP and to determine the need for any recommended changes to the plan. As described below, these discussions resulted in conclusions and recommendations regarding the plan, including recommendations as to the gas procurement incentive under the plan. However, as part of those discussions, the Company and the Division agreed that the current incentive calculation along with a $1 million cap should be utilized during the incentive period that just ended, which covers the period July 2009 through June 2010. Thus, although the calculation for that incentive period resulted in an incentive payment of $1,606,937, the Company is proposing that it be granted an incentive at the cap of $1,000,000.

Q. ARE THERE ANY RECOMMENDED CHANGES TO THE GPIP FOR THE PERIOD STARTING JULY 2010?

A. On October 27, 2009, in its Report and Order in the Annual Gas Cost Recovery Filing 2009, Docket No. 4097, the Rhode Island Public Utilities Commission ("Commission") directed National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") to engage in further discussions about the Gas Purchasing Incentive Plan ("GPIP") and to evaluate the existing plan to determine whether it still provides the intended benefits to customers and whether modifications are necessary. The Commission further directed that the Company file a written report with the Commission detailing the results from those discussions. (Order 19832) This report detailed the recommended changes and on February 25, 2010 it was filed in compliance with the Commission's directive. The report is attached as SAM-3.

Q. CAN YOU SUMMARIZE THE RECOMMENDED CHANGES TO THE GPIP?

A. The Company and Division staff continue to believe that the goals of the GPIP hedging plan are still appropriate, and propose that the GPIP and the imbedded incentive mechanism continue to remain in effect with two changes to the program. In order to address concerns regarding the execution of discretionary volumes at the end of the execution period, at a time when the mandatory price is known, the Company and the Division recommend that the Company incentive be reduced from 10 percent to 5 percent for volumes executed during the last four months of the execution period. The parties also believe that customers would further benefit from the removal of the incentive cap. The GPIP incentive, with the adjustment described above, in conjunction with the removal of the incentive cap ensures that the customers' interests and those of the

Company are always aligned. This alignment of goals should ensure that the Company is always executing the discretionary volumes when it is in the customer's best interest to do so. It is recommended that these changes go into effect for the gas-cost year starting July 1, 2010.

III NATURAL GAS PORTFOLIO MANAGEMENT PLAN (NGPMP)

Q. BRIEFLY DESCRIBE THE NGPMP?

A. In Docket 4038, the Commission approved the NGPMP which implemented changes to the management of the Company's Rhode Island gas portfolio. These changes were designed to provide various financial, regulatory, and risk management benefits over the previous asset management arrangements. The Company changed the management of the gas portfolio from an external third-party asset-management agreement to an internal portfolio management by the Company. The Company uses its transportation contracts, underground storage contracts, peaking supplies, and supply contracts first to purchase gas supplies to economically and reliably serve sales customers and then to make additional purchases and sales that generate revenue by extracting value from any assets that are not required to serve customers on any day.. The mix of supply, transportation, and storage contracts creates flexibility and opportunities for optimization to create value for Rhode Island customers. This potential optimization value is subject to market variables: the fluctuation of gas pricing, the value of temporarily unused assets, the existence of excess transportation and storage capacity, and the opportunities to optimize delivered supplies as storage fill opportunities arise. These activities were previously executed by external third-party asset managers. The Company believes that the internal management of the portfolio is superior to the external portfolio management for two primary reasons. First, active asset management by the Company reduces the potential for performance failure by a third-party asset manager, which would jeopardize supply reliability. Second, the NGPMP creates an appropriate incentive for the Company to maximize the savings to its customers at levels that would be comparable to or that would exceed those from a third-party asset manager.

Q. WHAT WERE THE RESULTS OF THE NPGMP FOR THE INCENTIVE YEAR APRIL 2009 THROUGH MARCH 2010?

A. As required by Order 19627 in Commission Docket 4038, the Company has filed comprehensive reports of its optimization activity each quarterly and on June 1st it filed its annual report showing the results of the first year of the NGPMP, April 2009 through March 2010. The report is provided as Attachment SAM-4. As shown in the report indicates the first year produced total savings of $2,876,377.65.

Q. WHAT IS THE NGPMP INCENTIVE THE COMPANY IS FILING?

A. The Company's incentive, as specified in the NGPMP, is determined as 20% of the total savings in excess of $1,000,000. Accordingly, the Company is filing for approval of an NGPMP incentive of $375,276 for the April 2009 through March 2010 period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

Attachments

SAM-1	Revised Gas Procurement Incentive Plan (GPIP) for National Grid
SAM-1a	Redlined Gas Procurement Incentive Plan
SAM-2	GPIP July 2009 through June 2010 Results
SAM-3	Evaluation Regarding Rhode Island Gas Procurement Incentive Plan (GPIP)
SAM-4	NGPMP Annual Report, April 2009 through March 2010

Gas Procurement Incentive Plan for National Grid

Revised Effective July 1, 2010

I. Objective

To encourage National Grid (or "Company") to achieve lower overall gas commodity costs for its customers.

II. Structure of the Gas Procurement Incentive Plan

A. The original Plan became effective June 1, 2003 and was most recently revised effective December 2008. It will be reviewed with each gas cost recovery ("GCR") filing. The Company will file the Plan results semi-annually in January and July. These reports shall include reporting for all Plan activity and results through the end of the month prior to the filing.

1. The Gas Procurement Incentive Plan revised effective December 1, 2008 applied to discretionary hedges that settled up through June 2010. .
2. This revised Plan will be effective for hedges that settle starting in July 2010.

B. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. The hedging plan volume will be adjusted based on this revised forecast. Changes to the hedged volume execution plan will become effective in November of each year. If a midyear revision is warranted the Company will file support for the revised purchase forecast with the Commission and Division.

III The Gas Procurement Incentive Program

A. The Company will make purchases of natural gas, natural gas swaps or natural gas futures which lock or hedge the NYMEX Henry Hub portion of the variable cost. For any future gas supply month the Company will make three types of gas purchases:

1. Mandatory Purchases and/or Hedges

a. Are defined as mandatory monthly purchases of gas volumes or hedges made in approximately uniform monthly increments. (Mandatory purchases and/or hedges will vary as the forecast of purchases is updated periodically and in order to adjust for the rounding of the 10,000 Dth futures contract.)

b. Will equal 60% of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70% of forecasted normal weather gas purchase requirements for the remaining ten months. Purchases and/or hedges will be based on the forecast of requirements in place when the purchases and/or hedges are made.

c. Will be purchased in approximately uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery and ending 4 months prior to the start of deliveries.

d. The first purchases and/or hedges made each month will be deemed the Company's mandatory hedge up to the amount of the Company's scheduled mandatory requirement for the month.

e. The Company will make the financial hedges in increments of one contract, 10,000 Dth. The Company will adjust the schedule of hedging to achieve the required mandatory level. Within the constraints of 10,000 Dth contract increments, the Company will seek to maximize the uniformity of monthly mandatory purchase/hedge volumes over the 20 month period specified in paragraph III.A.1.c.

f. The Company and the Division may agree to accelerate a portion of the mandatory hedges. They will notify the Commission of any such plan and provide 3 business days for the Commission to object. Accelerated hedges will neither earn an incentive nor be used in the calculation of mandatory benchmark.

2. Discretionary Purchases and/or Hedges

a. Are defined as the purchases and/or hedges established at least 6 business days prior to the start of the delivery month for delivery to the system or storage in excess of the mandatory hedging requirements in a month.

b. The cost and benefit of any financial purchases and/or hedges will be included in the calculation of the average unit price.

c. The total financial and physical hedged volume (planned mandatory plus accelerated plus discretionary), shall not exceed 95% of the forecasted normal weather requirements for a given supply month. Subsequent revisions to the forecast may impact the hedge percentage for existing hedge position.

3. Other Discretionary Purchases and/or Hedges Not Subject To Incentives

a. LNG

b. Supplies that lock in price but are not part of the program.

c. Hedges specifically put in place as part of the Natural Gas Procurement Management Program to lock in optimization savings for customers.

d. Purchases and/or hedges made less than 6 business days prior to the beginning of the month, during the month or under a contract which does not allow for the locking of the price.

e. Purchases and/or hedges made due to updated levels of forecasted migration of throughput volumes from transportation service to sales service.

B. Computation of Gas Procurement Incentives

Gas Procurement Incentives will be determined on the basis of comparisons of the volume-weighted average cost per dekatherm of discretionary purchases and/or hedges and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges for each gas supply month. All comparisons will be based on the NYMEX portion of the variable cost per dekatherm of the purchased gas supply or the price of the NYMEX futures contract.

C. Any purchases and/or hedges made for a future gas supply month, excluding other discretionary purchases and/or hedges not subject to incentives as shown in III.A.3, that are in excess of the mandatory purchases and/or hedges requirement for the month, will be deemed discretionary purchases and/or hedges.

D. The timing of discretionary purchases and/or hedges is left solely to the discretion of the Company. However, beginning in November 2005 the Company will make sufficient discretionary purchases and/or hedges by November 1st of each year, such that a minimum of 80% of supply needed for December, January and February and 75% of supply needed for a normal November and March will be at a fixed or capped price. The fixed and capped supplies will include all forward purchases, financially based purchases and/or hedges, DOMAC FCS contract purchases fixed in price, LNG supplies and storage supplies.

E. After all purchases and/or hedges for forecasted gas requirements for a given gas supply month are completed, the volume-weighted average cost of mandatory purchases and/or hedges will be computed. That volume weighted average cost for mandatory purchases and/or hedges will then be compared against the actual cost of each discretionary purchase and/or hedge made for the same gas supply month.

1. For all discretionary purchases and/or hedges executed more than eight months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases and/or hedges for the same gas supply month. In the event that the cost of the discretionary purchases/hedges is at least 50 cents less than the cost of the mandatory purchases/hedges, the incentive will be 20%.

2. For all discretionary purchases and/or hedges executed within the last five to eight months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month.

