Thomas R. Teehan
Senior Counsel
Rhode Island

September 1, 2009

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: National Grid, Annual Gas Cost Recovery Filing
Docket No._____

Dear Ms. Massaro:

Enclosed please find ten (10) copies of the pre-filed testimony and schedules of Elizabeth Arangio and Gary Beland 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, 2009 through October 31, 2010. 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 $7.68 over the currently effective rates. That customer should also experience an additional decrease of approximately $7.84 associated with the proposed Distribution Adjustment Charge rates found in Docket 4077. Overall, the combined impact of the proposed GCR and DAC rates is an annual reduction of approximately $15.50 for the average residential heating customer.

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 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.

Very truly yours,

Thomas R. Teehan

Enclosures
cc: Leo Wold, Esq. (w/confidential enc.)
Steve Scialabba (w/confidential enc.)
Bruce Oliver (w/confidential enc.)

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

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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Annual Gas Cost Recovery Filing 2009
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

[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 and Attachment EDA-4, pages 1 through 4 and pages 13 through 16 and page 18. 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.

The Company has also redacted confidential pricing information from its FCS contract with Distrigas, which information appears at EDA-2, pages 10 through 14 and page 17. The Company seeks protective treatment for that information because it is proprietary and competitively sensitive information that is the subject of a confidentiality agreement between the Company and Distrigas.

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

Dated: September 1, 2009

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NATIONAL GRID

DOCKET No. _____

DIRECT TESTIMONY

OF

ELIZABETH D. ARANGIO

September 1, 2009

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 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 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
EDA-7 Update of Forecasted Purchases for Incentive Plan

II. PROJECTED GAS COSTS

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 24, 2009 purchases; and (2) the difference between the futures contract purchases under the GPIP Plan as of July 31, 2008 and the August 24, 2009 NYMEX strip. The GCR factors also reflect storage and inventory costs as of April 1, 2009, as well as the projected cost of purchasing gas ratably through the summer, 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 for both forward purchases under the GPIP and the cost impact of financial hedges as well as the cost of supplies not locked in price.

Q. OVERALL, WHAT ARE THE PRICES AND QUANTITIES OF GAS PURCHASED UNDER THE PLAN?

A. Attachment EDA-3 is a graph that compares August 24, 2008 NYMEX pricing to August 24, 2009 pricing for the dates used in this filing. This graph shows a $3.29 decrease in average prices as compared to a year ago.

Q. WHAT MAJOR CHANGES HAVE OCCURRED IN THE SUPPLY OF NATURAL GAS?

A. Since the Company's May 23, 2008 filing, prices for natural gas have dropped significantly. The market has begun to recognize that domestic gas production is continuing to increase, extending the improvement begun two years ago. In the Gulf of Mexico, an area where a longer term decline had been accelerated by the production losses caused by hurricanes Katrina and Rita in 2005, there are new supplies coming on, though production is still below historical levels. There has been considerable success in the Rocky Mountain Basin with ample supply to support the new Rockies Express Pipeline which will be able to deliver approximately 1.8 Bcf/day by November 2009 to Clarington, Ohio. Beyond that, plans are being developed to move some of those supplies further east and northeast.

Furthermore, the Marcellus 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 between 200 Tcf to 500 Tcf. It is anticipated that the ramp up in supply from Marcellus shale will take place over the next 3 to 5 years. However, it should be noted that while there are many interconnections into the interstate pipelines, increasing the flow into New England and New York will require main line capacity expansions. As a result of these mainline capacity constraints, the impact of Marcellus shale supply may be more of displacement of long-haul gas supplies

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 this expansion of new supply basins will result in intensification of gas on gas competition, likely causing a flattening of the basis differentials throughout the United States.

Q. ARE THERE ANY LOCAL PROJECTS IN NEW ENGLAND THAT HAVE OCCURRED IN THE SUPPLY OF NATURAL GAS?

A. Yes. There are several local projects in the Northeast that will be in-service during the 2009/2010 year. Some of these projects are: (1) Maritimes Phase IV which was built to facilitate delivery of natural gas from the Canaport LNG Terminal to markets in the Northeast and was completed with an in service date of March 1, 2009. (2) The Repsol

Project which had its first LNG shipment arrived at the Repsol's Canaport LNG Terminal on June 27, 2009. Once fully operational, the Canaport LNG Terminal will have a firm sendout capacity of 1 billion cubic feet per day. (3) The Neptune Project 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 spring 2010.

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 24, 2009. For Company purchases at locations other than the Henry Hub, the model uses the forward 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.

For forecasting future supply costs, the Company uses a forward looking 12 month basis for projecting the differential. To the extent the Company has purchased gas

futures, the difference between the cost of the futures and the August 24, 2009 futures prices has also been reflected in the calculations.

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 are 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 24, 2009 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 2009 through October 2010 is shown on Attachment EDA-1.

5. The Storage Variable Non-Product Cost component includes all variable costs related to the operations, maintenance and delivery of storage, as determined in the most recent rate case proceeding, (Docket No. 3943) injection and withdrawal costs, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for storage gas working capital.

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 2009 through October 2010. 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 24th NYMEX strip. 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 first supply source shown is gas purchased on Tennessee Pipeline in Zone 0, located in South Texas. The calculation for November begins with the $4.307 NYMEX price which is then adjusted for basis by, in this case, subtracting $0.363. 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 $4.320. 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 16.25 cents is then added to reflect the cost of transportation on the pipeline, resulting in a delivered cost of $4.4823 per Dth.

III. MARKETER CAPACITY ASSIGNMENT

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 25,258 Dth per day of capacity on six different pipeline paths, which is unchanged from last year. The capacity provides marketers with the flexibility to select paths that best compliment their individual resource portfolios and requirements. In the event an individual path is over-subscribed, the Company will assign capacity on a pro rata basis.

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 $.9987 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 $.6020 per Dth. The variable costs include the pipeline compressor fuel loss and the usage fees on the pipelines. The system-average pipeline unit variable cost is $0.3976 per Dth. The sum of the $0.6020 (100% load factor) unit fixed-cost and $0.3967 system-average pipeline unit variable cost results in a weighted average pipeline cost of $.9987 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 $1,123,092 and total variable

costs of $14,158,645 are shown near the bottom, right of page 6 of EDA-4. Commodity gas costs of $13,133,118 priced at the August 24, 2009 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 $0.468 per Dth, or $.981 per Dth. The unit cost of $.981 per Dth represents the direct costs incurred by the marketer, which are paid to the transporter or other provider. Since these costs are $0.018 per Dth less than the system-average, marketers electing this path would be charged $0.018 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. MISCELLANEOUS ISSUES

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

A. No. The Company's next capacity change will occur November 1, 2010 or later with the addition of new Algonquin pipeline capacity from their East to West Project being added to serve a number of constrained areas. Originally, this capacity was scheduled to be added in November 2009 but the project has been delayed. That capacity addition is fully described in the Company's Long Range Plan filing.

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

A. Yes. There are three significant changes. (1) On March 31, 2009 the asset management contract with Merrill Lynch terminated. (2) The new Natural Gas Portfolio Management Plan ("NGPMP") became effective April 1, 2009 and (3) the LNG liquid supply contract with Distrigas of Massachusetts terminated on March 31, 2009.

The NGPMP (Docket No. 4038) was designed to encourage the Company to minimize gas costs to customers by coupling a least-cost dispatch with an asset optimization program designed to obtain the maximum value from the gas supply portfolio resources.

The Company's LNG liquid supply contract with Distrigas commenced in December 1, 2008 and ended on March 31, 2009. The Company retained the right to purchase a quantity of LNG up to the MDQ of 6,000 MMBtu/day with a total quantity during the term of up to 100,000 MMBtus. The contract was structured in a format that allowed the Company to request the total requirements on any two (2) occasions during the term

of the agreement. This filing reflects an estimate assuming replacement of the contract. The Company is still in the process of determining the appropriate level of LNG liquid that it should contract for the 2009/10 Peak Season.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SUMMARY OF ESTIMATED GAS COSTS FOR 2010 GCR Estimate

8/24/2009 NYMEX

Variable Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	GCR TOTAL
Total Pipeline Supply Costs	$22,375,581	$30,250,728	$31,146,819	$27,039,788	$27,078,385	$15,909,234	$9,001,181	$5,636,209	$5,349,464	$5,229,942	$5,643,940	$11,747,582	$196,408,852
Total Storage Product Costs	$0	$4,447,547	$13,466,174	$10,628,332	$3,517,993	$0	$0	$0	$0	$0	$0	$0	$32,060,046
Total Storage Delivery Costs	$0	$151,648	$469,552	$361,451	$145,672	$0	$0	$0	$0	$0	$0	$0	$1,128,324
Total LNG Costs	$125,258	$1,113,318	$1,752,499	$600,929	$127,954	$123,357	$125,005	$116,858	$121,004	$120,836	$116,371	$120,611	$4,564,001
Total All Variable Gas Costs	$22,500,839	$35,963,241	$46,835,045	$38,630,501	$30,870,004	$16,032,591	$9,126,186	$5,753,067	$5,470,467	$5,350,779	$5,760,311	$11,868,192	$234,161,223
Fixed Costs													
TOTAL PIPELINE DEMANDS	$2,652,963	$2,654,225	$2,652,955	$2,649,171	$2,652,955	$2,651,694	$2,652,955	$2,651,694	$2,652,955	$2,652,955	$2,651,694	$2,652,955	$31,829,169
TOTAL SUPPLIER DEMANDS	$302,000	$302,000	$302,000	$302,000	$302,000	$86,000	-$150,400	$263,120	$261,920	$261,920	$263,120	$261,920	$2,757,600
TOTAL STORAGE FACILITIES	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$387,299	$4,647,586
TOTAL STORAGE DELIVERY	$396,342	$441,342	$441,342	$441,342	$441,342	$612,342	$848,742	$435,222	$436,422	$436,422	$435,222	$436,422	$5,802,504
Total All Fixed Costs	$3,738,604	$3,784,865	$3,783,596	$3,779,812	$3,783,596	$3,737,334	$3,738,596	$3,737,334	$3,738,596	$3,738,596	$3,737,334	$3,738,596	$45,036,860
Capacity Release Credits	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$436,900	$5,242,797
NGPMP Credit	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$83,333	$1,000,000
Net Fixed Costs	$3,218,371	$3,264,632	$3,263,363	$3,259,579	$3,263,363	$3,217,101	$3,218,363	$3,217,101	$3,218,363	$3,218,363	$3,217,101	$3,218,363	$38,794,063
Total All Gas Costs	$25,719,210	$39,227,874	$50,098,407	$41,890,080	$34,133,367	$19,249,692	$12,344,549	$8,970,169	$8,688,830	$8,569,141	$8,977,412	$15,086,555	$272,955,286

National Grid
2009 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12.5.5 REP 13 26-Aug-2009
Report 13 10:00:27

Natural Gas Supply VS. Requirements Units: MDT

.	NOV 2009	DEC 2009	JAN 2010	FEB 2010	MAR 2010	APR 2010	MAY 2010	JUN 2010	JUL 2010	AUG 2010	SEP 2010	OCT 2010	Total/Average
Forecast Demand													
RI Sales GCR	2,886,000	4,089,600	4,962,900	4,144,500	3,612,600	2,067,800	1,273,200	788,600	759,100	752,000	833,200	1,714,100	27,883,600
Total Demand	2,886,000	4,089,600	4,962,900	4,144,500	3,612,600	2,067,800	1,273,200	788,600	759,100	752,000	833,200	1,714,100	27,883,600
Storage Injections													
TENN_62918	10,500	2,500	0	0	8,300	41,200	42,600	41,200	42,600	34,000	0	0	222,900
TENN_501	30,300	24,200	0	0	23,900	119,300	123,300	119,300	123,300	96,400	0	0	660,000
GSSTE 600045	68,800	0	0	0	0	223,500	231,000	127,300	0	0	0	0	650,600
GSS 300171	9,400	0	0	0	3,100	15,700	16,200	15,700	16,200	16,200	15,700	0	108,200
GSS 300169	10,300	0	0	0	0	33,500	34,600	15,900	0	0	0	0	94,300
GSS 300168	7,700	0	0	0	3,300	25,000	25,900	25,000	25,900	0	0	0	112,800
GSS 300170	24,500	0	0	0	600	79,600	82,300	79,600	0	0	0	0	266,600
TETCO_400221	59,400	0	0	0	32,300	180,900	186,900	180,900	186,900	186,900	0	0	1,014,200
TETCO_400515	2,800	0	0	0	1,700	8,600	8,900	8,600	8,900	8,900	0	0	48,400
TETCO 400185	2,600	0	0	0	0	7,900	0	0	0	0	0	0	10,500
COL FSS 7980	10,200	14,100	0	0	2,000	64,400	78,800	60,700	0	0	0	0	230,200
Total Underground Storage	236,500	40,800	0	0	75,200	799,600	830,500	674,200	403,800	342,400	15,700	0	3,418,700
LNG EXETER	3,000	1,600	0	0	0	132,200	53,900	3,000	3,100	3,100	3,000	3,100	206,000
LNG PROV	10,100	5,400	0	0	0	150,000	130,600	10,100	10,500	10,500	10,100	10,500	347,800
LNG VALLEY	3,000	1,600	0	0	0	17,800	3,900	3,000	3,100	3,100	3,000	3,100	41,600
Total LNG Injection	16,100	8,600	0	0	0	300,000	188,400	16,100	16,700	16,700	16,100	16,700	595,400
Total Injections	252,600	49,400	0	0	75,200	1,099,600	1,018,900	690,300	420,500	359,100	31,800	16,700	4,014,100

Delivered Firm Sales Supply

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENN_ZONE_0	245,128	253,289	253,289	228,783	253,289	242,135	176,030	94,142	74,523	58,155	30,235	153,419	2,062,417
TENN_ZONE_1	506,109	522,958	522,958	472,362	522,958	499,929	363,444	194,371	153,865	120,070	62,425	316,758	4,258,206
TENN_DRACUT	0	0	0	0	0	3,100	0	0	0	0	0	0	3,100
TENN_CONX	297,063	306,953	306,953	277,255	306,953	293,436	213,326	114,087	90,312	70,476	36,641	185,923	2,499,377
TETCO_STX	162,295	183,303	179,297	159,767	176,448	157,808	105,200	73,830	46,734	46,538	9,685	61,688	1,362,593
TETCO_ELA	363,477	410,526	401,555	357,815	395,175	353,429	235,606	165,351	104,665	104,226	21,691	138,158	3,051,674
TETCO_WLA	249,799	282,133	275,968	245,908	271,584	242,893	161,920	113,637	71,931	71,629	14,907	94,949	2,097,257
TETCO_ETX	108,888	122,983	120,295	107,192	118,384	105,878	70,581	49,535	31,355	31,223	6,498	41,388	914,201
TETCO - NF	17,033	19,237	18,817	16,767	18,518	16,562	11,041	7,748	4,905	4,884	1,016	6,474	143,002
HUBL NE	0	600	2,300	0	0	0	0	0	0	0	0	0	2,900
M3_DELIVERED	328,600	121,600	0	0	0	67,600	0	0	0	0	0	0	517,800
MAUMEE_SUPP	735,075	930,000	930,000	840,000	930,000	756,450	631,275	512,625	446,850	444,750	490,200	572,925	8,220,150
BROADRUN_COL	245,025	310,000	310,000	280,000	310,000	252,150	210,425	170,875	148,950	148,250	163,400	190,975	2,740,050
COLUMBIA TO AGT	0	0	0	0	0	0	0	0	0	0	0	0	0
TRAN WHART	4,200	4,400	4,400	3,900	4,100	0	0	0	0	0	0	0	21,000
TETCO B&W	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM TET FTS	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO DOM (B&W)	10,109	11,418	11,168	9,952	10,991	9,830	6,553	4,599	2,911	2,899	603	3,842	84,873
ANE II - AECO-TENN	30,400	31,500	31,500	28,400	31,500	30,400	31,400	30,400	31,400	31,400	30,400	31,400	370,100
NIAGARA	0	33,800	33,800	30,500	31,600	0	0	0	0	0	0	0	129,700

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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
NEWPORT_LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
DIST FCS VAP	16,200	257,900	281,100	200,100	183,800	210,000	0	0	0	0	0	0	1,149,100
DIST FCS LIQ	0	0	0	0	0	90,000	188,500	16,200	16,700	16,700	16,200	16,700	361,000
DISTRI FLS	0	30,000	40,000	30,000	0	0	0	0	0	0	0	0	100,000
SPOT LNG	0	0	0	0	0	0	0	0	0	0	0	0	0
Non LNG Liquid take	3,319,400	3,802,600	3,683,400	3,258,700	3,565,300	3,241,600	2,216,800	1,531,200	1,208,400	1,134,500	867,700	1,797,900	29,627,500
LNG Liquid take	0	30,000	40,000	30,000	0	90,000	188,500	16,200	16,700	16,700	16,200	16,700	461,000
Total take	3,319,400	3,832,600	3,723,400	3,288,700	3,565,300	3,331,600	2,405,300	1,547,400	1,225,100	1,151,200	883,900	1,814,600	30,088,500
Storage Withdrawals													
TENN_62918	0	2,500	150,700	59,300	0	0	0	0	0	0	0	0	212,500
TENN_501	0	131,800	206,800	256,600	34,400	0	0	0	0	0	0	0	629,600
GSS 600045	0	105,900	175,600	158,600	141,600	0	0	0	0	0	0	0	581,700
GSS 300171	0	0	65,000	33,800	0	0	0	0	0	0	0	0	98,800
GSS 300169	0	0	52,700	31,200	100	0	0	0	0	0	0	0	84,000
GSS 300168	0	21,000	43,400	27,700	12,900	0	0	0	0	0	0	0	105,000
GSS 300170	0	10,600	95,800	26,600	109,000	0	0	0	0	0	0	0	242,000
TETCO_400221	0	124,500	433,400	370,800	26,200	0	0	0	0	0	0	0	954,900
TETCO_400515	0	0	26,200	19,400	0	0	0	0	0	0	0	0	45,600
TETCO 400185	0	0	7,900	0	0	0	0	0	0	0	0	0	7,900
COL FSS 7980	0	46,200	78,900	71,300	23,700	0	0	0	0	0	0	0	220,100
LNG EXETER	3,000	3,100	120,300	55,100	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	206,000
LNG PROV	10,100	132,300	102,500	20,200	10,500	10,100	10,500	10,100	10,500	10,500	10,100	10,500	347,900
LNG VALLEY	3,000	7,700	3,600	2,800	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	41,600
Total Withdrawal Delivered	16,100	585,600	1,562,800	1,133,400	364,600	16,100	16,700	16,100	16,700	16,700	16,100	16,700	3,777,600
Total Storage withdrawal	0	442,500	1,336,400	1,055,300	347,900	0	0	0	0	0	0	0	3,182,100
Total Peaking withdrawal	16,100	143,100	226,400	78,100	16,700	16,100	16,700	16,100	16,700	16,700	16,100	16,700	595,500
Total Supply	**3,335,500**	**4,388,200**	**5,246,200**	**4,392,100**	**3,929,900**	**3,257,700**	**2,233,500**	**1,547,300**	**1,225,100**	**1,151,200**	**883,800**	**1,814,600**	**33,405,100**

Storage withdrawals at Storage Facilty							
TENN_8995	0	2,555	154,043	60,615	0	0	217,214
TENN_501	0	134,723	211,387	262,292	35,163	0	643,565
GSS 600045	0	114,351	189,612	171,256	152,899	0	628,118
GSS 300171	0	0	70,187	36,497	0	0	106,684
GSS 300169	0	0	56,905	33,690	108	0	90,703
GSS 300168	0	22,043	45,555	29,075	13,540	0	110,213
GSS 300170	0	11,126	100,556	27,921	114,412	0	254,015
TETCO_400221	0	130,435	454,060	388,476	27,449	0	1,000,419
TETCO_400515	0	0	27,738	20,539	0	0	48,276
TETCO 400185	0	0	8,277	0	0	0	8,277
COL FSS 7980	0	47,702	81,465	73,618	24,471	0	227,256
	0	462,935	1,399,785	1,103,978	368,042	0	3,334,740

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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
8/24/2009 NYMEX	**4.307**	**5.130**	**5.422**	**5.473**	**5.473**	**5.446**	**5.509**	**5.610**	**5.730**	**5.825**	**5.896**	**6.018**	
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	
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	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	
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 CONNEXION													
Basis	[redacted]												
usage to Zn 6	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0 0017	$0.0017	$0.0017	$0 0017	$0 0017	$0.0017	$0 0017	
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 DRACUT													
Basis	[redacted]												
usage	$0.0659	$0 0659	$0 0659	$0.0659	$0.0659	$0.0659	$0.0659	$0 0659	$0.0659	$0.0659	$0.0659	$0.0659	
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 STX													
Basis	[redacted]												
Usage to M3	$0.0715	$0.0715	$0.0715	$0.0715	$0.0715	$0 0715	$0.0715	$0.0715	$0 0715	$0 0715	$0.0715	$0 0715	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	
Fuel to M3	7 63%	8.59%	8.59%	8.59%	8.59%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0701	$0 0701	$0 0701	$0.0701	$0.0701	$0.0701	$0.0701	$0 0701	$0.0701	$0.0701	$0.0701	$0.0701	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	6 98%	7.72%	7.72%	7.72%	7.72%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												

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.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total/Average
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0695	$0 0695	$0 0695	$0.0695	$0.0695	$0.0695	$0.0695	$0 0695	$0.0695	$0.0695	$0.0695	$0.0695	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO ETX													
Basis	[redacted]												
Usage to M3	$0.0695	$0 0695	$0 0695	$0.0695	$0.0695	$0.0695	$0.0695	$0 0695	$0.0695	$0.0695	$0.0695	$0.0695	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO TO NF													
Basis	[redacted]												
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	
Usage on NF	$0.0086	$0 0086	$0 0086	$0.0086	$0.0086	$0.0086	$0.0086	$0 0086	$0.0086	$0.0086	$0.0086	$0.0086	
Usage on Transco	$0.0083	$0 0083	$0 0083	$0.0083	$0.0083	$0.0083	$0.0083	$0 0083	$0.0083	$0.0083	$0.0083	$0.0083	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel to M2	6 00%	6.42%	6.42%	6.42%	6.42%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Delivered to NF	[redacted]												
Delivered to Transco													
Delivered to Algonquin													
Total Delivered													
M3 DELIVERED													
Basis	[redacted]												
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
MAUMEE SUPPLY													
Basis	[redacted]												
Usage on Columbia	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214	$0.0214	$0.0214	$0 0214	$0.0214	$0.0214	$0.0214	$0 0214	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												

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BROADRUN COLUMBIA													
Basis	[redacted]												
Usage on Columbia	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214	$0.0214	$0.0214	$0 0214	$0.0214	$0.0214	$0.0214	$0 0214	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
COLUMBIA TO AGT													
Basis	[redacted]												
Usage on Columbia	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214	$0.0214	$0.0214	$0 0214	$0.0214	$0.0214	$0.0214	$0 0214	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO to DOMINION TO B & W													
Basis	[redacted]												
Usage on Dominion	$0.0247	$0 0247	$0 0247	$0.0247	$0.0247	$0.0247	$0.0247	$0 0247	$0.0247	$0.0247	$0.0247	$0 0247	
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	
Usage on Tetco	$0.0017	$0 0017	$0 0017	$0.0017	$0.0017	$0.0017	$0.0017	$0 0017	$0.0017	$0.0017	$0.0017	$0.0017	
Usage on AGT	$0.2294	$0 2294	$0 2294	$0.2294	$0.2294	$0.2294	$0.2294	$0 2294	$0.2294	$0.2294	$0.2294	$0.2294	
Fuel to M2	6 00%	6.42%	6.42%	6.42%	6.42%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Delivered to Dominion	[redacted]												
Delivered to Tetco													
Delivered to Algonquin													
Total Delivered													
TRANSCO AT WHARTON													
Basis	[redacted]												
Usage on Transco	$0.0083	$0 0083	$0 0083	$0.0083	$0.0083	$0.0083	$0.0083	$0 0083	$0.0083	$0.0083	$0.0083	$0.0083	
Usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
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	4.090%	4.090%	4.090%	4.090%	4.090%	4 090%	4.090%	4.090%	4 090%	4 090%	4.090%	4 090%	
Iroquois usage	$0 005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	
NETNE usage	$0 002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	
Fuel on Iroquois	0 30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	
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]												

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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
NIAGARA TO TENNESSEE													
Basis	[redacted]												
Tenn usage	$0.085	$0.085	$0.085	$0.085	$0 085	$0.085	$0.085	$0.085	$0.085	$0.085	$0 085	$0.085	
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													
Basis	[redacted]												
usage on Tetco	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	
usage on AGT	$0.2294	$0 2294	$0 2294	$0.2294	$0.2294	$0.2294	$0.2294	$0 2294	$0.2294	$0.2294	$0.2294	$0.2294	
fuel to ZN 3	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
Dominion to Tetco FTS													
Basis	[redacted]												
usage on Tetco	$0.0017	$0 0017	$0 0017	$0.0017	$0.0017	$0.0017	$0.0017	$0 0017	$0.0017	$0.0017	$0.0017	$0.0017	
usage on AGT	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
Tetco Fuel	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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
Total Delivered	[redacted]												
DISTRIGAS FCS													
Total Delivered	[redacted]												
Hubline													
Basis	[redacted]												
usage	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0.0129	$0.0129	
fuel	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	1.02%	
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													
Tennessee Zn 0													
Delivered Mmbtu	245,128	253,289	253,289	228,783	253,289	242,135	176,030	94,142	74,523	58,155	30,235	153,419	
NYMEX $/Mmbtu Del	$4.482	$5.311	$5.684	$5.766	$5.728	$5.871	$5.934	$6.034	$6.158	$6.263	$6 358	$6.479	
Total Delivered Cost	$1,098,726	$1,345,200	$1,439,646	$1,319,231	$1,450,744	$1,421,594	$1,044,611	$568,037	$458,918	$364,244	$192,223	$994,046	
TENN ZONE 1													
Delivered Mmbtu	506,109	522,958	522,958	472,362	522,958	499,929	363,444	194,371	153,865	120,070	62,425	316,758	
$/Mmbtu Del	$4.667	$5.544	$5.875	$5.937	$5 931	$5.845	$5.910	$6.013	$6.137	$6.239	$6 324	$6.445	
Total Delivered Cost	$2,362,104	$2,899,309	$3,072,456	$2,804,301	$3,101,446	$2,921,882	$2,147,978	$1,168,781	$944,336	$749,167	$394,785	$2,041,658	
TENN CONNEXION													
Delivered Mmbtu	297,063	306,953	306,953	277,255	306,953	293,436	213,326	114,087	90,312	70,476	36,641	185,923	
NYMEX $/Mmbtu Del	$4.321	$5.150	$5.523	$5.605	$5 567	$5.710	$5.773	$5.873	$5.997	$6.103	$6.197	$6.319	
Total Delivered Cost	$1,283,744	$1,580,847	$1,695,303	$1,554,151	$1,708,753	$1,675,600	$1,231,627	$670,040	$541,625	$430,084	$227,057	$1,174,756	
TENN DRACUT													
Delivered Mmbtu	0	0	0	0	0	3,100	0	0	0	0	0	0	
$/Mmbtu Del	$4.93	$6.68	$8.17	$8.11	$6.54	$5.93	$6 00	$6.12	$6.25	$6.34	$6.39	$6.54	
Total Delivered Cost	$0	$0	$0	$0	$0	$18,391	$0	$0	$0	$0	$0	$0	
TETCO STX													
Delivered Mmbtu	162,295	183,303	179,297	159,767	176,448	157,808	105,200	73,830	46,734	46,538	9,685	61,688	
NYMEX $/Mmbtu Del	$4.382	$5.284	$5.664	$5.747	$5.708	$5.755	$5.818	$5.912	$6.034	$6.143	$6 251	$6.367	
Total Delivered Cost	$711,189	$968,598	$1,015,593	$918,250	$1,007,116	$908,234	$612,014	$436,471	$281,970	$285,863	$60,537	$392,745	
TETCO ELA													
Delivered Mmbtu	363,477	410,526	401,555	357,815	395,175	353,429	235,606	165,351	104,665	104,226	21,691	138,158	
$/Mmbtu Del	$4.6774	$5 6206	$5 9503	$6.0112	$6.0060	$5.8329	$5.8982	$5 9997	$6.1244	$6.2290	$6.3137	$6.4359	
Total Delivered Cost	$1,700,109	$2,307,416	$2,389,384	$2,150,901	$2,373,405	$2,061,504	$1,389,643	$992,061	$641,008	$649,224	$136,947	$889,172	
TETCO WLA													
Delivered Mmbtu	249,799	282,133	275,968	245,908	271,584	242,893	161,920	113,637	71,931	71,629	14,907	94,949	
$/Mmbtu Del	$4.5819	$5 5324	$5 8638	$5.9252	$5.9197	$5.7789	$5.8447	$5 9477	$6.0734	$6.1781	$6.2620	$6.3859	
Total Delivered Cost	$1,144,546	$1,560,887	$1,618,228	$1,457,047	$1,607,688	$1,403,652	$946,372	$675,875	$436,867	$442,536	$93,346	$606,334	
TETCO ETX													
Delivered Mmbtu	108,888	122,983	120,295	107,192	118,384	105,878	70,581	49,535	31,355	31,223	6,498	41,388	
NYMEX $/Mmbtu Del	$4.2518	$5.1320	$5 5024	$5.5821	$5.5463	$5.5754	$5.6362	$5.7275	$5.8468	$5.9553	$6.0660	$6.1788	
Total Delivered Cost	$462,969	$631,154	$661,909	$598,354	$656,591	$590,308	$397,812	$283,710	$183,327	$185,946	$39,416	$255,733	

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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													
Delivered Mmbtu	17,033	19,237	18,817	16,767	18,518	16,562	11,041	7,748	4,905	4,884	1,016	6,474	
Delivered $/Mmbtu	$5.1297	$6 0759	$6.4100	$6.4717	$6.4664	$6.3034	$6.3697	$6.4729	$6.5995	$6.7057	$6.7917	$6 9159	
Delivered Cost	$87,373	$116,884	$120,616	$108,512	$119,743	$104,395	$70,325	$50,154	$32,368	$32,751	$6,903	$44,774	
M3 DELIVERED													
Delivered Mmbtu	328,600	121,600	0	0	0	67,600	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.8248	$6.3753	$7.7406	$7.6256	$6.5717	$5.8942	$5.9603	$6 0829	$6 2214	$6.3095	$6.3551	$6 5069	
Delivered Cost	$1,585,423	$775,239	$0	$0	$0	$398,447	$0	$0	$0	$0	$0	$0	
MAUMEE SUPP													
Delivered Mmbtu	735,075	930,000	930,000	840,000	930,000	756,450	631,275	512,625	446,850	444,750	490,200	572,925	
Delivered $/Mmbtu	$4.5585	$5.4392	$5.7315	$5.7790	$5.7858	$5.7299	$5.7961	$5 9037	$6.0303	$6.1266	$6.1958	$6 3275	
Total Delivered Cost	$3,350,838	$5,058,500	$5,330,283	$4,854,333	$5,380,803	$4,334,407	$3,658,934	$3,026,366	$2,694,651	$2,724,822	$3,037,182	$3,625,195	
BROADRUN COL													
Delivered Mmbtu	245,025	310,000	310,000	280,000	310,000	252,150	210,425	170,875	148,950	148,250	163,400	190,975	
Delivered $/Mmbtu	$4.5585	$5.4392	$5.7315	$5.7790	$5.7858	$5.7299	$5.7961	$5 9037	$6.0303	$6.1266	$6.1958	$6 3275	
Total Delivered Cost	$1,116,946	$1,686,167	$1,776,761	$1,618,111	$1,793,601	$1,444,802	$1,219,645	$1,008,789	$898,217	$908,274	$1,012,394	$1,208,398	
COLUMBIA AGT													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.9511	$6.5354	$7 9304	$7.8129	$6.7361	$6.0437	$6.1113	$6 2366	$6.3781	$6.4681	$6.5147	$6 6698	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO TO DOM B & W													
Delivered Mmbtu	10,109	11,418	11,168	9,952	10,991	9,830	6,553	4,599	2,911	2,899	603	3,842	
Delivered $/Mmbtu	$5.4532	$6 3938	$6.7342	$6.7971	$6.7916	$6.6256	$6.6932	$6.7983	$6.9273	$7.0356	$7.1232	$7 2498	
Delivered Cost	$55,126	$73,001	$75,208	$67,641	$74,644	$65,127	$43,859	$31,264	$20,165	$20,394	$4,297	$27,857	
DOMINION TO TETCO FTS													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.6372	$5 5303	$5 8013	$5.8433	$5.8577	$5.6939	$5.7598	$5 8680	$5.9948	$6.0893	$6.1545	$6 2874	
Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TRANSCO AT WHARTON													
Delivered Mmbtu	4,200	4,400	4,400	3,900	4,100	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.8786	$6.4187	$7.7586	$7.6485	$6.6222	$5.9457	$6.0125	$6.1374	$6.2782	$6.3667	$6.4110	$6.5660	
Delivered Cost	$20,490	$28,242	$34,138	$29,829	$27,151	$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
AECO/TENNESSEE - ANE II													
Delivered Mmbtu	30,400	31,500	31,500	28,400	31,500	30,400	31,400	30,400	31,400	31,400	30,400	31,400	
Delivered $/Mmbtu	$4.1663	$4 9584	$5 5108	$5.4154	$5.0705	$4.8715	$4.8003	$5 0396	$4.8492	$5.7205	$5.6199	$5 6727	
Total Delivered Cost	$126,654	$156,188	$173,591	$153,798	$159,720	$148,093	$150,730	$153,205	$152,266	$179,625	$170,845	$178,124	
NIAGARA TO TENNESSEE													
Delivered Mmbtu	0	33,800	33,800	30,500	31,600	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.8735	$5.7312	$6 0113	$6.0528	$6.0655	$6.0010	$6.0708	$6.1804	$6.3126	$6.4016	$6.4542	$6 6031	
Total Delivered Cost	$0	$193,715	$203,180	$184,611	$191,669	$0	$0	$0	$0	$0	$0	$0	
TETCO TO B&W													
Delivered Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$5.2541	$6.1989	$6 5286	$6.5895	$6.5843	$6.4096	$6.4749	$6 5765	$6.7011	$6.8058	$6.8904	$7 0127	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
DISTRIGAS FCS													
Delivered Mmbtu	16,200	257,900	281,100	200,100	183,800	210,000	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5 896	$6.018	
Total Delivered Cost	$69,773	$1,323,027	$1,524,124	$1,095,147	$1,005,937	$1,143,660	$0	$0	$0	$0	$0	$0	
HUBLINE													
Total Delivered Vol	0	600	2,300	0	0	0	0	0	0	0	0	0	
Delivered $/Mmbtu	$4.8788	$6.6644	$8.1639	$8.1062	$6.5201	$5.8897	$5.9532	$6 0742	$6 2122	$6.3001	$6.3491	$6.4955	
Total Delivered Cost	$0	$3,999	$18,777	$0	$0	$0	$0	$0	$0	$0	$0	$0	

	NOV 2009	**DEC** 2009	**JAN** 2010	**FEB** 2010	**MAR** 2010	**APR** 2010	**MAY** 2010	**JUN** 2010	**JUL** 2010	**AUG** 2010	**SEP** 2010	**OCT** 2010	
Financial Hedges as of 7/31/2009													
Quantity	2,160,000	2,750,000	2,890,000	2,360,000	2,210,000	1,200,000	780,000	560,000	480,000	370,000	340,000	360,000	**16,460,000**
Average Price	$8.435	$8.719	$8.881	$8.916	$8 642	$7.511	$7.406	$7.405	$7.289	$7.224	$6 990	$6.876	
8/24/2009 NYMEX	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5 896	$6.018	
Impact of Financial Hedges	**$8,916,080**	**$9,870,450**	**$9,997,620**	**$8,125,570**	**$7,002,820**	**$2,478,400**	**$1,480,030**	**$1,005,450**	**$748,450**	**$517,750**	**$372,010**	**$308,790**	**$50,823,420.00**
Total Pipeline Costs (Incl Inj)	**$24,092,090**	**$30,578,823**	**$31,146,819**	**$27,039,788**	**$27,661,834**	**$21,118,498**	**$14,393,578**	**$10,070,203**	**$8,034,168**	**$7,490,682**	**$5,747,942**	**$11,747,582**	**$219,122,007**
Total Delivered Pipeline Vol	**3,319,400**	**3,802,600**	**3,683,400**	**3,258,700**	**3,565,300**	**3,241,600**	**2,216,800**	**1,531,200**	**1,208,400**	**1,134,500**	**867,700**	**1,797,900**	**29,627,500**
WACOG (Cost/Volume)	$7.258	$8.042	$8.456	$8.298	$7.759	$6.515	$6.493	$6.577	$6.649	$6.603	$6 624	$6.534	$7.396
Injections	236,500	40,800	0	0	75,200	799,600	830,500	674,200	403,800	342,400	15,700	0	
Cost of Injections	$1,716,509	$328,096	$0	$0	$583,449	$5,209,264	$5,392,398	$4,433,993	$2,684,705	$2,260,740	$104,002	$0	**$22,713,155**
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	**$22,375,581**	**$30,250,728**	**$31,146,819**	**$27,039,788**	**$27,078,385**	**$15,909,234**	**$9,001,181**	**$5,636,209**	**$5,349,464**	**$5,229,942**	**$5,643,940**	**$11,747,582**	**$196,408,852**
Total Pipeline Purchase Volumes	**3,082,900**	**3,761,800**	**3,683,400**	**3,258,700**	**3,490,100**	**2,442,000**	**1,386,300**	**857,000**	**804,600**	**792,100**	**852,000**	**1,797,900**	**26,208,800**

2010 GCR estimate
FIXED COST ESTIMATES
Nov 2009 - Oct 2010

2009 Gas Supply Fixed Costs
UNIT PRICES

		NOV	DEC	JAN-10	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	$6.810	$6.810	$6.810	$6.810	$6 810	$6.810	$6 810	$6.810	$6.810	$6 810	$6 810	$6 810
TEXAS EASTERN WLA CDS DEMAND Z3	$/Dth	$2.828	$2.828	$2.828	$2.828	$2 828	$2.828	$2.828	$2.828	$2.828	$2 828	$2 828	$2 828
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	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142
TETCO SCT STX DEMAND	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
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	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457
TETCO SCT STX DEMAND Z2	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND Z2	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
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	$3.388	$3.388	$3.388	$3.388	$3 388	$3.388	$3.388	$3.388	$3.388	$3 388	$3 388	$3 388
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 CONNEX	$/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	$4.358	$4.358	$4.358	$4.358	$4 358	$4.358	$4 358	$4.358	$4.358	$4 358	$4 358	$4 358
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460
TRANSCO DEMAND ZONE 3 TO 6.	$/Dth	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434
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	$6.010	$6.010	$6.010	$6.010	$6 010	$6.010	$6 010	$6.010	$6.010	$6 010	$6 010	$6 010
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
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS FCS													
STORAGE FIXED COST UNIT PRICES													
TEXAS EASTERN SS-1 DEMAND	$/Dth	$5.565	$5.565	$5.565	$5.565	$5 565	$5.565	$5.565	$5.565	$5.565	$5 565	$5 565	$5 565
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	$1.882	$1.882	$1.882	$1.882	$1 882	$1.882	$1 882	$1.882	$1.882	$1 882	$1 882	$1 882
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	$1.882	$1.882	$1.882	$1.882	$1 882	$1.882	$1 882	$1.882	$1.882	$1 882	$1 882	$1 882
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	$1.505	$1.505	$1.505	$1.505	$1 505	$1.505	$1 505	$1.505	$1.505	$1 505	$1 505	$1 505
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

National Grid
Rhode Island - Gas

STORAGE DELIVERY FIXED		NOV	DEC	JAN-10	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	$5.326	$5.326	$5.326	$5.326	$5 326	$5.326	$5 326	$5.326	$5.326	$5 326	$5 326	$5 326
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 3576	$4.3576	$4.3576	$4.3576	$4 3576	$4.3576	$4.3576	$4.3576	$4.3576	$4 3576	$4 3576	$4 3576
DOMINION DELIVERY FOR GSS CONV.	$/Dth	$4 3576	$4.3576	$4.3576	$4.3576	$4 3576	$4.3576	$4.3576	$4.3576	$4.3576	$4 3576	$4 3576	$4 3576
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	$5.840	$5.840	$5.840	$5.840	$5 840	$5.840	$5 840	$5.840	$5.840	$5 840	$5 840	$5 840
DISTRIGAS FLS CALL PAYMENT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
								BILLING UNITS					
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 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
ROQUOIS	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	1,860	1,922	1,922	1,736	1,922	1,860	1,922	1,860	1,922	1,922	1,860	1,922
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

National Grid
Rhode Island - Gas

		NOV	DEC	JAN-10	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS FCS	Dth	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833
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	Dth	0	25,000	25,000	25,000	25,000	0	0	0	0	0	0	0

		NOV	DEC	JAN-10	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	$	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	
TEXAS EASTERN WLA CDS DEMAND Z3	$	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	
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	$	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	
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	$	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	
TETCO SCT WLA DEMAND	$	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	
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	$	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	
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	$	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	
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	$	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	
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	$	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,906	$1,970	$1,970	$1,779	$1,970	$1,906	$1,970	$1,906	$1,970	$1,970	$1,906	$1,970	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$40	$40	$36	$40	$39	$40	$39	$40	$40	$39	$40	
TRANSCO DEMAND ZONE 6	$	$221	$228	$228	$206	$228	$221	$228	$221	$228	$228	$221	$228	
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	$	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	
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	
WESTERLY LATERAL (Yankee)	$	$60,149	$60,149	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	
TOTAL PIPELINE DEMAND COSTS		**$2,652,963**	**$2,654,225**	**$2,652,955**	**$2,649,171**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$31,829,169**
SUPPLIER FIXED COST DOLLARS														
DISTRIGAS FCS - Vapor Portion	$	$302,000	$302,000	$302,000	$302,000	$302,000	$86,000	-$150,400	$263,120	$261,920	$261,920	$263,120	$261,920	
TOTAL SUPPLIER DEMAND COSTS		**$302,000**	**$302,000**	**$302,000**	**$302,000**	**$302,000**	**$86,000**	**-$150,400**	**$263,120**	**$261,920**	**$261,920**	**$263,120**	**$261,920**	**$2,757,600**
STORAGE FIXED COST DOLLARS														
TEXAS EASTERN SS-1 DEMAND	$	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	$82,373	
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	$	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	$21,455	
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	$	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	$26,975	
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	$	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	$3,830	
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	
KEYSPAN LNG TANK LEASE PAYMENTS	$	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	**$1,890,000**
TOTAL STORAGE DEMAND COSTS	$	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$4,647,586**

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	$	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	$5,028	
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	$	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	$23,200	
DOMINION DELIVERY FOR GSS CONV	$	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	$8,981	
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	$	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	$14,863	
DISTRIGAS FCS - LIQUID PORTION	$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DISTRIGAS FLS CALL PAYMENT	$													
TOTAL STORAGE DELIVERY DEMAND CHARGES		**$396,342**	**$441,342**	**$441,342**	**$441,342**	**$441,342**	**$612,342**	**$848,742**	**$435,222**	**$436,422**	**$436,422**	**$435,222**	**$436,422**	**$5,802,504**
TOTAL ALL DEMAND COSTS	$	**$3,738,604**	**$3,784,865**	**$3,783,596**	**$3,779,812**	**$3,783,596**	**$3,737,334**	**$3,738,596**	**$3,737,334**	**$3,738,596**	**$3,738,596**	**$3,737,334**	**$3,738,596**	**$45,036,860**

		NOV	DEC	JAN-10	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
Marketer Demand Charge Credits														
Capacity Release Volumes as of September 1														
Tennessee	Dth	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	
Algonquin	Dth	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	
Tetco STX/AGT	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	
Tetco WLA/AGT	Dth	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	
Tetco ELA/AGT	Dth	5,491	5,491	5,491	5,491	5,491	5,491	5,491	5,491	5,491	5,491	5,491	5,491	
Columbia/Downington	Dth	0	0	0	0	0	0	0	0	0	0	0	0	
Total		**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	**23,861**	
System Weighted Average cost per MMBtu		**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	**$18.3102**	
Total Demand Charge Credit		**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$5,242,797**
Demand Costs Net of Releases to Marketers	**$**	**$3,301,705**	**$3,347,966**	**$3,346,696**	**$3,342,912**	**$3,346,696**	**$3,300,435**	**$3,301,696**	**$3,300,435**	**$3,301,696**	**$3,301,696**	**$3,300,435**	**$3,301,696**	**$39,794,063**
TOTAL PIPELINE DEMANDS	**$**	**$2,652,963**	**$2,654,225**	**$2,652,955**	**$2,649,171**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$2,652,955**	**$2,651,694**	**$2,652,955**	**$31,829,169**
TOTAL SUPPLIER DEMANDS	**$**	**$302,000**	**$302,000**	**$302,000**	**$302,000**	**$302,000**	**$86,000**	**-$150,400**	**$263,120**	**$261,920**	**$261,920**	**$263,120**	**$261,920**	**$2,757,600**
TOTAL STORAGE FACILITIES	**$**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$387,299**	**$4,647,586**
TOTAL STORAGE DELIVERY DEMANDS	**$**	**$396,342**	**$441,342**	**$441,342**	**$441,342**	**$441,342**	**$612,342**	**$848,742**	**$435,222**	**$436,422**	**$436,422**	**$435,222**	**$436,422**	**$5,802,504**
Total All Demands	**$**	**$3,738,604**	**$3,784,865**	**$3,783,596**	**$3,779,812**	**$3,783,596**	**$3,737,334**	**$3,738,596**	**$3,737,334**	**$3,738,596**	**$3,738,596**	**$3,737,334**	**$3,738,596**	**$45,036,860**
Marketer Release Credits	**$**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$436,900**	**$5,242,797**
NGPMP credit		**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$83,333**	**$1,000,000**
Demand Net of Releases	**$**	**$3,218,371**	**$3,264,632**	**$3,263,363**	**$3,259,579**	**$3,263,363**	**$3,217,101**	**$3,218,363**	**$3,217,101**	**$3,218,363**	**$3,218,363**	**$3,217,101**	**$3,218,363**	**$38,794,063**

Storage Product Cost

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
WACOG INJECTIONS	$7.258	$8.042	$8.456	$8.298	$7.759	$6.515	$6.493	$6.577	$6.649	$6.603	$6.624	$6.534
Injection cost	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021	$0.021
Total injection cost	$7.279	$8.062	$8.477	$8.318	$7.779	$6.536	$6.514	$6.597	$6.669	$6.623	$6.645	$6.555

COMBINED STORAGE	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Beginning Inv Vol	4,495,012	4,731,512	4,309,377	2,909,592	1,805,614	1,512,772	2,312,372	3,142,872	3,817,072	4,220,872	4,563,272	4,578,972
Vol Withdrawn	0	462,935	1,399,785	1,103,978	368,042	0	0	0	0	0	0	0
Vol Injected	236,500	40,800	0	0	75,200	799,600	830,500	674,200	403,800	342,400	15,700	0
Begining Inv $ (virtual)	$26,565,521	$28,286,936	$25,848,259	$17,452,150	$10,830,331	$9,207,771	$14,433,623	$19,843,250	$24,291,230	$26,984,311	$29,252,155	$29,356,483
$ Withdrawn (1)	$0	$4,570,121	$13,846,365	$10,920,311	$3,640,590	$0	$0	$0	$0	$0	$0	$0
$ Injected	$1,721,415	$328,942	$0	$0	$585,009	$5,225,852	$5,409,626	$4,447,980	$2,693,082	$2,267,843	$104,328	$0
Ending Vol	4,731,512	4,309,377	2,909,592	1,805,614	1,512,772	2,312,372	3,142,872	3,817,072	4,220,872	4,563,272	4,578,972	4,578,972
Ending $	$28,286,936	$25,848,259	$17,452,150	$10,830,331	$9,207,771	$14,433,623	$19,843,250	$24,291,230	$26,984,311	$29,252,155	$29,356,483	$29,356,483
Avg $/Mmbtu	$5.978	$5.998	$5.998	$5.998	$6.087	$6.242	$6.314	$6.364	$6.393	$6.410	$6.411	$6.411
Withdrawal cost	**$0**	**$10,250**	**$33,586**	**$26,869**	**$6,587**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Transportation cost	**$0**	**$18,825**	**$55,775**	**$42,604**	**$16,488**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Costs allocated to fuel	**$0**	**$122,574**	**$380,191**	**$291,978**	**$122,598**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Storage value Less fuel	**$0**	**$4,447,547**	**$13,466,174**	**$10,628,332**	**$3,517,993**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Delivered Volumes	0	442,500	1,336,400	1,055,300	347,900	0	0	0	0	0	0	0
Hedge Amortization		**$1,802,502**	**$5,450,255**	**$4,298,491**	**$1,433,022**							

- amortization of hedges on injection gas
$12,984,271

(1) Includes Hedge Amortization
3,334,740 Withdrawal

Storage Withdrawal variable costs
2009-2010 GCR Storage surcharge estimate

Storage Withdrawals Dth	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
TENN_62918	0	2,500	150,700	59,300	0	0	0	0	0	0	0	0	212,500
TENN_501	0	131,800	206,800	256,600	34,400	0	0	0	0	0	0	0	629,600
GSS 600045	0	105,900	175,600	158,600	141,600	0	0	0	0	0	0	0	581,700
GSS 300171	0	0	65,000	33,800	0	0	0	0	0	0	0	0	98,800
GSS 300169	0	0	52,700	31,200	100	0	0	0	0	0	0	0	84,000
GSS 300168	0	21,000	43,400	27,700	12,900	0	0	0	0	0	0	0	105,000
GSS 300170	0	10,600	95,800	26,600	109,000	0	0	0	0	0	0	0	242,000
TETCO_400221	0	124,500	433,400	370,800	26,200	0	0	0	0	0	0	0	954,900
TETCO_400515	0	0	26,200	19,400	0	0	0	0	0	0	0	0	45,600
TETCO 400185	0	0	7,900	0	0	0	0	0	0	0	0	0	7,900
COL FSS 7980	0	46,200	78,900	71,300	23,700	0	0	0	0	0	0	0	220,100
TOTAL	0	442,500	1,336,400	1,055,300	347,900	0	0	0	0	0	0	0	3,182,100

STORAGE WITHDRAWAL PRICES	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Tennessee Wi hdrawal	$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 Withdrawal	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177	$0.0177
Tetco SS-1 Withdrawal	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461	$0.0461
Tetco FSS-1 Withdrawal	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280	$0.0280
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 2009 - 2010

Withdrawal Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Tennessee Wi hdrawal	$0	$1,370	$3,647	$3,222	$351	$0	$0	$0	$0	$0	$0	$0	$8,589
Dominion Withdrawal	$0	$2,434	$7,655	$4,919	$4,666	$0	$0	$0	$0	$0	$0	$0	$19,674
Tetco SS-1 Withdrawal	$0	$5,739	$20,344	$17,094	$1,208	$0	$0	$0	$0	$0	$0	$0	$44,385
Tetco FSS-1 Withdrawal	$0	$0	$734	$543	$0	$0	$0	$0	$0	$0	$0	$0	$1,277
Columbia Withdrawal	$0	$707	$1,207	$1,091	$363	$0	$0	$0	$0	$0	$0	$0	$3,368
Totals	$0	$10,250	$33,586	$26,869	$6,587	$0	$0	$0	$0	$0	$0	$0	$77,292

Storage Tramportation Prices												
Tennessee Transportation	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851
Dominion Trans on Tetco/AGT	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144	$0.0144
Dominion Trans on Tennessee	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851	$0.0851
Tetco SS-1 Trans	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129	$0.0129
Tetco FSS-1 Trans	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343	$0.0343
Columbia Trans	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341	$0.0341

Storage Transportation Costs													
Tennessee Transportation	$0	$11,429	$30,423	$26,883	$2,927	$0	$0	$0	$0	$0	$0	$0	$71,663
Dominion Trans on Tetco/AGT	$0	$1,525	$4,224	$3,220	$2,040	$0	$0	$0	$0	$0	$0	$0	$11,009
Dominion Trans on Tennseess	$0	$2,689	$11,846	$4,621	$10,374	$0	$0	$0	$0	$0	$0	$0	$29,530
Tetco SS-1 Trans	$0	$1,606	$5,693	$4,783	$338	$0	$0	$0	$0	$0	$0	$0	$12,420
Tetco FSS-1 Trans	$0	$0	$899	$665	$0	$0	$0	$0	$0	$0	$0	$0	$1,564
Columbia Trans	$0	$1,575	$2,690	$2,431	$808	$0	$0	$0	$0	$0	$0	$0	$7,505
Total	$0	$18,825	$55,775	$42,604	$16,488	$0	$0	$0	$0	$0	$0	$0	$133,691
Total Variable	$0	$29,074	$89,361	$69,473	$23,075	$0	$0	$0	$0	$0	$0	$0	$210,983

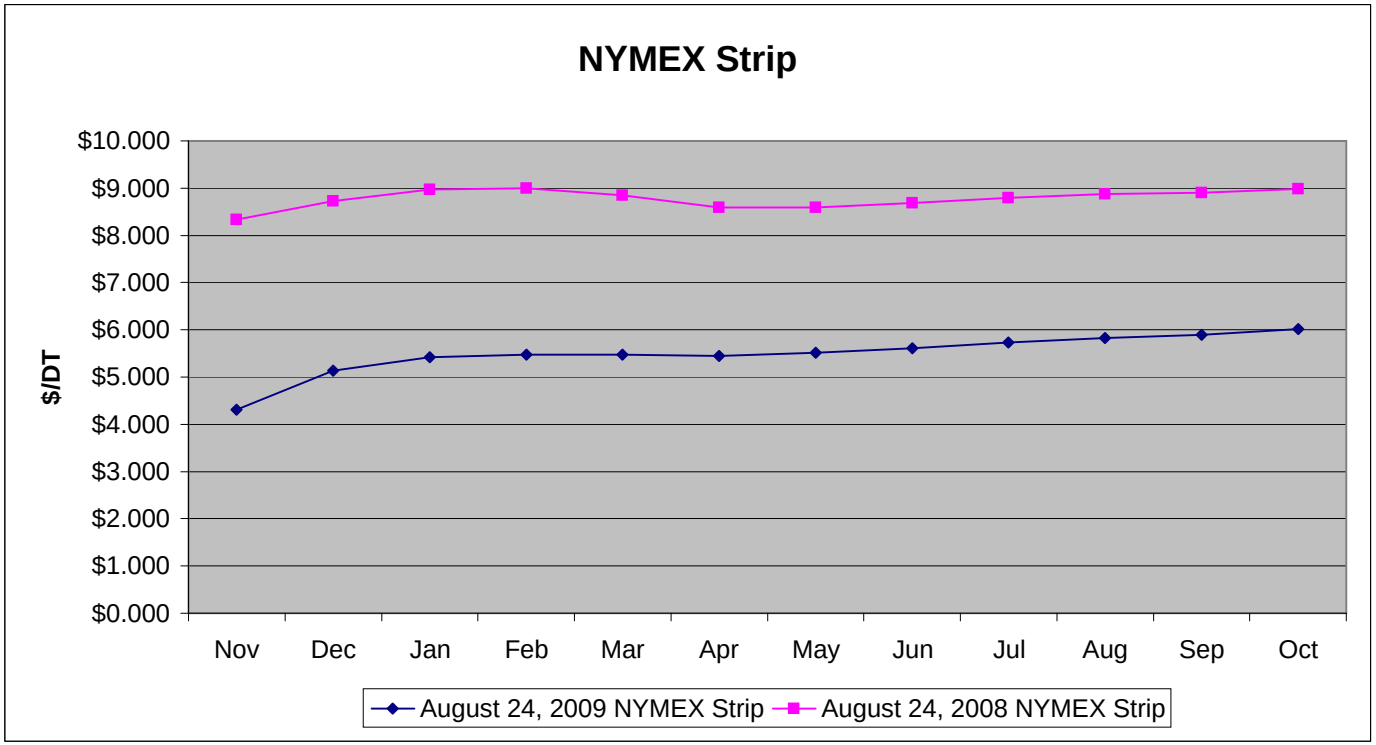
LNG Estimate for 2010

NATIONAL GRID - RI SERVICE AREA
NOVEMBER 2009 - OCTOBER 2010

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
8/24/2009 NYMEX	$4.307	$5.130	$5.422	$5.473	$5.473	$5.446	$5.509	$5.610	$5.730	$5.825	$5.896	$6.018
Trucking	[redacted]											
Delivered Cost - FCS contract												
Basis FLS contract TGP Zone 6		[redacted]										
Delivered Cost - FLS contract												
Basis New England Spot LNG						$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
Delivered Cost - FCS contract	$0.00	$0.00	$0.00	$0.00	$0.00	$8.51	$8.57	$8.67	$8.79	$8.88	$8.96	$9.08

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Combined LNG Inv												
Beginning Inv Vol	896,000	879,900	766,800	580,400	532,300	515,600	589,500	761,300	761,400	761,400	761,400	761,500
Vol Injected - FCS	0	0	0	0	0	90,000	188,500	16,200	16,700	16,700	16,200	16,700
Vol Injected - FLS		30,000	40,000	30,000	0	0	0	0	0	0	0	0
Vol Injected - Spot LNG		0	0	0	0	0	0	0	0	0	0	0
Vol Withdrawn	16,100	143,100	226,400	78,100	16,700	16,100	16,700	16,100	16,700	16,700	16,100	16,700
Begining Inv $ 11/1 = $7.78	$6,970,880	$6,845,622	$5,935,584	$4,465,806	$4,078,446	$3,950,492	$4,412,606	$5,525,714	$5,516,898	$5,509,274	$5,503,405	$5,499,708
$ Injected	$0	$203,280	$282,720	$213,570	$0	$585,471	$1,238,113	$108,042	$113,380	$114,967	$112,675	$118,190
$ Withdrawn	$125,258	$1,113,318	$1,752,499	$600,929	$127,954	$123,357	$125,005	$116,858	$121,004	$120,836	$116,371	$120,611
Ending Vol	879,900	766,800	580,400	532,300	515,600	589,500	761,300	761,400	761,400	761,400	761,500	761,500
Ending $	$6,845,622	$5,935,584	$4,465,806	$4,078,446	$3,950,492	$4,412,606	$5,525,714	$5,516,898	$5,509,274	$5,503,405	$5,499,708	$5,497,288
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	$0.00	$0	$0	$0	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total All LNG Costs	**$125,258**	**$1,113,318**	**$1,752,499**	**$600,929**	**$127,954**	**$123,357**	**$125,005**	**$116,858**	**$121,004**	**$120,836**	**$116,371**	**$120,611**

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 24, 2008 NYMEX Strip	**$8.335**	**$8.728**	**$8.968**	**$8.998**	**$8.848**	**$8.585**	**$8.588**	**$8.683**	**$8.795**	**$8.870**	**$8.902**	**$8.984**
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**



PRELIMINARY ESTIMATE **PRELIMINARY ESTIMATE**

National Grid
Summary of Transportation Capacity Release
Pipeline Path Availability and Pricing
November 2009 - October 2010

Path to City Gate	As of 9/1/09 Existing Releases	Total Available	Remaining Available	Cost /Dth	New Credit/ Surcharge	Old Credit / Surcharge
Company Weighted Average				[redacted]		
Tennessee Zone 1	5,992	6,000	8	[redacted]	[redacted]	[redacted]
Algonquin @ Lambertville, NJ	2,334	2,714	380	[redacted]	[redacted]	[redacted]
Texas Eastern - South Texas Algonquin @ Lambertville, NJ	4,044	4,044	0	[redacted]	[redacted]	[redacted]
Texas Eastern - West La Algonquin @ Lambertville, NJ	6,000	6,000	0	[redacted]	[redacted]	[redacted]
Texas Eastern - East La Algonquin @ Lambertville, NJ	5,491	5,500	9	[redacted]	[redacted]	[redacted]
Columbia (Maumee/Downington) at 5:1 ratio**	0	1,000	1,000	[redacted]	[redacted]	[redacted]
Totals	23,861	25,258	1,397			

** 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 2009 - 2010
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	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
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	$0.072	$0.072	$0.072	$0.072	$0 072	$0 072	$0 072	$0 072	$0 072	$0.072	$0.072	$0.072	
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	
8/24/2009 NYMEX	$/Dth	$5.078	$5.748	$6.055	$6.087	$6 019	$5 896	$5 938	$6 033	$6.148	$6.238	$6.298	$6.411	
SUPPLY AREA BASIS (12 month average)	$/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	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TECCO WLA SUPPLY ZONE DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TETCO ELA SUPPLY ZONE DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
TETCO STX M1 TO M3 DEMAND	$/Dth	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	4,086	
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	132,695	139,148	139,148	125,682	139,148	132,695	137,118	132,695	137,118	137,118	132,695	137,118	1,622,379
ALGONQUIN USAGE	Dth	122,570	127,196	127,196	114,886	127,196	122,570	126,656	122,570	126,656	126,656	122,570	126,656	1,493,378
PURCHASE VOLUMES	Dth	132,695	139,148	139,148	125,682	139,148	132,695	137,118	132,695	137,118	137,118	132,695	137,118	1,622,379
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	%	7.63%	8.59%	8.59%	8.59%	8.59%	7 63%	7 63%	7 63%	7 63%	7.63%	7.63%	7.63%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	1.02%	
FIXED														
TETCO STX SUPPLY ZONE DEMAND	$	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$27,823	$333,881
TECCO WLA SUPPLY ZONE DEMAND	$	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$11,554	$138,651
TETCO ELA SUPPLY ZONE DEMAND	$	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$9,703	$116,442
TETCO STX M1 TO M3	$	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$45,523	$546,271
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	$	$9,488	$9,949	$9,949	$8,986	$9,949	$9,488	$9,804	$9,488	$9,804	$9,804	$9,488	$9,804	$116,000
ALGONQUIN USAGE	$	$1,581	$1,641	$1,641	$1,482	$1,641	$1,581	$1,634	$1,581	$1,634	$1,634	$1,581	$1,634	$19,265
PURCHASE COST	$	$623,613	$747,172	$789,890	$717,471	$784,881	$732,157	$762,321	$750,336	$791,116	$803,457	$785,500	$827,178	$9,115,092
TOTAL FIXED	$	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$118,775	$1,425,302
TOTAL VARIABLE	$	$634,681	$758,762	$801,480	$727,939	$796,471	$743,226	$773,759	$761,405	$802,554	$814,894	$796,569	$838,616	$9,250,356
DELIVERED COST AT NYMEX	$	$616,063	$720,592	$759,079	$689,243	$754,566	$715,303	$744,411	$731,924	$770,738	$782,021	$764,073	$803,709	$8,851,721
NET NON-GAS VARIABLE COST	$	$18,619	$38,169	$42,401	$38,696	$41,905	$27,923	$29,348	$29,481	$31,816	$32,874	$32,496	$34,907	$398,635
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.153**	**$0.304**	**$0.338**	**$0.342**	**$0.334**	**$0.230**	**$0.234**	**$0.243**	**$0.254**	**$0.262**	**$0.268**	**$0.278**	**$0.270**
AVERAGE FIXED COST	$/Dth													[redacted]
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													

Gas Year 2009 - 2010
TEXAS EASTERN WEST LOUISIANA SUPPLY PATH TO ALGONQUIN CITY GATE
CITY GATE DELIVERED MDQ = 6,000

UNIT PRICING

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
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	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
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	$0.070	$0.070	$0.070	$0.070	$0 070	$0 070	$0 070	$0 070	$0 070	$0.070	$0.070	$0.070	
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	
8/24/2009 NYMEX	$/Dth	$5.08	$5.75	$6 05	$6 09	$6 02	$5.90	$5.94	$6.03	$6.15	$6 24	$6 30	$6.41	
SUPPLY AREA BASIS (12 month average)	$/Dth	[redacted]												
NET COST AFTER BASIS	$/Dth													

BILLING UNITS

FIXED														
TETCO WLA SUPPLY ZONE DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
TETCO ELA SUPPLY ZONE DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
TETCO WLA M1 TO M3 DEMAND	Dth	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	6,062	
ALGONQUIN AFT-E DEMAND	Dth	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
VARIABLE														
TETCO USAGE WLA TO M3	Dth	195,501	204,505	204,505	184,715	204,505	195,501	202,018	195,501	202,018	202,018	195,501	202,018	2,388,304
ALGONQUIN USAGE	Dth	181,855	188,718	188,718	170,455	188,718	181,855	187,917	181,855	187,917	187,917	181,855	187,917	2,215,694
PURCHASE VOLUMES	Dth	195,501	204,505	204,505	184,715	204,505	195,501	202,018	195,501	202,018	202,018	195,501	202,018	2,388,304
DELIVERED VOLUMES	Dth	180,000	186,000	186,000	168,000	186,000	180,000	186,000	180,000	186,000	186,000	180,000	186,000	2,190,000

FUEL USE %

TETCO WLA M1 TO M3 FUEL	%	6.98%	7.72%	7.72%	7.72%	7.72%	6 98%	6 98%	6 98%	6 98%	6.98%	6.98%	6.98%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	1.02%	
FIXED														
TETCO WLA SUPPLY ZONE	$	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$17,143	$205,714
TETCO ELA SUPPLY ZONE DEMAND	$	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$14,397	$172,762
TETCO WLA M1 TO M3	$	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$67,541	$810,491
ALGONQUIN AFT-E	$	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$35,863	$430,351
VARIABLE														
TETCO USAGE WLA TO M3	$	$13,705	$14,336	$14,336	$12,948	$14,336	$13,705	$14,161	$13,705	$14,161	$14,161	$13,705	$14,161	$167,420
ALGONQUIN USAGE	$	$2,346	$2,434	$2,434	$2,199	$2,434	$2,346	$2,424	$2,346	$2,424	$2,424	$2,346	$2,424	$28,582
PURCHASE COST	$	$960,398	$1,141,651	$1,204,434	$1,093,787	$1,197,072	$1,120,318	$1,166,147	$1,147,101	$1,208,570	$1,226,752	$1,198,909	$1,261,701	$13,926,840
TOTAL FIXED	$	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$134,943	$1,619,319
TOTAL VARIABLE	$	$976,449	$1,158,421	$1,221,204	$1,108,934	$1,213,842	$1,136,368	$1,182,732	$1,163,152	$1,225,156	$1,243,337	$1,214,960	$1,278,286	$14,122,842
DELIVERED VOLUMES AT NYMEX	$	$914,040	$1,069,128	$1,126,230	$1,022,616	$1,119,534	$1,061,280	$1,104,468	$1,085,940	$1,143,528	$1,160,268	$1,133,640	$1,192,446	$13,133,118
NET NON-GAS VARIABLE COST	$	$62,409	$89,293	$94,975	$86,318	$94,308	$75,088	$78,264	$77,212	$81,628	$83,069	$81,320	$85,840	$989,724
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.35**	**$0.48**	**$0.51**	**$0.51**	**$0.51**	**$0.42**	**$0.42**	**$0.43**	**$0.44**	**$0.45**	**$0.45**	**$0.46**	**$0.45**
AVERAGE FIXED COST	$/Dth													
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													
TOTAL PATH COST	$/Dth													[redacted]