3. For all discretionary purchases and/or hedges executed within the last four months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 5% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month

4. For any and all discretionary purchases and/or hedges that are made at a cost which is greater than the volume-weighted average cost for mandatory purchases and/or hedges, made for the same gas supply month, regardless of when they occur prior to the start of the gas supply month, the Company will be assess a penalty equal to 10% of the difference between the volume-weighted average cost for mandatory purchases and/or hedges and the cost of the each such discretionary purchase,

5. The net incentive/penalty for the Company for each gas supply month shall equal the sum of the incentives/penalties calculated for all individual discretionary purchases and/or hedges executed for the subject gas supply month.

Gas Procurement Incentive Plan for National Grid

Revised Effective July 1, 2010

Deleted: December
Deleted: 2008

I. Objective

To encourage National Grid (or "Company") to achieve lower overall gas commodity costs for its customers.

II. Structure of the Gas Procurement Incentive Plan

A. The original Plan became effective June 1, 2003 and was most recently revised effective December 2008. It will be reviewed with each gas cost recovery ("GCR") filing. The Company will file the Plan results semi-annually in January and July. These reports shall include reporting for all Plan activity and results through the end of the month prior to the filing.

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1. The Gas Procurement Incentive Plan revised effective December 1, 2008 applied to discretionary hedges that settled up through June 2010. .

2. This revised Plan will be effective for hedges that settle starting in July 2010.

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¶

Deleted: GPIP will be subject to limits on the magnitude of incentives applicable to the Company in each fiscal year. ¶
¶
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<#>National Grid may not earn more than $1,000,000 in Gas Procurement Incentives in any fiscal year; and ¶
¶
National Grid may not be exposed to penalties of more than $500,000 in any fiscal year.

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B. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. The hedging plan volume will be adjusted based on this revised forecast. Changes to the hedged volume execution plan will become effective in November of each year. If a midyear revision is warranted the Company will file support for the revised purchase forecast with the Commission and Division.

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III The Gas Procurement Incentive Program

A. The Company will make purchases of natural gas, natural gas swaps or natural gas futures which lock or hedge the NYMEX Henry Hub portion of the variable cost. For any future gas supply month the Company will make three types of gas purchases:

1. Mandatory Purchases and/or Hedges

a. Are defined as mandatory monthly purchases of gas volumes or hedges made in approximately uniform monthly increments. (Mandatory purchases and/or hedges will vary as the forecast of purchases is updated periodically and in order to adjust for the rounding of the 10,000 Dth futures contract.)

b. Will equal 60% of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70% of forecasted normal weather gas purchase requirements for the remaining ten months. Purchases and/or hedges will be based on the forecast of requirements in place when the purchases and/or hedges are made.

c. Will be purchased in approximately uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery and ending 4 months prior to the start of deliveries.

d. The first purchases and/or hedges made each month will be deemed the Company's mandatory hedge up to the amount of the Company's scheduled mandatory requirement for the month.

e. The Company will make the financial hedges in increments of one contract, 10,000 Dth. The Company will adjust the schedule of hedging to achieve the required mandatory level. Within the constraints of 10,000 Dth contract increments, the Company will seek to maximize the uniformity of monthly mandatory purchase/hedge volumes over the 20 month period specified in paragraph III.A.1.c.

f. The Company and the Division may agree to accelerate a portion of the mandatory hedges. They will notify the Commission of any such plan and provide 3 business days for the Commission to object. Accelerated hedges will neither earn an incentive nor be used in the calculation of mandatory benchmark.

2. Discretionary Purchases and/or Hedges

a. Are defined as the purchases and/or hedges established at least 6 business days prior to the start of the delivery month for delivery to the system or storage in excess of the mandatory hedging requirements in a month.

b. The cost and benefit of any financial purchases and/or hedges will be included in the calculation of the average unit price.

c. The total financial and physical hedged volume (planned mandatory plus accelerated plus discretionary), shall not exceed 95% of the forecasted normal weather requirements for a given supply month. Subsequent revisions to the forecast may impact the hedge percentage for existing hedge position.

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3. Other Discretionary Purchases and/or Hedges Not Subject To Incentives

a. LNG

b. Supplies that lock in price but are not part of the program.

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c. Hedges specifically put in place as part of the Natural Gas Procurement Management Program to lock in optimization savings for customers.

d. Purchases and/or hedges made less than 6 business days prior to the beginning of the month, during the month or under a contract which does not allow for the locking of the price.

e. Purchases and/or hedges made due to updated levels of forecasted migration of throughput volumes from transportation service to sales service.

B. Computation of Gas Procurement Incentives

Gas Procurement Incentives will be determined on the basis of comparisons of the volume-weighted average cost per dekatherm of discretionary purchases and/or hedges and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges, for each gas supply month. All comparisons will be based on the NYMEX portion of the variable cost per dekatherm of the purchased gas supply or the price of the NYMEX futures contract.

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C. Any purchases and/or hedges made for a future gas supply month, excluding other discretionary purchases and/or hedges not subject to incentives as shown in III.A.3, that are in excess of the mandatory purchases and/or hedges requirement for the month, will be deemed discretionary purchases and/or hedges.

D. The timing of discretionary purchases and/or hedges is left solely to the discretion of the Company. However, beginning in November 2005 the Company will make sufficient discretionary purchases and/or hedges by November 1st of each year, such that a minimum of 80% of supply needed for December, January and February and 75% of supply needed for a normal November and March will be at a fixed or capped price. The fixed and capped supplies will include all forward purchases, financially based purchases and/or hedges, DOMAC FCS contract purchases fixed in price, LNG supplies and storage supplies.

E. After all purchases and/or hedges for forecasted gas requirements for a given gas supply month are completed, the volume-weighted average cost of mandatory purchases and/or hedges will be computed. That volume weighted average cost for mandatory purchases and/or hedges will then be compared against the actual cost of each discretionary purchase and/or hedge made for the same gas supply month.

1. For all discretionary purchases and/or hedges executed more than eight months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases and/or hedges for the same gas supply month. In the event that the cost of the discretionary purchases/hedges is at least 50 cents less than the

cost of the mandatory purchases/hedges, the incentive will be 20%.

2. For all discretionary purchases and/or hedges executed within the last five to eight months prior to the start of the gas supply month, the Company will be provided as positive incentive equal to 10% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month.

3. For all discretionary purchases and/or hedges executed within the last four months prior to the start of the gas supply month, the Company will be provided a positive incentive equal to 5% of the difference between the cost of each discretionary purchase and the volume-weighted average cost for mandatory purchases and/or hedges for the same gas supply month if the cost of the discretionary purchase and/or hedge is less than the volume weighted average of mandatory purchases for the same gas supply month

4. For any and all discretionary purchases and/or hedges that are made at a cost which is greater than the volume-weighted average cost for mandatory purchases and/or hedges, made for the same gas supply month, regardless of when they occur prior to the start of the gas supply month, the Company will be assess a penalty equal to 10% of the difference between the volume-weighted average cost for mandatory purchases and/or hedges and the cost of the each such discretionary purchase,

5. The net incentive/penalty for the Company for each gas supply month shall equal the sum of the incentives/penalties calculated for all individual discretionary purchases and/or hedges executed for the subject gas supply month.

nationalgrid

Thomas R. Teehan
Senior Counsel – Rhode Island

August 2, 2010

VIA HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: <u>Semi-annual Report on Gas Procurement Incentive Plan</u>

Dear Ms. Massaro:

Pursuant to the provisions of the Gas Procurement Incentive Plan ("Plan") initially approved in Docket No. 3436, Order No. 17444, enclosed please find ten (10) copies of National Grid's semi-annual report on the status of the penalties and incentives as of the end of June 2010.

A summary of incentives and penalties associated with the GPIP is shown on page 1 of the attachment. This summary shows the purchases made under the GPIP for the months of July 2009 to June 2012 as of June 30, 2010. For each month the schedule shows the average unit cost for mandatory and discretionary purchases and the difference. The schedule also shows the discretionary volume, the gain/loss from the discretionary hedges, the incentive percent and the incentive earned by the Company. As of June 30, 2010, 9.2 million DT in discretionary purchases have resulted in $12.5 million in savings compared to the benchmark mandatory prices. Details on the hedge incentive are shown on pages 2 through 4 while pages 5 and 6 show a summary of the hedge positions by month and by type. Additional details on the purchases are also available in the quarterly report filed July 20, 2010.

The incentive/penalty impact on the Company as of June 30, 2010 is shown in the last column of page 1. Note that the $1.6 million in incentive for the July 2009 to June 2010 year would be capped at $1 million.

Thank you for your attention to this matter. If you have any questions, please do not hesitate to contact Stephen Mc Cauley at (516) 545-5403 or me at (401) 784-7667.

Very truly yours,

TRTeehan

Thomas R. Teehan

Enclosures
cc: Thomas Ahern, Division
Stephen Scialabba, Division
Bruce Oliver, Division
Leo Wold, Esq.

Gas Procurement Incentive Program Worksheet - Jun 30, 2010
Incentive Calculation
National Grid - Rhode Island

TOTAL

	Mandatory NYMEX	Discretionary NYMEX	Difference	Discretionary Volumes (Dt)	Gain/ (Loss)	Aggregate * Incentive %	Company Incentive	
Jul-09	$ 8.2187	$ 6.7181	$ 1.50	200,000	$ 300,111	12.08%	$ 36,260	**
Aug-09	$ 8.4090	$ 5.9470	$ 2.46	250,000	$ 615,502	11.37%	$ 70,004	
Sep-09	$ 8.5793	$ 5.8915	$ 2.69	250,000	$ 671,957	15.76%	$ 105,913	**
Oct-09	$ 8.6087	$ 4.9288	$ 3.68	500,000	$ 1,839,971	11.84%	$ 217,854	
Nov-09	$ 9.0895	$ 6.5111	$ 2.58	350,000	$ 902,432	15.98%	$ 144,204	
Dec-09	$ 9.3808	$ 6.5491	$ 2.83	450,000	$ 1,274,270	15.45%	$ 196,864	
Jan-10	$ 9.6441	$ 6.6709	$ 2.97	500,000	$ 1,486,575	13.37%	$ 198,693	
Feb-10	$ 9.6066	$ 6.8329	$ 2.77	500,000	$ 1,386,825	15.98%	$ 221,547	
Mar-10	$ 9.3888	$ 6.6991	$ 2.69	450,000	$ 1,210,370	16.79%	$ 203,252	
Apr-10	$ 7.2889	$ 5.6178	$ 1.67	400,000	$ 668,445	20.00%	$ 133,689	
May-10	$ 6.4765	$ 5.3401	$ 1.14	231,000	$ 262,502	14.72%	$ 38,645	
Jun-10	$ 6.7184	$ 5.6994	$ 1.02	300,000	$ 305,708	13.09%	$ 40,012	
Subtotal 09-10				4,381,000	$ 10,924,667		$ 1,606,937	
Jul-10	$ 6.9731	$ 5.9670	$ 1.01	250,000	$ 251,533	20.00%	$ 50,307	
Aug-10	$ 6.8592	$ 6.0422	$ 0.82	250,000	$ 204,250	20.00%	$ 40,850	
Sep-10	$ 6.7443	$ 6.1150	$ 0.63	200,000	$ 125,851	20.00%	$ 25,170	
Oct-10	$ 6.3375	$ 6.1043	$ 0.23	645,000	$ 150,463	10.00%	$ 15,046	
Nov-10	$ 6.0936	$ 6.0690	$ 0.02	616,000	$ 15,167	10.00%	$ 1,517	
Dec-10	$ 6.5329	$ 6.2682	$ 0.26	410,000	$ 108,525	10.00%	$ 10,853	
Jan-11	$ 6.7563	$ 6.4031	$ 0.35	400,000	$ 141,317	10.00%	$ 14,132	
Feb-11	$ 6.6145	$ 6.1779	$ 0.44	660,000	$ 288,156	10.00%	$ 28,816	
Mar-11	$ 6.3136	$ 5.8079	$ 0.51	400,000	$ 202,284	20.00%	$ 40,457	**
Apr-11	$ 5.8273	$ 5.8606	$ (0.03)	266,000	$ (8,836)	-10.00%	$ (884)	
May-11	$ 5.8520	$ 5.8320	$ 0.02	178,000	$ 3,563	10.00%	$ 356	
Jun-11	$ 5.9785	$ 5.4698	$ 0.51	54,000	$ 27,468	20.00%	$ 5,494	
Subtotal 10-11				4,329,000	$ 1,509,740		$ 232,113	
Jul-11	$ 5.9868	$ 5.5073	$ 0.48	52,000	$ 24,934	10.00%	$ 2,493	
Aug-11	$ 6.0003	$ 5.6037	$ 0.40	92,000	$ 36,485	10.00%	$ 3,649	
Sep-11	$ 6.0901	$ 5.7625	$ 0.33	56,000	$ 18,345	10.00%	$ 1,834	
Oct-11	$ 6.0172	$ 5.9505	$ 0.07	33,000	$ 2,203	10.00%	$ 220	
Nov-11	$ 6.1939	$ 6.1787	$ 0.02	42,000	$ 641	10.00%	$ 64	
Dec-11	$ 6.5312	$ 6.5098	$ 0.02	29,000	$ 620	10.00%	$ 62	
Jan-12	$ 6.6620	$ 6.6374	$ 0.02	31,000	$ 762	10.00%	$ 76	
Feb-12	$ 6.4903	$ 6.4891	$ 0.00	86,000	$ 101	10.00%	$ 10	
Mar-12	$ 5.9863	$ 5.8000	$ 0.19	3,000	$ 559	10.00%	$ 56	
Apr-12	$ 5.5730	$ 5.5244	$ 0.05	8,000	$ 389	10.00%	$ 39	
May-12	$ 5.6393	$ 5.5610	$ 0.08	10,000	$ 783	10.00%	$ 78	
Jun-12	$ 5.5200	$ 5.4800	$ 0.04	10,000	$ 400	10.00%	$ 40	
Subtotal 11-12				452,000	$ 86,223		$ 8,622	
TOTAL				9,162,000	$ 12,520,630		$ 1,847,671	

* Percentage Computed as the weighted average of the three levels of incentive as detailed below:

a) OLD MECHANISM — Deals executed prior to Dec 1 2008.

b) NEW MECHANISM — Deals executed after Dec 1 2008

b. i) 10% for trades executed within the 8 months to the start of the Supply Month.

b. ii) 20% for trades executed at least 8 months prior to the start of the Supply Month and Margin is higher than $.50, 10% if margin is lower than $0.50.

In both a & b explained above a 10% Penalty is applicable for months where discretionary price is higher than the mandatory hedged price.

***** See "Exception (Error) Trades" tab!***

OLD MECHANISM

~ Volumes purchase before Dec 2008

	VOLUME (Dth)			**PURCHASE (USD)**			**Average Price ($/Dth)**			**Margin**	**Incentive**
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	($/Dth)	(USD)
Jul-09	890,000	80,000	100,000	$ 7,314,610	$ 585,000	$ 743,000	$ 8.2187	$ 7.3125	$ 7.4300	$ 0.7887	$ 15,773
Aug-09	830,000	110,000	50,000	$ 6,979,450	$ 813,800	$ 342,500	$ 8.4090	$ 7.3982	$ 6.8500	$ 1.5590	$ 15,590
Sep-09	780,000	170,000	50,000	$ 6,691,840	$ 1,258,250	$ 344,000	$ 8.5793	$ 7.4015	$ 6.8800	$ 1.6993	$ 16,993
Oct-09	940,000	250,000	50,000	$ 8,092,200	$ 1,868,750	$ 348,750	$ 8.6087	$ 7.4750	$ 6.9750	$ 1.6337	$ 16,337
Nov-09	1,350,000	570,000	100,000	$ 12,270,850	$ 4,155,010	$ 802,250	$ 9.0895	$ 7.2895	$ 8.0225	$ 1.0670	$ 21,340
Dec-09	1,680,000	940,000	100,000	$ 15,759,750	$ 6,973,350	$ 840,250	$ 9.3808	$ 7.4185	$ 8.4025	$ 0.9783	$ 19,566
Jan-10	1,660,000	1,110,000	100,000	$ 16,009,200	$ 8,470,060	$ 863,750	$ 9.6441	$ 7.6307	$ 8.6375	$ 1.0066	$ 20,132
Feb-10	1,300,000	1,040,000	100,000	$ 12,488,550	$ 7,894,390	$ 864,000	$ 9.6066	$ 7.5908	$ 8.6400	$ 0.9666	$ 19,332
Mar-10	1,130,000	1,160,000	100,000	$ 10,609,400	$ 8,454,680	$ 844,500	$ 9.3888	$ 7.2885	$ 8.4450	$ 0.9438	$ 18,877
Apr-10	1,320,000	740,000	-	$ 9,621,300	$ 4,061,470	$ -	$ 7.2889	$ 5.4885	$ -	$ -	$ -
May-10	1,320,000	320,000	-	$ 8,548,950	$ 1,766,040	$ -	$ 6.4765	$ 5.5189	$ -	$ -	$ -
Jun-10	855,000	280,000	-	$ 5,744,250	$ 1,569,890	$ -	$ 6.7184	$ 5.6068	$ -	$ -	$ -
Jul-10	607,000	290,000	-	$ 4,232,690	$ 1,657,680	$ -	$ 6.9731	$ 5.7161	$ -	$ -	$ -
Aug-10	526,000	310,000	-	$ 3,607,940	$ 1,794,470	$ -	$ 6.8592	$ 5.7886	$ -	$ -	$ -
Sep-10	470,000	330,000	-	$ 3,169,800	$ 1,920,490	$ -	$ 6.7443	$ 5.8197	$ -	$ -	$ -
Oct-10	695,000	440,000	-	$ 4,404,590	$ 2,601,660	$ -	$ 6.3375	$ 5.9129	$ -	$ -	$ -
Nov-10	1,700,000	770,000	-	$ 10,359,200	$ 4,796,230	$ -	$ 6.0936	$ 6.2289	$ -	$ -	$ -
Dec-10	1,640,000	1,110,000	-	$ 10,713,900	$ 7,326,740	$ -	$ 6.5329	$ 6.6007	$ -	$ -	$ -
Jan-11	1,370,000	1,240,000	-	$ 9,256,190	$ 8,466,940	$ -	$ 6.7563	$ 6.8282	$ -	$ -	$ -
Feb-11	1,150,000	1,100,000	-	$ 7,606,650	$ 7,510,920	$ -	$ 6.6145	$ 6.8281	$ -	$ -	$ -
Mar-11	1,180,000	1,140,000	-	$ 7,450,060	$ 7,850,420	$ -	$ 6.3136	$ 6.8863	$ -	$ -	$ -
Apr-11	874,000	820,000	-	$ 5,093,100	$ 5,159,890	$ -	$ 5.8273	$ 6.2925	$ -	$ -	$ -
May-11	679,000	620,000	-	$ 3,973,495	$ 4,212,900	$ -	$ 5.8520	$ 6.7950	$ -	$ -	$ -
Jun-11	427,000	480,000	-	$ 2,552,815	$ 3,177,600	$ -	$ 5.9785	$ 6.6200	$ -	$ -	$ -
Jul-11	250,000	480,000	-	$ 1,496,700	$ 3,084,500	$ -	$ 5.9868	$ 6.4260	$ -	$ -	$ -
Aug-11	218,000	470,000	-	$ 1,308,060	$ 3,109,050	$ -	$ 6.0003	$ 6.6150	$ -	$ -	$ -
Sep-11	116,000	470,000	-	$ 706,450	$ 3,062,050	$ -	$ 6.0901	$ 6.5150	$ -	$ -	$ -
Oct-11	270,000	590,000	-	$ 1,624,650	$ 3,986,800	$ -	$ 6.0172	$ 6.7573	$ -	$ -	$ -
Nov-11	446,000	1,510,000	-	$ 2,762,500	$ 9,795,450	$ -	$ 6.1939	$ 6.4871	$ -	$ -	$ -
Dec-11	524,000	1,700,000	-	$ 3,422,360	$ 11,367,600	$ -	$ 6.5312	$ 6.6868	$ -	$ -	$ -
Jan-12	442,000	1,670,000	-	$ 2,944,600	$ 11,361,150	$ -	$ 6.6620	$ 6.8031	$ -	$ -	$ -
Feb-12	330,000	1,500,000	-	$ 2,141,800	$ 9,728,000	$ -	$ 6.4903	$ 6.4853	$ -	$ -	$ -
Mar-12	300,000	1,670,000	-	$ 1,795,900	$ 9,787,250	$ -	$ 5.9863	$ 5.8606	$ -	$ -	$ -
Apr-12	219,000	970,000	-	$ 1,220,495	$ 5,431,650	$ -	$ 5.5730	$ 5.5996	$ -	$ -	$ -
May-12	125,000	740,000	-	$ 704,915	$ 4,133,550	$ -	$ 5.6393	$ 5.5859	$ -	$ -	$ -
Jun-12	60,000	540,000	-	$ 331,200	$ 2,972,800	$ -	$ 5.5200	$ 5.5052	$ -	$ -	$ -