Gas Year 2009 - 2010
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	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	$11.14	
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	$0.070	$0.070	$0.070	$0.070	$0 070	$0 070	$0 070	$0 070	$0 070	$0.070	$0.070	$0.070	
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	
8/24/2009 NYMEX	$/Dth	$5.078	$5.748	$6.055	$6 087	$6 019	$5 896	$5 938	$6 033	$6.148	$6.238	$6.298	$6.411	
SUPPLY AREA BASIS (12 month average)		[redacted]												
NET COST AFTER BASIS														
BILLING UNITS														
FIXED														
TETCO ELA SUPPLY ZONE DEMAND	Dth	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	
TETCO ELA M1 TO M3 DEMAND	Dth	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	5,557	
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	178,671	186,694	186,694	168,627	186,694	178,671	184,627	178,671	184,627	184,627	178,671	184,627	2,181,904
ALGONQUIN USAGE	Dth	166,700	172,991	172,991	156,250	172,991	166,700	172,257	166,700	172,257	172,257	166,700	172,257	2,031,053
PURCHASE VOLUMES	Dth	178,671	186,694	186,694	168,627	186,694	178,671	184,627	178,671	184,627	184,627	178,671	184,627	2,181,904
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	%	6.70%	7.34%	7.34%	7.34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	1.02%	
FIXED														
TETCO ELA SUPPLY ZONE	$	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$13,197	$158,365
TETCO ELA M1 TO M3	$	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$61,913	$742,950
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	$	$12,418	$12,975	$12,975	$11,720	$12,975	$12,418	$12,832	$12,418	$12,832	$12,832	$12,418	$12,832	$151,642
ALGONQUIN USAGE	$	$2,150	$2,232	$2,232	$2,016	$2,232	$2,150	$2,222	$2,150	$2,222	$2,222	$2,150	$2,222	$26,201
PURCHASE COST	$	$895,804	$1,061,115	$1,118,430	$1,015,591	$1,111,709	$1,041,958	$1,084,444	$1,066,436	$1,123,215	$1,139,832	$1,113,783	$1,171,772	$12,944,091
TOTAL FIXED	$	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$107,984	$1,295,804
TOTAL VARIABLE	$	$910,373	$1,076,322	$1,133,637	$1,029,326	$1,126,916	$1,056,526	$1,099,498	$1,081,004	$1,138,269	$1,154,886	$1,128,351	$1,186,826	$13,121,934
DELIVERED VOLUMES AT NYMEX	$	$837,870	$980,034	$1,032,377	$937,398	$1,026,240	$972,840	$1,012,429	$995,445	$1,048,234	$1,063,579	$1,039,170	$1,093,075	$12,038,691
NET NON-GAS VARIABLE COST	$	$72,502	$96,288	$101,260	$91,928	$100,677	$83,686	$87,068	$85,559	$90,035	$91,307	$89,182	$93,751	$1,083,242
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.439**	**$0.565**	**$0.594**	**$0.597**	**$0.590**	**$0.507**	**$0.511**	**$0.519**	**$0.528**	**$0.536**	**$0.540**	**$0.550**	**$0.540**
AVERAGE FIXED COST	$/Dth													$19.633
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.645**
TOTAL PATH COST	$/Dth													**$1.185**

Gas Year 2009 - 2010
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	$6.010	$6.010	$6.010	$6.010	$6 010	$6 010	$6 010	$6 010	$6 010	$6.010	$6.010	$6.010	
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	$0.021	$0.021	$0.021	$0.021	$0 021	$0 021	$0 021	$0 021	$0 021	$0.021	$0.021	$0.021	
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	
8/24/2009 NYMEX	$/Dth	$5.078	$5.748	$6.055	$6 087	$6 019	$5 896	$5 938	$6 033	$6.148	$6.238	$6.298	$6.411	
SUPPLY BASIS MAUMEE	$/Dth	$0.075	$0.075	$0.075	$0.075	$0 075	$0 075	$0 075	$0 075	$0 075	$0.075	$0.075	$0.075	
SUPPLY BASIS DOWNINGTON	$/Dth	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	
NET COST AFTER BASIS MAUMEE	$/Dth	$5.154	$5.824	$6.130	$6.162	$6 095	$5 971	$6 014	$6.108	$6.223	$6.313	$6.373	$6.486	
NET COST AFTER BASIS DOWNINGTON	$/Dth	$5.534	$6.204	$6.511	$6 543	$6.475	$6 352	$6 394	$6.489	$6.604	$6.694	$6.754	$6.867	
BILLING UNITS														
FIXED														
COLUMBIA FTS DEMAND	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	
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	90,927	94,359	94,359	85,227	94,359	90,927	93,958	90,927	93,958	93,958	90,927	93,958	
ALGONQUIN USAGE	Dth	90,000	93,000	93,000	84,000	93,000	90,000	93,000	90,000	93,000	93,000	90,000	93,000	
PURCHASE VOLUMES MAUMEE	Dth	75,773	78,632	78,632	71,023	78,632	75,773	78,299	75,773	78,299	78,299	75,773	78,299	
PURCHASE VOLUMES DOWNINGTON	Dth	15,155	15,726	15,726	14,205	15,726	15,155	15,660	15,155	15,660	15,660	15,155	15,660	
DELIVERED VOLUMES MAUMEE	Dth	75,000	77,500	77,500	70,000	77,500	75,000	77,500	75,000	77,500	77,500	75,000	77,500	912,500
DELIVERED VOLUMES DOWNINGTON	Dth	15,000	15,500	15,500	14,000	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	182,500
FUEL USE %														
COLUMBIA FUEL	%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	
ALGONQUIN AFT-E FUEL	%	1.02%	1.44%	1.44%	1.44%	1.44%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	1.02%	
FIXED														
COLUMBIA FTS DEMAND	$	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$6,141	$73,689
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	$	$1,946	$2,019	$2,019	$1,824	$2,019	$1,946	$2,011	$1,946	$2,011	$2,011	$1,946	$2,011	$23,708
ALGONQUIN USAGE	$	$1,161	$1,200	$1,200	$1,084	$1,200	$1,161	$1,200	$1,161	$1,200	$1,200	$1,161	$1,200	$14,126
PURCHASE COST MAUMEE	$	$390,496	$457,915	$482,055	$437,678	$479,225	$452,478	$470,849	$462,859	$487,292	$494,338	$482,938	$507,884	$5,606,006
PURCHASE COST DOWNINGTON	$	$83,862	$97,564	$102,392	$92,937	$101,826	$96,259	$100,125	$98,335	$103,414	$104,823	$102,351	$107,532	$1,191,420
TOTAL FIXED	$	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$12,118	$145,414
TOTAL VARIABLE	$	$477,465	$558,698	$587,666	$533,523	$584,269	$551,843	$574,185	$564,301	$593,916	$602,372	$588,396	$618,627	$6,835,260
DELIVERED VOLUMES AT NYMEX	$	$457,020	$534,564	$563,115	$511,308	$559,767	$530,640	$552,234	$542,970	$571,764	$580,134	$566,820	$596,223	$6,566,559
NET NON-GAS VARIABLE COST	$	$20,445	$24,134	$24,551	$22,215	$24,502	$21,203	$21,950	$21,331	$22,152	$22,238	$21,576	$22,404	$268,701
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.227**	**$0.260**	**$0.264**	**$0.264**	**$0.263**	**$0.236**	**$0.236**	**$0.237**	**$0.238**	**$0.239**	**$0.240**	**$0.241**	**$0.245**
AVERAGE FIXED COST	$/Dth													$12.118
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.398**
TOTAL PATH COST	$/Dth													**$0.644**

Gas Year 2009 - 2010
TENNESSEE ZONE 1 TO CITY GATE
CITY GATE DELIVERED MDQ = 6,000

		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	
8/24/2009 NYMEX	$/Dth	$5.078	$5.748	$6.055	$6 087	$6 019	$5 896	$5 938	$6 033	$6.148	$6.238	$6.298	$6.411	
SUPPLY AREA BASIS (12 month average)	$/Dth	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	($0.145)	
NET COST AFTER BASIS	$/Dth	$4.933	$5.603	$5.910	$5 942	$5 874	$5.751	$5.793	$5 888	$6.003	$6.093	$6.153	$6.266	
FIXED														
TENNESSEE ZONE 1 TO 6 DEMAND	Dth	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	Dth	195,270	201,779	201,779	182,252	201,779	192,864	199,293	192,864	199,293	199,293	192,864	199,293	2,358,623
PURCHASE VOLUMES	Dth	195,270	201,779	201,779	182,252	201,779	192,864	199,293	192,864	199,293	199,293	192,864	199,293	2,358,623
DELIVERED VOLUMES	Dth	180,000	186,000	186,000	168,000	186,000	180,000	186,000	180,000	186,000	186,000	180,000	186,000	2,190,000
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	$	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$1,123,092
VARIABLE														
TENNESSE ZONE 1 TO 6 USAGE	$	$29,681	$30,670	$30,670	$27,702	$30,670	$29,315	$30,293	$29,315	$30,293	$30,293	$29,315	$30,293	$358,511
PURCHASE COST	$	$963,287	$1,130,589	$1,192,535	$1,082,960	$1,185,271	$1,109,180	$1,154,523	$1,135,603	$1,196,375	$1,214,311	$1,186,712	$1,248,789	$13,800,134
TOTAL FIXED	$	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$93,591	$1,123,092
TOTAL VARIABLE	$	$992,968	$1,161,259	$1,223,205	$1,110,663	$1,215,941	$1,138,496	$1,184,816	$1,164,918	$1,226,667	$1,244,604	$1,216,027	$1,279,081	$14,158,645
DELIVERED VOLUMES AT NYMEX	$	$914,040	$1,069,128	$1,126,230	$1,022,616	$1,119,534	$1,061,280	$1,104,468	$1,085,940	$1,143,528	$1,160,268	$1,133,640	$1,192,446	$13,133,118
NET NON-GAS VARIABLE COST	$	$78,928	$92,131	$96,975	$88,047	$96,407	$77,216	$80,348	$78,978	$83,139	$84,336	$82,387	$86,635	$1,025,527
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.438**	**$0.495**	**$0.521**	**$0.524**	**$0.518**	**$0.429**	**$0.432**	**$0.439**	**$0.447**	**$0.453**	**$0.458**	**$0.466**	**$0.468**
AVERAGE FIXED COST	$/Dth													$15.599
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.513**
TOTAL PATH COST	$/Dth													**$0.981**

Gas Year 2009 - 2010
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	
8/24/2009 NYMEX	$/Dth	$5.078	$5.748	$6.055	$6.087	$6 019	$5 896	$5 938	$6 033	$6.148	$6.238	$6.298	$6.411	
SUPPLY AREA BASIS (12 month average)	$/Dth	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	$0.456	
NET COST AFTER BASIS	$/Dth	$5.534	$6.204	$6.511	$6.543	$6.475	$6 352	$6 394	$6.489	$6 604	$6.694	$6.754	$6.867	
					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	81,936	85,216	85,216	76,970	85,216	81,936	84,667	81,936	84,667	84,667	81,936	84,667	999,033
PURCHASE VOLUMES	Dth	81,936	85,216	85,216	76,970	85,216	81,936	84,667	81,936	84,667	84,667	81,936	84,667	999,033
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	%	1.02%	1.44%	1.44%	1.44%	1.44%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	1.02%	
					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	$	$1,057	$1,099	$1,099	$993	$1,099	$1,057	$1,092	$1,057	$1,092	$1,092	$1,057	$1,092	$12,888
PURCHASE COST	$	$453,419	$528,665	$554,826	$503,596	$551,758	$520,442	$541,346	$531,668	$559,127	$566,747	$553,381	$581,394	$6,446,368
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	$	$454,476	$529,764	$555,925	$504,589	$552,857	$521,499	$542,439	$532,725	$560,219	$567,839	$554,438	$582,486	$6,459,255
DELIVERED VOLUMES AT NYMEX	$	$413,451	$483,602	$509,431	$462,563	$506,403	$480,052	$499,588	$491,207	$517,256	$524,828	$512,783	$539,383	$5,940,547
NET NON-GAS VARIABLE COST	$	$41,025	$46,162	$46,494	$42,026	$46,455	$41,447	$42,851	$41,518	$42,963	$43,011	$41,655	$43,103	$518,708
AVERAGE NON-GAS VARIABLE COST	$/Dth	**$0.504**	**$0.549**	**$0.553**	**$0.553**	**$0.552**	**$0.509**	**$0.509**	**$0.510**	**$0.511**	**$0.511**	**$0.512**	**$0.512**	**$0.524**
AVERAGE FIXED COST	$/Dth													$5.977
AVERAGE COST AT 100% LOAD FACTOR	$/Dth													**$0.197**
TOTAL PATH COST	$/Dth													**$0.720**

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update **UNIT PRICES**

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
		2009		2010									
PIPELINE FIXED COST UNIT PRICES													
ALGONQU N 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
ALGONQU N 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
ALGONQU N 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	$6.810	$6.810	$6.810	$6 810	$6.810	$6 810	$6.810	$6.810	$6 810	$6.810	$6.810	$6 810
TEXAS EASTERN WLA CDS DEMAND M3	$/Dth	$2.828	$2.828	$2.828	$2 828	$2.828	$2 828	$2.828	$2.828	$2 828	$2.828	$2.828	$2 828
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	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142	$11.142
TETCO SCT STX DEMAND	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
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	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457	$4.457
TETCO SCT STX DEMAND M2	$/Dth	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724	$2.724
TETCO SCT WLA DEMAND M2	$/Dth	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131	$1.131
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	$3 388	$3.388	$3.388	$3 388	$3.388	$3 388	$3.388	$3.388	$3 388	$3.388	$3.388	$3 388
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
ROQUOIS	$/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
DOM NION FTNN DEMAND	$/Dth	$4 358	$4.358	$4.358	$4 358	$4.358	$4 358	$4.358	$4.358	$4 358	$4.358	$4.358	$4 358
TRANSCO DEMAND ZONE 2 TO 6	$/Dth	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460	$0.460
TRANSCO DEMAND ZONE 3 TO 6.	$/Dth	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434	$0.434
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	$6.010	$6.010	$6.010	$6 010	$6.010	$6 010	$6.010	$6.010	$6 010	$6.010	$6.010	$6 010
HUBL NE	$/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
HUBL NE	$/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
HUBL NE	$/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
SUPPLIER FIXED COST UNIT PRICES													
DISTRIGAS FCS	$/Dth	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400	$2.400

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update

		UNIT PRICES											
		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
PIPELINE FIXED COST BILLING UNITS													
ALGONQU N 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
ALGONQU N 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
ALGONQU N 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
SUPPLIER FIXED COST BILLING UNITS													
DISTRIGAS FCS	DTH	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833	125,833

CALCULATION OF SYSTEM WEIGHTED AVERAGE DEMAND COSTS **2009 - 2010 GCR PROJECTED PRICES**

August 1, 2009 Update

UNIT PRICES

		NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	
PIPELINE FIXED COST DOLLARS														
ALGONQU N 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	
ALGONQU N 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	
ALGONQU N 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	$	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	$94,278	
TEXAS EASTERN WLA CDS DEMAND M3	$	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	$44,445	
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	$	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	$511,797	
TETCO SCT STX DEMAND	$	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	$1,555	
TETCO SCT WLA DEMAND	$	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	
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	$	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	$9,355	
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	$	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	$515	
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	$	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	$4,994	
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	
ROQUOIS	$	$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	
DOM NION FTNN DEMAND	$	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	$2,340	
TRANSCO DEMAND ZONE 2 TO 6	$	$1,906	$1,970	$1,970	$1,779	$1,970	$1,906	$1,970	$1,906	$1,970	$1,970	$1,906	$1,970	
TRANSCO DEMAND ZONE 3 TO 6.	$	$39	$40	$40	$36	$40	$39	$40	$39	$40	$40	$39	$40	
TRANSCO DEMAND ZONE 6	$	$4,416	$4,563	$4,563	$4,121	$4,563	$4,416	$4,563	$4,416	$4,563	$4,563	$4,416	$4,563	
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	$	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	$285,205	
HUBL NE	$	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	$46,233	
HUBL NE	$	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	$3,498	
HUBL NE	$	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	$24,472	
WESTERLY LATERAL (Yankee)	$	$60,149	$60,149	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	$58,879	
	$	**$2,657,158**	**$2,658,559**	**$2,657,290**	**$2,653,086**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$2,657,290**	**$2,655,888**	**$2,657,290**	**$31,880,207**
SUPPLIER FIXED COST DOLLARS														
DISTRIGAS FCS	$	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	$302,000	**$3,624,000**
TOTAL PIPELINE FIXED DEMAND CHARGES		**$2,959,158**	**$2,960,559**	**$2,959,290**	**$2,955,086**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$2,959,290**	**$2,957,888**	**$2,959,290**	**$35,504,207**
TOTAL DEMAND UNITS DTH		5,062,752	5,534,368	5,534,368	4,998,784	5,534,368	4,912,752	4,928,652	4,314,203	4,458,010	4,458,010	4,314,203	4,928,652	**58,979,122**
100% LOAD FACTOR UNIT VALUE $/DTH														**0.6020**
Average rate per unit per month														**18.3102**
AVERAGE SYSTEM VARIABLE UNIT VALUE $/DTH														**0.3967**
TOTAL AVERAGE SYSTEM UNIT VALUE $/DTH														**$ 0.9987**

National Grid
2009 Estimated GCR
Normal Weather Scenario

Ventyx
SENDOUT® Version 12 5.5 REP 13 26-Aug-2009
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Natural Gas Supply VS. Requirements Units: MDT

.	NOV 2009	DEC 2009	JAN 2010	FEB 2010	MAR 2010	APR 2010	MAY 2010	JUN 2010	JUL 2010	AUG 2010	SEP 2010	OCT 2010	Total
Forecast Demand													
RI Sales GCR	2,622,717	4,241,840	5,044,293	4,438,288	3,632,328	2,108,674	1,232,306	831,637	745,208	776,452	801,792	1,460,795	27,936,330
NON EX TR DE	313,107	469,231	497,378	474,703	426,684	275,870	166,121	134,770	109,906	111,264	127,782	170,974	3,277,790
Total Demand	2,935,824	4,711,071	5,541,671	4,912,991	4,059,012	2,384,544	1,398,427	966,407	855,114	887,716	929,574	1,631,769	31,214,120
Storage Injections													
TENN_8995	0	0	0	0	0	14,700	21,840	26,460	26,250	26,250	26,250	26,250	168,000
TENN_501	0	0	0	0	0	50,454	63,738	54,097	124,000	109,264	60,534	54,481	516,568
GSS 600045	0	0	0	0	0	150,000	137,632	137,632	137,632	137,632	137,632	123,869	962,029
GSS 300171	0	0	0	0	0	31,470	32,519	30,418	18,881	18,881	18,881	16,993	168,043
GSS 300169	0	0	0	0	0	43,771	31,000	28,279	20,610	20,610	20,610	18,549	183,429
GSS 300168	0	0	0	0	0	21,025	31,000	25,000	15,405	15,405	15,405	13,865	137,105
GSS 300170	0	0	0	0	0	60,000	62,000	60,000	62,000	49,034	49,034	44,131	386,199
TETCO_400221	0	0	0	0	0	120,000	124,000	120,000	118,804	118,804	118,804	106,923	827,335
TETCO_400515	0	0	0	0	0	8,730	5,664	5,664	5,664	5,664	5,664	5,098	42,148
TETCO 400185	0	0	0	0	0	10,918	5,199	5,199	5,199	5,199	5,199	4,679	41,592
COL FS 38010	0	0	0	0	0	24,000	24,800	24,000	20,396	20,396	20,396	18,356	152,344
LNG EXETER	13,000	0	16,462	0	0	58,610	5,400	0	35,100	65,790	10,500	3,100	207,962
LNG PROV	15,000	7,593	29,400	6,587	0	16,206	78,300	81,000	45,900	0	30,791	15,500	326,277
LNG VALLEY	2,700	15,570	5,438	9,028	0	6,184	0	0	2,700	17,910	2,700	2,790	65,020
Total Injections	30,700	23,163	51,300	15,615	0	616,068	623,092	597,749	638,541	610,839	522,400	454,584	4,184,051
Non-LNG Injections	0	0	0	0	0	535,068	539,392	516,749	554,841	527,139	478,409	433,194	3,584,792
Total LNG Injection	30,700	23,163	51,300	15,615	0	81,000	83,700	81,000	83,700	83,700	43,991	21,390	599,259
Total Req less LNG inj.	2,935,824	4,711,071	5,541,671	4,912,991	4,059,012	2,919,612	1,937,819	1,483,156	1,409,955	1,414,855	1,407,983	2,064,963	34,798,912

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
Sources of Supply													
TENN_ZONE_0	282,960	292,392	292,392	264,096	292,392	282,960	292,392	282,960	292,392	292,392	282,960	292,392	3,442,680
TENN_ZONE_1	0	441,768	445,104	409,964	315,884	0	0	0	0	0	0	0	1,612,720
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_DRACUT	29,700	53,188	138,354	125,891	30,690	450,000	357,877	0	0	10,424	0	465,000	1,661,124
TETCO_STX	274,620	283,774	283,774	256,312	283,774	274,620	283,774	274,620	283,774	283,774	274,620	283,774	3,341,210
TETCO_ELA	36,521	71,559	74,458	63,480	42,012	0	0	0	0	0	0	0	288,030
TETCO_WLA	204,888	279,014	284,466	255,388	234,220	0	0	0	0	0	0	0	1,257,976
TETCO_ETX	296,580	306,466	306,466	276,808	306,466	296,580	306,466	296,580	306,466	306,466	296,580	306,466	3,608,390
TETCO - NF	0	16,692	22,932	20,286	12,348	0	0	0	0	0	0	0	72,258
HUBL NE	0	47,085	103,540	73,148	4,931	240,000	248,000	201,297	94,938	89,413	134,728	248,000	1,485,080
M3_DELIVERED	0	117,409	125,513	103,225	42,973	0	0	0	0	0	0	0	389,120
MAUMEE_SUPP	885,069	902,619	907,355	806,912	868,104	682,970	15,200	14,400	16,000	16,396	12,396	8,356	5,135,777
BROADRUN_COL	289,616	296,040	305,908	276,304	286,172	234,125	9,600	9,600	4,396	4,000	8,000	10,000	1,733,761
Col Tran-Tet	0	52,351	111,542	84,426	7,360	0	0	0	0	0	0	0	255,679
TRAN WHART	0	930	2,170	2,170	0	0	0	0	0	0	0	0	5,270
TETCO B&W	12,432	35,076	37,296	31,080	12,846	0	0	0	0	0	0	0	128,730
DOM TET FTS	0	31,843	63,550	52,312	9,730	0	0	0	0	0	0	0	157,435
TETCO DOM	0	1,590	3,710	3,710	0	0	0	0	0	0	0	0	9,010
ANE	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000	365,000
NIAGARA	24,000	31,000	31,000	28,000	31,000	30,000	12,521	5,000	0	0	0	31,000	223,521
DIST FCS VAP	190,821	236,096	236,096	213,248	236,096	29,658	0	0	0	0	0	7,985	1,150,000
Total Pipeline Supply Deliveries	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,898,913	1,916,430	1,462,457	1,388,566	1,393,465	1,387,284	2,043,573	30,556,771
CITY GATE DELIVERED MDQ = 6,000 DTH													
Storage Withdrawals													
TENN_8995	8,400	29,494	56,116	56,031	17,960	0	0	0	0	0	0	0	168,001
TENN_501	1,517	131,936	131,936	119,168	131,936	0	0	0	0	0	0	0	516,493
GSS 600045	0	193,803	282,810	263,956	221,463	0	0	0	0	0	0	0	962,032
GSS 300171	0	38,851	64,972	49,096	15,751	0	0	0	0	0	0	0	168,670
GSS 300169	0	38,665	61,050	54,945	28,974	0	0	0	0	0	0	0	183,634
GSS 300168	0	26,277	41,490	38,724	31,266	0	0	0	0	0	0	0	137,757
GSS 300170	0	82,923	136,656	102,483	64,313	0	0	0	0	0	0	0	386,375
TETCO_400221	0	150,175	308,889	285,129	83,140	0	0	0	0	0	0	0	827,333
TETCO_400515	0	9,627	14,726	13,594	4,192	0	0	0	0	0	0	0	42,139
TETCO 400185	0	7,129	13,517	12,478	8,411	0	0	0	0	0	0	0	41,535
COL FS 38010	0	29,809	55,757	44,151	22,617	0	0	0	0	0	0	0	152,334
LNG EXETER	3,000	14,662	56,800	99,000	3,100	3,000	3,100	3,000	3,100	3,100	3,000	3,100	197,962
LNG PROV	15,000	27,993	117,000	43,787	15,500	15,000	15,500	15,000	15,500	15,500	15,000	15,500	326,280
LNG VALLEY	2,700	16,688	11,028	12,554	2,790	2,700	2,790	2,700	2,790	2,790	2,700	2,790	65,020
Total Withdrawals	30,617	798,032	1,352,747	1,195,096	651,413	20,700	21,390	20,700	21,390	21,390	20,700	21,390	4,175,565
Total Supply	2,935,824	4,685,524	5,518,973	4,894,656	4,059,011	2,919,613	1,937,820	1,483,157	1,409,956	1,414,855	1,407,984	2,064,963	34,732,336

.	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	Total
8/24/2009 NYMEX	**$5.078**	**$5.748**	**$6.055**	**$6.087**	**$6.019**	**$5.896**	**$5.938**	**$6.033**	**$6.148**	**$6.238**	**$6.298**	**$6.411**	
TENNESSEE ZN 0													
Basis	[redacted]												
usage	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	$0.1625	
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 CONNEXION													
Basis	[redacted]												
usage	$0.0017	$0.0017	$0.0017	$0 0017	$0 0017	$0.0017	$0 0017	$0.0017	$0 0017	$0 0017	$0.0017	$0.0017	
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	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	$0.1520	
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	$0.0659	$0.0659	$0.0659	$0 0659	$0 0659	$0.0659	$0 0659	$0.0659	$0 0659	$0 0659	$0.0659	$0.0659	
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 STX													
Basis	[redacted]												
Usage to M3	$0.0715	$0.0715	$0.0715	$0 0715	$0.0715	$0.0715	$0 0715	$0 0715	$0 0715	$0 0715	$0.0715	$0.0715	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0.0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129	
Fuel to M3	7 63%	8.59%	8.59%	8 59%	8.59%	7.63%	7 63%	7 63%	7 63%	7 63%	7.63%	7.63%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO WLA													
Basis	[redacted]												
Usage to M3	$0.0701	$0.0701	$0.0701	$0 0701	$0 0701	$0.0701	$0 0701	$0 0701	$0 0701	$0 0701	$0.0701	$0.0701	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129	
Fuel to M3	6 98%	7.72%	7.72%	7.72%	7.72%	6.98%	6 98%	6 98%	6 98%	6 98%	6.98%	6.98%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	
Total Delivered	[redacted]												
TETCO ELA													
Basis	[redacted]												
Usage to M3	$0.0695	$0.0695	$0.0695	$0 0695	$0 0695	$0.0695	$0 0695	$0 0695	$0 0695	$0 0695	$0.0695	$0.0695	
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129	
Fuel to M3	6.70%	7.34%	7.34%	7 34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%	
Total Delivered	[redacted]												

TETCO ETX												
Basis	[redacted]											
Usage to M3	$0.0695	$0.0695	$0.0695	$0 0695	$0 0695	$0.0695	$0 0695	$0 0695	$0 0695	$0 0695	$0.0695	$0.0695
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel to M3	6.70%	7.34%	7.34%	7 34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											
TETCO TO NF												
Basis	[redacted]											
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192
Usage on NF	$0.0086	$0.0086	$0.0086	$0 0086	$0 0086	$0.0086	$0 0086	$0.0086	$0 0086	$0 0086	$0.0086	$0.0086
Usage on Transco	$0.0083	$0.0083	$0.0083	$0 0083	$0 0083	$0.0083	$0 0083	$0.0083	$0 0083	$0 0083	$0.0083	$0.0083
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel to M2	6 00%	6.00%	6.00%	6 00%	6.00%	6.00%	6 00%	6 00%	6 00%	6 00%	6.00%	6.00%
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Delivered to NF	[redacted]											
Delivered to Transco												
Delivered to Algonquin												
Total Delivered												
M3 DELIVERED												
Basis	[redacted]											
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											
MAUMEE SUPPLY												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0 0214	$0 0214	$0.0214	$0 0214	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											
BROADRUN COLUMBIA												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0 0214	$0 0214	$0.0214	$0 0214	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											
COLUMBIA TO AGT												
Basis	[redacted]											
Usage on Columbia	$0.0214	$0.0214	$0.0214	$0 0214	$0 0214	$0.0214	$0 0214	$0.0214	$0 0214	$0 0214	$0.0214	$0.0214
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Fuel on Columbia	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%	2.13%
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											

TETCO to DOMINION TO B & W												
Basis												
Usage on Dominion	$0.0247	$0.0247	$0.0247	$0 0247	$0 0247	$0.0247	$0 0247	$0.0247	$0 0247	$0 0247	$0.0247	$0.0247
Usage to M2	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192	$0.4192
Usage on Tetco	$0.0017	$0.0017	$0.0017	$0 0017	$0 0017	$0.0017	$0 0017	$0.0017	$0 0017	$0 0017	$0.0017	$0.0017
Usage on AGT	$0.2294	$0.2294	$0.2294	$0 2294	$0 2294	$0.2294	$0 2294	$0 2294	$0 2294	$0 2294	$0.2294	$0.2294
Fuel to M2	6 00%	6.00%	6.00%	6 00%	6.00%	6.00%	6 00%	6 00%	6 00%	6 00%	6.00%	6.00%
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Delivered to Dominion												
Delivered to Tetco												
Delivered to Algonquin												
Total Delivered												
TRANSCO AT WHARTON												
Basis												
Usage on Transco	$0.0083	$0.0083	$0.0083	$0 0083	$0 0083	$0.0083	$0 0083	$0.0083	$0 0083	$0 0083	$0.0083	$0.0083
Usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered												
AECO TO TENNESSEE - ANE II												
Basis												
Transcanada usage	$0 085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0 085	$0.085	$0.085	$0 085	$0.085
Transcanada pressure chg	$0 017	$0.017	$0.017	$0.017	$0.017	$0.017	$0.017	$0 017	$0.017	$0.017	$0 017	$0.017
Fuel on TCPL	4.090%	4.090%	4.090%	4 090%	4 090%	4.090%	4 090%	4.090%	4 090%	4 090%	4.090%	4.090%
Iroquois usage	$0 005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0 005	$0.005	$0.005	$0 005	$0.005
Tennessee usage	$0 002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0 002	$0.002	$0.002	$0 002	$0.002
Fuel on Iroquois	0 30%	0.30%	0.30%	0 30%	0.30%	0.30%	0 30%	0 30%	0 30%	0 30%	0.30%	0.30%
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												
NIAGARA TO TENNESSEE												
Basis												
Tenn usage	$0 085	$0.085	$0.085	$0.085	$0.085	$0.085	$0.085	$0 085	$0 085	$0.085	$0 085	$0.085
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												
Tetco to B&W												
Basis												
usage on Tetco	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426	$0.426
usage on AGT	$0 229	$0.229	$0.229	$0.229	$0.229	$0.229	$0.229	$0 229	$0.229	$0.229	$0 229	$0.229
fuel to ZN 3	6.70%	7.34%	7.34%	7 34%	7.34%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Fuel on AGT	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered												

Dominion to Tetco FTS												
Basis	[redacted]											
usage on Tetco	$0.0017	$0.0017	$0.0017	$0 0017	$0 0017	$0.0017	$0 0017	$0.0017	$0 0017	$0 0017	$0.0017	$0.0017
usage on AGT	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0 0129	$0 0129	$0 0129	$0.0129	$0.0129
Tetco Fuel	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	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											
DISTRIGAS FCS												
Total Delivered	[redacted]											
Hubline												
Basis	[redacted]											
usage	$0.0129	$0.0129	$0.0129	$0 0129	$0 0129	$0.0129	$0 0129	$0.0129	$0 0129	$0 0129	$0.0129	$0.0129
fuel	1 02%	1.44%	1.44%	1.44%	1.44%	1.02%	1 02%	1 02%	1 02%	1 02%	1.02%	1.02%
Total Delivered	[redacted]											