NEW MECHANISM_< 8 MONTHS ~ 10%

	VOLUME (Dth)			PURCHASE (USD)			Average Price ($/Dth)			Margin	10% Incentive
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	($/Dth)	(USD)
Jul-09	890,000	80,000	100,000	$ 7,314,610	$ 585,000	$ 617,000	$ 8.2187	$ 7.3125	$ 6.1700	$ 2.0487	$ 20,487
Aug-09	830,000	110,000	200,000	$ 6,979,450	$ 813,800	$ 1,137,650	$ 8.4090	$ 7.3982	$ 5.6883	$ 2.7207	$ 54,415
Sep-09	780,000	170,000	50,000	$ 6,691,840	$ 1,258,250	$ 188,750	$ 8.5793	$ 7.4015	$ 3.7750	$ 4.8043	$ 24,021
Oct-09	940,000	250,000	300,000	$ 8,092,200	$ 1,868,750	$ 1,191,270	$ 8.6087	$ 7.4750	$ 3.9709	$ 4.6378	$ 139,135
Nov-09	1,350,000	570,000	50,000	$ 12,270,850	$ 4,155,010	$ 240,250	$ 9.0895	$ 7.2895	$ 4.8050	$ 4.2845	$ 21,423
Dec-09	1,680,000	940,000	100,000	$ 15,759,750	$ 6,973,350	$ 533,000	$ 9.3808	$ 7.4185	$ 5.3300	$ 4.0508	$ 40,508
Jan-10	1,660,000	1,110,000	200,000	$ 16,009,200	$ 8,470,060	$ 1,105,350	$ 9.6441	$ 7.6307	$ 5.5268	$ 4.1173	$ 82,347
Feb-10	1,300,000	1,040,000	100,000	$ 12,488,550	$ 7,894,390	$ 571,850	$ 9.6066	$ 7.5908	$ 5.7185	$ 3.8881	$ 38,881
Mar-10	1,130,000	1,160,000	50,000	$ 10,609,400	$ 8,454,680	$ 275,500	$ 9.3888	$ 7.2885	$ 5.5100	$ 3.8788	$ 19,394
Apr-10	1,320,000	740,000	-	$ 9,621,300	$ 4,061,470	$ -	$ 7.2889	$ 5.4885	$ -	$ -	$ -
May-10	1,320,000	320,000	81,000	$ 8,548,950	$ 1,766,040	$ 387,585	$ 6.4765	$ 5.5189	$ 4.7850	$ 1.6915	$ 13,701
Jun-10	855,000	280,000	200,000	$ 5,744,250	$ 1,569,890	$ 1,116,250	$ 6.7184	$ 5.6068	$ 5.5813	$ 1.1372	$ 22,743
Jul-10	607,000	290,000	-	$ 4,232,690	$ 1,657,680	$ -	$ 6.9731	$ 5.7161	$ -	$ -	$ -
Aug-10	526,000	310,000	-	$ 3,607,940	$ 1,794,470	$ -	$ 6.8592	$ 5.7886	$ -	$ -	$ -
Sep-10	470,000	330,000	-	$ 3,169,800	$ 1,920,490	$ -	$ 6.7443	$ 5.8197	$ -	$ -	$ -
Oct-10	695,000	440,000	-	$ 4,404,590	$ 2,601,660	$ -	$ 6.3375	$ 5.9129	$ -	$ -	$ -
Nov-10	1,700,000	770,000	-	$ 10,359,200	$ 4,796,230	$ -	$ 6.0936	$ 6.2289	$ -	$ -	$ -
Dec-10	1,640,000	1,110,000	-	$ 10,713,900	$ 7,326,740	$ -	$ 6.5329	$ 6.6007	$ -	$ -	$ -
Jan-11	1,370,000	1,240,000	-	$ 9,256,190	$ 8,466,940	$ -	$ 6.7563	$ 6.8282	$ -	$ -	$ -
Feb-11	1,150,000	1,100,000	-	$ 7,606,650	$ 7,510,920	$ -	$ 6.6145	$ 6.8281	$ -	$ -	$ -
Mar-11	1,180,000	1,140,000	-	$ 7,450,060	$ 7,850,420	$ -	$ 6.3136	$ 6.8863	$ -	$ -	$ -
Apr-11	874,000	820,000	-	$ 5,093,100	$ 5,159,890	$ -	$ 5.8273	$ 6.2925	$ -	$ -	$ -
May-11	679,000	620,000	-	$ 3,973,495	$ 4,212,900	$ -	$ 5.8520	$ 6.7950	$ -	$ -	$ -
Jun-11	427,000	480,000	-	$ 2,552,815	$ 3,177,600	$ -	$ 5.9785	$ 6.6200	$ -	$ -	$ -
Jul-11	250,000	480,000	-	$ 1,496,700	$ 3,084,500	$ -	$ 5.9868	$ 6.4260	$ -	$ -	$ -
Aug-11	218,000	470,000	-	$ 1,308,060	$ 3,109,050	$ -	$ 6.0003	$ 6.6150	$ -	$ -	$ -
Sep-11	116,000	470,000	-	$ 706,450	$ 3,062,050	$ -	$ 6.0901	$ 6.5150	$ -	$ -	$ -
Oct-11	270,000	590,000	-	$ 1,624,650	$ 3,986,800	$ -	$ 6.0172	$ 6.7573	$ -	$ -	$ -
Nov-11	446,000	1,510,000	-	$ 2,762,500	$ 9,795,450	$ -	$ 6.1939	$ 6.4871	$ -	$ -	$ -
Dec-11	524,000	1,700,000	-	$ 3,422,360	$ 11,367,600	$ -	$ 6.5312	$ 6.6868	$ -	$ -	$ -
Jan-12	442,000	1,670,000	-	$ 2,944,600	$ 11,361,150	$ -	$ 6.6620	$ 6.8031	$ -	$ -	$ -
Feb-12	330,000	1,500,000	-	$ 2,141,800	$ 9,728,000	$ -	$ 6.4903	$ 6.4853	$ -	$ -	$ -
Mar-12	300,000	1,670,000	-	$ 1,795,900	$ 9,787,250	$ -	$ 5.9863	$ 5.8606	$ -	$ -	$ -
Apr-12	219,000	970,000	-	$ 1,220,495	$ 5,431,650	$ -	$ 5.5730	$ 5.5996	$ -	$ -	$ -
May-12	125,000	740,000	-	$ 704,915	$ 4,133,550	$ -	$ 5.6393	$ 5.5859	$ -	$ -	$ -
Jun-12	60,000	540,000	-	$ 331,200	$ 2,972,800	$ -	$ 5.5200	$ 5.5052	$ -	$ -	$ -