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
Tennessee Zn 0												
Delivered Mmbtu	282,960	292,392	292,392	264,096	292,392	282,960	292,392	282,960	292,392	292,392	282,960	292,392
NYMEX $/Mmbtu Del	$5.3268	$5.9879	$6.3772	$6.4389	$6 3257	$6.3571	$6 3976	$6.4908	$6 6096	$6.7095	$6.7919	$6.9038
Total Delivered Cost	$1,507,275	$1,750,812	$1,864,642	$1,700,480	$1,849,589	$1,798,817	$1,870,621	$1,836,624	$1,932,586	$1,961,800	$1,921,836	$2,018,617
TENNESSEE 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	5.1660	5.8271	6.2164	6 2781	6.1649	6.1963	6 2368	6.3300	6.4488	6 5487	6.6311	6.7430
Total Delivered Cost	$1,797,772	$2,095,422	$2,235,418	$2,039,118	$2,216,904	$2,156,327	$2,242,771	$2,202,825	$2,318,979	$2,354,908	$2,307,623	$2,424,784
TENN ZONE 1												
Delivered Mmbtu	0	441,768	445,104	409,964	315,884	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$5 504	$6.214	$6.562	$6.603	$6.523	$6.327	$6.370	$6.466	$6 585	$6.682	$6.755	$6.867
Total Delivered Cost	$0	$2,745,361	$2,920,706	$2,706,934	$2,060,481	$0	$0	$0	$0	$0	$0	$0
TENN DRACUT												
Delivered Mmbtu at Historical	29,700	53,188	138,354	125,891	30,690	450,000	357,877	0	0	10,424	0	465,000
NYMEX $/Mmbtu Del	$5.703	$7.304	$8.810	$8.734	$7.088	$6.387	$6.429	$6 543	$6 676	$6.759	$6.797	$6.934
Total Delivered Cost	$169,390	$388,486	$1,218,944	$1,099,512	$217,528	$2,873,936	$2,300,678	$0	$0	$70,455	$0	$3,224,206
TETCO STX												
Delivered Mmbtu	274,620	283,774	283,774	256,312	283,774	274,620	283,774	274,620	283,774	283,774	274,620	283,774
NYMEX $/Mmbtu Del	$5.2254	$5.9701	$6.3669	$6.4290	$6 3137	$6.2475	$6 2869	$6.3745	$6.4907	$6 5943	$6.6902	$6.7964
Delivered Cost	$1,434,990	$1,694,158	$1,806,762	$1,647,817	$1,791,675	$1,715,684	$1,784,047	$1,750,557	$1,841,902	$1,871,295	$1,837,273	$1,928,653
TETCO WLA												
Delivered Mmbtu	204,888	279,014	284,466	255,388	234,220	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$5.4193	$6.2119	$6.5598	$6 6003	$6 5200	$6.2676	$6 3106	$6.4071	$6 5274	$6 6267	$6.6986	$6.8128
Delivered Cost	$1,110,343	$1,733,215	$1,866,042	$1,685,629	$1,527,116	$0	$0	$0	$0	$0	$0	$0
TETCO ELA												
Delivered Mmbtu	36,521	71,559	74,458	63,480	42,012	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$5.5122	$6.2973	$6.6435	$6 6835	$6 6038	$6.3202	$6 3627	$6.4578	$6 5770	$6 6762	$6.7490	$6.8615
Delivered Cost	$201,312	$450,631	$494,658	$424,270	$277,439	$0	$0	$0	$0	$0	$0	$0

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
TETCO ETX												
Delivered Mmbtu	296,580	306,466	306,466	276,808	306,466	296,580	306,466	296,580	306,466	306,466	296,580	306,466
NYMEX $/Mmbtu Del	$5.0867	$5.8087	$6.1955	$6 2544	$6.1441	$6.0626	$6.1008	$6.1856	$6 2995	$6.4026	$6.5013	$6.6044
Delivered Cost	$1,508,605	$1,780,184	$1,898,709	$1,731,270	$1,882,970	$1,798,061	$1,869,678	$1,834,512	$1,930,573	$1,962,166	$1,928,160	$2,024,025
TETCO - NF												
Delivered Mmbtu	0	16,692	22,932	20,286	12,348	0	0	0	0	0	0	0
Delivered $/Mmbtu	$5.9777	$6.7335	$7.0826	$7.1230	$7 0426	$6.7983	$6 8415	$6 9381	$7 0592	$7.1599	$7.2339	$7.3481
Delivered Cost	$0	$112,395	$162,418	$144,498	$86,962	$0	$0	$0	$0	$0	$0	$0
M3 DELIVERED												
Delivered Mmbtu	0	117,409	125,513	103,225	42,973	0	0	0	0	0	0	0
Delivered $/Mmbtu	$5.6037	$7.0023	$8.3828	$8 2486	$7.1257	$6.3488	$6 3937	$6.5103	$6 6437	$6.7268	$6.7612	$6.9040
Delivered Cost	$0	$822,139	$1,052,154	$851,461	$306,214	$0	$0	$0	$0	$0	$0	$0
Transco at Wharton												
Delivered Mmbtu	0	930	2,170	2,170	0	0	0	0	0	0	0	0
Delivered $/Mmbtu	$5 665	$7.051	$8.407	$8.277	$7.181	$6.404	$6.450	$6 569	$6.704	$6.788	$6 821	$6.967
Delivered Cost	$0	$6,558	$18,242	$17,961	$0	$0	$0	$0	$0	$0	$0	$0
MAUMEE SUPP												
Delivered Mmbtu	885,069	902,619	907,355	806,912	868,104	682,970	15,200	14,400	16,000	16,396	12,396	8,356
NYMEX $/Mmbtu Del	$5 354	$6.080	$6.388	$6.415	$6.352	$6.194	$6.239	$6 340	$6.462	$6.553	$6 611	$6.733
Delivered Cost	$4,739,003	$5,487,848	$5,795,918	$5,176,736	$5,514,056	$4,230,630	$94,832	$91,301	$103,389	$107,443	$81,947	$56,263
BROADRUN COL												
Delivered Mmbtu	289,616	296,040	305,908	276,304	286,172	234,125	9,600	9,600	4,396	4,000	8,000	10,000
Daily pricing wacog	$5 354	$6.080	$6.388	$6.415	$6.352	$6.194	$6.239	$6 340	$6.462	$6.553	$6 611	$6.733
Delivered Cost	$1,550,716	$1,799,898	$1,954,051	$1,772,626	$1,817,718	$1,450,278	$59,894	$60,867	$28,406	$26,212	$52,886	$67,332
COLUMBIA AGT												
Delivered Mmbtu	0	52,351	111,542	84,426	7,360	0	0	0	0	0	0	0
Delivered $/Mmbtu	$5.747	$7.176	$8.587	$8.449	$7.302	$6.508	$6.554	$6 673	$6 810	$6.894	$6 930	$7.076
Delivered Cost	$0	$375,676	$957,768	$713,354	$53,744	$0	$0	$0	$0	$0	$0	$0
AECO TO TENNESSEE - ANE II												
Delivered Mmbtu	30,000	31,000	31,000	28,000	31,000	30,000	31,000	30,000	31,000	31,000	30,000	31,000
Delivered $/Mmbtu	$4 983	$5.613	$6.181	$6.066	$5.649	$5.348	$5.255	$5.488	$5 292	$6.158	$6 046	$6.089
Delivered Cost	$149,484	$173,999	$191,618	$169,839	$175,111	$160,442	$162,894	$164,628	$164,050	$190,896	$181,369	$188,757

Total delivered to the City Gas Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
NIAGARA TO TENNESSEE	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
Delivered Mmbtu Niagara	24,000	31,000	31,000	28,000	31,000	30,000	12,521	5,000	0	0	0	31,000
Delivered $/Mmbtu Niagara	$5 661	$6.362	$6.658	$6.680	$6.623	$6.460	$6.508	$6 611	$6.739	$6.822	$6 864	$7.004
Total Delivered cosl	$135,862	$197,234	$206,391	$187,038	$205,318	$193,787	$81,486	$33,057	$0	$0	$0	$217,111
TETCO TO B&W												
Delivered Mmbtu	12,432	35,076	37,296	31,080	12,846	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$6 089	$6.876	$7.222	$7.262	$7.182	$6.897	$6.939	$7 035	$7.154	$7.253	$7 326	$7.438
Total Delivered cosl	$75,699	$241,170	$269,343	$225,698	$92,262	$0	$0	$0	$0	$0	$0	$0
Dominion to Tetco FTS												
Delivered Mmbtu	0	1,590	3,710	3,710	0	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	$5.426	$6.166	$6.452	$6.474	$6.419	$6.154	$6.199	$6 301	$6.423	$6.512	$6 566	$6.690
Total Delivered cosl	$0	$9,803	$23,937	$24,020	$0	$0	$0	$0	$0	$0	$0	$0
Dominion to Tetco FTS												
Delivered Mmbtu	0	31843	63550	52312	9730	0	0	0	0	0	0	0
NYMEX $/Mmbtu Del	5.4263	6.1655	6.4520	6.4744	6.4189	6.1544	6.1989	6.3009	6.4226	6 5121	6.5660	6.6896
Total Delivered cosl	$0	$196,328	$410,023	$338,688	$62,456	$0	$0	$0	$0	$0	$0	$0
DISTRIGAS FCS												
Delivered Mmbtu	190,821	236,096	236,096	213,248	236,096	29,658	0	0	0	0	0	7,985
Delivered $/Mmbtu	$5 078	$5.748	$6.055	$6.087	$6.019	$5.896	$5.938	$6 033	$6.148	$6.238	$6 298	$6.411
Delivered Cost	$968,989	$1,357,080	$1,429,561	$1,298,041	$1,421,062	$174,864	$0	$0	$0	$0	$0	$51,192
HUBLINE												
Delivered Mmbtu at Historical	0	47,085	103,540	73,148	4,931	240,000	248,000	201,297	94,938	89,413	134,728	248,000
Delivered $/Mmbtu	$5 658	$7.291	$8.806	$8.729	$7.074	$6.344	$6.387	$6 502	$6 635	$6.717	$6.755	$6.893
Delivered Historical	$0	$343,316	$911,786	$638,525	$34,882	$1,522,651	$1,583,880	$1,308,749	$629,870	$600,622	$910,124	$1,709,358

	NOV	DEC	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	JUN	**JUL**	**AUG**	**SEP**	**OCT**	
Total Pipeline Costs	$15,349,440	$23,761,713	$27,689,089	$24,593,514	$21,593,485	$18,075,477	$12,050,781	$9,283,120	$8,949,755	$9,145,796	$9,221,219	$13,910,299	$193,623,687
Total Pipeline Volumes	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,898,913	1,916,430	1,462,457	1,388,566	1,393,465	1,387,284	2,043,573	30,556,771
WACOG	$5 283	$6.112	$6.646	$6.648	$6.337	$6.235	$6.288	$6 348	$6.445	$6.563	$6 647	$6.807	$6 337
Injections	0	0	0	0	0	535,068	539,392	516,749	554,841	527,139	478,409	433,194	3,584,792
Value at WACOG	$0	$0	$0	$0	$0	$3,336,288	$3,391,773	$3,280,126	$3,576,129	$3,459,797	$3,179,965	$2,948,687	$23,172,765
Pipeline Costs less Injections	$15,349,440	$23,761,713	$27,689,089	$24,593,514	$21,593,485	$14,739,188	$8,659,008	$6,002,994	$5,373,626	$5,685,999	$6,041,254	$10,961,612	$170,450,922
Pipeline Volumes less injections	2,905,207	3,887,492	4,166,226	3,699,560	3,407,598	2,363,845	1,377,038	945,708	833,725	866,326	908,875	1,610,379	26,971,979
NYMEX cost of Supplies	$14,752,641	$22,345,305	$25,226,498	$22,519,221	$20,510,333	$13,937,230	$8,176,852	$5,705,456	$5,125,741	$5,404,142	$5,724,095	$10,324,139	[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, 2008 through October 31, 2009

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, 2008= 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.

GPIP Purchase Calculation	NOV 2009	DEC 2009	JAN 2010	FEB 2010	MAR 2010	APR 2010	MAY 2010	JUN 2010	JUL 2010	AUG 2010	SEP 2010	OCT 2010	GCR Total
Total Pipeline Volumes	3,319,400	3,802,600	3,683,400	3,258,700	3,565,300	3,241,600	2,216,800	1,531,200	1,208,400	1,134,500	867,700	1,797,900	29,627,500
Pipeline Fuel	210,441	250,397	246,403	221,304	244,720	190,423	137,331	90,320	68,006	62,504	37,422	106,328	1,865,599
Purchases at Point of receipt	3,529,841	4,052,997	3,929,803	3,480,004	3,810,020	3,432,023	2,354,131	1,621,520	1,276,406	1,197,004	905,122	1,904,228	31,493,099
Percent mandatory	70%	70%	70%	70%	70%	60%	70%	70%	70%	70%	70%	60%	
Mandatory	2,470,889	2,837,098	2,750,862	2,436,003	2,667,014	2,059,214	1,647,892	1,135,064	893,484	837,903	633,585	1,142,537	21,511,544
Maximum Discretionary	882,460	1,013,249	982,451	870,001	952,505	1,201,208	588,533	405,380	319,102	299,251	226,280	666,480	8,406,900

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NATIONAL GRID

DOCKET No. ____

DIRECT TESTIMONY

OF

GARY L. BELAND

September 1, 2009

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gary L. Beland. My business address is 40 Sylvan Way, Waltham Massachusetts,02451-1120.

Q. WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am Manager of Gas Supply Regulatory for National Grid (The Narragansett Electric Company d/b/a National Grid hereinafter referred to as "National Grid" or the "Company"). My responsibilities include various projects and filings concerning gas supply regulatory matters.

Q. WHAT IS YOUR BACKGROUND AND EXPERIENCE?

A. I began my career in the natural gas industry in June 1977 as an analyst in the Rates and Regulatory Affairs Department of Michigan Consolidated Gas ("MichCon") after receiving a Masters of Business Administration from the State University of New York in Albany. At MichCon, I worked on a variety of projects and studies including pipeline rate filings, state rate cases, demand modeling, gas-supply cost simulations, conservation planning and strategic analyses.

In 1983, I was hired by Niagara Mohawk as a Corporate Planner. In that position, I was responsible for strategic analysis and a variety of projects including integrated

resource planning, pipeline regulatory monitoring and intervention, both end-use based and econometric electric and gas-demand forecasting, fuel-cost forecasting and modeling and gas market unbundling. In 1987, I joined the newly formed gas business unit as Manager of Gas Supply Planning. While I was at Niagara Mohawk, I was involved in the Forecasting and Planning Sub-Committee of the New York Power Pool and the Planning Committee of the New York Gas Group, serving as Chairman at the time I left to join the Providence Gas Company ("ProvGas") in 1994.

I joined ProvGas in 1994 as the Manager of Gas Supply with the responsibility for Gas Supply, Gas Control and Gas Accounting. In 1997, I became Assistant Vice President. After the merger with Southern Union Company, I was named Director of Gas Supply for the New England Division. From 1997 to 1999 I served on the Executive Committee of the Gas Industries Standards Board.

I have testified in several dockets before the Federal Energy Regulatory Commission. I have also testified before the New York Public Service Commission on gas and electric market forecasts and a gas-cost incentive mechanism. In Rhode Island, I have testified before this Commission on numerous gas supply issues over the last 15 years.

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, 2009 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. My testimony will also address the Natural Gas Vehicle ("NGV") rate, certain updates and edits to the Company's tariff and the Gas Procurement Incentive Plan ("GPIP"), and present the results of the GPIP for the July 1, 2008 to June 30, 2009 plan year.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is composed of nine (9) general sections: *I.* the Introduction; *II.* a GCR Rate Development Overview; *III*. GCR Rate Development Details; *IV*. Bill Impacts; *V.* Natural Gas Vehicles; *VI.* Marketer Factors; *VII.* Rate Case GCR Changes; *VIII.* Tariff Changes and Amendments; *IX*. Gas Purchase Incentive Plan

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

A. Yes. I am sponsoring the following Attachments:

GLB-1 Gas Cost Recovery Factors
GLB -2 GCR Reconciliation Filing
GLB -3 Projected Gas Cost Balances
GLB -4 Bill Impacts
GLB -5 NGV Tariff
GLB -6 Marketer Transportation Factors
GLB -7 NEC Gas Tariff, Marked and Unmarked Versions
GLB -8 Gas Procurement Incentive Plan Outline
GLB -9 Gas Procurement Incentive Plan Results

II. GCR RATE DEVELOPOMENT OVERVIEW

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, 2009 through October 31, 2010. As shown in the testimony of Ms. Arangio on Attachment EDA-1, gas costs for the period are projected to be $273.0 million for the twelve months ended October 2010. In addition to these projected costs, the GCR factors also reflect Working Capital Costs of $2.0 million (Attachment GLB-1, pages 8-10), Inventory Financing Costs of $2.9 million (Attachment GLB-1, page 11), a prior period Deferred Balance of $11.7 million (Attachment GLB-1, pages 6-7; based on actual data through July 2009 and forecast data for the period August 2009 through October 2009), LNG Operation and Maintenance ("O&M") Costs of $1.0 million (Docket No. 3943), and a credit of $1.4 million associated with LNG Costs which will be collected via the Distribution Adjustment Clause ("DAC") factor. Thus, the GCR factors are intended to recover $290.4 million in costs over the period November 2009 through October 2010. Attachment GLB-1, page 1 provides a summary of the GCR factors by customer rate class.

III. GCR RATE DEVELOPOMENT DETAILS

Q. ATTACHMENT GLB-1, PAGE 1 SHOWS A GCR FACTOR OF $10.4017 PER DEKATHERM FOR RESIDENTIAL NON-HEAT AND BOTH LARGE AND EXTRA LARGE HIGH LOAD FACTOR. PLEASE EXPLAIN HOW THIS FACTOR WAS DERIVED.

A. The $10.4017 per dekatherm 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 $10.4017 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 $0.78 per Dth, $0.29 per Dth, $8.87 per Dth, $0.29 per Dth, and ($0.07) per Dth respectively.

The derivation of the Supply Fixed Cost component is reflected on Attachment GLB-1, page 2. As shown, Supply Fixed Costs total $29,343,973 (see also Attachment EDA-1; Pipeline Demand Costs of $31,829,169, Supplier Demand Costs of $2,757,600, and Marketer/Capacity Release Revenues of $5,242,797). Also, the guaranteed credit of $1,000,000 to customers required under the Natural Gas Portfolio Management Plan ("NGPMP") is subtracted, the Working Capital Costs (Attachment

GLB-1, page 8) associated with Supply Fixed Costs of $218,227 is added and the prior period Supply Fixed Gas Cost under-collection of $1,802,253 (Attachment GLB-1, page 6) is subtracted, resulting in total Supply Fixed Gas Costs of $30,146,225 to be collected over the period November 2009 through October 2010. 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, Large-HLF and Extra Large HLF design sales represents 3.6% of Design Winter Sales (GLB-1, Page 2, High Load Factor Total, Line 14). Thus, 3.6% of total Supply Fixed Costs, or $1,086,437 is allocated to the Residential and HLF classes. Dividing $1,086,437 by the November 2009 through October 2010 forecasted sales to those classes,1,401,026 dekatherms, results in a Supply Fixed Cost rate component of $0.7755 per Dth.

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 GLB-1, page 3. As shown, Storage Fixed Costs total $10,450,090 (see also Attachment GLB-1). Deducted from this amount are $493,315 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 $78,647 of Working Capital Costs associated with Storage Fixed

Costs (Attachment GLB-1, page 8). The prior period under-collection associated with Storage Fixed Costs of $1,211,860 is added. Thus, Total Storage Fixed Costs to be collected over the period November 2008 through October 2009 amount to $11,865,873. As with Supply Fixed Costs, the Storage Fixed Costs are allocated on the basis of design winter throughput. Thus, 3.95%, or $468,292 of total Storage Fixed Costs is allocated to the Residential and HLF classes. Dividing $468,292 by forecasted period sales of 1,622,468 Dths results in the Storage Fixed Cost component of $0.2886 per Dth.

Q. THE PERCENT OF RESIDENTIAL AND SMALL C & I DESIGN SALES USED FOR ALLOCATED SUPPLY FIXED COSTS WAS 3.6%. WHY IS THE COMPANY USING 3.95% 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 GLB-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 GCR tariff. 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 $8.8677 per Dth for all customer classes, including the Residential and HLF classes. Attachment GLB-1, page 4 shows the derivation of the $8.8677 per Dth Supply Variable Cost component. As shown, projected Variable Supply Costs are $196,408,852 (see Attachment GLB-1). Deducted from this amount are Variable Delivery Storage Costs of $210,983, Variable Injection Storage Costs of $80,294, and Fuel Costs Allocated to Storage of $1,360,930, resulting in total deductions of $1,652,207. 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 $1,448,375 (Attachment GLB-1, page 9) and the prior period under-collection associated with Supply Variable Costs of $45,481,451. Thus, total Supply Variable Costs for the period November 2009 through October 2010 are $235,285,006. Dividing $235,285,006 by projected period sales of 27,254,552 Dths results in the Supply Variable Cost factor of $8.8677per 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 GLB-1, page 5. As shown, projected Storage Variable Product Costs are $36,624,047. Deducted from this amount are $766,752 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. 3401), $269,864 of Working Capital Costs (Attachment GLB-1, page 9), Inventory Financing Costs of $483,932, and $2,458,050 for LNG and Underground Storage, respectively (Attachment GLB-1, page 11). The prior period over-collection of $31,689,296 is subtracted. Thus, Total Storage Variable Costs to be collected over the period November 2009 through October 2010 are $7,809,975. Dividing $7,809,975 by forecasted period sales of 27,254,552 Dths results in the $0.2866 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 GLB-1, page 5. As shown, projected Storage Variable Non-Product Costs are $1,128,324. Added to this amount are Variable Delivery Storage Costs of $210,983, Variable Injection Costs of $80,294, and Fuel Costs Allocated to Storage of $1,360,930. Also, Working Capital Costs of $8,391 are added to the calculation and the prior period over-collection of $4,883,861 is subtracted, resulting in total Storage Variable Non-Product Costs of ($2,094,939) to be refunded over the period November 2009 through October 2010. Dividing ($2,094,939) by forecasted period throughput of 28,852,480 Dth's results in the ($0.0726) per Dth Storage Variable Non-Product Cost factor.

Q. WHY WERE THE STORAGE VARIABLE NON-PRODUCT COSTS DIVIDED BY FORECASTED THROUGHPUT OF 27,254,552 DTH WHILE STORAGE VARIABLE PRODUCT COSTS AND SUPPLY VARIABLE COSTS WERE DIVIDED BY FORECASTED SALES OF 28,852,480 DTH?

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 are assigned to FT-2 Marketers (see Attachment GLB-6).

In summary, the $10.4017 per Dth GCR factor applicable to the Residential and HLF classes consists of a $0.7755 per Dth Supply Fixed Cost component, $0.2886 Storage Fixed Cost component, $8.8677 Supply Variable Cost component, $0.2866 Storage Variable Product Cost component and ($0.0726) Storage Variable Non-Product Cost component. The sum total of these gas cost components is $10.1458 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 $10.4017 per Dth or $1.0402 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 undercollection of approximately $11.7 million in the deferred gas cost account at the end of October 2009. 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 1, 2009, actual data for July 2009, and our latest August 2009 through October 2009 projection using the current GCR factors and the estimate of gas costs included in the Company's

August 20, 2009 deferred gas cost filing. A copy of the annual GCR reconciliation filing is attached here as Attachment GLB-2 and the updated deferred gas cost balance projections for July 2008 through October 2008 are provided in Attachment GLB-1 at pages 6-7.

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

A. Based on actual data through July 2009, and forecasted data for the period August 2009 through October 2009, the total estimated deferred balance at October 31, 2009 is $11.7 million. The projected gas cost balances for the period November 2009 through October 31, 2010 are shown on Attachment GLB-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 May 2008 – April 2009 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, and commercial/industrial classes. Statistical models were developed for the numbers of customers and the use per customer using personal

disposable income and time trends as independent variables. The Company obtained forecasts of personal income from an independent economic forecasting firm. 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.

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 $7 (an average $0.64 per month), or an annual 0.5 percent decrease over the currently effective rates. A summary of annual bill impacts for customers with various levels of usage is provided on Attachment GLB-4. Please note, in addition to the proposed GCR factors, the bill impact analysis also incorporates the proposed decrease in DAC factors that was filed on August 1st and updated on September 1 in Docket No. 4077 for effect November 1, 2009. The annual decrease associated with the decreased GCR rates for a residential heating customer is $7.68 with an additional decrease of $7.84 associated with the proposed DAC rates.

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 Variable Costs identified in the Company's GCR filing. Accordingly, the NGV commodity charge is being updated to reflect the Supply Variable Costs included in this filing. A revised NGV tariff is provided as Attachment GLB-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, 2009 are shown on Attachment GLB-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 GLB-6, page 2 shows the calculation of the $0.0337 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 GLB-6, page 3, the proposed balancing charge is $0.0018 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 GLB-6, page 1. The testimony of Company witness Mr. Gary Beland describes its calculation as well as the calculation of the associated credits/surcharges applied to marketers for pipeline capacity assignments.

VII. RATE CASE GCR CHANGES

Q. PLEASE DESCRIBE THE CHANGES TO THE GCR TARIFF THAT RESULTED FROM THE COMPANY'S BASE GAS DISTRIBUTION RATE CASE IN DOCKET NO. 3943.

A. Beginning December 1, 2008, the Company began using the new methodology and factors approved in Docket No. 3943 to calculate the GCR tariff factors. The most significant change was the consolidation of the six gas cost factors into just two. That change is reflected in the calculated rates and in the discussion of the development of the GCR rates for Residential and HLF classes presented above. The DAC filing, Docket 4077, uses the approved 16.8% factor to allocate the LNG costs associated with maintaining system pressure, LNG operating and maintenance costs, as well as the capital structure and days lag incorporated in the working capital calculations, to the DAC.

VIII ***TARRIFF EDITS AND AMENDMENTS***

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO MAKE TO ITS TARIFF?

A. The Company is requesting the following changes:

1. Eliminate references to the Asset Management Incentive Plan (AMIP).

2. Add terms needed to cover the changes related to the new Natural Gas Portfolio Management Plan (NGPMP).

3. Upgrade and improve the credit standards for marketers providing gas supply service to transportation customers.

4. Update the communication options for marketers to reflect implementation of the Company's new electronic bulletin board (EBB).

5. Provide marketers with more timely estimates of the path costs, weighted average upstream pipeline cos,t and expected surcharge/credit that will be in effect for the upcoming GCR year.

Attachment GLB-7 contains a copy of the proposed tariff with both a final version and a version marked with the proposed changes.

Q. WHY IS THE COMPANY ELIMINATING REFERENCES TO THE AMIP?

A. The termination of the AMIP was ordered by the Commission in Docket 3982.

Q. WHAT CHANGE DOES THE COMPANY PROPOSE TO MAKE TO REFLECT THE NGPMP IN ITS TARIFF?

A. The Company proposes to change the calculation of the Supply Fixed Cost Component in the Gas Charge Recovery Clause. The change will provide that the amount guaranteed to customers under the NGPMP's terms will be included in the calculation of the GCR prospectively while the remaining revenue from optimization transactions, net of the guarantee and Company incentive portion, will be flowed through the GCR following Commission approval after the Commission has reviewed the Plan results for the year. The description of the credits shown in Section 2, Schedule A Sheet 5, the Credits to Supply Fixed Costs, TRFC, has been modified to add these additional credits. This is the same category in which any credit previously received from an asset manager would have been included.

Q. WHAT CHANGE DOES THE COMPANY PROPOSE TO MAKE TO THE MARKETER CREDITWORTHINESS STANDARDS IN ITS TARIFF?

A. The Company proposes to amend its tariff to add specific credit requirements to replace the existing credit requirements wherein the Company relied on the credit check performed by the upstream pipelines, Algonquin Gas Transmission and Tennessee Gas Pipeline. Unfortunately, such pipeline credit standards are subject to change by the pipelines and may be different for each pipeline. This creates

uncertainty as to when creditworthiness standards will change and which standards may apply. Accordingly, the Company's tariff change details the specific criteria to apply and the methods that a Marketer may utilize to demonstrate that they meet the Company's creditworthiness standards. This includes the current methods of providing an advanced deposit, providing an irrevocable letter of credit or providing a guarantee acceptable to the Company.

The new creditworthiness test will also allow marketers' creditworthiness to be more thoroughly and readily verified than the previous approach and will also include a check of the marketers' payment history to the Company. The proposed standards appear in Section 6, Transportation Terms and Conditions, Schedule C, Sheets 30 to 32.

Q. WHAT CHANGE IS THE COMPANY PROPOSING TO MAKE TO ITS COMMUNICATIONS WITH MARKETERS?

A. The Company believes it is no longer necessary to maintain the option for marketers to submit nominations through faxes and has eliminated that option from its tariff (Section 6, Transportation Terms and Conditions, Schedule C, Sheet 6).

The entire industry has migrated to using the internet to manage the gas nomination and scheduling process. In addition, the Company is in the process of making substantial upgrades and improvements to its EBB in order to simplify and streamline the nomination process and overall communication with marketers. Essentially, the

Company seeks to specify that all nominations will go through the Company's newly upgraded Electronic Bulletin Board (EBB) and that the Marketer will be responsible for monitoring the EBB. This provision codifies the current Marketer responsibility.

Q. WHAT CHANGE IS THE COMPANY PROPOSING TO MAKE FOR PROVIDING MARKETERS WITH ESTIMATES OF FUTURE PIPELINE PATH COSTS AND THE SURCHARGES/CREDITS THEY WILL BE SUBJECT TO?

A. Rather than providing an estimate at June 1 of the projected path costs, the Company is proposing to provide such estimates at the request of marketers with three weeks notice. The calculated rates for path costs and the system weighted average cost are subject to significant changes as commodity prices and supply and demand conditions for gas change. Past experience has shown that a calculation done in May to meet a June 1 filing requirement is not a good predictor of the surcharge/credit rates that will be put in effect for the November 1 start of the GCR year. The proposed changes to the tariff can be found in Section 2, Gas Charge, Schedule A, Sheet 14.

IX 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 GPIP is provided in Attachment GLB-8.

The gas procurement portion of the GPIP is based on the Company's gas purchasing program under which the Company locks in the pricing of commodity purchases through purchases or financial hedges over a 24-month horizon. The minimum amount locked in price or financially hedged is 60% of the expected purchases for April and October, and 70% for all other months. 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 RESULT OF THE GAS PROCUREMENT INCENTIVE FOR THE PAST YEAR?

A. Attachment GLB-9 shows the results for the period July 1, 2008 to June 30, 2009 by month. As shown, the Company purchased discretionary supply of 3,353,056 Dth during the period resulting in a net calculated incentive of $1,097,727. The average cost of discretionary purchases was $ 2.575 per Dth less than the mandatory locks.

The calculation of the savings and incentive is shown for each month. For example, in November 2008 the average purchase cost per Dth for mandatory purchases was $9.227 and discretionary purchases were made at an average cost of $7.683, which equates to a savings of $1.545 per Dth on discretionary purchases of 300,000 Dth, resulting in a savings for the month of $463,383.

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

A. While the calculated incentive is $1,097,727, the GPIP Outline states in Section II B:

> B The GPIP will be subject to limits on the magnitude of incentives applicable to the Company in each fiscal year.
>
> 1. For the Gas Procurement Incentive Program limitations are placed on the maximum amount of incentives that can be earned or penalties paid by National Grid for each fiscal year. For at least the first two years of the program (i.e., through June 30, 2005):
>
> a. National Grid may not earn more than $1,000,000 in Gas Procurement Incentives in any fiscal year; and

Thus it is somewhat unclear whether the Commission intends for the limit to continue to be $1,000,000 at this time or if it wishes to allow the award of the full $1,097,727.

Q. ARE THERE ANY ADDITIONAL CHANGES IN GAS COSTS AS RESULT OF THE HEDGING PROGRAM?

A. Yes. The Company has experienced a significant and unexpected increase in costs as a result of the GPIP hedging position collateral requirements. Because of the sharp decline in natural gas commodity prices, the Company has had to provide large amounts of collateral to cover losses on the hedge positions. In the past, the interest paid on such collateral has been at a level that provided a significant offset to the carrying cost of the posted collateral. More recently, because of the fallout of the credit crisis, that is no longer the case as the payments by the vendor have declined even as the Company's short term borrowing costs have increased.

At this point the Company is requesting that it be allowed to recover its short term borrowing cost, less any interest earnings it may receive on the collateral from the party requiring the posting of the collateral, currently the New York Mercantile Exchange (NYMEX). After discussions with the Division, the Company has included in its gas costs the carrying cost of its hedge positions at its short term borrowing rate, net of the interest earned, on the basis that this expense is, consistent with the tariff, a recoverable gas cost. In addition, the expense was not included in the recent rate case because during the test year the vast majority of hedges were done through forward physical purchases of supply rather than financial hedges. To the extent a small portion of hedges were done financially during the test year, the collateral costs were

minimal and the compensation on the collateral by the vendor was adequate to cover the cost.