NEW MECHANISM_> 8 MONTHS ~ 20%

	VOLUME (Dth)			PURCHASE (USD)			Average Price ($/Dth)			Margin	Incentive
											20%
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	($/Dth)	(USD)
Jul-09	890,000	80,000	-	$ 7,314,610	$ 585,000	$ -	$ 8.2187	$ 7.3125	$ -	$ -	$ -
Aug-09	830,000	110,000	-	$ 6,979,450	$ 813,800	$ -	$ 8.4090	$ 7.3982	$ -	$ -	$ -
Sep-09	780,000	170,000	150,000	$ 6,691,840	$ 1,258,250	$ 962,400	$ 8.5793	$ 7.4015	$ 6.4160	$ 2.1633	$ 64,898
Oct-09	940,000	250,000	150,000	$ 8,092,200	$ 1,868,750	$ 979,400	$ 8.6087	$ 7.4750	$ 6.5293	$ 2.0794	$ 62,382
Nov-09	1,350,000	570,000	200,000	$ 12,270,850	$ 4,155,010	$ 1,310,700	$ 9.0895	$ 7.2895	$ 6.5535	$ 2.5360	$ 101,441
Dec-09	1,680,000	940,000	250,000	$ 15,759,750	$ 6,973,350	$ 1,661,250	$ 9.3808	$ 7.4185	$ 6.6450	$ 2.7358	$ 136,790
Jan-10	1,660,000	1,110,000	200,000	$ 16,009,200	$ 8,470,060	$ 1,447,750	$ 9.6441	$ 7.6307	$ 7.2388	$ 2.4053	$ 96,214
Feb-10	1,300,000	1,040,000	300,000	$ 12,488,550	$ 7,894,390	$ 2,065,300	$ 9.6066	$ 7.5908	$ 6.8843	$ 2.7222	$ 163,335
Mar-10	1,130,000	1,160,000	300,000	$ 10,609,400	$ 8,454,680	$ 1,991,750	$ 9.3888	$ 7.2885	$ 6.6392	$ 2.7497	$ 164,981
Apr-10	1,320,000	740,000	400,000	$ 9,621,300	$ 4,061,470	$ 2,247,100	$ 7.2889	$ 5.4885	$ 5.6178	$ 1.6711	$ 133,689
May-10	1,320,000	320,000	150,000	$ 8,548,950	$ 1,766,040	$ 846,750	$ 6.4765	$ 5.5189	$ 5.6450	$ 0.8315	$ 24,944
Jun-10	855,000	280,000	100,000	$ 5,744,250	$ 1,569,890	$ 585,500	$ 6.7184	$ 5.6068	$ 5.8550	$ 0.8634	$ 17,268
Jul-10	607,000	290,000	250,000	$ 4,232,690	$ 1,657,680	$ 1,491,750	$ 6.9731	$ 5.7161	$ 5.9670	$ 1.0061	$ 50,307
Aug-10	526,000	310,000	250,000	$ 3,607,940	$ 1,794,470	$ 1,510,550	$ 6.8592	$ 5.7886	$ 6.0422	$ 0.8170	$ 40,850
Sep-10	470,000	330,000	200,000	$ 3,169,800	$ 1,920,490	$ 1,223,000	$ 6.7443	$ 5.8197	$ 6.1150	$ 0.6293	$ 25,170
Oct-10	695,000	440,000	645,000	$ 4,404,590	$ 2,601,660	$ 3,937,250	$ 6.3375	$ 5.9129	$ 6.1043	$ 0.2333	$ 15,046
Nov-10	1,700,000	770,000	616,000	$ 10,359,200	$ 4,796,230	$ 3,738,520	$ 6.0936	$ 6.2289	$ 6.0690	$ 0.0246	$ 1,517
Dec-10	1,640,000	1,110,000	410,000	$ 10,713,900	$ 7,326,740	$ 2,569,950	$ 6.5329	$ 6.6007	$ 6.2682	$ 0.2647	$ 10,853
Jan-11	1,370,000	1,240,000	400,000	$ 9,256,190	$ 8,466,940	$ 2,561,220	$ 6.7563	$ 6.8282	$ 6.4031	$ 0.3533	$ 14,132
Feb-11	1,150,000	1,100,000	660,000	$ 7,606,650	$ 7,510,920	$ 4,077,400	$ 6.6145	$ 6.8281	$ 6.1779	$ 0.4366	$ 28,816
Mar-11	1,180,000	1,140,000	400,000	$ 7,450,060	$ 7,850,420	$ 2,323,160	$ 6.3136	$ 6.8863	$ 5.8079	$ 0.5057	$ 40,457
Apr-11	874,000	820,000	266,000	$ 5,093,100	$ 5,159,890	$ 1,558,910	$ 5.8273	$ 6.2925	$ 5.8606	$ (0.0332)	$ (884)
May-11	679,000	620,000	178,000	$ 3,973,495	$ 4,212,900	$ 1,038,090	$ 5.8520	$ 6.7950	$ 5.8320	$ 0.0200	$ 356
Jun-11	427,000	480,000	54,000	$ 2,552,815	$ 3,177,600	$ 295,370	$ 5.9785	$ 6.6200	$ 5.4698	$ 0.5087	$ 5,494
Jul-11	250,000	480,000	52,000	$ 1,496,700	$ 3,084,500	$ 286,380	$ 5.9868	$ 6.4260	$ 5.5073	$ 0.4795	$ 2,493
Aug-11	218,000	470,000	92,000	$ 1,308,060	$ 3,109,050	$ 515,540	$ 6.0003	$ 6.6150	$ 5.6037	$ 0.3966	$ 3,649
Sep-11	116,000	470,000	56,000	$ 706,450	$ 3,062,050	$ 322,700	$ 6.0901	$ 6.5150	$ 5.7625	$ 0.3276	$ 1,834
Oct-11	270,000	590,000	33,000	$ 1,624,650	$ 3,986,800	$ 196,365	$ 6.0172	$ 6.7573	$ 5.9505	$ 0.0668	$ 220
Nov-11	446,000	1,510,000	42,000	$ 2,762,500	$ 9,795,450	$ 259,505	$ 6.1939	$ 6.4871	$ 6.1787	$ 0.0153	$ 64
Dec-11	524,000	1,700,000	29,000	$ 3,422,360	$ 11,367,600	$ 188,785	$ 6.5312	$ 6.6868	$ 6.5098	$ 0.0214	$ 62
Jan-12	442,000	1,670,000	31,000	$ 2,944,600	$ 11,361,150	$ 205,760	$ 6.6620	$ 6.8031	$ 6.6374	$ 0.0246	$ 76
Feb-12	330,000	1,500,000	86,000	$ 2,141,800	$ 9,728,000	$ 558,065	$ 6.4903	$ 6.4853	$ 6.4891	$ 0.0012	$ 10
Mar-12	300,000	1,670,000	3,000	$ 1,795,900	$ 9,787,250	$ 17,400	$ 5.9863	$ 5.8606	$ 5.8000	$ 0.1863	$ 56
Apr-12	219,000	970,000	8,000	$ 1,220,495	$ 5,431,650	$ 44,195	$ 5.5730	$ 5.5996	$ 5.5244	$ 0.0487	$ 39
May-12	125,000	740,000	10,000	$ 704,915	$ 4,133,550	$ 55,610	$ 5.6393	$ 5.5859	$ 5.5610	$ 0.0783	$ 78
Jun-12	60,000	540,000	10,000	$ 331,200	$ 2,972,800	$ 54,800	$ 5.5200	$ 5.5052	$ 5.4800	$ 0.0400	$ 40

NEC Gas Cost Volatility Hedging Summary

		Volume **Forecast** (Dth)	HEDGED VOLUME (Dth) Mandatory	Accelerated	Discretionary	Monthly "Locked"	Percentage "Locked"		Average NYMEX	**Total Cost**
200907	07/01/2009	1,382,347	890,000	80,000	200,000	1,170,000	85%	**	$ 7.9142	$ 9,259,610
200908	08/01/2009	1,347,742	830,000	110,000	250,000	1,190,000	88%		$ 7.7928	$ 9,273,400
200909	09/01/2009	1,361,066	780,000	170,000	250,000	1,200,000	88%	**	$ 7.8710	$ 9,445,240
200910	10/01/2009	1,981,805	940,000	250,000	500,000	1,690,000	85%		$ 7.3848	$ 12,480,370
200911	11/01/2009	2,739,093	1,350,000	570,000	350,000	2,270,000	83%		$ 8.2727	$ 18,779,060
200912	12/01/2009	4,052,997	1,680,000	940,000	450,000	3,070,000	76%		$ 8.3934	$ 25,767,600
201001	01/01/2010	3,929,803	1,660,000	1,110,000	500,000	3,270,000	83%		$ 8.5309	$ 27,896,110
201002	02/01/2010	3,480,004	1,300,000	1,040,000	500,000	2,840,000	82%		$ 8.4099	$ 23,884,090
201003	03/01/2010	3,810,020	1,130,000	1,160,000	450,000	2,740,000	72%		$ 8.0934	$ 22,175,830
201004	04/01/2010	3,432,023	1,320,000	740,000	400,000	2,460,000	72%		$ 6.4756	$ 15,929,870
201005	05/01/2010	2,354,131	1,320,000	320,000	231,000	1,871,000	79%		$ 6.1728	$ 11,549,325
201006	06/01/2010	1,621,520	855,000	280,000	300,000	1,435,000	88%		$ 6.2829	$ 9,015,890
201007	07/01/2010	1,276,406	607,000	290,000	250,000	1,147,000	90%		$ 6.4360	$ 7,382,120
201008	08/01/2010	1,197,004	526,000	310,000	250,000	1,086,000	91%		$ 6.3655	$ 6,912,960
201009	09/01/2010	905,122	470,000	330,000	200,000	1,000,000	110%		$ 6.3133	$ 6,313,290
201010	10/01/2010	1,904,228	695,000	440,000	645,000	1,780,000	93%		$ 6.1480	$ 10,943,500
201011	11/01/2010	3,529,841	1,700,000	770,000	616,000	3,086,000	87%		$ 6.1225	$ 18,893,950
201012	12/01/2010	4,052,997	1,640,000	1,110,000	410,000	3,160,000	78%		$ 6.5223	$ 20,610,590
201101	01/01/2011	3,929,803	1,370,000	1,240,000	400,000	3,010,000	77%		$ 6.7390	$ 20,284,350
201102	02/01/2011	3,480,004	1,150,000	1,100,000	660,000	2,910,000	84%		$ 6.5962	$ 19,194,970
201103	03/01/2011	3,810,020	1,180,000	1,140,000	400,000	2,720,000	71%	**	$ 6.4793	$ 17,623,640
201104	04/01/2011	3,432,023	874,000	820,000	266,000	1,960,000	57%		$ 6.0265	$ 11,811,900
201105	05/01/2011	2,354,131	679,000	620,000	178,000	1,477,000	63%		$ 6.2454	$ 9,224,485
201106	06/01/2011	1,621,520	427,000	480,000	54,000	961,000	59%		$ 6.2703	$ 6,025,785
201107	07/01/2011	1,276,406	250,000	480,000	52,000	782,000	61%		$ 6.2245	$ 4,867,580
201108	08/01/2011	1,197,004	218,000	470,000	92,000	780,000	65%		$ 6.3239	$ 4,932,650
201109	09/01/2011	905,122	116,000	470,000	56,000	642,000	71%		$ 6.3726	$ 4,091,200
201110	10/01/2011	1,904,228	270,000	590,000	33,000	893,000	47%		$ 6.5037	$ 5,807,815
201111	11/01/2011	3,529,841	446,000	1,510,000	42,000	1,998,000	57%		$ 6.4151	$ 12,817,455
201112	12/01/2011	4,052,997	524,000	1,700,000	29,000	2,253,000	56%		$ 6.6484	$ 14,978,745
201201	01/01/2012	3,929,803	442,000	1,670,000	31,000	2,143,000	55%		$ 6.7716	$ 14,511,510
201202	02/01/2012	3,480,004	330,000	1,500,000	86,000	1,916,000	55%		$ 6.4864	$ 12,427,865
201203	03/01/2012	3,810,020	300,000	1,670,000	3,000	1,973,000	52%		$ 5.8797	$ 11,600,550
201204	04/01/2012	3,432,023	219,000	970,000	8,000	1,197,000	35%		$ 5.5943	$ 6,696,340
201205	05/01/2012	2,354,131	125,000	740,000	10,000	875,000	37%		$ 5.5932	$ 4,894,075
201206	06/01/2012	1,621,520	60,000	540,000	10,000	610,000	38%		$ 5.5062	$ 3,358,800