The Company believes that in the future the change it is requesting is likely to benefit customers as the need for the Company to post collateral is expected to decline significantly as gas costs recover from their extremely depressed current level and rise above the price paid for existing hedges. Note that the posting of collateral is symmetrical and hedge gains result in a payout to the Company. Under the Company's proposal the customers will then be credited interest on the funds held by the Company at the same short term rate. If in the future prices move up as a result of the current dramatic decrease in drilling, customers would likely see a reduction in the carrying cost of collateral as the spread between the interest rate paid on the short term collateral required by the vendor and the borrowing rate for the Company return to their historical relative levels.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Gas Cost Recovery (GCR)
Factors Effective November 1, 2009

($ 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	$0.7755	$1.1240	$1.1240	$1.1240	$1.1240	$0.7755	$1.1240	$0.7755	n/a	
2	Storage Fixed Cost Factor	pg. 3	$0.2886	$0.4186	$0.4186	$0.4186	$0.4186	$0.2886	$0.4186	$0.2886	$0.4015	
3	Supply Variable Cost Factor	pg. 4	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	n/a	$8.8677
4a	Storage Variable Product Cost Factor	pg. 5	$0.2866	$0.2866	$0.2866	$0.2866	$0.2866	$0.2866	$0.2866	$0.2866	n/a	
4b	Storage Variable Non-product Cost Factor	pg. 5	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	($0.0726)	
5	Total Gas Cost Recovery Charge	(1)+(2)+(3)+(4)	$10.1458	$10.6243	$10.6243	$10.6243	$10.6243	$10.1458	$10.6243	$10.1458	$0.3289	$8.8677
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)]	$10.4017	$10.8922	$10.8922	$10.8922	$10.8922	$10.4017	$10.8922	$10.4017	$0.3371	$9.0913
8	**GCR Charge on a per therm basis**	(7) / 10	**$1.0402**	**$1.0892**	**$1.0892**	**$1.0892**	**$1.0892**	**$1.0402**	**$1.0892**	**$1.0402**	**$0.0337**	**$0.9091**
	Current rate effective 12/01/08		$1.0636	$1.0975	$1.0975	$1.0975	$1.0975	$1.0636	$1.0975	$1.0636	$0.0501	$0.9326
	difference		($0.0234)	($0.0083)	($0.0083)	($0.0083)	($0.0083)	($0.0234)	($0.0083)	($0.0234)	($0.0164)	($0.0235)
			-2.2%	-0.8%	-0.8%	-0.8%	-0.8%	-2.2%	-0.8%	-2.2%	-32.7%	-2.5%

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	$29,343,973											1
2	Less:													2
3	NGPMP Guarantee	EDA-1	$1,000,000											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)]	$1,000,000											8
9	Plus:													9
10	Working Capital Requirement	pg 8	$218,227											10
11	Reconciliation Amount	pg 6	$1,584,026											11
12	Total Additions	(10) + (11)	$1,802,253											12
13	Total Supply Fixed Costs	(1) - (8) + (12)	$30,146,225											13
14	Design Winter Sales Percentage	pg 13		63.76%	9.96%	15.98%	5.69%	1.01%	96.40%	1.68%	1.16%	0.76%	3.60%	14
15	Allocated Supply Fixed Costs	(13) x (14)		$19,222,444	$3,002,412	$4,816,204	$1,714,399	$304,330	$29,059,788	$507,033	$349,353	$230,051	$1,086,437	15
16	Sales (Dt) Nov 2009 - Oct 2010	pg 12	27,254,552	17,121,459	2,672,144	4,405,703	1,419,227	234,991	25,853,526	650,517	437,759	312,750	1,401,026	16
17	**Supply Fixed Factor**	(15) / (16)							**$1.1240**				**$0.7755**	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	$10,450,090											1
2	Less:													2
3	LNG Demand to DAC	EDA-2/Dkt 3943	$493,315											3
4	Credits		$0											4
5	Refunds		$0											5
6	Total Credits	sum [(3):(5)]	$493,315											6
7	Plus:													7
8	Supply Related LNG O&M Costs	Rate Case	$618,591											8
9	Working Capital Requirement	pg 8	$78,647											9
10	Reconciliation Amount	pg 6	$1,211,860											10
11	Total Additions	sum [(8):(10)]	$1,909,098											11
12	Total Storage Fixed Costs	(1) - (6) + (11)	$11,865,873											12
13	Design Winter Throughput Percentage	pg 13		60.51%	9.45%	17.55%	7.52%	1.03%	96.05%	1.60%	1.40%	0.95%	3.95%	13
14	Allocated Storage Fixed Costs	(12) x (13)		$7,179,544	$1,121,395	$2,082,145	$892,557	$121,940	$11,397,581	$189,376	$165,905	$113,012	$468,292	14
15	Throughput (Dt) Nov 09 - Oct 10	pg 12	28,852,480	17,121,459	2,672,144	5,143,724	2,041,155	251,529	27,230,012	650,517	564,623	407,328	1,622,468	15
16	**Storage Fixed Factor**	(14) / (15)							**$0.4186**				**$0.2886**	16

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

Line No.	Description	Reference	Amount	Line No.
1	**Variable Supply Costs**	EDA-1	$196,408,852	1
2	Less:			2
3	Non-Firm Sales		$0	3
4	Variable Delivery Storage Costs	EDA-2/ GLB 7 p5	$210,983	4
5	Variable Injection Storage Costs	EDA-2/ GLB 7 p5	$80,294	5
6	Fuel Costs Allocated to Storage	EDA-2/ GLB 7 p5	$1,360,930	6
7	Refunds		$0	7
8	Total Credits	sum [(3):(7)]	$1,652,207	8
9	Plus:			9
10	Working Capital	pg 9	$1,448,375	10
11	Reconciliation Amount	pg 6	$45,481,451	11
12	Total Additions	(10)+(11)	$46,929,826	12
13	Total Variable Supply Costs	(1)-(8)+(12)	$241,686,471	13
14	Sales (Dt) Dec 2008 - Oct 2009	pg 12	27,254,552	14
15	**Supply Variable Cost Factor**	(13)/(14)	**$8.8677**	15

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

Line No.	Description	Reference	Amount	Line No.
1	**Storage Variable Product Costs**	EDA 1	$36,624,047	1
2	Less:			2
3	Balancing Related LNG Costs (to DAC)	EDA 2/Dkt 3943	$766,752	3
4	Refunds		$0	4
5	Total Credits	(3)+(4)	$766,752	5
6	Plus:			6
7	Supply Related LNG O&M	Docket 3943	$430,129	7
8	Working Capital	pg 9	$269,864	8
9	Inventory Financing - LNG (Supply)	pg 11	$483,932	9
10	Inventory Financing - Storage	pg 11	$2,458,050	10
11	Reconciliation Amount	pg 7	($31,689,296)	11
12	Total Additions	sum[(7):(12)]	($28,047,320)	12
13	Total Storage Variable Costs	(1)-(5)+(13)	$7,809,975	13
14	Sales (Dt) Dec 2008 - Oct 2009	pg 12	27,254,552	14
15	**Storage Variable Product Cost Factor**	(14) / (15)	**$0.2866**	15
16	**Storage Variable Non-Product Costs**	EDA-1	$1,128,324	16
17	Less:			17
18	Refunds		$0	18
19	Total Credits		$0	19
20	Plus:			20
21	Variable Delivery Storage Costs	pg 4	$210,983	21
22	Variable Injection Storage Costs	pg 4	$80,294	22
23	Fuel Costs Allocated to Storage	pg 4	$1,360,930	23
24	Working Capital	pg 10	$8,391	24
25	Inventory Financing - Storage	pg 11	$0	25
26	Reconciliation Amount	pg 7	($4,883,861)	26
27	Total Additions	sum[(22):(27)]	($3,223,263)	27
28	Total Storage Variable Costs	(17)-(20)+(28)	($2,094,939)	28
29	Throughput (Dt)	pg 12	28,852,480	29
30	**Storage Variable Product Cost Factor**	(29) / (30)	**($0.0726)**	30

Line No.		Mar-09 31 actual	Apr-09 30 actual	May-09 31 actual	Jun-09 30 actual	Jul-09 31 actual
	I. Supply Fixed Cost Deferred					
1	Beginning Balance	($6,288,682)	($7,564,780)	($8,132,795)	($6,714,569)	($5,471,703)
2	Supply Fixed Costs (net of cap rel)	$1,757,653	$1,765,882	$2,591,897	$1,942,053	$1,778,133
3	Capacity Release	$0	$0	$0	$0	$0
4	Working Capital	$13,407	$13,470	$19,771	$14,814	$13,563
5	Total Supply Fixed Costs	$1,771,060	$1,779,352	$2,611,667	$1,956,867	$1,791,696
6	Supply Fixed - Collections	$3,039,808	$2,339,307	$1,185,564	$707,745	$613,147
7	Prelim. Ending Balance	($7,557,430)	($8,124,735)	($6,706,692)	($5,465,447)	($4,293,154)
8	Month's Average Balance	($6,923,056)	($7,844,758)	($7,419,743)	($6,090,008)	($4,882,429)
9	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
10	Interest Applied	($7,350)	($8,060)	($7,877)	($6,257)	($5,183)
11	Natural Gas Portfolio Management Plan	$0	$0	$0	$0	$0
12	Supply Fixed Ending Balance	($7,564,780)	($8,132,795)	($6,714,569)	($5,471,703)	($4,298,338)
	II. Storage Fixed Cost Deferred					
13	Beginning Balance	($1,928,427)	($2,241,786)	($2,350,918)	($1,485,263)	($1,057,907)
14	Storage Fixed Costs	$974,956	$848,099	$1,366,769	$733,332	$946,348
15	LNG Demand to DAC	($77,112)	($57,601)	($54,260)	($57,009)	($77,196)
16	Supply Related LNG O & M	$47,253	$47,253	$47,253	$47,253	$47,253
17	Working Capital	$7,209	$6,390	$10,372	$5,519	$6,990
18	Total Storage Fixed Costs	$952,307	$844,141	$1,370,134	$729,097	$923,396
19	TSS Peaking Collections	$0	$0	$0	$0	$0
20	Storage Fixed - Collections	$1,263,453	$950,916	$502,444	$300,435	$260,209
21	Prelim. Ending Balance	($2,239,573)	($2,348,560)	($1,483,228)	($1,056,602)	($394,721)
22	Month's Average Balance	($2,084,000)	($2,295,173)	($1,917,073)	($1,270,933)	($726,314)
23	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
24	Interest Applied	($2,212)	($2,358)	($2,035)	($1,306)	($771)
25	Storage Fixed Ending Balance	($2,241,786)	($2,350,918)	($1,485,263)	($1,057,907)	($395,492)
	III. Variable Supply Cost Deferred					
26	Beginning Balance	$57,813,800	$59,613,979	$51,659,406	$45,872,883	$43,804,405
27	Variable Supply Costs	$33,798,176	$16,808,105	$6,754,846	$6,093,700	$5,032,342
28	Variable Delivery Storage	$0	$0	$0	$0	$0
29	Variable Injections Storage	$0	$11,100	$11,260	$11,057	$10,712
30	Fuel Cost Allocated to Storage	$0	$72,157	$97,908	$56,372	$58,527
31	Working Capital	$257,806	$128,844	$52,357	$46,996	$38,914
32	Total Supply Variable Costs	$34,055,983	$17,020,206	$6,916,372	$6,208,125	$5,140,495
33	Supply Variable - Collections	$32,313,986	$25,001,371	$12,711,046	$8,322,646	$6,672,963
34	Customer Deferred Responsibility	$4,117	$30,540	$43,594	$0	$66,711
35	Prelim. Ending Balance	$59,551,679	$51,602,275	$45,821,138	$43,758,361	$42,205,226
36	Month's Average Balance	$58,682,740	$55,608,127	$48,740,272	$44,815,622	$43,004,815
37	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
38	Interest Applied	$62,300	$57,132	$51,745	$46,043	$45,656
39	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0
40	Supply Variable Ending Balance	$59,613,979	$51,659,406	$45,872,883	$43,804,405	$42,250,882

Line No.		Mar-09 31 actual	Apr-09 30 actual	May-09 31 actual	Jun-09 30 actual	Jul-09 31 actual
	IVa. Storage Variable Product Cost Deferred					
41	Beginning Balance	($19,539,695)	($24,192,079)	($27,306,368)	($28,934,515)	($29,697,766)
42	Storage Variable Prod. Costs - LNG	$565,503	$125,465	$150,779	$169,989	$126,042
43	Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0
44	Storage Variable Prod. Costs - UG	$0	$575,851	$26,538	$10,405	$4,445
45	Supply Related LNG to DAC	($95,005)	($21,078)	($25,331)	($28,558)	($21,175)
46	Supply Related LNG O & M	$32,857	$35,844	$32,857	$32,857	$32,857
47	Inventory Financing - LNG	$38,950	$39,578	$38,159	$39,282	$44,813
48	Inventory Financing - UG	$53,529	$187,574	$230,252	$278,443	$319,576
49	Inventory Financing - LP	$0	$0	$0	$0	$0
50	Working Capital	$3,840	$5,439	$1,410	$1,409	$1,084
51	Total Storage Variable Product Costs	$599,674	$948,674	$454,665	$503,827	$507,643
52	Storage Variable Product Collections	$5,228,856	$4,036,522	$2,052,974	$1,236,974	$1,072,736
53	Prelim. Ending Balance	($24,168,877)	($27,279,927)	($28,904,677)	($29,667,663)	($30,262,860)
54	Month's Average Balance	($21,854,286)	($25,736,003)	($28,105,522)	($29,301,089)	($29,980,313)
55	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
56	Interest Applied	($23,201)	($26,441)	($29,838)	($30,104)	($31,828)
57	Storage Variable Product Ending Bal.	($24,192,079)	($27,306,368)	($28,934,515)	($29,697,766)	($30,294,688)
	IVb. Stor Var Non-Prod Cost Deferred					
58	Beginning Balance	($1,770,233)	($3,315,644)	($3,772,937)	($4,071,588)	($4,255,144)
59	Storage Variable Non-prod. Costs	($1,071,743)	$0	$0	$0	$0
60	Variable Delivery Storage Costs	$0	$0	$0	$0	$0
61	Variable Injection Storage Costs	$0	($11,100)	($11,260)	($11,057)	($10,712)
62	Fuel Costs Allocated to Storage	$0	($72,157)	($97,908)	($56,372)	($58,527)
63	Working Capital	($8,175)	($635)	($833)	($514)	($528)
64	Total Storage Var Non-product Costs	($1,079,918)	($83,892)	($110,001)	($67,944)	($69,768)
65	Storage Var Non-Product Collections	$462,794	$369,761	$184,489	$111,337	$96,509
66	Prelim. Ending Balance	($3,312,945)	($3,769,297)	($4,067,426)	($4,250,868)	($4,421,421)
67	Month's Average Balance	($2,541,589)	($3,542,470)	($3,920,181)	($4,161,228)	($4,338,282)
68	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
69	Interest Applied	($2,698)	($3,640)	($4,162)	($4,275)	($4,606)
70	Storage Var Non-Product Ending Bal.	($3,315,644)	($3,772,937)	($4,071,588)	($4,255,144)	($4,426,026)
	GCR Deferred Summary					
71	Beginning Balance	$28,286,762	$22,299,691	$10,096,389	$4,666,947	$3,321,883
72	Gas Costs	$36,025,019	$20,354,973	$11,159,760	$9,261,748	$8,233,439
73	Working Capital	$274,087	$153,509	$83,077	$68,223	$60,024
74	Total Costs	$36,299,105	$20,508,481	$11,242,837	$9,329,972	$8,293,462
75	Collections	$42,313,014	$32,728,417	$16,680,111	$10,679,137	$8,782,275
76	Prelim. Ending Balance	$22,272,853	$10,079,755	$4,659,115	$3,317,782	$2,833,071
77	Month's Average Balance	$25,279,808	$16,189,723	$7,377,752	$3,992,365	$3,077,477
78	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.25%
79	Interest Applied	$26,838	$16,633	$7,833	$4,102	$3,267
80	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0
81	**Ending Bal. W/ Interest**	$22,299,691	$10,096,389	$4,666,947	$3,321,883	$2,836,338
82	Under/(Over)-collection	($6,013,909)	($12,219,936)	($5,437,274)	($1,349,166)	($488,813)

Line No.		Aug-09 31 forecast	Sep-09 30 forecast	Oct-09 31 forecast	Line No.
	I. Supply Fixed Cost Deferred				
1	Beginning Balance	($4,298,338)	($2,251,707)	($280,674)	1
2	Supply Fixed Costs (net of cap rel)	$2,505,794	$2,504,685	$2,505,794	2
3	Capacity Release	$0	$0	$0	3
4	Working Capital	$19,114	$19,105	$19,114	4
5	Total Supply Fixed Costs	$2,524,907	$2,523,791	$2,524,907	5
6	Supply Fixed - Collections	$474,802	$551,457	$660,899	6
7	Prelim. Ending Balance	($2,248,232)	($279,374)	$1,583,334	7
8	Month's Average Balance	($3,273,285)	($1,265,541)	$651,330	8
9	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	9
10	Interest Applied	($3,475)	($1,300)	$691	10
11	Natural Gas Portfolio Management Plan	$0	$0	$0	
12	Supply Fixed Ending Balance	($2,251,707)	($280,674)	$1,584,026	12
	II. Storage Fixed Cost Deferred				
13	Beginning Balance	($395,492)	$176,061	$716,112	13
14	Storage Fixed Costs	$741,011	$741,011	$741,011	14
15	LNG Demand to DAC	($26,460)	($26,460)	($26,460)	15
16	Supply Related LNG O & M	$47,253	$47,253	$47,253	16
17	Working Capital	$5,811	$5,811	$5,811	17
18	Total Storage Fixed Costs	$767,615	$767,615	$767,615	18
19	TSS Peaking Collections	$0	$0	$0	19
20	Storage Fixed - Collections	$195,946	$228,022	$272,890	20
21	Prelim. Ending Balance	$176,177	$715,654	$1,210,837	21
22	Month's Average Balance	($109,657)	$445,857	$963,475	22
23	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	23
24	Interest Applied	($116)	$458	$1,023	24
25	Storage Fixed Ending Balance	$176,061	$716,112	$1,211,860	25
	III. Variable Supply Cost Deferred				
26	Beginning Balance	$42,250,882	$42,689,235	$42,548,989	26
27	Variable Supply Costs	$5,471,525	$5,721,448	$9,914,834	27
28	Variable Delivery Storage	$0	$0	$0	28
29	Variable Injections Storage	$9,924	$9,781	$8,830	29
30	Fuel Cost Allocated to Storage	$50,336	$49,999	$48,651	30
31	Working Capital	$42,195	$44,098	$76,067	31
32	Total Supply Variable Costs	$5,573,981	$5,825,326	$10,048,382	32
33	Supply Variable - Collections	$5,180,692	$6,009,336	$7,162,624	33
34	Customer Deferred Responsibility	$0	$0	$0	34
35	Prelim. Ending Balance	$42,644,171	$42,505,225	$45,434,747	35
36	Month's Average Balance	$42,447,526	$42,597,230	$43,991,868	36
37	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	37
38	Interest Applied	$45,064	$43,764	$46,704	38
39	Gas Procurement Incentive/(penalty)	$0	$0	$0	
40	Supply Variable Ending Balance	$42,689,235	$42,548,989	$45,481,451	40

Line No.		Aug-09 31 forecast	Sep-09 30 forecast	Oct-09 31 forecast	Line No.
	IVa. Storage Variable Product Cost Deferre				
41	Beginning Balance	($30,294,688)	($30,634,306)	($31,082,682)	41
42	Storage Variable Prod. Costs - LNG	$168,832	$161,201	$164,662	42
43	Storage Variable Prod. Costs - LP	$0	$0	$0	43
44	Storage Variable Prod. Costs - UG	$0	$0	$0	44
45	Supply Related LNG to DAC	($28,364)	($27,082)	($27,663)	45
46	Supply Related LNG O & M	$32,857	$32,857	$32,857	46
47	Inventory Financing - LNG	$44,920	$47,468	$50,330	47
48	Inventory Financing - UG	$311,776	$340,370	$364,675	48
49	Inventory Financing - LP	$0	$0	$0	49
50	Working Capital	$1,322	$1,274	$1,296	50
51	Total Storage Variable Product Costs	$531,344	$556,088	$586,157	51
52	Storage Variable Product Collections	$838,637	$972,776	$1,159,467	52
53	Prelim. Ending Balance	($30,601,981)	($31,050,995)	($31,655,993)	53
54	Month's Average Balance	($30,448,335)	($30,842,650)	($31,369,337)	54
55	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	55
56	Interest Applied	($32,325)	($31,688)	($33,303)	56
57	Storage Variable Product Ending Bal.	($30,634,306)	($31,082,682)	($31,689,296)	57
	IVb. Stor Var Non-Prod Cost Deferred				
58	Beginning Balance	($4,426,026)	($4,566,059)	($4,717,702)	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	($9,924)	($9,781)	($8,830)	61
62	Fuel Costs Allocated to Storage	($50,336)	($49,999)	($48,651)	62
63	Working Capital	($460)	($456)	($438)	63
64	Total Storage Var Non-product Costs	($60,720)	($60,236)	($57,919)	64
65	Storage Var Non-Product Collections	$74,542	$86,640	$103,146	65
66	Prelim. Ending Balance	($4,561,289)	($4,712,935)	($4,878,767)	66
67	Month's Average Balance	($4,493,657)	($4,639,497)	($4,798,234)	67
68	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	68
69	Interest Applied	($4,771)	($4,767)	($5,094)	69
70	Storage Var Non-Product Ending Bal.	($4,566,059)	($4,717,702)	($4,883,861)	70
	GCR Deferred Summary				
71	Beginning Balance	$2,836,338	$5,413,223	$7,184,043	71
72	Gas Costs	$9,269,145	$9,542,752	$13,767,293	72
73	Working Capital	$67,983	$69,832	$101,849	73
74	Total Costs	$9,337,127	$9,612,584	$13,869,142	74
75	Collections	$6,764,619	$7,848,231	$9,359,026	75
76	Prelim. Ending Balance	$5,408,846	$7,177,575	$11,694,159	76
77	Month's Average Balance	$4,122,592	$6,295,399	$9,439,101	77
78	Interest Rate (BOA Prime minus 200 bp	1.25%	1.25%	1.25%	78
79	Interest Applied	$4,377	$6,468	$10,021	79
80	Gas Purchase Plan Incentives/(Penalties	$0	$0	$0	
81	**Ending Bal. W/ Interest**	$5,413,223	$7,184,043	$11,704,180	81
82	Under/(Over)-collection	$2,572,508	$1,764,353	$4,510,116	82

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Supply Fixed Costs (net of Cap Rel)**	EDA-1	$29,343,973	1
2	Capacity Release Revenue		$0	2
3	Allowable Working Capital Costs	(1) - (2)	$29,343,973	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$1,961,624	5
6	Cost of Capital	Docket 4077	8.43%	6
7	Return on Working Capital Requirement	(5) x (6)	$165,313	7
8	Weighted Cost of Debt	Docket 4077	3.42%	8
9	Interest Expense	(5) x (8)	$67,044	9
10	Taxable Income	(7) - (9)	$98,269	10
11	1 - Combined Tax Rate	Docket 3943	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$151,182	12
13	**Supply Fixed Working Capital Requirement**	(9) + (12)	**$218,227**	13
14	**Storage Fixed Costs**	EDA-1	$10,450,090	14
15	Less: LNG Demand to DAC		($493,315)	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)	$10,575,366	18
19	Number of Days Lag	Docket 3943	24.40	19
20	Working Capital Requirement	[(18) x (19)] / 365	$706,956	20
21	Cost of Capital	Docket 4077	8.43%	21
22	Return on Working Capital Requirement	(20) x (21)	$59,578	22
23	Weighted Cost of Debt	Docket 4077	3.42%	23
24	Interest Expense	(20) x (23)	$24,162	24
25	Taxable Income	(22) - (24)	$35,415	25
26	1 - Combined Tax Rate	Docket 3943	0.6500	26
27	Return and Tax Requirement	(25) / (26)	$54,485	27
28	**Storage Fixed Working Capital Requirement**	(24) + (27)	**$78,647**	28

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Supply Variable Costs**	EDA-1	$196,408,852	1
2	Credits		$1,652,207	2
3	Allowable Working Capital Costs	(1) - (2)	$194,756,645	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$13,019,348	5
6	Cost of Capital	Docket 3943	8.43%	6
7	Return on Working Capital Requirement	(5) x (6)	$1,097,185	7
8	Weighted Cost of Debt	Docket 3943	3.42%	8
9	Interest Expense	(5) x (8)	$444,974	9
10	Taxable Income	(7) - (9)	$652,211	10
11	1 - Combined Tax Rate	Rate Case	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$1,003,401	12
13	**Supply Variable Working Capital Requirement**	(9) + (12)	**$1,448,375**	13
14	**Storage Variable Product Costs**	GLB 1	$36,624,047	14
15	Less: Balancing Related LNG Commodity (to DAC)		($766,752)	15
16	Plus: Supply Related LNG O&M Costs		$430,129	16
17	Allowable Working Capital Costs	(14) + (15) + (16)	$36,287,424	17
18	Number of Days Lag	Docket 3943	24.40	18
19	Working Capital Requirement	[(17) * (18)] / 365	$2,425,789	19
20	Cost of Capital	Docket 3943	8.43%	20
21	Return on Working Capital Requirement	(19) x (20)	$204,430	21
22	Weighted Cost of Debt	Docket 3943	3.42%	22
23	Interest Expense	(19) x (22)	$82,908	23
24	Taxable Income	(21) - (23)	$121,521	24
25	1 - Combined Tax Rate	Rate Case	0.6500	25
26	Return and Tax Requirement	(24) / (25)	$186,956	26
27	**Storage Var. Product Working Capital Requir.**	(23) + (26)	**$269,864**	27

Gas Cost Recovery (GCR)
Working Capital Calculation

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	**Storage Variable Non-Product Costs**	GLB 1	$1,128,324	1
2	Credits		$0	2
3	Allowable Working Capital Costs	(1) - (2)	$1,128,324	3
4	Number of Days Lag	Docket 3943	24.40	4
5	Working Capital Requirement	[(3) x (4)] / 365	$75,428	5
6	Cost of Capital	Docket 3943	8.43%	6
7	Return on Working Capital Requirement	(5) x (6)	$6,357	7
8	Weighted Cost of Debt	Docket 3943	3.42%	8
9	Interest Expense	(5) x (8)	$2,578	9
10	Taxable Income	(7) - (9)	$3,779	10
11	1 - Combined Tax Rate	Docket 3943	0.6500	11
12	Return and Tax Requirement	(10) / (11)	$5,813	12
13	**Storage Variable Non-product WC Requir.**	(9) + (12)	**$8,391**	13

Line No.	Description (a)	Reference (b)	Nov-09 (c)	Dec-09 (d)	Jan-10 (e)	Feb-10 (f)	Mar-10 (g)	Apr-10 (h)	May-10 (i)	Jun-10 (j)	Jul-10 (k)	Aug-10 (l)	Sep-10 (m)	Oct-10 (n)	Total (p)	Line No.
1	**Storage Inventory Balance**	GLB 2 pg 16	$28,286,936	$25,848,259	$17,452,150	$10,830,331	$9,207,771	$14,433,623	$19,843,250	$24,291,230	$26,984,311	$29,252,155	$29,356,483	$29,356,483		1
2	Hedging															
3	Subtotal	(1) + (2)	$28,286,936	$25,848,259	$17,452,150	$10,830,331	$9,207,771	$14,433,623	$19,843,250	$24,291,230	$26,984,311	$29,252,155	$29,356,483	$29,356,483		
4	Cost of Capital	Rate Case	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%		2
5	Return on Working Capital Requirement	(3) * (4)	$2,383,837	$2,178,321	$1,470,752	$912,709	$775,970	$1,216,371	$1,672,259	$2,047,105	$2,274,060	$2,465,179	$2,473,971	$2,473,971	$22,344,506	3
6	Weighted Cost of Debt	Rate Case	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%		4
7	Interest Charges Financed	(1) * (6)	$966,789	$883,440	$596,478	$370,158	$314,702	$493,311	$678,201	$830,224	$922,268	$999,778	$1,003,343	$1,003,343	$9,062,035	5
8	Taxable Income	(5) - (7)	$1,417,048	$1,294,881	$874,274	$542,551	$461,268	$723,060	$994,058	$1,216,881	$1,351,793	$1,465,401	$1,470,628	$1,470,628		6
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		7
10	Return and Tax Requirement	(8) / (9)	$2,180,074	$1,992,125	$1,345,037	$834,694	$709,643	$1,112,399	$1,529,319	$1,872,125	$2,079,681	$2,254,464	$2,262,504	$2,262,504	$20,434,570	8
11	Working Capital Requirement	(7) + (10)	$3,146,863	$2,875,565	$1,941,515	$1,204,852	$1,024,345	$1,605,711	$2,207,520	$2,702,349	$3,001,948	$3,254,241	$3,265,848	$3,265,848	$29,496,605	9
12	Monthly Average	(11) / 12	$262,239	$239,630	$161,793	$100,404	$85,362	$133,809	$183,960	$225,196	$250,162	$271,187	$272,154	$272,154	$2,458,050	10
13	**LNG Inventory Balance**	GLB 2 pg 17	$6,845,622	$5,935,584	$4,465,806	$4,078,446	$3,950,492	$4,412,606	$5,525,714	$5,516,898	$5,509,274	$5,503,405	$5,499,708	$5,497,288		11
14	Cost of Capital	Rate Case	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%		12
15	Return on Working Capital Requirement	(13) * (14)	$576,904	$500,212	$376,349	$343,705	$332,921	$371,865	$465,671	$464,928	$464,285	$463,791	$463,479	$463,275	$5,287,385	13
16	Weighted Cost of Debt	Rate Case	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%		14
17	Interest Charges Financed	(13) * (16)	$233,969	$202,866	$152,632	$139,393	$135,020	$150,814	$188,857	$188,556	$188,296	$188,095	$187,969	$187,886	$2,144,351	15
18	Taxable Income	(15) - (17)	$342,935	$297,346	$223,717	$204,312	$197,902	$221,052	$276,813	$276,372	$275,990	$275,696	$275,511	$275,389		16
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		17
20	Return and Tax Requirement	(18) / (19)	$527,592	$457,455	$344,180	$314,326	$304,464	$340,080	$425,867	$425,187	$424,600	$424,147	$423,863	$423,676	$4,835,437	18
21	Working Capital Requirement	(17) + (20)	$761,561	$660,321	$496,812	$453,719	$439,484	$490,893	$614,724	$613,743	$612,895	$612,242	$611,831	$611,562	$6,979,788	19
22	Monthly Average	(21) / 12	$63,463	$55,027	$41,401	$37,810	$36,624	$40,908	$51,227	$51,145	$51,075	$51,020	$50,986	$50,963	$581,649	20
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%		21
24	Balancing Related Inventory Costs	(22) * (23)	$10,662	$9,244	$6,955	$6,352	$6,153	$6,873	$8,606	$8,592	$8,581	$8,571	$8,566	$8,562	$97,717	22
25	Supply Related Inventory Costs	(22) - (24)	$52,802	$45,782	$34,446	$31,458	$30,471	$34,035	$42,621	$42,553	$42,494	$42,449	$42,420	$42,402	$483,932	23

Line No.	Rate Class (a)	Nov-09 (b)	Dec-09 (c)	Jan-10 (d)	Feb-10 (e)	Mar-10 (f)	Apr-10 (g)	May-10 (h)	Jun-10 (i)	Jul-10 (j)	Aug-10 (k)	Sep-10 (l)	Oct-10 (m)	Total Dec-Oct (o)	Line No.
1	**SALES (dth)**														1
2	Residential Non-Heating	46,350	60,595	74,986	74,836	65,606	62,697	59,731	49,819	41,240	37,916	37,067	39,674	650,517	2
3	Residential Heating	1,039,084	1,973,922	2,916,336	3,018,749	2,542,355	1,926,568	1,205,748	697,238	460,692	374,569	407,299	558,900	17,121,459	3
4	Small C&I	147,903	297,612	460,582	481,750	413,015	298,434	162,103	99,689	77,031	67,983	75,604	90,438	2,672,144	4
5	Medium C&I	286,111	481,058	700,072	729,734	704,566	423,940	292,664	197,283	141,790	129,233	138,056	181,197	4,405,703	5
6	Large LLF	100,575	174,839	254,864	261,225	220,652	165,100	97,167	43,020	21,798	14,915	19,394	45,677	1,419,227	6
7	Large HLF	33,904	42,994	50,091	49,275	45,895	41,705	35,008	30,375	23,983	25,952	30,312	28,264	437,759	7
8	Extra Large LLF	18,261	34,300	44,722	40,855	40,438	25,604	12,721	6,507	2,541	1,034	1,642	6,368	234,991	8
9	Extra Large HLF	24,203	27,106	34,088	34,491	29,085	26,706	24,851	24,041	19,397	21,061	23,975	23,746	312,750	9
10	**Total Sales**	1,696,390	3,092,425	4,535,743	4,690,914	4,061,612	2,970,754	1,889,993	1,147,972	788,472	672,664	733,349	974,264	27,254,552	10
11	**FT-2 TRANSPORTATION**														11
12	FT-2 Medium	47,966	76,481	115,071	117,550	100,180	82,623	60,705	37,821	21,962	22,767	20,908	33,989	738,021	12
13	FT-2 Large LLF	31,997	68,692	109,150	101,011	92,479	78,892	44,818	31,731	17,144	11,979	13,000	21,033	621,927	13
14	FT-2 Large HLF	8,719	11,978	13,625	12,611	13,984	12,674	11,380	9,233	7,343	8,243	8,828	8,245	126,864	14
15	FT-2 Extra Large LLF	1,042	2,633	3,628	2,894	2,716	1,965	1,094	369	9	0	3	185	16,538	15
16	FT-2 Extra Large HLF	6,066	7,257	10,805	10,875	11,046	9,111	8,595	7,702	2,691	7,776	5,890	6,764	94,578	16
17	**Total Transportation**	95,791	167,042	252,279	244,941	220,406	185,264	126,591	86,855	49,149	50,766	48,629	70,215	1,597,928	17
18	**Sales & FT-2 THROUGHPUT**														18
19	Residential Non-Heating	46,350	60,595	74,986	74,836	65,606	62,697	59,731	49,819	41,240	37,916	37,067	39,674	650,517	19
20	Residential Heating	1,039,084	1,973,922	2,916,336	3,018,749	2,542,355	1,926,568	1,205,748	697,238	460,692	374,569	407,299	558,900	17,121,459	20
21	Small C&I	147,903	297,612	460,582	481,750	413,015	298,434	162,103	99,689	77,031	67,983	75,604	90,438	2,672,144	21
22	Medium C&I	334,077	557,539	815,142	847,284	804,746	506,563	353,369	235,104	163,752	152,001	158,964	215,185	5,143,724	22
23	Large LLF	132,572	243,532	364,014	362,236	313,131	243,992	141,985	74,751	38,943	26,894	32,395	66,710	2,041,155	23
24	Large HLF	42,623	54,972	63,716	61,886	59,879	54,379	46,388	39,608	31,326	34,196	39,140	36,509	564,623	24
25	Extra Large LLF	19,303	36,933	48,350	43,748	43,154	27,568	13,815	6,876	2,550	1,034	1,644	6,552	251,529	25
26	Extra Large HLF	30,270	34,363	44,894	45,365	40,131	35,816	33,446	31,744	22,088	28,837	29,865	30,510	407,328	26
27	**Total Throughput**	1,792,181	3,259,467	4,788,021	4,935,855	4,282,018	3,156,018	2,016,584	1,234,827	837,621	723,430	781,977	1,044,480	28,852,480	27
28	**FT-1 TRANSPORTATION**														28
29	FT-1 Medium	61,601	96,811	101,148	102,150	81,439	56,993	34,834	25,608	20,856	22,704	29,877	45,660	679,681	29
30	FT-1 Large LLF	94,429	134,438	139,587	132,229	132,088	83,716	33,090	27,995	30,457	25,702	30,940	41,632	906,304	30
31	FT-1 Large HLF	49,507	57,593	63,647	62,742	62,324	45,256	39,801	38,489	34,522	47,361	40,668	38,002	579,912	31
32	FT-1 Extra Large LLF	55,327	77,383	76,463	75,523	68,149	51,560	25,083	29,860	31,465	28,568	27,615	33,974	580,971	32
33	FT-1 Extra Large HLF	355,668	324,158	376,712	326,835	348,518	420,903	282,420	256,275	239,946	241,558	289,315	297,281	3,759,588	33
34	**Total Transportation**	616,532	690,383	757,557	699,480	692,518	658,428	415,228	378,227	357,245	365,893	418,416	456,548	6,506,456	34
35	**Total THROUGHPUT**														35
36	Residential Non-Heating	46,350	60,595	74,986	74,836	65,606	62,697	59,731	49,819	41,240	37,916	37,067	39,674	650,517	36
37	Residential Heating	1,039,084	1,973,922	2,916,336	3,018,749	2,542,355	1,926,568	1,205,748	697,238	460,692	374,569	407,299	558,900	17,121,459	37
38	Small C&I	147,903	297,612	460,582	481,750	413,015	298,434	162,103	99,689	77,031	67,983	75,604	90,438	2,672,144	38
39	Medium C&I	395,678	654,350	916,290	949,435	886,185	563,556	388,203	260,711	184,607	174,705	188,841	260,845	5,823,405	39
40	Large LLF	227,001	377,970	503,601	494,466	445,219	327,708	175,075	102,746	69,399	52,596	63,335	108,342	2,947,458	40
41	Large HLF	92,131	112,565	127,363	124,629	122,203	99,635	86,190	78,097	65,848	81,556	79,808	74,511	1,144,535	41
42	Extra Large LLF	74,630	114,316	124,814	119,271	111,303	79,128	38,897	36,736	34,015	29,602	29,260	40,527	832,500	42
43	Extra Large HLF	385,937	358,521	421,606	372,201	388,649	456,719	315,865	288,018	262,033	270,396	319,180	327,791	4,166,917	43
44	**Total Throughput**	2,408,713	3,949,851	5,545,579	5,635,335	4,974,536	3,814,446	2,431,812	1,613,054	1,194,866	1,089,323	1,200,393	1,501,028	**35,358,936**	44