NEC Gas Cost Volatility Hedging Summary

	PURCHASE (USD)			Average Price ($/Dth)			
	Mandatory	Accelerated	Discretionary	Mandatory	Accelerated	Discretionary	
07/01/2009	$ 7,314,610	$ 585,000	$ 1,360,000	$ 8.2187	$ 7.3125	$ 6.8000	**
08/01/2009	$ 6,979,450	$ 813,800	$ 1,480,150	$ 8.4090	$ 7.3982	$ 5.9206	
09/01/2009	$ 6,691,840	$ 1,258,250	$ 1,495,150	$ 8.5793	$ 7.4015	$ 5.9806	**
10/01/2009	$ 8,092,200	$ 1,868,750	$ 2,519,420	$ 8.6087	$ 7.4750	$ 5.0388	
11/01/2009	$ 12,270,850	$ 4,155,010	$ 2,353,200	$ 9.0895	$ 7.2895	$ 6.7234	
12/01/2009	$ 15,759,750	$ 6,973,350	$ 3,034,500	$ 9.3808	$ 7.4185	$ 6.7433	
01/01/2010	$ 16,009,200	$ 8,470,060	$ 3,416,850	$ 9.6441	$ 7.6307	$ 6.8337	
02/01/2010	$ 12,488,550	$ 7,894,390	$ 3,501,150	$ 9.6066	$ 7.5908	$ 7.0023	
03/01/2010	$ 10,609,400	$ 8,454,680	$ 3,111,750	$ 9.3888	$ 7.2885	$ 6.9150	
04/01/2010	$ 9,621,300	$ 4,061,470	$ 2,247,100	$ 7.2889	$ 5.4885	$ 5.6178	
05/01/2010	$ 8,548,950	$ 1,766,040	$ 1,234,335	$ 6.4765	$ 5.5189	$ 5.3434	
06/01/2010	$ 5,744,250	$ 1,569,890	$ 1,701,750	$ 6.7184	$ 5.6068	$ 5.6725	
07/01/2010	$ 4,232,690	$ 1,657,680	$ 1,491,750	$ 6.9731	$ 5.7161	$ 5.9670	
08/01/2010	$ 3,607,940	$ 1,794,470	$ 1,510,550	$ 6.8592	$ 5.7886	$ 6.0422	
09/01/2010	$ 3,169,800	$ 1,920,490	$ 1,223,000	$ 6.7443	$ 5.8197	$ 6.1150	
10/01/2010	$ 4,404,590	$ 2,601,660	$ 3,937,250	$ 6.3375	$ 5.9129	$ 6.1043	
11/01/2010	$ 10,359,200	$ 4,796,230	$ 3,738,520	$ 6.0936	$ 6.2289	$ 6.0690	
12/01/2010	$ 10,713,900	$ 7,326,740	$ 2,569,950	$ 6.5329	$ 6.6007	$ 6.2682	
01/01/2011	$ 9,256,190	$ 8,466,940	$ 2,561,220	$ 6.7563	$ 6.8282	$ 6.4031	
02/01/2011	$ 7,606,650	$ 7,510,920	$ 4,077,400	$ 6.6145	$ 6.8281	$ 6.1779	
03/01/2011	$ 7,450,060	$ 7,850,420	$ 2,323,160	$ 6.3136	$ 6.8863	$ 5.8079	**
04/01/2011	$ 5,093,100	$ 5,159,890	$ 1,558,910	$ 5.8273	$ 6.2925	$ 5.8606	
05/01/2011	$ 3,973,495	$ 4,212,900	$ 1,038,090	$ 5.8520	$ 6.7950	$ 5.8320	
06/01/2011	$ 2,552,815	$ 3,177,600	$ 295,370	$ 5.9785	$ 6.6200	$ 5.4698	
07/01/2011	$ 1,496,700	$ 3,084,500	$ 286,380	$ 5.9868	$ 6.4260	$ 5.5073	
08/01/2011	$ 1,308,060	$ 3,109,050	$ 515,540	$ 6.0003	$ 6.6150	$ 5.6037	
09/01/2011	$ 706,450	$ 3,062,050	$ 322,700	$ 6.0901	$ 6.5150	$ 5.7625	
10/01/2011	$ 1,624,650	$ 3,986,800	$ 196,365	$ 6.0172	$ 6.7573	$ 5.9505	
11/01/2011	$ 2,762,500	$ 9,795,450	$ 259,505	$ 6.1939	$ 6.4871	$ 6.1787	
12/01/2011	$ 3,422,360	$ 11,367,600	$ 188,785	$ 6.5312	$ 6.6868	$ 6.5098	
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02/01/2012	$ 2,141,800	$ 9,728,000	$ 558,065	$ 6.4903	$ 6.4853	$ 6.4891	
03/01/2012	$ 1,795,900	$ 9,787,250	$ 17,400	$ 5.9863	$ 5.8606	$ 5.8000	
04/01/2012	$ 1,220,495	$ 5,431,650	$ 44,195	$ 5.5730	$ 5.5996	$ 5.5244	
05/01/2012	$ 704,915	$ 4,133,550	$ 55,610	$ 5.6393	$ 5.5859	$ 5.5610	
06/01/2012	$ 331,200	$ 2,972,800	$ 54,800	$ 5.5200	$ 5.5052	$ 5.4800	

Exception (Error) Trades

Following trades are either over hedges or violate other strategy rules and are not incorporated in Incentive Calculation

Reason to exclude	DEAL TYPE	DEAL KEY	BUY/SELL	CONTRACT MONTH	TRADE DATE	COMMODITY	VOLUME (Dth)	PRICE	M2M PRICE	PROFIT (LOSS)
July 09 Disc Hedge executed within 6 Business Days prior to the start of supply month	FUTS	11942	PURCHASE	200907	06/24/2009	NG	50,000	$ 3.800	$ 3.949	$ 7,450
July 09 Disc Hedge executed within 6 Business Days prior to the start of supply month	FUTS	11946	SALE	200907	06/24/2009	NG	(250,000)	$ 3.780	$ 3.949	$ (42,250)
Sep 09 Overhedge Mandatory	FUTS	10632	PURCHASE	200909	12/13/2007	NG	50,000	$ 8.100	$ 2.843	$ (262,850)
Sep 09 Overhedge Mandatory	FUTS	10790	SALE	200909	01/25/2008	NG	(50,000)	$ 8.190	$ 2.843	$ 267,350
Mar 11, Overhedge Accelerated	SWPS	14422	PURCHASE	201103	03/19/2009	NG	270,000	$ 6.640	$ 6.630	$ (2,653)
Mar 11, Overhedge Accelerated	SWPS	14423	SALE	201103	03/20/2009	NG	(270,000)	$ 6.705	$ 6.630	$ 19,896

nationalgrid

Thomas R. Teehan
Senior Counsel

February 25, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4097 – Gas Cost Recovery
<u>Gas Purchasing Incentive Plan ("GPIP")</u>

Dear Ms. Massaro:

In the October 2009 Gas Cost Recovery filing, the Commission directed National Grid[1] and the Rhode Island Division of Public Utilities and Carriers ("Division") to engage in discussions to evaluate the existing Gas Purchasing Incentive Plan ("GPIP") in order to determine if it still provides the intended benefits to customers. The Commission further directed that the Company file a written report with the Commission detailing the results of those discussions. (Order 19832) The enclosed report is filed in compliance with that directive.

The report is the product of collaborative meetings and discussions involving representatives from the Company, the Division, and the Division's consultant. The report contains a description of the plan components and an assessment of the plan's success in achieving its goals. The parties support the continued importance of the GPIP as a tool to reduce the price volatility of customers' gas costs, and they recommend consideration of certain discreet changes in the incentive plan relative to discretionary purchases and with respect to the incentive cap.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid ("Company").

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.

___________________________ Joanne M. Scanlon

February 25, 2010
Date

Docket No. 4097 – National Grid – Annual Gas Cost Recovery Filing ("GCR") - Service List as of 10/5/09

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File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Lmassaro@puc.state.ri.us Plucarelli@puc.state.ri.us Sccamara@puc.state.ri.us	401-780-2107 401-941-1691

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2009
Docket No. 4097

Evaluation Regarding Rhode Island Gas Procurement Incentive Plan (GPIP)

On October 27, 2009, in its Report and Order in the above-referenced Gas Cost Recovery proceeding, the Rhode Island Public Utilities Commission ("Commission") directed National Grid [1] and the Rhode Island Division of Public Utilities and Carriers ("Division") to engage in further discussions about the Gas Purchasing Incentive Plan ("GPIP") and to evaluate the existing plan to determine whether it still provides the intended benefits to customers and whether modifications are necessary. The Commission further directed that the Company file a written report with the Commission detailing the results from those discussions. (Order 19832) This report is filed in compliance with the Commission's directive.