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

Line No.	Rate Class (a)	Nov-09 (b)	Dec-09 (c)	Jan-10 (d)	Feb-10 (e)	Mar-10 (f)	Total (h)	% (i)	Line No.
1	**SALES (dth)**								1
2	Residential Non-Heating	56,014	73,103	76,637	71,248	66,335	343,337	1.68%	2
3	Residential Heating	1,698,031	2,862,740	3,119,983	2,965,658	2,370,054	13,016,465	63.76%	3
4	Small C&I	268,790	446,374	485,520	460,996	371,401	2,033,081	9.96%	4
5	Medium C&I	438,593	714,442	775,085	734,875	598,294	3,261,290	15.98%	5
6	Large LLF	144,083	256,899	281,974	269,074	208,874	1,160,904	5.69%	6
7	Large HLF	38,617	50,364	52,792	49,077	45,714	236,564	1.16%	7
8	Extra Large LLF	24,939	45,740	50,376	48,161	36,861	206,077	1.01%	8
9	Extra Large HLF	26,989	32,831	33,978	31,348	30,633	155,779	0.76%	9
10	Total Sales	2,696,056	4,482,493	4,876,345	4,630,437	3,728,166	20,413,496	100.00%	10
11	**FT-2 TRANSPORTATION**								11
12	FT-2 Medium	69,237	112,484	121,987	115,635	94,282	513,626		12
13	FT-2 Large LLF	59,450	100,618	109,715	104,318	83,195	457,296		13
14	FT-2 Large HLF	10,837	13,596	14,153	13,103	12,530	64,220		14
15	FT-2 Extra Large LLF	1,766	3,340	3,692	3,536	2,666	15,000		15
16	FT-2 Extra Large HLF	7,976	10,464	10,980	10,214	9,476	49,111		16
17	Total Transportation	149,266	240,503	260,528	246,806	202,149	1,099,252		17
18	**Sales & FT-2 THROUGHPUT**								18
19	Residential Non-Heating	56,014	73,103	76,637	71,248	66,335	343,337	1.60%	19
20	Residential Heating	1,698,031	2,862,740	3,119,983	2,965,658	2,370,054	13,016,465	60.51%	20
21	Small C&I	268,790	446,374	485,520	460,996	371,401	2,033,081	9.45%	21
22	Medium C&I	507,830	826,926	897,073	850,511	692,576	3,774,915	17.55%	22
23	Large LLF	203,533	357,517	391,689	373,392	292,069	1,618,200	7.52%	23
24	Large HLF	49,454	63,961	66,946	62,180	58,244	300,784	1.40%	24
25	Extra Large LLF	26,705	49,080	54,068	51,697	39,527	221,077	1.03%	25
26	Extra Large HLF	34,965	43,295	44,958	41,562	40,109	204,890	0.95%	26
27	Total Throughput	2,845,322	4,722,995	5,136,873	4,877,244	3,930,315	21,512,749	100.00%	27

nationalgrid

Thomas R. Teehan
Senior Counsel
Rhode Island

August 3, 2009

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, 2009 and consists of seven schedules.

Schedule 1 presents the monthly gas cost-specific ending deferred balances for the period July 2008 through June 2009, resulting in an end-of-period under-collection balance of $3,321,883, as shown on the bottom of page 2. The $3,321,883 under-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. The Company is currently reviewing the results of the assignment of costs to certain component categories. Certain features of the Company's asset management arrangement with Merrill Lynch have caused the classification of costs to be different than in prior periods even though the portfolio is fundamentally the same. In addition, the insourcing of the portfolio that began April 1, 2009 has altered the traditional injection pattern and caused the Company to purchase supplies to support optimization transactions. These issues will be addressed in the Company's upcoming September 1, 2009 GCR filing.

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 November 2008. Schedule 4 summarizes Gas Cost Collections for the period of December 2008 to June 2009 which reflects the new structure approved in Docket No.3982. Schedule 5 presents the calculation of inventory financing costs. For the twelve months ended June 2009, underground storage financing costs totaled $1,184,870, and LNG inventory storage financing costs totaled $588,568. Of the $588,568 of LNG inventory financing costs, $131,353 is associated with system balancing which is allocated to the Distribution Adjustment Clause account. The remaining $457,215 of LNG inventory financing costs is associated with the GCR. 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

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

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is summarized in Schedule 7. This schedule indicates that for the twelve month period that total firm throughput was 35, 250,639 dths, which was comprised of firm sales, including Transitional Sales Service of 26,734,245 dths, FT-1 throughput of 7,307,086dths and FT-2 throughput of 1,209,308 dths..

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

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National Grid
Rhode Island Service Area
Deferred Gas Cost Balance

	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul - Jun
	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	($7,977,817)	($5,887,819)	($4,573,887)	($3,435,225)	($2,203,784)	($1,873,133)	($2,660,560)	($4,537,969)	($6,288,682)	($7,564,780)	($8,132,795)	($6,714,569)	
Supply Fixed Costs (net of cap rel)	$2,885,908	$2,044,179	$1,767,703	$2,139,679	$2,077,178	$2,006,675	$1,644,941	$2,004,324	$1,757,653	$1,765,882	$2,591,897	$1,942,053	$24,628,072
Capacity Release	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$12,475	$8,837	$7,642	$9,250	$15,844	$15,307	$12,547	$15,289	$13,407	$13,470	$19,771	$14,814	$158,651
Total Supply Fixed Costs	$2,898,383	$2,053,016	$1,775,345	$2,148,929	$2,093,022	$2,021,982	$1,657,488	$2,019,613	$1,771,060	$1,779,352	$2,611,667	$1,956,867	$24,786,723
Supply Fixed - Collections	$790,743	$725,773	$626,821	$911,353	$1,758,187	$2,805,840	$3,531,078	$3,765,138	$3,039,808	$2,339,307	$1,185,564	$707,745	$22,187,357
Prelim. Ending Balance	($5,870,177)	($4,560,576)	($3,425,363)	($2,197,650)	($1,868,949)	($2,656,992)	($4,534,150)	($6,283,494)	($7,557,430)	($8,124,735)	($6,706,692)	($5,465,447)	
Month's Average Balance	($6,923,997)	($5,224,197)	($3,999,625)	($2,816,438)	($2,036,367)	($2,265,062)	($3,597,355)	($5,410,731)	($6,923,056)	($7,844,758)	($7,419,743)	($6,090,008)	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($17,642)	($13,311)	($9,862)	($6,134)	($4,184)	($3,568)	($3,819)	($5,188)	($7,350)	($8,060)	($7,877)	($6,257)	($93,253)
Asset Management Incentive	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Supply Fixed Ending Balance	($5,887,819)	($4,573,887)	($3,435,225)	($2,203,784)	($1,873,133)	($2,660,560)	($4,537,969)	($6,288,682)	($7,564,780)	($8,132,795)	($6,714,569)	($5,471,703)	
II. Storage Fixed Cost Deferred													
Beginning Balance	($2,909,401)	($2,471,911)	($1,911,144)	($1,427,779)	($633,536)	($590,794)	($690,750)	($1,107,708)	($1,928,427)	($2,241,786)	($2,350,918)	($1,485,263)	
Storage Fixed Costs	$743,858	$850,485	$752,604	$1,133,842	$706,326	$978,503	$1,085,153	$759,164	$974,956	$848,099	$1,366,769	$733,332	$10,933,091
LNG Demand to DAC	($56,282)	($56,282)	($56,282)	($56,282)	($26,460)	($35,994)	($98,428)	($39,623)	($77,112)	($57,601)	($54,260)	($57,009)	($671,615)
Supply Related LNG O & M	$43,241	$43,241	$43,241	$43,241	$43,241	$47,253	$47,253	$47,253	$47,253	$47,253	$47,253	$47,253	$546,980
Working Capital	$3,159	$3,620	$3,197	$4,845	$5,516	$7,550	$7,887	$5,849	$7,209	$6,390	$10,372	$5,519	$71,113
Total Storage Fixed Costs	$733,977	$841,064	$742,760	$1,125,646	$728,623	$997,312	$1,041,866	$772,643	$952,307	$844,141	$1,370,134	$729,097	$10,879,570
TSS Peaking Collections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Storage Fixed - Collections	$289,639	$274,721	$255,284	$329,161	$684,624	$1,096,260	$1,457,869	$1,591,907	$1,263,453	$950,916	$502,444	$300,435	$8,996,713
Prelim. Ending Balance	($2,465,064)	($1,905,567)	($1,423,668)	($631,294)	($589,537)	($689,742)	($1,106,754)	($1,926,972)	($2,239,573)	($2,348,560)	($1,483,228)	($1,056,602)	
Month's Average Balance	($2,687,233)	($2,188,739)	($1,667,406)	($1,029,537)	($611,537)	($640,268)	($898,752)	($1,517,340)	($2,084,000)	($2,295,173)	($1,917,073)	($1,270,933)	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($6,847)	($5,577)	($4,111)	($2,242)	($1,257)	($1,009)	($954)	($1,455)	($2,212)	($2,358)	($2,035)	($1,306)	($31,363)
Storage Fixed Ending Balance	($2,471,911)	($1,911,144)	($1,427,779)	($633,536)	($590,794)	($690,750)	($1,107,708)	($1,928,427)	($2,241,786)	($2,350,918)	($1,485,263)	($1,057,907)	
III. Variable Supply Cost Deferred													
Beginning Balance	$7,791,754	$7,280,749	$8,515,621	$9,365,411	$14,704,530	$25,739,329	$39,733,501	$54,500,333	$57,813,800	$59,613,979	$51,659,406	$45,872,883	
Variable Supply Costs	$5,322,469	$7,557,368	$6,326,879	$13,216,341	$26,151,719	$39,470,206	$51,940,843	$42,921,436	$33,798,176	$16,808,105	$6,754,846	$6,093,700	$256,362,089
Variable Delivery Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variable Injections Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,100	$11,260	$11,057	$33,418
Fuel Cost Allocated to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$72,157	$97,908	$56,372	$226,436
Working Capital	$23,008	$32,669	$27,350	$57,132	$199,480	$301,071	$396,195	$327,397	$257,806	$128,844	$52,357	$46,996	$1,850,308
Total Supply Variable Costs	$5,345,477	$7,590,038	$6,354,229	$13,273,474	$26,351,200	$39,771,278	$52,337,038	$43,248,833	$34,055,983	$17,020,206	$6,916,372	$6,208,125	$258,472,252
Supply Variable - Collections	$5,871,095	$6,376,416	$5,524,729	$8,022,367	$15,357,422	$26,744,454	$37,604,824	$39,976,880	$32,313,986	$25,001,371	$12,711,046	$8,322,646	$223,827,237
Deferred Responsibility	$4,565	($1,152)	$1,729	($61,828)	$488	$33,936	$15,378	$12,309	$4,117	$30,540	$43,594	$0	
Prelim. Ending Balance	$7,261,571	$8,495,523	$9,343,393	$14,678,345	$25,697,820	$38,732,217	$54,450,338	$57,759,977	$59,551,679	$51,602,275	$45,821,138	$43,758,361	
Month's Average Balance	$7,526,663	$7,888,136	$8,929,507	$12,021,878	$20,201,175	$32,235,773	$47,091,920	$56,130,155	$58,682,740	$55,608,127	$48,740,272	$44,815,622	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	$19,178	$20,099	$22,018	$26,185	$41,509	$50,782	$49,995	$53,823	$62,300	$57,132	$51,745	$46,043	$500,809
Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$950,502	$0	$0	$0	$0	$0	$0	$950,502
Supply Variable Ending Balance	$7,280,749	$8,515,621	$9,365,411	$14,704,530	$25,739,329	$39,733,501	$54,500,333	$57,813,800	$59,613,979	$51,659,406	$45,872,883	$43,804,405	

National Grid
Rhode Island Service Area
Deferred Gas Cost Balance

	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul - Jun
	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	($2,405,878)	($3,192,369)	($3,877,973)	($4,429,098)	($5,292,877)	($6,814,088)	($9,627,224)	($13,868,371)	($19,539,695)	($24,192,079)	($27,306,368)	($28,934,515)	
Storage Variable Prod. Costs - LNG	$138,890	$159,479	$169,734	$238,700	$752,235	$1,431,628	$2,056,513	$818,537	$565,503	$125,465	$150,779	$169,989	$6,777,452
Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Variable Prod. Costs - UG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$575,851	$26,538	$10,405	$612,794
Supply Related LNG to DAC	($28,320)	($32,518)	($34,609)	($48,671)	($126,376)	($240,514)	($345,494)	($137,514)	($95,005)	($21,078)	($25,331)	($28,558)	($1,163,986)
Supply Related LNG O & M	$30,455	$30,455	$30,455	$30,455	$30,455	$32,857	$32,857	$32,857	$32,857	$35,844	$32,857	$32,857	$385,264
Inventory Financing - LNG	$52,996	$55,942	$59,387	$62,440	$59,423	$55,377	$45,913	$41,119	$38,950	$39,578	$38,159	$39,282	$588,568
Inventory Financing - UG	$55,239	$55,239	$55,239	$55,239	$53,529	$53,529	$53,529	$53,529	$53,529	$187,574	$230,252	$278,443	$1,184,870
Inventory Financing - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$610	$680	$716	$953	$5,025	$9,336	$13,302	$5,445	$3,840	$5,439	$1,410	$1,409	$48,165
Total Storage Variable Product Costs	$249,871	$269,278	$280,922	$339,117	$774,292	$1,342,214	$1,856,620	$813,973	$599,674	$948,674	$454,665	$503,827	$8,433,127
Storage Variable Product Collections	$1,029,239	$945,886	$821,818	$1,192,319	$2,283,078	$4,142,409	$6,085,302	$6,469,288	$5,228,856	$4,036,522	$2,052,974	$1,236,974	$35,524,665
Prelim. Ending Balance	($3,185,246)	($3,868,977)	($4,418,869)	($5,282,300)	($6,801,662)	($9,614,283)	($13,855,905)	($19,523,685)	($24,168,877)	($27,279,927)	($28,904,677)	($29,667,663)	
Month's Average Balance	($2,795,562)	($3,530,673)	($4,148,421)	($4,855,699)	($6,047,270)	($8,214,186)	($11,741,564)	($16,696,028)	($21,854,286)	($25,736,003)	($28,105,522)	($29,301,089)	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($7,123)	($8,996)	($10,229)	($10,576)	($12,426)	($12,940)	($12,465)	($16,010)	($23,201)	($26,441)	($29,838)	($30,104)	($200,350)
Storage Variable Product Ending Bal.	($3,192,369)	($3,877,973)	($4,429,098)	($5,292,877)	($6,814,088)	($9,627,224)	($13,868,371)	($19,539,695)	($24,192,079)	($27,306,368)	($28,934,515)	($29,697,766)	
IVb. Stor Var Non-Prod Cost Deferred													
Beginning Balance	($988,320)	($1,055,840)	($1,120,245)	($1,180,547)	($1,256,994)	($1,411,684)	($1,730,359)	($1,669,611)	($1,770,233)	($3,315,644)	($3,772,937)	($4,071,588)	
Storage Variable Non-prod. Costs	$0	$0	$0	$0	$0	$0	$594,288	$477,455	($1,071,743)	$0	$0	$0	($1)
Variable Delivery Storage Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variable Injection Storage Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11,100)	($11,260)	($11,057)	($33,418)
Fuel Costs Allocated to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	($72,157)	($97,908)	($56,372)	($226,436)
Working Capital	$0	$0	$0	$0	$0	$0	$4,533	$3,642	($8,175)	($635)	($833)	($514)	($1,982)
Total Storage Var Non-product Costs	$0	$0	$0	$0	$0	$0	$598,821	$481,097	($1,079,918)	($83,892)	($110,001)	($67,944)	($261,837)
Storage Var Non-Product Collections	$64,919	$61,636	$57,469	$73,796	$151,951	$316,202	$536,269	$580,070	$462,794	$369,761	$184,489	$111,337	$2,970,693
Prelim. Ending Balance	($1,053,239)	($1,117,476)	($1,177,714)	($1,254,343)	($1,408,945)	($1,727,886)	($1,667,808)	($1,768,585)	($3,312,945)	($3,769,297)	($4,067,426)	($4,250,868)	
Month's Average Balance	($1,020,779)	($1,086,658)	($1,148,979)	($1,217,445)	($1,332,970)	($1,569,785)	($1,699,083)	($1,719,098)	($2,541,589)	($3,542,470)	($3,920,181)	($4,161,228)	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($2,601)	($2,769)	($2,833)	($2,652)	($2,739)	($2,473)	($1,804)	($1,648)	($2,698)	($3,640)	($4,162)	($4,275)	($34,293)
Storage Var Non-Product Ending Bal.	($1,055,840)	($1,120,245)	($1,180,547)	($1,256,994)	($1,411,684)	($1,730,359)	($1,669,611)	($1,770,233)	($3,315,644)	($3,772,937)	($4,071,588)	($4,255,144)	
GCR Deferred Summary													
Beginning Balance	($6,489,662)	($5,327,190)	($2,967,628)	($1,107,239)	$5,317,339	$15,049,629	$25,024,608	$33,316,674	$28,286,762	$22,299,691	$10,096,389	$4,666,947	
Gas Costs	$9,188,455	$10,707,589	$9,114,352	$16,814,985	$29,721,272	$43,799,522	$57,057,369	$46,978,537	$36,025,019	$20,354,973	$11,159,760	$9,261,748	$300,183,580
Working Capital	$39,253	$45,807	$38,905	$72,180	$225,865	$333,264	$434,465	$357,622	$274,087	$153,509	$83,077	$68,223	$2,126,255
Total Costs	$9,227,708	$10,753,396	$9,153,256	$16,887,165	$29,947,137	$44,132,786	$57,491,833	$47,336,159	$36,299,105	$20,508,481	$11,242,837	$9,329,972	$302,309,835
Collections	$8,050,200	$8,383,280	$7,287,850	$10,467,168	$20,235,750	$35,139,101	$49,230,720	$52,395,592	$42,313,014	$32,728,417	$16,680,111	$10,679,137	$293,590,341
Prelim. Ending Balance	($5,312,155)	($2,957,074)	($1,102,221)	$5,312,759	$15,028,725	$24,043,314	$33,285,722	$28,257,241	$22,272,853	$10,079,755	$4,659,115	$3,317,782	
Month's Average Balance	($5,900,908)	($4,142,132)	($2,034,924)	$2,102,760	$10,173,032	$19,546,471	$29,155,165	$30,786,957	$25,279,808	$16,189,723	$7,377,752	$3,992,365	
Interest Rate (BOA Prime minus 200 bps)	3.00%	3.00%	3.00%	2.56%	2.50%	1.85%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	
Interest Applied	($15,035)	($10,554)	($5,018)	$4,580	$20,903	$30,792	$30,952	$29,522	$26,838	$16,633	$7,833	$4,102	$141,549
Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$950,502	$0	$0	$0	$0	$0	$0	
Ending Bal. W/ Interest	($5,327,190)	($2,967,628)	($1,107,239)	$5,317,339	$15,049,629	$25,024,608	$33,316,674	$28,286,762	$22,299,691	$10,096,389	$4,666,947	$3,321,883	
Under/(Over)-collection	$1,177,508	$2,370,116	$1,865,406	$6,419,997	$9,711,387	$8,993,685	$8,261,114	($5,059,433)	($6,013,909)	($12,219,936)	($5,437,274)	($1,349,166)	

National Grid
Rhode Island Service Area
GCR Gas Costs

Projected Gas costs using 07-13-2009 NYMEX	Jul-08 actual	Aug-08 actual	Sep-08 actual	Oct-08 actual	Nov-08 actual	Dec-08 actual	Jan-09 actual	Feb-09 actual	Mar-09 actual	Apr-09 actual	May-09 actual	Jun-09 actual	Jul - Jun
SUPPLY FIXED COSTS - Pipeline & Supplier													
Merrill Lynch	($505,200)	($673,841)	($669,199)	($520,374)	($571,083)	($165,087)	(315,516)	(89,448)	(186,131)	$13,278			
Algonquin	$603,757	$626,975	$485,758	$893,765	$696,699	$660,748	$658,696	$665,662	$658,696	$546,189	$730,679	$655,475	$7,883,099
Texas Eastern					$0	$0	$0	$0	$0				$0
TETCO/Texas Eastern	$597,759	$697,613	$556,405	$310,541	$537,403	$512,721	$527,921	$552,519	$544,453	$544,552	$776,938	$525,487	$6,684,312
Tennessee	$1,512,738	$733,592	$729,222	$786,680	$713,379	$711,520	$705,562	$694,581	$698,234	$696,712	$785,021	$694,251	$9,461,491
NETNE													$0
Nova													$0
Transcanada													$0
Dominion					$35,201	$34,521	$35,201	$35,201	$34,521	$2,340	$2,340	$2,340	$181,665
Transco					$0	$0	$0	$0	$0		$0	$0	$0
Columbia	$283,259	$283,259	$283,259	$283,164	$283,164	$283,164	$283,164	$283,164	$282,120	$282,120	$282,120	$319,428	$3,431,385
Hubline													$0
Westerly Lateral	$63,370	$59,857	$59,483	$61,446	$61,453	$61,426	$63,479	$57,194	$51,235			$60,149	$599,092
Others	$330,225	$316,724	$322,775	$324,457	$320,962	$316,511	($53,970)	$295,873	$73,141	$175,541	$548,537	$210,279	$3,181,056
Less Credits from Insourcing										$83,333	$83,333	$83,333	$250,000
Less Credits from Mkter Releases	$0	$0	$0	$0		$408,849	$259,596	$490,422	$398,616	$411,517	$450,405	$442,022	$2,861,427
TOTAL SUPPLY FIXED COSTS - Pipeline & Supplier	$2,885,908	$2,044,179	$1,767,703	$2,139,679	$2,077,178	$2,006,675	$1,644,941	$2,004,324	$1,757,653	$1,765,882	$2,591,897	$1,942,053	$28,560,674
STORAGE FIXED COSTS - Facilities													
Texas Eastern SS-1 Demand	($2,770)	$200,720	$97,212	$22,306	$87,900	$87,903	$87,886	$87,830	$88,258	$84,360	$82,280	$86,996	$1,010,881
Texas Eastern SS-1 Capacity													$0
Texas Eastern FSS-1 Demand													$0
Texas Eastern FSS-1 Capacity													$0
Dominion GSS Demand	$128,858	$83,367	$83,367	$177,130	$83,366	$83,507	$83,435	$83,435	$83,456	$83,456	$83,456	$36,525	$1,093,359
Dominion GSS Capiacity													$0
Dominion GSS-TE Demand													$0
Dominion GSS-TE Capacity													$0
Tennessee FSMA Demand	$79,792	$43,164	$35,853	$38,704	$39,428	$39,428	$34,310	$40,153	$39,428	$39,428	$39,428	$39,428	$508,545
Tennessee FSMA Capacity													$0
Columbia FSS Demand	$9,750	$9,750	$9,750	$9,745	$9,745	$9,745	$9,745	$9,745	$9,725	$9,745		($9,725)	$87,720
Columbia FSS Capacity													$0
Keyspan LNG Tank Lease Payment	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$157,500	$1,890,000
TOTAL FIXED STORAGE COSTS	$373,130	$494,501	$383,682	$405,385	$377,939	$378,083	$372,876	$378,663	$378,367	$374,489	$362,665	$310,725	$4,590,504
STORAGE FIXED COSTS - Delivery													
Algonquin for TETCO SS-1													
Algonquin delivery for FSS													
TETCO delivery for FSS													
Algonquin SCT for SS-1													
Algonquin delivery for GSS, GSS-TE,													
Algonquin SCT delivery for GSS-TE													
Algonquin delivery for GSS Conv													
Tennessee delivery for GSS													
Tennessee delivery for FSMA													
TETCO delivery for GSS													
TETCO delivery for GSS-TE													
TETCO delivery for GSS-TE													
TETCO delivery for GSS Conv													
Dominion delivery for GSS Conv													
Dominion delivery for GSS													
Algonquin delivery for FSS													
Columbia Delivery for FSS													
Distrigas FLS call payment													
TRANSCO											($965)		
Conoco											$560,448		
Williams													
STORAGE DELIVERY FIXED COST $	$370,728	$355,984	$368,922	$728,457	$328,387	$600,420	$712,277	$380,501	$596,589	$473,610	$1,004,105	$422,608	$5,527,705
TOTAL STORAGE FIXED	$743,858	$850,485	$752,604	$1,133,842	$706,326	$978,503	$1,085,153	$759,164	$974,956	$848,099	$1,366,769	$733,332	$10,933,091
TOTAL FIXED COSTS	$3,629,766	$2,894,664	$2,520,307	$3,273,521	$2,783,504	$2,985,178	$2,730,094	$2,763,488	$2,732,609	$2,613,981	$3,958,666	$2,675,386	$35,561,164

National Grid
Rhode Island Service Area
GCR Gas Costs

Projected Gas costs using 07-13-2009 NYMEX	Jul-08 actual	Aug-08 actual	Sep-08 actual	Oct-08 actual	Nov-08 actual	Dec-08 actual	Jan-09 actual	Feb-09 actual	Mar-09 actual	Apr-09 actual	May-09 actual	Jun-09 actual	Jul - Jun
VARIABLE SUPPLY COSTS (Includes Injections)													
Tennessee Zone 0					$174,060	$372,099	($475,370)	$15,221	$19,385	$10,642	$42,612		$158,649
Tennessee Zone 1													$0
Tennessee Connexion													$0
Tennessee Dracut													$0
TETCO STX													$0
TETCO ELA													$0
TETCO WLA													$0
TETCO ETX													$0
TETCO NF													$0
M3 Delivered	($1,928)	$2,028	$0	$0									$100
Maumee Supplemental													$0
Broadrun Col													$0
Columbia AGT													$0
Dominion to B&W					$2,695	$3,062	$3,523	$3,829	$179	$1,731	$279		$15,298
Dominion to TETCO FTS													$0
Transco at Wharton													$0
ANE to Tennessee	($94,434)	$0	$0	$0									($94,434)
Niagara to Tennessee													$0
TETCO to B & W													$0
DistriGas FCS					$627,493	$1,253,616	$1,441,960	$3,089,011	$661,128	$570,261	$0		$7,643,469
Hubline					$0	($15,330)	$0	$0	$0	$0	$0		($15,330)
Suppliers	$7,451,627	$11,153,292	$7,307,824	$11,601,477	$19,826,952	$30,210,771	$42,316,949	$26,657,358	$19,715,729	$8,883,088	$2,034,605	$2,668,278	
Total Pipeline Commodity Charges	$5,594,451	$10,716,796	$7,332,123	$12,455,333	$20,631,200	$31,824,218	$43,287,062	$29,765,419	$20,396,421	$9,465,722	$2,077,495	$2,668,278	$7,707,751
Hedging	($1,760,814)	($438,524)	$24,299	$853,856	$5,685,821	$7,825,066	$8,653,781	$14,662,194	$13,603,541	$7,732,609	$4,864,551	$3,257,085	$64,963,464
Costs of Injections							$0						$0
TOTAL VARIABLE SUPPLY COSTS	$5,594,451	$10,716,796	$7,332,123	$12,455,333	$26,317,021	$39,649,284	$51,940,843	$44,427,613	$33,999,962	$17,198,331	$6,942,046	$5,925,362	$262,499,165
VARIABLE STORAGE COSTS													
Underground Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$575,851	$26,538	$10,405	$612,794
LNG Withdrawals/Westerly Trucking	$138,890	$159,479	$169,734	$238,700	$752,235	$1,431,628	$2,056,513	$818,537	$565,503	$125,465	$150,779	$169,989	$6,777,452
LP	$0	$0	$0	$0									$0
TOTAL VARIABLE STORAGE COSTS	$138,890	$159,479	$169,734	$238,700	$752,235	$1,431,628	$2,056,513	$818,537	$565,503	$701,316	$177,317	$180,393	$7,390,246
TOTAL VARIABLE COSTS	$5,733,341	$10,876,275	$7,501,857	$12,694,033	$27,069,256	$41,080,912	$53,997,356	$45,246,150	$34,565,465	$17,899,647	$7,119,363	$6,105,756	$269,889,411
TOTAL SUPPLY COSTS AFTER CREDITS	$9,363,107	$13,770,939	$10,022,164	$15,967,554	$29,852,760	$44,066,090	$56,727,450	$48,009,638	$37,298,074	$20,513,628	$11,078,030	$8,781,141	$305,450,575
Storage Costs for FT-2 Calculation													
Storage Fixed Costs - Facilities	$373,130	$494,501	$383,682	$405,385	$377,939	$378,083	$372,876	$378,663	$378,367	$374,489	$362,665	$310,725	$4,590,504
Storage Fixed Costs - Deliveries	$370,728	$355,984	$368,922	$728,457	$328,387	$600,420	$712,277	$380,501	$596,589	$473,610	$1,004,105	$422,608	$6,342,587
Variable Delivery Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,189	$0	$0	$1,189
Variable Injection Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,100	$11,260	$11,057	$33,418
Fuel Costs Allocated to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$72,157	$97,908	$56,372	$226,436
Total Storage Costs	$743,858	$850,485	$752,604	$1,133,842	$706,326	$978,503	$1,085,153	$759,164	$974,956	$932,545	$1,475,937	$800,762	$11,194,134
Pipeline Variable	$5,594,451	$10,716,796	$7,332,123	$12,455,333	$26,317,021	$39,649,284	$51,940,843	$44,427,613	$33,999,962	$17,198,331	$6,942,046	$5,925,362	$262,499,165
Less Non-firm Gas Costs	$310,623	$2,629,278	$797,163	$728,540	$752,895	$57,532	$125,110	$91,273	($943,372)	$291,600	$163,193	$129,713	$5,133,548
Less Company Use	$65,503	$56,361	$37,401	$18,923	$40,127	$132,531	$217,983	$233,298	$128,542	$93,421	$93,421	($9,616)	$1,107,896
Less Manchester St Balancing	$12,816	$10,054	$9,722	$4,683	$9,938	$6,254	$0	$6,973	$4,473	$8,631	$8,631	($8,631)	$73,544
Plus Cashout	$0	$0	$0	$0									
Less Mkter Over-takes	$239,913	$514,834	$203,188	$120,610	$190,775	$206,378	$852,005	$569,651	$737,582	$261,233	$19,122	$2,684	$3,917,974
Less Mkter W/drawals	($2,075)	($4,890)	$258,936	($194,188)	($486,767)	$252,858	$4,462	$135,237	$278,092	$175,636	$298,450	($3,804)	$711,947
Plus Mkter Undertakes	$117,399	($198,710)	$57,571	$1,204,037	$101,175	$229,693	$252,384	$86,010	($139,416)	$272,544	$237,281	$108,968	$2,328,937
Plus Mkter Injections	$0	$0	$0	$0	$0	$0	$0	$32,012	$5,138	$0	$0	$0	$37,150
Storage Service Charge													
Plus Pipeline Srchg/Credit	$237,398	$244,919	$243,595	$235,539	$240,491	$246,783	$201,068	$158,340	$137,810	$167,750	$158,336	$169,716	$2,441,746
TOTAL FIRM COMMODITY COSTS	$5,322,469	$7,557,368	$6,326,879	$13,216,341	$26,151,719	$39,470,206	$51,194,735	$43,667,544	$33,798,176	$16,808,105	$6,754,846	$6,093,700	$256,362,089