Representatives from the Company, the Division, and the Division's consultant met to discuss the plan on several occasions. Initially, in order to determine the benefits of the plan, a three-step analysis was employed. First, the plan goals were clarified. Then, the parties were to determine whether those goals are being met. Finally, there was a reassessment of whether those goals are still relevant today.

[1] The Narragansett Electric Company d/b/a National Grid ('National Grid" or "Company").

The goal of the hedging program is to reduce the price volatility of the customer's gas costs. Gas costs are impacted by three primary factors: (1) fixed charges on pipeline, storage, and peaking supplies; (2) local distribution charges; and (3) commodity costs. Of the three, commodity costs are what drive the volatility of the customer's gas costs. In the late 1990's and early 2000's, the industry experienced a dramatic increase in the volatility of natural gas, both to the upside and downside. The mandatory volume component of the GPIP was developed at that time to help control this volatility. This mandatory component has specific volume targets and execution timing requirements. Because the Mandatory program locks in 60%-70% of the firm sales price, its execution provides the greatest impact to reducing price volatility to the customer. To date, the mandatory program has been very successful in reducing the gas cost volatility. For example, over the past three years the NYMEX volatility has been 14.6%. By comparison, during the same period under the gas purchasing plan, the mandatory hedged volume reduced the volatility of the purchased volume to 6.1%.

The GPIP supplements the mandatory volume component with additional "Discretionary" volumes. The volume and execution of Discretionary purchases are left to the Company's discretion. The goal of Discretionary purchases differs from that of the Mandatory purchasing program in that the primary purpose of Discretionary purchases is to reduce the overall hedged price to the customer. The discretionary volume was included in the GPIP because the Company and Division believed that natural gas prices would not always increase, but would also have periods of volatility to the downside. This depressed gas price would be due to temporary periods of over supply in the market, which would ultimately correct itself causing prices to again rise. Consequently, the GPIP incentive was devised by the Division and the Company to encourage the Company to be watchful for these moments and to lock up volumes in excess to the mandatory volumes at times when gas prices became depressed.

The incentive portion of the GPIP is a means to encourage the Company to execute these additional volumes. In order to determine how well the Company has performed under the GPIP, there must be a clearly defined goal and benchmark. As stated above, the goal of the discretionary volume incentive is to encourage the Company to lock up additional volumes when prices are trading at levels that are historically low. These incremental volumes should have the added benefit of lowering and not raising the overall hedged price. The GPIP incentive is currently structured such that the customers will have greater volumes hedged at lower prices because the incentive uses the mandatory average price as the benchmark and the Company earns an incentive only when it is a benefit to the customers. The average mandatory price is an effective benchmark because it is reflective of the average price over the most recent 24-month period.

More recently, the Division and its consultant were concerned that the Company had been primarily capturing "low hanging fruit" by executing the discretionary volume purchases at the end of the execution period when the mandatory price was known. This concern was addressed in the 2008 Gas Cost Recovery filing by reducing the incentive the Company would earn from 20% down to 10% on discretionary purchases executed within eight months prior to the month of flow. As a result of this change the Company would earn an incentive of 10% on any discretionary purchases when the average discretionary price was less than the mandatory price. The Company would earn an additional 10%, for a total incentive of 20%, on discretionary purchases when the average discretionary price was greater than fifty cents below the average mandatory price <u>and</u> the execution of the discretionary purchase was done in the period greater than eight months prior to the month of flow. Since this change was instituted, the Company has executed a greater percentage of discretionary volume in the greater than eight month period. The change in the program has had the intended effect on the Company's actions.

In addition, the Commission has recently questioned whether the incentive is still necessary to encourage the Company to execute the additional discretionary volumes, suggesting that the Company's actions would be the same with or without the incentive. The Company and the Division continue to believe that the incentive is necessary. With an incentive in place, the Company will look to maximize the price difference between the benchmark price and the discretionary hedge price and therefore maximize the benefit to the customers and the Company. Without an incentive, the Company's discretionary volume purchasing activities would be more defensive and the execution timing would be dictated by prudence risk and not maximizing customer benefits. The Company's discretionary execution strategy would most likely follow the more predictable execution pattern seen in the execution of the mandatory volume. In the case of continuously falling prices, however, the Company would be more concerned about prices rising, which would force the Company to execute sooner for fear of missing the bottom.

The GPIP incentive provides the Company with clear guidance as to the regulator's expectations relative to the Company's discretionary purchases. In the absence of this guidance, it is likely that the Company would migrate to the most conservative approach of hedging only those volumes that are mandatory. The GPIP incentive simultaneously provides the necessary, quantitative guidance that allows the Company to understand how the regulator intends this discretion to be employed, yet allows the company the flexibility to effectively execute within those guiding principals. With the incentive, the Company is driven to maximize the benefit to customers and the Company.

The last item of discussion was the issue of the incentive cap. The parties agree that the inclusion of a cap when the GPIP was first implemented in 2003 was intended as a short-term ceiling during the initial years of the program while the parties gained experience in the operation of the plan, and was not intended as a permanent component of the plan. The parties believe that the same arguments that support retaining the overall incentive apply equally to removing the incentive cap. An incentive cap may have the unintended effect of encouraging the Company to execute the discretionary volumes in a manner that is not consistent with the Commission's expectations for discretionary purchases. This unintended result may occur because with an incentive cap the customers' and Company's benefits are not aligned. For example, without an incentive cap, the Company will be encouraged to continue to increase total benefits to the customers and not to protect the incentive benefits to the Company. On the other hand, with a cap in place, it may be more beneficial for the Company to lock up discretionary volumes either earlier or in greater quantity because doing anything different would not further benefit the Company. If the Company has already reached the cap, the Company's focus may shift to other more pressing issues or it may actually deter the Company from executing incremental volumes since incremental transactions may only decrease the Company's benefit.

The Company and the Division staff continue to believe that the goals of the GPIP hedging plan are still appropriate, and we propose that the GPIP and the imbedded incentive mechanism continue to remain in effect with two changes to the program. In order to address concerns regarding the execution of discretionary volumes at the end of the execution period, when the mandatory price is known, the Company and the Division recommend that the Company incentive be reduced from 10% to 5% for volumes executed during the last four months of the execution period. The parties also believe that customers would further benefit with the removal of the incentive cap. The GPIP incentive, with the adjustment described above in conjunction with the removal of the incentive cap ensures that the customers' interests and those of the Company are always aligned. This alignment of goals should ensure that the Company is always executing the discretionary volumes when it is in the customer's best interest to do so. It is recommended that these changes go into effect for the gas cost year starting July 2010.

nationalgrid

Thomas R. Teehan
Senior Counsel

June 1, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4038 – National Grid Natural Gas Portfolio Management Plan
<u>Annual Report – April 1, 2009 to March 31, 2010</u>

Dear Ms. Massaro:

On behalf of National Grid[1] enclosed please find ten (10) copies of the Company's Annual Report of activity relating to the Natural Gas Portfolio Management Plan ("NGPMP"). This filing is also accompanied by a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I.G.L. §38-2-2(4)(B). The Company seeks protection from public disclosure of the identities of certain companies in order to protect their pricing information for delivered volumes that are identified in the report. Additionally, the Company seeks protected treatment for account numbers to the extent that they appear on the attachments to this filing. Consequently and pursuant to Commission rules, the Company has provided the Commission with one copy of the confidential materials for its review, and has otherwise included redacted copies of the plan.

In this docket, the Commission approved the NGPMP, which implemented changes in the management of the Company's Rhode Island gas portfolio. These changes were designed to provide various financial, regulatory and risk management benefits over the asset management arrangement which it replaced. One of those benefits was to encourage the Company to minimize gas costs to customers by combining a least-cost dispatch with an asset optimization program designed to obtain the maximum value from the Rhode Island gas supply portfolio resources. As part of the NGPMP, the Company is required to file quarterly and annual reports in order to provide transparency in measuring the Company's performance.

This annual report covers the measurement year April 1, 2009 through March 31, 2010.

The enclosed report provides a Monthly Summary which calculates the savings achieved based on supporting data contained in Attachments 1 through 8. The Monthly Report indicates that the preliminary estimate of savings for the first year of the optimization program is $2,876,377.65 with the incentive to the Company of $375,276.

[1] The Narragansett Electric Company d/b/a National Grid.

Also enclosed as part of this filing is a discussion of the Monthly Summary Report by section that describes the entries in the Monthly Summary and traces the entries in that report to the sources from which they are derived. This summary also explains many of the terms that are used in the summary and supporting schedules.

Thank you for your attention to this filing. Please feel free to contact me if you have any questions at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4038 Service List
Leo Wold, Esq.
Steve Scialabba, Division

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically submitted, hand delivered and mailed to the individuals listed below.

Joanne M. Scanlon
National Grid

June 1, 2010
Date

Docket 4038 – National Grid – Natural Gas Portfolio Management Plan Service List as of 3/11/09

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Natural Gas Portfolio Management Plan
Docket No. 4038

NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission ("Commission") provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(i)(B). National Grid also hereby requests that, pending entry of that finding, the Commission preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On June 1, 2010, National Grid filed with the Commission its Quarterly Report of activity undertaken in pursuing the Natural Gas Portfolio Management Plan that was approved by the Commission in Order No. 19627. This filing includes information relative to the identity of companies that discloses the names of the suppliers and the paid for the supplies purchased. These references occur in Attachment 2 ("Flowing Transaction Deal"), Attachment 4 ("Storage Injection Transactions"), Attachment 7

("Realized Financial Transactions"), and Attachment 8 ("Narragansett Mark to Market"). National Grid is seeking protective treatment with respect to the identities of those companies in order to protect the pricing information, which is competitively sensitive information.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1, *et seq*. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(i)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; <u>or</u> (2) to cause

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[1] The Narragansett Electric Company d/b/a National Grid ("National Grid or "the Company").

substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company has redacted the names of the companies from which purchases were made in order to protect the pricing information for those companies. Were this information revealed, those companies could be harmed in future negotiations with other parties. Public dissemination of this type of information could disincline these and other companies to deal with National Grid or to provide National Grid with their lowest prices. Thus, the absence of confidential treatment would negatively influence National Grid's ability to negotiate with these and other similar companies and to receive least cost pricing

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of its Natural Gas Portfolio Procurement Plan Quarterly Report.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorney,

Thomas R. Teehan

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Dated: June 1, 2010

National Grid
Natural Gas Portfolio Management Plan Report
Plan Results for April 1, 2009 to March 31, 2010

Introduction

In Docket 4038 the Commission approved a new approach to the management of the gas supply portfolio called the Natural Gas Portfolio Management Plan (NGPMP). One of the conditions included in that filing was a requirement that the Company file reports on the results of the Plan each quarter and annually and that the filings provide sufficient detail and transparency for the Commission and Division to determine the reasonableness and appropriateness of the costs associated with asset management transactions.