National Grid
Rhode Island Service Area
GCR Gas Cost Collections

	Jul-08 actual	Aug-08 actual	Sep-08 actual	Oct-08 actual	Nov-08 actual
I. Supply Fixed Cost Collections --					
(a) Resid. & Small C & I dth	548,396	519,103	425,476	576,734	1,239,954
Supply Fixed Cost Factor	$1.0735	$1.0383	$1.0745	$1.0692	$1.0774
Res & Small C & I collections	$588,700	$538,979	$457,153	$616,655	$1,335,903
(b) C & I Medium dth	128,312	122,016	90,061	210,385	239,833
Supply Fixed Cost Factor	$1.0280	$0.9956	$1.0307	$1.0180	$1.0204
C & I Medium collections	$131,905	$121,481	$92,829	$214,172	$244,715
(c) C & I Large LLF dth	20,823	16,773	18,583	20,549	92,467
Supply Fixed Cost Factor	$1.0208	$0.9860	$1.0219	$1.0104	$1.0106
C & I Large LLF collections	$21,256	$16,539	$18,990	$20,762	$93,450
(d) C & I Large HLF dth	27,485	29,741	31,675	25,770	35,774
Supply Fixed Cost Factor	$0.9161	$0.8822	$0.8916	$0.9327	$0.9452
C & I Large HLF collections	$25,180	$26,238	$28,242	$24,036	$33,812
(e) C & I Extra Large LLF dth	7,677	5,712	2,379	4,464	17,640
Supply Fixed Cost Factor	$1.0100	$0.9494	$1.0025	$1.0022	$1.0024
C & I XL LLF collections	$7,754	$5,423	$2,385	$4,474	$17,682
(f) C & I Extra Large HLF dth	18,683	21,018	32,329	37,117	38,746
Supply Fixed Cost Factor	$0.8536	$0.8142	$0.8420	$0.8420	$0.8420
C & I XL HLF collections	$15,948	$17,113	$27,222	$31,254	$32,625
sub-total Dth	751,376	714,363	600,503	875,019	1,664,414
sub-total Supply Fixed Collections	**$790,743**	**$725,773**	**$626,821**	**$911,353**	**$1,758,187**
II. Storage Fixed Cost Collections --					
(a) Resid. & Small C & I dth	548,396	519,103	425,476	576,734	1,239,954
Storage Fixed Cost Factor	$0.3778	$0.3654	$0.3781	$0.3763	$0.3792
Res & Small C & I collections	$207,185	$189,685	$160,889	$217,023	$470,152
(b) C & I Medium dth	128,312	122,016	90,061	210,385	239,833
Storage Fixed Cost Factor	$0.4132	$0.4002	$0.4143	$0.4092	$0.4101
C & I Medium collections	$53,018	$48,828	$37,312	$86,084	$98,361
(c) C & I Large LLF dth	20,823	16,773	18,583	20,549	92,467
Storage Fixed Cost Factor	$0.4637	$0.4479	$0.4641	$0.4590	$0.4591
C & I Large LLF collections	$9,655	$7,513	$8,625	$9,431	$42,447
(d) C & I Large HLF dth	27,485	29,741	31,675	25,770	35,774
Storage Fixed Cost Factor	$0.3098	$0.2983	$0.3015	$0.3154	$0.3196
C & I Large HLF collections	$8,516	$8,873	$9,551	$8,129	$11,435
(e) C & I XL LLF dth	7,677	5,712	2,379	4,464	17,640
Storage Fixed Cost Factor	$0.4398	$0.4133	$0.4363	$0.4364	$0.4364
C & I XL LLF collections	$3,376	$2,361	$1,038	$1,948	$7,698
(f) C & I XL HLF dth	18,683	21,018	32,329	37,117	38,746
Storage Fixed Cost Factor	$0.2760	$0.2632	$0.2722	$0.2722	$0.2722
C & I XL HLF collections	$5,156	$5,532	$8,800	$10,104	$10,547
(g) FT-2 dth	(50,828)	29,441	71,741	(8,781)	108,548
Storage Fixed Cost Factor	($0.0538)	$0.4052	$0.4052	$0.4052	$0.4052
FT-2 collection	$2,733	$11,929	$29,069	($3,558)	$43,984
sub-total Dth	700,548	743,804	672,244	866,238	1,772,962
sub-total Storage Fixed Collections	**$289,639**	**$274,721**	**$255,284**	**$329,161**	**$684,624**

National Grid
Rhode Island Service Area
GCR Gas Cost Collections

	Jul-08 actual	Aug-08 actual	Sep-08 actual	Oct-08 actual	Nov-08 actual
III. Variable Supply Cost Collections --					
(a) Firm Sales dth	751,376	714,363	600,503	875,019	1,664,414
Variable Supply Cost Factor	$7.6859	$8.8557	$9.1518	$8.9835	$9.2925
Variable Supply collections	**$5,774,967**	**$6,326,210**	**$5,495,700**	**$7,860,760**	**$15,466,501**
(b) TSS Sales dth	656	547	841	2,486	3,615
TSS Variable Supply Cost F.	$3.9270	$1.1350	$0.3930	$0.00	$0.00
TSS Surcharge collections	**$2,576**	**$621**	**$331**	**$0**	**$0**
(c) NGV Sales dth	1,141	2,230	-43	833	1,080
Variable Supply Cost Factor	$7.7344	$7.7350	$7.7442	$7.7347	$7.7352
Variable Supply collections	**$8,825**	**$17,249**	**($333)**	**$6,443**	**$8,354**
(d) Default Sales dth	5,078	2,688	2,757	16,604	(10,666)
Variable Supply Cost Factor	$16.69	$12.03	$10.53	$9.35	$10.04
Variable Supply collections	**$84,726**	**$32,337**	**$29,031**	**$155,164**	**($117,433)**
TOTAL Variable Supply Collections	**$5,871,095**	**$6,376,416**	**$5,524,729**	**$8,022,367**	**$15,357,422**
IVa. Storage Variable Product Cost Collections --					
(a) Firm Sales dth	751,376	714,363	600,503	875,019	1,664,414
Variable Supply Cost Factor	$1.3698	$1.3241	$1.3685	$1.3626	$1.3717
Stor Var Product collections	**$1,029,239**	**$945,886**	**$821,818**	**$1,192,319**	**$2,283,078**
IVb. Storage Variable Non-product Cost Collections --					
(a) Firm Sales dth	751,376	714,363	600,503	875,019	1,664,414
Variable Supply Cost Factor	$0.0856	$0.0828	$0.0856	$0.0852	$0.0880
Stor Var Non-Product collec	**$64,346**	**$59,136**	**$51,378**	**$74,542**	**$146,496**
(b) FT-2 dth	(50,828)	29,441	71,741	(8,781)	55,279
Variable Supply Cost Factor	($0.0113)	$0.0849	$0.0849	$0.0850	$0.0987
Stor Var Non-Product collec	**$573**	**$2,500**	**$6,091**	**($746)**	**$5,455**
(c) Total Firm Sales/FT-2 dth	700,548	743,804	672,244	866,238	1,719,693
Stor Var Non-Product collec	**$64,919**	**$61,636**	**$57,469**	**$73,796**	**$151,951**
Total Gas Cost Collections	**$8,045,635**	**$8,384,432**	**$7,286,121**	**$10,528,996**	**$20,235,262**

National Grid
Rhode Island Service Area
GCR Gas Cost Collections

Actual numbers reflect new structure approved in Dkt 3982 issued 12/01/08	Dec-08 actual	Jan-09 actual	Feb-09 actual	Mar-09 actual	Apr-09 actual	May-09 actual	Jun-09 actual
I. Supply Fixed Cost Collections --							
(a) RH, SM, Med C & I dth	2,621,471	4,203,177	4,519,766	3,610,908	2,699,301	1,399,137	795,014
Supply Fixed Cost Factor	$0.9635	$0.7613	$0.7786	$0.7789	$0.7778	$0.7793	$0.7802
Res & Small C & I collections	$2,525,737	$3,199,868	$3,518,975	$2,812,641	$2,099,440	$1,090,374	$620,282
(b) Res Non-Heat dth	75,675	107,166	104,454	87,796	80,975	51,342	39,059
Supply Fixed Cost Factor	$0.8239	$0.5402	$0.5443	$0.5568	$0.5570	$0.5678	$0.5473
Res Non-heat collections	$62,350	$57,891	$56,856	$48,884	$45,102	$29,150	$21,376
(c) C & I Large LLF dth	149,246	207,332	189,683	161,876	171,866	25,095	39,649
Supply Fixed Cost Factor	$0.9157	$0.7801	$0.7615	$0.7877	$0.7223	$1.2190	$0.6926
C & I Large LLF collections	$136,671	$161,748	$144,435	$127,517	$124,141	$30,590	$27,460
(d) C & I Large HLF dth	42,621	55,007	50,622	43,136	39,064	27,502	23,391
Supply Fixed Cost Factor	$0.7135	$0.5470	$0.5409	$0.5409	$0.5329	$0.5561	$0.7783
C & I Large HLF collections	$30,410	$30,088	$27,380	$23,332	$20,818	$15,295	$18,205
(e) C & I Extra Large LLF dth	28,564	39,118	26,091	22,290	24,379	11,739	109,734
Supply Fixed Cost Factor	$0.9064	$0.7783	$0.7783	$0.7666	$0.7783	$0.7782	$0.0550
C & I XL LLF collections	$25,891	$30,445	$20,306	$17,087	$18,974	$9,136	$6,039
(f) C & I Extra Large HLF dth	34,887	79,368	(5,295)	15,222	53,580	24,431	23,910
Supply Fixed Cost Factor	$0.7103	$0.6431	$0.5314	$0.6797	$0.5754	$0.4510	$0.6015
C & I XL HLF collections	$24,781	$51,038	($2,814)	$10,347	$30,832	$11,019	$14,383
sub-total Dth	2,952,464	4,691,168	4,885,321	3,941,229	3,069,165	1,539,246	1,030,758
sub-total Supply Fixed Collections	**$2,805,840**	**$3,531,078**	**$3,765,138**	**$3,039,808**	**$2,339,307**	**$1,185,564**	**$707,745**
II. Storage Fixed Cost Collections --							
(a) RH, SM, Med C & I dth	2,621,471	4,203,177	4,519,766	3,610,908	2,699,301	1,399,137	795,014
Storage Fixed Cost Factor	$0.3610	$0.3015	$0.3083	$0.3084	$0.3080	$0.3086	$0.3090
Res & Small C & I collections	$946,399	$1,267,120	$1,393,483	$1,113,781	$831,360	$431,779	$245,626
(b) Res Non-Heat dth	75,675	107,166	104,454	87,796	80,975	51,342	39,059
Storage Fixed Cost Factor	$0.3025	$0.2145	$0.2162	$0.2211	$0.2212	$0.2255	$0.2173
Res Non-heat collections	$22,892	$22,990	$22,579	$19,413	$17,910	$11,576	$8,489
(c) C & I Large LLF dth	149,246	207,332	189,683	161,876	171,866	25,095	39,649
Storage Fixed Cost Factor	$0.3927	$0.3089	$0.3015	$0.3119	$0.2860	$0.4827	$0.2743
C & I Large LLF collections	$58,616	$64,051	$57,195	$50,496	$49,159	$12,113	$10,874
(d) C & I Large HLF dth	42,621	55,007	50,622	43,136	39,064	27,502	23,391
Storage Fixed Cost Factor	$0.2570	$0.2172	$0.2148	$0.2148	$0.2116	$0.2208	$0.3091
C & I Large HLF collections	$10,953	$11,948	$10,873	$9,266	$8,267	$6,073	$7,229
(e) C & I XL LLF dth	28,564	39,118	26,091	22,290	24,379	11,739	109,734
Storage Fixed Cost Factor	$0.3790	$0.3082	$0.3082	$0.3035	$0.3082	$0.3082	$0.0218
C & I XL LLF collections	$10,826	$12,056	$8,041	$6,766	$7,513	$3,618	$2,391
(f) C & I XL HLF dth	34,887	79,368	(5,295)	15,222	53,580	24,431	23,910
Storage Fixed Cost Factor	$0.2502	$0.2265	$0.1871	$0.2394	$0.2026	$0.1588	$0.2118
C & I XL HLF collections	$8,727	$17,973	($991)	$3,644	$10,858	$3,880	$5,065
(g) FT-2 dth	99,142	195,879	319,615	190,660	82,020	105,995	65,876
Storage Fixed Cost Factor	$0.3817	$0.3151	$0.3152	$0.3152	$0.3152	$0.3152	$0.3152
FT-2 collection	$37,847	$61,731	$100,727	$60,087	$25,849	$33,405	$20,761
sub-total Dth	3,051,606	4,887,047	5,204,936	4,131,889	3,151,185	1,645,241	1,096,633
sub-total Storage Fixed Collections	**$1,096,260**	**$1,457,869**	**$1,591,907**	**$1,263,453**	**$950,916**	**$502,444**	**$300,435**

National Grid
Rhode Island Service Area
GCR Gas Cost Collections

Actual numbers reflect new structure approved in Dkt 3982 issued 12/01/08	Dec-08 actual	Jan-09 actual	Feb-09 actual	Mar-09 actual	Apr-09 actual	May-09 actual	Jun-09 actual
III. Variable Supply Cost Collections --							
(a) Firm Sales dth	2,947,113	4,691,168	4,884,146	3,943,787	3,067,239	1,554,928	1,037,170
Variable Supply Cost Factor	$9.0710	$8.0134	$8.1824	$8.1904	$8.1297	$8.1562	$7.3676
Variable Supply collections	**$26,733,125**	**$37,592,032**	**$39,964,110**	**$32,301,325**	**$24,935,675**	**$12,682,283**	**$7,641,440**
(b) TSS Sales dth	5,351	11,370	(410)	10,937	(3,896)	23,845	15,267
TSS Variable Supply Cost F.	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
TSS Surcharge collections	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
(c) NGV Sales dth	1,389	1,561	1,561	1,545	1,462	1,229	882
Variable Supply Cost Factor	$7.7351	$7.4990	$8.1807	$8.1815	$8.1815	$8.1815	$8.1815
Variable Supply collections	**$10,744**	**$11,706**	**$12,770**	**$12,643**	**$11,964**	**$10,054**	**$7,220**
(d) Default Sales dth	46	87	0	2	4,896	1,705	61,411
Variable Supply Cost Factor	$12.7100	$12.4350	$10.9750	$10.9750	$10.9750	$10.9750	$10.9750
Variable Supply collections	**$585**	**$1,086**	**$0**	**$19**	**$53,732**	**$18,709**	**$673,987**
TOTAL Variable Supply Collections	**$26,744,454**	**$37,604,824**	**$39,976,880**	**$32,313,986**	**$25,001,371**	**$12,711,046**	**$8,322,646**
IVa. Storage Variable Product Cost Collections --							
(a) Firm Sales dth	2,947,113	4,691,168	4,884,146	3,943,787	3,067,239	1,554,928	1,037,170
Variable Supply Cost Factor	$1.4056	$1.2972	$1.3245	$1.3258	$1.3160	$1.3203	$1.1926
Stor Var Product collections	**$4,142,409**	**$6,085,302**	**$6,469,288**	**$5,228,856**	**$4,036,522**	**$2,052,974**	**$1,236,974**
IVb. Storage Variable Non-product Cost Collections --							
(a) Firm Sales dth	2,952,464	4,691,168	4,885,321	3,941,229	3,069,165	1,539,246	1,030,758
Variable Supply Cost Factor	$0.1035	$0.1106	$0.1129	$0.1131	$0.1121	$0.1137	$0.1023
Stor Var Non-Product collec	$305,460	$518,748	$551,481	$445,740	$344,097	$175,008	$105,444
(b) FT-2 dth	99,142	195,879	319,615	190,660	82,020	105,995	65,876
Variable Supply Cost Factor	$0.1083	$0.0894	$0.0894	$0.0894	$0.0895	$0.0894	$0.0895
Stor Var Non-Product collec	$10,742	$17,521	$28,589	$17,054	$7,337	$9,481	$5,893
Total Firm Sales/FT-2 dth	3,051,606	4,887,047	5,204,936	4,131,889	3,151,185	1,645,241	1,096,633
Stor Var Non-Product collec	**$316,202**	**$536,269**	**$580,070**	**$462,794**	**$351,434**	**$184,489**	**$111,337**
Total Gas Cost Collections	**$35,105,165**	**$49,215,342**	**$52,383,283**	**$42,308,897**	**$32,679,550**	**$16,636,517**	**$10,679,137**

National Grid
Rhode Island Service Area
Gas Cost Inventory Financing Calculation

Line No.	Description (a)	Reference (b)	Jul-08 (c)	Aug-08 (d)	Sep-08 (e)	Oct-08 (f)	Nov-08 (g)	Dec-08 (h)	Jan-09 (i)	Feb-09 (j)	Mar-09 (k)	Apr-09 (l)	May-09 (m)	Jun-09 (n)	Total (o)
1	**Storage Inventory Balance**		$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$17,877,235	$20,125,174	$23,021,875	
2	Hedging											$1,849,310	$4,089,668	$6,261,058	
3	Subtotal	(1) + (2)	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$5,629,465	$19,726,545	$24,214,842	$29,282,932	
4	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
5	Return on Working Capital Requirement	(3) * (4)	$514,185	$514,185	$514,185	$514,185	$490,496	$490,496	$490,496	$490,496	$490,496	$1,718,776	$2,109,842	$2,551,425	$10,889,262
6	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
7	Interest Charges Financed	(1) * (6)	$238,059	$238,059	$238,059	$238,059	$208,485	$208,485	$208,485	$208,485	$208,485	$730,565	$896,787	$1,084,482	$4,706,498
8	Taxable Income	(5) - (7)	$276,125	$276,125	$276,125	$276,125	$282,011	$282,011	$282,011	$282,011	$282,011	$988,211	$1,213,055	$1,466,943	
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)	$424,808	$424,808	$424,808	$424,808	$433,863	$433,863	$433,863	$433,863	$433,863	$1,520,325	$1,866,238	$2,256,836	$9,511,945
11	Working Capital Requirement	(7) + (10)	$662,867	$662,867	$662,867	$662,867	$642,348	$642,348	$642,348	$642,348	$642,348	$2,250,890	$2,763,025	$3,341,318	$14,218,443
12	Monthly Average	(11) / 12	$55,239	$55,239	$55,239	$55,239	$53,529	$53,529	$53,529	$53,529	$53,529	$187,574	$230,252	$278,443	$1,184,870
13	**LNG Inventory Balance**		$6,784,235	$7,161,303	$7,602,268	$7,993,140	$7,511,236	$6,999,769	$5,803,567	$5,197,569	$4,923,352	$5,002,769	$4,823,401	$4,965,379	
14	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
15	Return on Working Capital Requirement	(13) * (14)	$619,659	$654,100	$694,377	$730,078	$654,455	$609,891	$505,665	$452,865	$428,972	$435,892	$420,264	$432,634	$6,638,851
16	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
17	Interest Charges Financed	(13) * (16)	$286,892	$302,838	$321,485	$338,015	$278,176	$259,234	$214,933	$192,490	$182,334	$185,276	$178,633	$183,891	$2,924,197
18	Taxable Income	(15) - (17)	$332,767	$351,262	$372,891	$392,064	$376,279	$350,657	$290,733	$260,375	$246,638	$250,616	$241,631	$248,743	
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)	$511,949	$540,403	$573,679	$603,175	$578,891	$539,472	$447,281	$400,577	$379,443	$385,563	$371,740	$382,682	$5,714,853
21	Working Capital Requirement	(17) + (20)	$798,841	$843,241	$895,164	$941,189	$857,067	$798,706	$662,214	$593,067	$561,777	$570,839	$550,372	$566,573	$8,639,050
22	Monthly Average	(21) / 12	$66,570	$70,270	$74,597	$78,432	$71,422	$66,559	$55,184	$49,422	$46,815	$47,570	$45,864	$47,214	$719,921
23	System Balancing Factor	Rate Case	20.39%	20.39%	20.39%	20.39%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	
24	Balancing Related Inventory Costs	(22) * (23)	$13,574	$14,328	$15,210	$15,992	$11,999	$11,182	$9,271	$8,303	$7,865	$7,992	$7,705	$7,932	$131,353
25	Supply Related Inventory Costs	(22) - (24)	$52,996	$55,942	$59,387	$62,440	$59,423	$55,377	$45,913	$41,119	$38,950	$39,578	$38,159	$39,282	$588,568

National Grid
Rhode Island Service Area
Gas Cost Working Capital Calculation

Line No.	Description (a)	Reference (b)	Jul-08 (c)	Aug-08 (d)	Sep-08 (e)	Oct-08 (f)	Nov-08 (g)	Dec-08 (h)	Jan-09 (i)	Feb-09 (j)	Mar-09 (k)	Apr-09 (l)	May-09 (m)	Jun-09 (n)	Total (o)
1	**Supply Fixed Costs**		$2,885,908	$2,044,179	$1,767,703	$2,139,679	$2,077,178	$2,006,675	$1,644,941	$2,004,324	$1,757,653	$1,765,882	$2,591,897	$1,942,053	$24,628,072
2	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	$2,885,908	$2,044,179	$1,767,703	$2,139,679	$2,077,178	$2,006,675	$1,644,941	$2,004,324	$1,757,653	$1,765,882	$2,591,897	$1,942,053	$24,628,072
4	Number of Days Lag	Rate Case	13.40	13.40	13.40	13.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$105,948	$75,047	$64,896	$78,553	$138,858	$134,145	$109,963	$133,988	$117,498	$118,048	$173,267	$129,825	
6	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
7	Return on Working Capital Requirement	(5) * (6)	$9,677	$6,855	$5,928	$7,175	$12,099	$11,688	$9,581	$11,674	$10,238	$10,286	$15,097	$11,312	
8	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
9	Interest Expense	(5) * (8)	$4,480	$3,174	$2,744	$3,322	$5,143	$4,968	$4,072	$4,962	$4,351	$4,372	$6,417	$4,808	
10	Taxable Income	(7) - (9)	$5,197	$3,681	$3,183	$3,853	$6,956	$6,720	$5,509	$6,712	$5,886	$5,914	$8,680	$6,504	
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)	$7,995	$5,663	$4,897	$5,928	$10,702	$10,339	$8,475	$10,326	$9,056	$9,098	$13,354	$10,006	
13	**Supply Fixed Working Capital Requirement**	(9) + (12)	$12,475	$8,837	$7,642	$9,250	$15,844	$15,307	$12,547	$15,289	$13,407	$13,470	$19,771	$14,814	$158,651
14	**Storage Fixed Costs**		$743,858	$850,485	$752,604	$1,133,842	$706,326	$978,503	$1,085,153	$759,164	$974,956	$848,099	$1,366,769	$733,332	$10,933,091
15	Less: LNG Demand to DAC		$56,282	$56,282	$56,282	$56,282	$26,460	$35,994	$98,428	$39,623	$77,112	$57,601	$54,260	$57,009	$671,615
16	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Plus: Supply Related LNG O&M Costs		$43,241	$43,241	$43,241	$43,241	$43,241	$47,253	$47,253	$47,253	$47,253	$47,253	$47,253	$47,253	$546,980
18	Allowable Working Capital Costs	(14) - (15) + (16)	$730,817	$837,444	$739,563	$1,120,801	$723,107	$989,762	$1,033,979	$766,794	$945,098	$837,751	$1,359,762	$723,577	$10,808,457
19	Number of Days Lag	Rate Case	13.40	13.40	13.40	13.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
20	Working Capital Requirement	[(17) * (18)] / 365	$26,830	$30,745	$27,151	$41,147	$48,339	$66,165	$69,121	$51,260	$63,179	$56,003	$90,899	$48,371	
21	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
22	Return on Working Capital Requirement	(19) * (20)	$2,451	$2,808	$2,480	$3,758	$4,212	$5,765	$6,023	$4,466	$5,505	$4,880	$7,920	$4,215	
23	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
24	Interest Expense	(19) * (22)	$1,135	$1,300	$1,148	$1,740	$1,790	$2,450	$2,560	$1,898	$2,340	$2,074	$3,366	$1,791	
25	Taxable Income	(19) - (23)	$1,316	$1,508	$1,332	$2,018	$2,422	$3,315	$3,463	$2,568	$3,165	$2,806	$4,554	$2,423	
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)	$2,025	$2,320	$2,049	$3,105	$3,726	$5,099	$5,327	$3,951	$4,869	$4,316	$7,006	$3,728	
28	**Storage Fixed Working Capital Requirement**	(23) + (26)	$3,159	$3,620	$3,197	$4,845	$5,516	$7,550	$7,887	$5,849	$7,209	$6,390	$10,372	$5,519	$71,113
1	**Supply Variable Costs**		$5,322,469	$7,557,368	$6,326,879	$13,216,341	$26,151,719	$39,470,206	$51,940,843	$42,921,436	$33,798,176	$16,808,105	$6,754,846	$6,093,700	$256,362,089
2a	Less: Non-firm Sales														
2b	Less: Variable Delivery Storage Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2c	Less: Variable Injection Storage Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	($11,100)	($11,260)	($11,057)	($33,418)
2d	Less: Fuel Costs Allocated to Storage		$0	$0	$0	$0	$0	$0	$0	$0	$0	($72,157)	($97,908)	($56,372)	($226,436)
2e	Less: Supply Refunds														$0
2	Total Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	($83,257)	($109,168)	($67,429)	($259,854)
3	Allowable Working Capital Costs	(1) - (2)	$5,322,469	$7,557,368	$6,326,879	$13,216,341	$26,151,719	$39,470,206	$51,940,843	$42,921,436	$33,798,176	$16,891,362	$6,864,014	$6,161,129	$256,621,944
4	Number of Days Lag	Rate Case	13.40	13.40	13.40	13.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$195,400	$277,449	$232,274	$485,203	$1,748,225	$2,638,556	$3,472,210	$2,869,269	$2,259,385	$1,129,176	$458,855	$411,867	
6	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
7	Return on Working Capital Requirement	(5) * (6)	$17,847	$25,342	$21,216	$44,317	$152,323	$229,898	$302,534	$250,000	$196,860	$98,385	$39,980	$35,886	
8	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
9	Interest Expense	(5) * (8)	$8,263	$11,733	$9,822	$20,518	$64,745	$97,718	$128,592	$106,262	$83,675	$41,819	$16,994	$15,253	
10	Taxable Income	(7) - (9)	$9,584	$13,609	$11,393	$23,799	$87,578	$132,180	$173,942	$143,737	$113,185	$56,567	$22,987	$20,633	
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)	$14,745	$20,937	$17,528	$36,614	$134,736	$203,354	$267,603	$221,135	$174,131	$87,026	$35,364	$31,743	

National Grid
Rhode Island Service Area
Gas Cost Working Capital Calculation

Line No.	Description (a)	Reference (b)	Jul-08 (c)	Aug-08 (d)	Sep-08 (e)	Oct-08 (f)	Nov-08 (g)	Dec-08 (h)	Jan-09 (i)	Feb-09 (j)	Mar-09 (k)	Apr-09 (l)	May-09 (m)	Jun-09 (n)	Total (o)
13	**Supply Variable Working Capital Requirement**	(9) + (12)	$23,008	$32,669	$27,350	$57,132	$199,480	$301,071	$396,195	$327,397	$257,806	$128,844	$52,357	$46,996	$1,850,308
14	**Storage Variable Product Costs**		$138,890	$159,479	$169,734	$238,700	$752,235	$1,431,628	$2,056,513	$818,537	$565,503	$701,316	$177,317	$180,393	$7,390,246
15	Less: Balancing Related LNG Commodity (to DAC)		($28,320)	($32,518)	($34,609)	($48,671)	($126,376)	($240,514)	($345,494)	($137,514)	($95,005)	($21,078)	($25,331)	($28,558)	($1,163,986)
16	Plus: Supply Related LNG O&M Costs		$30,455	$30,455	$30,455	$30,455	$32,857	$32,857	$32,857	$32,857	$32,857	$32,857	$32,857	$32,857	$384,678
17	Allowable Working Capital Costs	(14) + (15) + (16)	$141,026	$157,417	$165,581	$220,485	$658,717	$1,223,972	$1,743,876	$713,880	$503,356	$713,095	$184,843	$184,692	$6,610,938
18	Number of Days Lag	Rate Case	13.40	13.40	13.40	13.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
19	Working Capital Requirement	[(17) * (18)] / 365	$5,177	$5,779	$6,079	$8,095	$44,035	$81,822	$116,577	$47,722	$33,649	$47,670	$12,357	$12,347	
20	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
21	Return on Working Capital Requirement	(19) * (20)	$473	$528	$555	$739	$3,837	$7,129	$10,157	$4,158	$2,932	$4,153	$1,077	$1,076	
22	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
23	Interest Expense	(19) * (22)	$219	$244	$257	$342	$1,631	$3,030	$4,317	$1,767	$1,246	$1,765	$458	$457	
24	Taxable Income	(19) - (23)	$254	$283	$298	$397	$2,206	$4,099	$5,840	$2,391	$1,686	$2,388	$619	$619	
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)	$391	$436	$459	$611	$3,394	$6,306	$8,985	$3,678	$2,593	$3,674	$952	$952	
27	**Storage Var. Product Working Capital Requir.**	(23) + (26)	$610	$680	$716	$953	$5,025	$9,336	$13,302	$5,445	$3,840	$5,439	$1,410	$1,409	$48,165
1	**Storage Variable Non-Product Costs**		$0	$0	$0	$0	$0	$0	$594,288	$477,455	($1,071,743)	($83,257)	($109,168)	($67,429)	($259,855)
2	Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Allowable Working Capital Costs	(1) - (2)	$0	$0	$0	$0	$0	$0	$594,288	$477,455	($1,071,743)	($83,257)	($109,168)	($67,429)	($259,855)
4	Number of Days Lag	Rate Case	13.40	13.40	13.40	13.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	24.40	
5	Working Capital Requirement	[(3) * (4)] / 365	$0	$0	$0	$0	$0	$0	$39,728	$31,918	($71,645)	($5,566)	($7,298)	($4,508)	
6	Cost of Capital	Rate Case	9.13%	9.13%	9.13%	9.13%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%	
7	Return on Working Capital Requirement	(5) * (6)	$0	$0	$0	$0	$0	$0	$3,461	$2,781	($6,242)	($485)	($636)	($393)	
8	Weighted Cost of Debt	Rate Case	4.23%	4.23%	4.23%	4.23%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
9	Interest Expense	(5) * (8)	$0	$0	$0	$0	$0	$0	$1,471	$1,182	($2,653)	($206)	($270)	($167)	
10	Taxable Income	(7) - (9)	$0	$0	$0	$0	$0	$0	$1,990	$1,599	($3,589)	($279)	($366)	($226)	
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)	$0	$0	$0	$0	$0	$0	$3,062	$2,460	($5,522)	($429)	($562)	($347)	
13	**Storage Variable Non-product WC Requir.**	(9) + (12)	$0	$0	$0	$0	$0	$0	$4,533	$3,642	($8,175)	($635)	($833)	($514)	($1,982)

National Grid
Rhode Island Service Area
Actual Throughput (Dth)