The Commission's order in this docket requires the Company to provide in the Annual Report the information suggested by Mr. Oliver in his testimony. In addition to the detailed information on each optimization transaction included with each quarterly report and also attached to this report, Mr. Oliver requested that annual reports contain information on the assignment of the Service Company costs associated with asset management activities allocated to the Narragansett Electric Company. Essentially, 8.68% of the full cost of the energy transactions team is allocated to the Narragansett Electric Company's Gas Division (NEC-Gas) based on a three point allocation methodology that is updated each year. The 8.68% allocation is derived based on NEC-Gas' share of revenue, payroll and assets as compared to the total for all National Grid USA gas utilities with each component given an equal weight.

Coinciding with National Grid assuming responsibility for management of the NEC portfolio, the energy transactions team was increased by 2.75 FTEs (full time equivalent employees). By virtue of reflecting the economies of scale pursuant to the cost allocation methodology described above, only 8.68% of this incremental cost, or effectively the fractional cost of .24 of an FTE, is incrementally charged to NEC-Gas.

The goal of the NGPMP is to minimize gas costs to customers by encouraging the Company to obtain as much value as possible from the Rhode Island gas supply portfolio assets. In order to measure the impact of the Company's efforts to optimize the value of the portfolio, the NGPMP establishes two benchmarks that exactly parallel the approach used in its past contracting for asset management services.

The first benchmark is built on the concept of least cost dispatch and focuses on the optimization of flowing supply. It provides that as the starting point for the management of flowing supplies, the Company will set up its dispatch of supply resources for each month and each day so that it utilizes the lowest cost flowing supplies available from its existing supply portfolio in the same fashion it would have if it used an asset manager (Attachment 6).

The second benchmark is used to measure the effectiveness of the Company's efforts to minimize the cost of supply injected into storage and is also drawn directly from the asset management contracting approach. This benchmark has as its starting point the concept that storage will be filled based on uniform monthly injections over the full seven months of the injection season. To the extent the Company can reduce the cost of supplies injected into storage from that injection schedule it provides savings to customers. In order to be certain customers will benefit from the injection optimization transactions in spite of significant movements up or down in natural gas prices, the Company puts hedge positions in place to guarantee their effectiveness. These hedge positions cover price changes within the injection season and thus are short term in nature and also completely unrelated to the hedge positions utilized in the execution of the Gas Purchase Incentive Program.

Monthly Summary Report

The report consists of a series of attachments that begins with the Monthly Summary Report (Attachment 1) which provides an overview of the results followed by additional attachments that provide detailed support for the information in the Monthly Summary report. The Monthly Summary Report is divided into two sections. Section 1 shows the results from the Company's efforts to optimize flowing supply while Section 2 shows the results from optimizing the purchase of gas injected into storage. Section 2 is, itself, divided into 3 parts with 2a showing the injection cost and 2b and 2c showing the hedging results broken down into those that have been realized and those that will occur in the future and are, as yet, unrealized.

Section 1 Flowing Supply/Storage Withdrawals

This Section shows the calculation of the savings to customers generated by the Company's optimization activities as it purchases supplies for delivery to the city gate. The calculation starts with the total actual cost of all flowing supplies for each month. That cost is subtracted from the sum of those purchases made to support sales to third parties as part of optimization transactions and the cost of supply for customers calculated using the least cost dispatch for the monthly and daily supplies delivered to the RI gas system. This difference is the savings generated by the optimization transactions executed during each month as flowing supplies were purchased and sales were made to third parties to generate revenues.

The costs for each supply purchase are the actual delivered costs including both the supply acquisition cost and any pipeline related charges for the volumes purchased during the month. The purchases included in the actual delivered cost are both the supplies needed to support third party sales and the gas supplies delivered to the citygate for the firm sales customers. As part of the optimization process, the Company purchases supplies to reduce overall costs and it is common for specific supply purchases to be used to meet a different need than that for which they were initially purchased. For instance volumes that were purchased to meet a third party sale may have been injected into storage if that resulted in a lower overall cost for all supply purchases. When the schedulers transport the purchase volumes to meet the various demands, such as storage injections, baseload, swing or sales, they look to move the volumes most efficiently. The Actual Flowing Cost also includes any storage withdrawals delivered to the firm customers at the delivered weighted average cost of supply (WACOG) based on the benchmark dispatch.

The actual flowing supply costs are listed by transaction on the Flowing Transaction Detail Report (Attachment 2). Third Party sales are the aggregate monthly sales volume and revenue associated with sales off system. The revenue for each deal is also listed in the Flowing Transaction Deal Report.

The Flowing Transaction Deal (FTD) Report shows for each month all gas purchases and storage withdrawals. In the January section of the report the total 5,592,062 dekatherms and $36,513,083.27 of purchases are shown as the sub-total for the month and can also be found in the Monthly Summary Report under the Actual Flowing Cost for Jan-10. The report shows city-gate purchases, those purchases entered into as part of optimization transactions and any storage withdrawals. It ties directly to the Company's booked gas cost payable amount. The second part of the FTD Report for January shows the revenue from off-system sales which is also shown on the Monthly Summary Report under the 3rd Party Sales column.

The Customer Cost, or dispatch cost, is calculated as the product of the price and volume received each day by the firm sales customers based on the least cost dispatch structure. The cost of the supplies for customers for each day is shown in the attached Customer Transaction Summaries (Attachments 3) for the months of April 2009 through March 2010. For example, the volume and cost shown in the Customer Cost section of Attachment 1 for April 2009 are from Attachment 3a, which shows that the total delivered volume was 1,780,762 DT and the total delivered cost was $7,259,477.59. The detail provided in the Customer Transaction Summaries includes the price and volume by delivering pipeline with a breakdown into baseload purchases, swing purchases and storage withdrawals.

<u>Section 2a</u> Storage Injections

This section lays out the actual and benchmark cost of storage injections for each month. Because the Company uses hedges to guarantee that the economics of any optimized injections are actually achieved, it is also necessary to show the impact of the hedge transactions. In addition, the hedge transactions can be broken down into those for months where the NYMEX contract expiration date has passed and the exact final results are known and those where the contract remains open and subject to market volatility. The April 2009 through March 2010 contracts have closed and become "realized", shown in Attachment 1, Section 2b, while hedges put in place to cover certain storage optimization transactions using available storage capacity in the future, remain open and are currently "unrealized", are shown in section 2c.

<u>Section 2a</u> Storage Transactions

This section shows the actual storage costs and volumes based on the optimized storage fill and the benchmark inventory cost based on the planned storage fill using a ratable, one-seventh per month approach as has been used in past asset management arrangements. The costs for the purchase of supply for injection are the actual delivered costs for the volumes purchased during the month and scheduled to be injected into the storage fields. Similar to the flowing costs, the volumes purchased and scheduled for injection may not be the specific volumes purchased for injection. The actual cost of injections into the storage fields is shown by transaction on the Storage Injection Transaction Deal report (Attachment 4).

The Customer Inventory Cost is the monthly ratable injection volume and price. It is the benchmark for measurement of the savings to customers from optimized storage fill. Attachment 5 lists the actual and Customer and Inventory Costs by storage field.

<u>Section 2b</u> Realized Hedging Impact on Storage Transactions

Realized hedging gains/losses are calculated based on the final monthly settlements of any financial transactions that were used to hedge forward transactions designed to lock in cost savings for supplies injected into storage. These gains or losses are separated here but are already included in actual costs in Section 1. The realized financial transactions are listed in Attachment 7.

<u>Section 2c</u> Unrealized Hedging Impact on Storage Transactions

Unrealized activity represents the results of the forward transactions that have not been financially settled or physically delivered. The storage long/short position is the excess gas that was injected into the storage capacity that is not currently being used by the firm sales customers. The MTM is the mark to market position of the financial transactions that were executed to lock in margins (savings) on the excess gas injected into storage. The Physical Storage Value is the difference in the inventory cost of the actual inventory and the Benchmark inventory. The Forward Storage Value is the value of the excess gas in storage when there is more gas in inventory then the benchmark inventory, or the forecasted replacement cost, when there is less gas in inventory than the benchmark inventory. These forward values are priced based on the future markets. The total unrealized value is the net value of the future activity; financial hedges, cost of excess gas in storage and expected forward value at market prices.

Position and Margin Sharing

The last section on the Monthly Summary Report is a calculation of the total savings to customers under the Plan and any incentive earned by the Company. This total is the sum of the Savings from Section 1 and the Total Unrealized value shown at the end of Section 2c. Any realized savings from storage activity is embedded in the Section 1 flowing supply activity which includes the impact of any optimization hedges for months where the NYMEX contract has closed.

The final value of the savings from all optimization transactions, as shown on page 2, is $2,876,377.65. This value is currently $1,876,377.65 more than the $1,000,000 guaranteed to customers. This amount of savings would be split with the customer's receiving $1,501,102 plus the $1,000,000 guaranteed amount and the Company receiving $375,276.