Line No.	Rate Class	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul - Jun
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)
		actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	actual	
1	**SALES (dth)**													
2	Residential Non-Heating	28,457	38,140	32,091	35,639	56,197	74,260	105,168	104,454	87,796	80,975	51,342	39,059	733,578
3	Residential Non-Heating Low Income						1,415	1,998	2,363	2,559	2,234	1,767	509	12,845
4	Residential Heating	450,662	417,902	380,484	489,431	1,047,572	1,905,706	2,841,943	3,169,269	2,456,092	1,854,829	924,654	507,219	16,445,763
5	Residential Heating Low Income						158,314	221,411	246,102	218,543	179,606	105,449	61,202	1,190,627
6	Small C&I	69,277	63,061	12,901	51,664	136,185	243,234	468,169	445,253	404,908	268,425	132,795	60,022	2,355,894
7	Medium C&I	128,225	121,924	89,870	208,714	239,162	313,646	668,869	657,578	527,224	392,280	226,309	157,207	3,731,008
8	Large LLF	20,823	16,773	18,389	20,307	89,907	144,636	198,749	189,683	155,082	171,866	25,095	39,649	1,090,958
9	Large HLF	26,916	29,286	31,219	25,197	35,390	42,451	55,005	50,622	43,136	39,064	27,502	23,391	429,179
10	Extra Large LLF	7,677	5,712	2,379	4,464	17,640	28,564	39,118	26,091	22,290	24,379	11,739	109,734	299,788
11	Extra Large HLF	18,683	21,018	32,329	37,117	38,746	34,887	79,368	(5,295)	15,222	53,580	24,431	23,910	373,996
	Total Sales	750,720	713,816	599,662	872,533	1,660,799	2,947,113	4,679,798	4,886,120	3,932,851	3,067,239	1,531,083	1,021,903	26,663,637
12	**TSS**													
13	Medium	87	92	191	1,671	671	571	2,785	1,564	4,142	4,160	9,930	9,363	35,228
14	Large LLF	0	0	194	242	2,560	4,610	8,583	(1,972)	6,794	(8,056)	13,140	(4,363)	21,732
15	Large HLF	569	455	456	573	384	170	2	(2)	0	0	775	10,266	13,648
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**	656	547	841	2,486	3,615	5,351	11,370	(410)	10,937	(3,896)	23,845	15,267	70,608
19	**FT-2 TRANSPORTATION**													
20	FT-2 Medium	8,674	17,738	59,949	(24,995)	75,145	30,048	81,959	201,285	81,623	(15,465)	45,012	25,967	586,940
21	FT-2 Large LLF	(7,112)	3,258	5,593	8,950	23,240	55,156	92,226	101,097	77,810	81,830	29,732	21,922	493,701
22	FT-2 Large HLF	(53,112)	5,056	4,742	5,180	7,511	9,765	11,555	11,117	9,834	11,082	8,930	8,452	40,112
23	FT-2 Extra Large LLF	0	0	0	350	974	1,667	2,198	2,619	2,210	398	2,151	67	12,634
24	FT-2 Extra Large HLF	722	3,389	1,457	1,734	1,678	2,506	7,941	3,497	19,184	4,175	20,171	9,467	75,921
25	**Total FT-2 Transportation**	(50,828)	29,441	71,741	(8,781)	108,548	99,142	195,879	319,615	190,660	82,020	105,995	65,876	1,209,308
26	**Sales & FT-2 THROUGHPUT**													
27	Residential Non-Heating	28,457	38,140	32,091	35,639	56,197	74,260	105,168	104,454	87,796	80,975	51,342	39,059	733,578
28	Residential Non-Heating Low Income						1,415	1,998	2,363	2,559	2,234	1,767	509	12,845
29	Residential Heating	450,662	417,902	380,484	489,431	1,047,572	1,905,706	2,841,943	3,169,269	2,456,092	1,854,829	924,654	507,219	16,445,763
30	Residential Heating Low Income						158,314	221,411	246,102	218,543	179,606	105,449	61,202	1,190,627
31	Small C&I	69,277	63,061	12,901	51,664	136,185	243,234	468,169	445,253	404,908	268,425	132,795	60,022	2,355,894
32	Medium C&I	136,986	139,754	150,010	185,390	314,978	344,265	753,613	860,427	612,989	380,975	281,251	192,538	4,353,176
33	Large LLF	13,711	20,031	24,176	29,499	115,707	204,402	299,558	288,807	239,686	245,640	67,966	57,208	1,606,391
34	Large HLF	(25,627)	34,797	36,417	30,950	43,285	52,386	66,562	61,737	52,970	50,145	37,207	42,109	482,939
35	Extra Large LLF	7,677	5,712	2,379	4,814	18,614	30,231	41,316	28,710	24,500	24,777	13,890	109,802	312,422
36	Extra Large HLF	19,405	24,407	33,786	38,851	40,424	37,393	87,309	(1,799)	34,406	57,756	44,601	33,378	449,917
37	**Total Sales & FT-2 Throughput**	700,548	743,804	672,244	866,238	1,772,962	3,051,606	4,887,047	5,205,324	4,134,448	3,145,363	1,660,923	1,103,046	27,943,553
38	**FT-1 TRANSPORTATION**													
39	FT-1 Medium	92,707	58,992	(64,227)	30,750	38,827	96,524	110,676	96,175	86,238	(11,750)	32,662	32,158	599,731
40	FT-1 Large LLF	72,542	54,604	(49,316)	57,648	66,319	159,315	169,518	159,007	171,963	119,249	34,165	(8,920)	1,006,093
41	FT-1 Large HLF	37,781	31,353	23,551	76,607	132,271	109,635	(144,121)	(65,321)	47,523	34,712	33,740	29,195	346,925
42	FT-1 Extra Large LLF	80,091	65,765	(73,160)	22,442	26,687	61,588	96,220	92,732	108,974	90,420	17,172	17,246	606,177
43	FT-1 Extra Large HLF	271,836	352,888	400,234	496,289	115,775	383,277	532,886	510,433	452,017	431,360	303,667	412,889	4,663,551
44	Default	5,078	2,688	2,757	16,604	(10,666)	46	87	0	2	4,896	1,705	61,411	84,607
45	**Total FT-1 Transportation**	560,035	566,290	239,839	700,340	369,213	810,385	765,266	793,026	866,715	668,886	423,112	543,978	7,307,086
46	**Total THROUGHPUT**													
47	Residential Non-Heating	28,457	38,140	32,091	35,639	56,197	74,260	105,168	104,454	87,796	80,975	51,342	39,059	733,578
48	Residential Non-Heating Low Income						1,415	1,998	2,363	2,559	2,234	1,767	509	12,845
49	Residential Heating	450,662	417,902	380,484	489,431	1,047,572	1,905,706	2,841,943	3,169,269	2,456,092	1,854,829	924,654	507,219	16,445,763
50	Residential Heating Low Income						158,314	221,411	246,102	218,543	179,606	105,449	61,202	1,190,627
51	Small C&I	69,277	63,061	12,901	51,664	136,185	243,234	468,169	445,253	404,908	268,425	132,795	60,022	2,355,894
52	Medium C&I	229,693	198,746	85,783	216,140	353,805	440,789	864,289	956,602	699,226	369,225	313,913	224,696	4,952,907
53	Large LLF	86,253	74,635	(25,140)	87,147	182,026	363,717	469,076	447,814	411,649	364,889	102,132	48,288	2,612,485
53	Large HLF	12,154	66,150	59,968	107,557	175,556	162,021	(77,559)	(3,583)	100,492	84,857	70,947	71,304	829,864
54	Extra Large LLF	87,768	71,477	(70,781)	27,256	45,301	91,819	137,536	121,443	133,474	115,198	31,062	127,047	918,599
55	Extra Large HLF	291,241	377,295	434,020	535,140	156,199	420,670	620,195	508,634	486,423	489,115	348,269	446,267	5,113,468
56	Default	5,078	2,688	2,757	16,604	(10,666)	46	87	0	2	4,896	1,705	61,411	84,607
57	**Total Throughput**	1,260,583	1,310,094	912,083	1,566,578	2,142,175	3,861,991	5,652,313	5,998,350	5,001,163	3,814,249	2,084,035	1,647,024	35,250,639

Gas Cost Recovery (GCR) Filing
Projected Gas Cost Balances

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov - Oct
	30	31	31	28	31	30	31	30	31	31	30	31	365
	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	
I. Supply Fixed Cost Deferred													
Beginning Balance	$1,584,026	$2,171,985	$1,197,542	($1,392,439)	($4,163,399)	($6,232,343)	($7,298,774)	($7,392,179)	($6,240,784)	($4,690,885)	($3,008,996)	($1,391,312)	
Supply Fixed Costs (net of cap rel)	$2,434,730	$2,435,992	$2,434,722	$2,430,938	$2,434,722	$2,217,461	$1,982,322	$2,394,581	$2,394,642	$2,394,642	$2,394,581	$2,394,642	$28,343,973
Capacity Release	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$8,479	$18,116	$18,107	$18,079	$18,107	$16,491	$14,742	$17,808	$17,809	$17,809	$17,808	$17,809	$201,162
Total Supply Fixed Costs	$2,443,209	$2,454,108	$2,452,828	$2,449,017	$2,452,828	$2,233,951	$1,997,064	$2,412,389	$2,412,450	$2,412,450	$2,412,389	$2,412,450	$28,545,134
Supply Fixed - Collections	$1,857,178	$3,430,339	$5,042,706	$5,217,314	$4,516,257	$3,293,435	$2,082,675	$1,253,994	$856,752	$726,476	$792,446	$1,063,120	$30,132,692
Prelim. Ending Balance	$2,170,057	$1,195,754	($1,392,336)	($4,160,737)	($6,226,828)	($7,291,826)	($7,384,385)	($6,233,784)	($4,685,085)	($3,004,911)	($1,389,053)	($41,982)	
Month's Average Balance	$1,877,041	$1,683,870	($97,397)	($2,776,588)	($5,195,113)	($6,762,085)	($7,341,579)	($6,812,982)	($5,462,935)	($3,847,898)	($2,199,024)	($716,647)	
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	$1,928	$1,788	($103)	($2,662)	($5,515)	($6,947)	($7,794)	($7,000)	($5,800)	($4,085)	($2,259)	($761)	($39,211)
Asset Management Incentive	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Supply Fixed Ending Balance	$2,171,985	$1,197,542	($1,392,439)	($4,163,399)	($6,232,343)	($7,298,774)	($7,392,179)	($6,240,784)	($4,690,885)	($3,008,996)	($1,391,312)	($42,743)	
II. Storage Fixed Cost Deferred													
Beginning Balance	$1,211,860	$1,318,506	$789,810	($374,474)	($1,602,010)	($2,559,874)	($2,867,759)	($2,503,097)	($2,160,022)	($1,652,498)	($1,096,541)	($564,694)	
Storage Fixed Costs	$783,641	$783,641	$783,641	$783,641	$783,641	$999,641	$1,236,041	$822,521	$823,721	$823,721	$822,521	$823,721	$10,270,090
LNG Demand to DAC	($26,460)	($26,460)	($26,460)	($26,460)	($26,460)	($62,748)	($102,463)	($32,992)	($33,193)	($33,193)	($32,992)	($33,193)	($463,075)
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	$618,591
Working Capital	$6,014	$6,014	$6,014	$6,014	$6,014	$7,351	$8,814	$6,255	$6,262	$6,262	$6,255	$6,262	$77,534
Total Storage Fixed Costs	$814,745	$814,745	$814,745	$814,745	$814,745	$995,793	$1,193,941	$847,333	$848,339	$848,339	$847,333	$848,339	$10,503,140
TSS Peaking Collections	$0	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	
Storage Fixed - Collections	$709,398	$1,344,559	$1,979,248	$2,041,331	$1,770,397	$1,300,888	$826,424	$501,858	$338,785	$290,916	$314,624	$424,096	$11,842,524
Prelim. Ending Balance	$1,317,206	$788,691	($374,695)	($1,601,063)	($2,557,666)	($2,864,973)	($2,500,248)	($2,157,628)	($1,650,475)	($1,095,083)	($563,841)	($140,461)	
Month's Average Balance	$1,264,533	$1,053,598	$207,557	($987,769)	($2,079,838)	($2,712,423)	($2,684,004)	($2,330,363)	($1,905,249)	($1,373,790)	($830,191)	($352,577)	
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	$1,299	$1,119	$220	($947)	($2,208)	($2,787)	($2,849)	($2,394)	($2,023)	($1,458)	($853)	($374)	($13,256)
Storage Fixed Ending Balance	$1,318,506	$789,810	($374,474)	($1,602,010)	($2,559,874)	($2,867,759)	($2,503,097)	($2,160,022)	($1,652,498)	($1,096,541)	($564,694)	($140,835)	
III. Variable Supply Cost Deferred													
Beginning Balance	$45,481,451	$53,030,933	$56,294,706	$47,979,922	$34,026,619	$25,467,548	$15,172,208	$7,492,464	$2,996,103	$1,395,748	$700,714	($116,189)	
Variable Supply Costs	$22,375,581	$30,250,728	$31,146,819	$27,039,788	$27,078,385	$15,909,234	$9,001,181	$5,636,209	$5,349,464	$5,229,942	$5,643,940	$11,747,582	$196,408,852
Variable Delivery Storage	$0	$18,825	$55,775	$42,604	$16,488	$0	$0	$0	$0	$0	$0	$0	$133,691
Variable Injections Storage	$0	$10,250	$33,586	$26,869	$6,587	$0	$0	$0	$0	$0	$0	$0	$77,292
Fuel Cost Allocated to Storage	$0	$122,574	$380,191	$291,978	$122,598	$0	$0	$0	$0	$0	$0	$0	$917,341
Working Capital	$166,404	$226,098	$235,126	$203,779	$202,461	$118,315	$66,940	$41,916	$39,783	$38,894	$41,973	$87,365	$1,469,054
Total Supply Variable Costs	$22,541,985	$30,628,474	$31,851,497	$27,605,018	$27,426,518	$16,027,548	$9,068,121	$5,678,125	$5,389,247	$5,268,836	$5,685,913	$11,834,947	$199,006,230
Supply Variable - Collections	$15,043,082	$27,422,702	$40,221,604	$41,597,620	$36,017,154	$26,343,754	$16,759,890	$10,179,871	$6,991,932	$5,964,982	$6,503,117	$8,639,485	$241,685,193
Deferred Responsibility	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Prelim. Ending Balance	$52,980,353	$56,236,705	$47,924,600	$33,987,320	$25,435,984	$15,151,342	$7,480,439	$2,990,718	$1,393,418	$699,602	($116,490)	$3,079,272	
Month's Average Balance	$49,230,902	$54,633,819	$52,109,653	$40,983,621	$29,731,301	$20,309,445	$11,326,323	$5,241,591	$2,194,760	$1,047,675	$292,112	$1,481,541	
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	$50,580	$58,002	$55,322	$39,299	$31,564	$20,866	$12,025	$5,385	$2,330	$1,112	$300	$1,573	$278,358
Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Supply Variable Ending Balance	$53,030,933	$56,294,706	$47,979,922	$34,026,619	$25,467,548	$15,172,208	$7,492,464	$2,996,103	$1,395,748	$700,714	($116,189)	$3,080,845	

Gas Cost Recovery (GCR) Filing
Projected Gas Cost Balances

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov - Oct
	30	31	31	28	31	30	31	30	31	31	30	31	365
	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	forecast	
IVa. Storage Variable Product Cost Deferred													
Beginning Balance	($31,689,296)	($31,751,914)	($26,934,023)	($12,987,555)	($2,960,576)	($323,027)	($867,705)	($1,042,921)	($971,156)	($767,864)	($510,297)	($272,652)	
Storage Variable Prod. Costs - LNG	$125,258	$1,113,318	$1,752,499	$600,929	$127,954	$123,357	$125,005	$116,858	$121,004	$120,836	$116,371	$120,611	$4,564,001
Storage Variable Prod. Costs - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Variable Prod. Costs - UG	$0	$4,447,547	$13,466,174	$10,628,332	$3,517,993	$0	$0	$0	$0	$0	$0	$0	$32,060,046
Supply Related LNG to DAC	($21,043)	($187,037)	($294,420)	($100,956)	($21,496)	($20,724)	($21,001)	($19,632)	($20,329)	($20,301)	($19,550)	($20,263)	($766,752)
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	$430,129
Inventory Financing - LNG	$52,802	$45,782	$34,446	$31,458	$30,471	$34,035	$42,621	$42,553	$42,494	$42,449	$42,420	$42,402	$483,932
Inventory Financing - UG	$262,239	$239,630	$161,793	$100,404	$85,362	$133,809	$183,960	$225,196	$250,162	$271,187	$272,154	$272,154	$2,458,050
Inventory Financing - LP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital	$1,042	$40,231	$111,256	$83,026	$27,221	$1,030	$1,040	$990	$1,015	$1,014	$987	$1,013	$269,864
Total Storage Variable Product Costs	$456,140	$5,735,316	$15,267,592	$11,379,038	$3,803,349	$307,352	$367,469	$401,808	$430,191	$451,030	$448,226	$451,761	$39,499,270
Storage Variable Product Collections	$486,186	$886,289	$1,299,944	$1,344,416	$1,164,058	$851,418	$541,672	$329,009	$225,976	$192,785	$210,178	$279,224	$7,811,155
Prelim. Ending Balance	($31,719,341)	($26,902,888)	($12,966,375)	($2,952,933)	($321,285)	($867,094)	($1,041,908)	($970,122)	($766,942)	($509,619)	($272,250)	($100,115)	
Month's Average Balance	($31,704,318)	($29,327,401)	($19,950,199)	($7,970,244)	($1,640,931)	($595,060)	($954,806)	($1,006,522)	($869,049)	($638,742)	($391,274)	($186,384)	
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	($32,573)	($31,135)	($21,180)	($7,643)	($1,742)	($611)	($1,014)	($1,034)	($923)	($678)	($402)	($198)	($99,133)
Storage Variable Product Ending Bal.	($31,751,914)	($26,934,023)	($12,987,555)	($2,960,576)	($323,027)	($867,705)	($1,042,921)	($971,156)	($767,864)	($510,297)	($272,652)	($100,313)	
IVb. Stor Var Non-Prod Cost Deferred													
Beginning Balance	($4,883,861)	($4,758,700)	($4,526,989)	($4,184,001)	($3,829,498)	($3,522,525)	($3,296,899)	($3,153,917)	($3,067,463)	($3,009,876)	($2,960,522)	($2,906,764)	
Storage Variable Non-prod. Costs	$0	$151,648	$469,552	$361,451	$145,672	$0	$0	$0	$0	$0	$0	$0	$1,128,324
Variable Delivery Storage Costs	$0	($18,825)	($55,775)	($42,604)	($16,488)	$0	$0	$0	$0	$0	$0	$0	($133,691)
Variable Injection Storage Costs	$0	($10,250)	($33,586)	($26,869)	($6,587)	$0	$0	$0	$0	$0	$0	$0	($77,292)
Fuel Costs Allocated to Storage	$0	($122,574)	($380,191)	($291,978)	($122,598)	$0	$0	$0	$0	$0	$0	$0	($917,341)
Working Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Storage Var Non-product Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Var Non-Product Collections	($130,112)	($236,637)	($347,610)	($358,343)	($310,874)	($229,127)	($146,404)	($89,649)	($60,811)	($52,521)	($56,771)	($75,830)	($2,094,689)
Prelim. Ending Balance	($4,753,749)	($4,522,063)	($4,179,379)	($3,825,658)	($3,518,624)	($3,293,398)	($3,150,495)	($3,064,268)	($3,006,652)	($2,957,355)	($2,903,751)	($2,830,934)	
Month's Average Balance	($4,818,805)	($4,640,381)	($4,353,184)	($4,004,829)	($3,674,061)	($3,407,961)	($3,223,697)	($3,109,093)	($3,037,057)	($2,983,615)	($2,932,137)	($2,868,849)	
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	($4,951)	($4,926)	($4,622)	($3,840)	($3,901)	($3,501)	($3,422)	($3,194)	($3,224)	($3,168)	($3,012)	($3,046)	($44,808)
Storage Var Non-Product Ending Bal.	($4,758,700)	($4,526,989)	($4,184,001)	($3,829,498)	($3,522,525)	($3,296,899)	($3,153,917)	($3,067,463)	($3,009,876)	($2,960,522)	($2,906,764)	($2,833,980)	
GCR Deferred Summary													
Beginning Balance	$11,704,180	$20,010,810	$26,821,046	$29,041,454	$21,471,139	$12,829,785	$841,081	($6,599,636)	($9,443,301)	($8,725,347)	($6,875,607)	($5,251,567)	
Gas Costs	$26,074,140	$39,342,182	$50,016,159	$41,936,919	$34,243,637	$19,421,458	$12,535,059	$9,272,687	$9,015,358	$8,916,676	$9,326,838	$15,435,048	$275,536,161
Working Capital	$181,939	$290,459	$370,503	$310,898	$253,803	$143,186	$91,536	$66,968	$64,869	$63,979	$67,023	$112,449	$2,017,613
Total Costs	$26,256,079	$39,632,641	$50,386,662	$42,247,817	$34,497,440	$19,564,644	$12,626,595	$9,339,655	$9,080,227	$8,980,656	$9,393,861	$15,547,497	$277,553,774
Collections	$17,965,732	$32,847,252	$48,195,892	$49,842,338	$43,156,992	$31,560,368	$20,064,257	$12,175,083	$8,352,634	$7,122,638	$7,763,594	$10,330,095	$289,376,875
Prelim. Ending Balance	$19,994,527	$26,796,200	$29,011,816	$21,446,932	$12,811,587	$834,062	($6,596,581)	($9,435,064)	($8,715,708)	($6,867,330)	($5,245,340)	($34,165)	
Month's Average Balance	$15,849,353	$23,403,505	$27,916,431	$25,244,193	$17,141,363	$6,831,923	($2,877,750)	($8,017,350)	($9,079,505)	($7,796,339)	($6,060,473)	($2,642,866)	
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	$16,284	$24,846	$29,637	$24,207	$18,198	$7,019	($3,055)	($8,237)	($9,639)	($8,277)	($6,227)	($2,806)	$81,950
Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Ending Bal. W/ Interest	$20,010,810	$26,821,046	$29,041,454	$21,471,139	$12,829,785	$841,081	($6,599,636)	($9,443,301)	($8,725,347)	($6,875,607)	($5,251,567)	($36,971)	
Under/(Over)-collection	$8,290,347	$6,785,389	$2,190,770	($7,594,521)	($8,659,552)	($11,995,724)	($7,437,662)	($2,835,428)	$727,593	$1,858,018	$1,630,267	$5,217,402	

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$1,031	$1,041	($10)	-1.0%	$0	($5.00)	($5.10)	$0.00
	664	$1,125	$1,136	($11)	-1.0%	$0	($5.54)	($5.67)	$0.00
	730	$1,222	$1,235	($12)	-1.0%	$0	($6.09)	($6.19)	$0.00
	794	$1,315	$1,328	($13)	-1.0%	$0	($6.59)	($6.76)	$0.00
	857	$1,404	$1,418	($14)	-1.0%	$0	($7.14)	($7.26)	$0.00
Average Customer	**922**	**$1,494**	**$1,510**	**($16)**	**-1.0%**	**$0**	**($7.68)**	**($7.84)**	**$0.00**
	987	$1,585	$1,602	($17)	-1.0%	$0	($8.21)	($8.39)	$0.00
	1,051	$1,674	$1,692	($18)	-1.0%	$0	($8.74)	($8.93)	$0.00
	1,114	$1,760	$1,779	($19)	-1.1%	$0	($9.23)	($9.47)	$0.00
	1,180	$1,850	$1,870	($20)	-1.1%	$0	($9.78)	($10.01)	$0.00
	1,247	$1,941	$1,961	($21)	-1.1%	$0	($10.36)	($10.57)	$0.00

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	600	$993	$1,004	($10)	-1.0%	$0	($5.00)	($5.10)	$0.00
	664	$1,085	$1,096	($11)	-1.0%	$0	($5.54)	($5.67)	$0.00
	730	$1,180	$1,192	($12)	-1.0%	$0	($6.09)	($6.19)	$0.00
	794	$1,270	$1,283	($13)	-1.0%	$0	($6.59)	($6.76)	$0.00
	857	$1,357	$1,371	($14)	-1.1%	$0	($7.14)	($7.26)	$0.00
Average Customer	**922**	**$1,446**	**$1,461**	**($16)**	**-1.1%**	**$0**	**($7.68)**	**($7.84)**	**$0.00**
	987	$1,535	$1,551	($17)	-1.1%	$0	($8.21)	($8.39)	$0.00
	1,051	$1,622	$1,640	($18)	-1.1%	$0	($8.74)	($8.93)	$0.00
	1,114	$1,706	$1,725	($19)	-1.1%	$0	($9.23)	($9.47)	$0.00
	1,180	$1,794	$1,814	($20)	-1.1%	$0	($9.78)	($10.01)	$0.00
	1,247	$1,883	$1,904	($21)	-1.1%	$0	($10.36)	($10.57)	$0.00

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$298	$302	($4)	-1.3%	$0	($2.91)	($1.01)	$0
	137	$318	$323	($4)	-1.4%	$0	($3.23)	($1.18)	$0
	147	$333	$337	($5)	-1.4%	$0	($3.46)	($1.27)	$0
	161	$353	$358	($5)	-1.5%	$0	($3.81)	($1.40)	$0
	176	$375	$380	($6)	-1.5%	$0	($4.16)	($1.49)	$0
Average Customer	**189**	**$393**	**$399**	**($6)**	**-1.5%**	**$0**	**($4.46)**	**($1.61)**	**$0**
	202	$412	$419	($7)	-1.6%	$0	($4.79)	($1.71)	$0
	217	$434	$441	($7)	-1.6%	$0	($5.12)	($1.86)	$0
	231	$454	$462	($7)	-1.6%	$0	($5.45)	($1.98)	$0
	241	$469	$476	($8)	-1.6%	$0	($5.68)	($2.06)	$0
	256	$490	$498	($8)	-1.6%	$0	($6.04)	($2.18)	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	123	$281	$285	($4)	-1.4%	$0	($2.91)	($1.01)	$0
	137	$301	$305	($4)	-1.4%	$0	($3.23)	($1.18)	$0
	147	$315	$319	($5)	-1.5%	$0	($3.46)	($1.27)	$0
	161	$334	$340	($5)	-1.5%	$0	($3.81)	($1.40)	$0
	176	$355	$361	($6)	-1.6%	$0	($4.16)	($1.49)	$0
Average Customer	**189**	**$374**	**$380**	**($6)**	**-1.6%**	**$0**	**($4.46)**	**($1.61)**	**$0**
	202	$392	$399	($7)	-1.6%	$0	($4.79)	($1.71)	$0
	217	$413	$420	($7)	-1.7%	$0	($5.12)	($1.86)	$0
	231	$433	$440	($7)	-1.7%	$0	($5.45)	($1.98)	$0
	241	$447	$455	($8)	-1.7%	$0	($5.68)	($2.06)	$0
	256	$468	$476	($8)	-1.7%	$0	($6.04)	($2.18)	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	824	$1,711	$1,725	($14)	-0.8%	$0	($7)	($7)	$0
	916	$1,838	$1,854	($15)	-0.8%	$0	($8)	($8)	$0
	1,003	$1,959	$1,975	($17)	-0.9%	$0	($8)	($9)	$0
	1,092	$2,081	$2,100	($18)	-0.9%	$0	($9)	($9)	$0
	1,179	$2,198	$2,218	($20)	-0.9%	$0	($10)	($10)	$0
Average Customer	**1,269**	**$2,316**	**$2,337**	**($21)**	**-0.9%**	**$0**	**($11)**	**($11)**	**$0**
	1,359	$2,434	$2,456	($23)	-0.9%	$0	($11)	($12)	$0
	1,447	$2,549	$2,573	($24)	-0.9%	$0	($12)	($12)	$0
	1,535	$2,664	$2,690	($26)	-1.0%	$0	($13)	($13)	$0
	1,622	$2,778	$2,805	($27)	-1.0%	$0	($13)	($14)	$0
	1,715	$2,900	$2,928	($29)	-1.0%	$0	($14)	($15)	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	7,117	$10,226	$10,345	($120)	-1.2%	$0	($59)	($61)	$0
	7,884	$11,250	$11,382	($132)	-1.2%	$0	($65)	($67)	$0
	8,649	$12,272	$12,417	($145)	-1.2%	$0	($72)	($74)	$0
	9,416	$13,296	$13,454	($158)	-1.2%	$0	($78)	($80)	$0
	10,185	$14,323	$14,495	($171)	-1.2%	$0	($85)	($87)	$0
Average Customer	**10,950**	**$15,345**	**$15,529**	**($184)**	**-1.2%**	**$0**	**($91)**	**($93)**	**$0**
	11,715	$16,367	$16,564	($197)	-1.2%	$0	($97)	($100)	$0
	12,484	$17,394	$17,604	($210)	-1.2%	$0	($104)	($106)	$0
	13,251	$18,418	$18,641	($223)	-1.2%	$0	($110)	($113)	$0
	14,016	$19,440	$19,676	($236)	-1.2%	$0	($116)	($119)	$0
	14,783	$20,464	$20,713	($248)	-1.2%	$0	($123)	($126)	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,532	$52,049	$52,680	($631)	-1.2%	$0	($312)	($319)	$0
	41,573	$57,498	$58,197	($699)	-1.2%	$0	($345)	($353)	$0
	45,616	$62,950	$63,717	($767)	-1.2%	$0	($379)	($388)	$0
	49,660	$68,403	$69,238	($835)	-1.2%	$0	($413)	($422)	$0
	53,699	$73,850	$74,752	($903)	-1.2%	$0	($446)	($456)	$0
Average Customer	**57,742**	**$79,301**	**$80,272**	**($971)**	**-1.2%**	**$0**	**($480)**	**($491)**	**$0**
	61,785	$84,753	$85,791	($1,039)	-1.2%	$0	($513)	($525)	$0
	65,824	$90,199	$91,306	($1,106)	-1.2%	$0	($547)	($559)	$0
	69,868	$95,652	$96,827	($1,174)	-1.2%	$0	($581)	($594)	$0
	73,911	$101,104	$102,346	($1,242)	-1.2%	$0	($614)	($628)	$0
	77,952	$106,553	$107,863	($1,310)	-1.2%	$0	($648)	($663)	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	37,970	$47,252	$48,465	($1,213)	-2.5%	$0	($890)	($323)	$0
	42,061	$52,188	$53,532	($1,344)	-2.5%	$0	($986)	($358)	$0
	46,151	$57,123	$58,597	($1,474)	-2.5%	$0	($1,082)	($392)	$0
	50,240	$62,056	$63,661	($1,605)	-2.5%	$0	($1,178)	($427)	$0
	54,329	$66,990	$68,725	($1,736)	-2.5%	$0	($1,274)	($462)	$0
Average Customer	**58,418**	**$71,923**	**$73,790**	**($1,866)**	**-2.5%**	**$0**	**($1,370)**	**($497)**	**$0**
	62,508	$76,858	$78,855	($1,997)	-2.5%	$0	($1,466)	($531)	$0
	66,596	$81,791	$83,918	($2,127)	-2.5%	$0	($1,561)	($566)	$0
	70,686	$86,725	$88,983	($2,258)	-2.5%	$0	($1,657)	($601)	$0
	74,775	$91,659	$94,047	($2,389)	-2.5%	$0	($1,753)	($636)	$0
	78,867	$96,596	$99,115	($2,519)	-2.5%	$0	($1,849)	($670)	$0

Bill Impact Analysis with Various Levels of Consumption:

Current Distribution, GCR, DAC and Energy Efficiency Rates vs. 2009-2010 Proposed GCR and DAC

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	189,450	$232,533	$235,718	($3,185)	-1.4%	$0	($1,574)	($1,610)	$0
	209,855	$257,191	$260,718	($3,528)	-1.4%	$0	($1,744)	($1,784)	$0
	230,255	$281,842	$285,713	($3,870)	-1.4%	$0	($1,913)	($1,957)	$0
	250,655	$306,494	$310,708	($4,213)	-1.4%	$0	($2,083)	($2,131)	$0
	271,059	$331,150	$335,706	($4,556)	-1.4%	$0	($2,252)	($2,304)	$0
Average Customer	**291,462**	**$355,806**	**$360,705**	**($4,899)**	**-1.4%**	**$0**	**($2,422)**	**($2,477)**	**$0**
	311,865	$380,461	$385,703	($5,242)	-1.4%	$0	($2,591)	($2,651)	$0
	332,269	$405,117	$410,702	($5,585)	-1.4%	$0	($2,761)	($2,824)	$0
	352,669	$429,769	$435,697	($5,928)	-1.4%	$0	($2,930)	($2,998)	$0
	373,069	$454,420	$460,691	($6,271)	-1.4%	$0	($3,100)	($3,171)	$0
	393,474	$479,078	$485,692	($6,614)	-1.4%	$0	($3,269)	($3,345)	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed November-09	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC	EnergyEff
	184,661	$218,823	$224,722	($5,899)	-2.6%	$0	($4,329)	($1,570)	$0
	204,549	$242,002	$248,537	($6,534)	-2.6%	$0	($4,796)	($1,739)	$0
	224,435	$265,180	$272,349	($7,170)	-2.6%	$0	($5,262)	($1,908)	$0
	244,321	$288,357	$296,162	($7,805)	-2.6%	$0	($5,728)	($2,077)	$0
	264,206	$311,533	$319,973	($8,440)	-2.6%	$0	($6,194)	($2,246)	$0
Average Customer	**284,094**	**$334,712**	**$343,788**	**($9,075)**	**-2.6%**	**$0**	**($6,661)**	**($2,415)**	**$0**
	303,982	$357,892	$367,602	($9,711)	-2.6%	$0	($7,127)	($2,584)	$0
	323,867	$381,068	$391,414	($10,346)	-2.6%	$0	($7,593)	($2,753)	$0
	343,753	$404,245	$415,226	($10,981)	-2.6%	$0	($8,059)	($2,922)	$0
	363,639	$427,422	$439,039	($11,616)	-2.6%	$0	($8,525)	($3,091)	$0
	383,527	$450,601	$462,853	($12,252)	-2.6%	$0	($8,992)	($3,260)	$0

Deleted: Third

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:	$0.9091 Therm

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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.

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Summary of Marketer Transportation Factors

Item	Reference	Proposed	Billing Units
FT-2 Firm Transportation Marketer Gas Charge	pg 15	$0.0337	Therms throughput of Marketer Pool
Pool Balancing Charge	pg 16	$0.0018	Per % of balancing elected per Therm throughput of Marketer Pool
Weighted Average Upstream Pipeline Transportation Cost	EDA - 4	$0.0999	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	GLB-1, pg 3	$2,082,145
3	C & I Large LLF	GLB-1, pg 3	$892,557
4	C & I Large HLF	GLB-1, pg 3	$165,905
5	C & I Extra Large LLF	GLB-1, pg 3	$121,940
6	C & I Extra Large HLF	GLB-1, pg 3	$113,012
7	sub-total	sum ([1]:[6])	$3,375,559
8	Through-put (dth)	GLB-1, pg 12	8,408,359
9	Storage Fixed Factor	[7] / [8]	$0.4015
	II. Storage Variable Cost Factor	GLB-1, pg 1	($0.0726)
	TOTAL FT-2 Gas Marketer Charge (per Dth)		$0.3289
	Uncollectible %	Dkt 3943	2.46%
	TOTAL FT-2 Gas Marketer Charge adj for uncollectible ($/dth)		**$0.3371**

Calculation of Pool Balancing Charge

		reference	Medium C&I	Large LLF	Large HLF	Extra Large LLF	Extra Large HLF	Total
1	Throughput (dth)	GLB-1, pg 1-14	5,143,724	2,041,155	564,623	251,529	407,328	8,408,359
2	% allocation		61.17%	24.28%	6.72%	2.99%	4.84%	100.00%
3	Supply Fixed Cost Factor	GLB-1, pg 1	$1.1240	$1.1240	$0.7755	$1.1240	$0.7755	
4	Storage Fixed Cost Factor	GLB-1, pg 1	$0.4186	$0.4186	$0.2886	$0.4186	$0.2886	
5	Storage Variable Cost Factor	GLB-1, pg 1	$0.2866	$0.2866	$0.2866	$0.2866	$0.2866	
6	Class Specific Pool Balancing Charge	([3]+[4]+[5]) x 1%	$0.0183	$0.0183	$0.0135	$0.0183	$0.0135	
7	Class Specific Weighted Average ($/dth)	[6] x [2]	$0.0112	$0.0044	$0.0009	$0.0005	$0.0007	$0.0177
8	Uncollectible %	Docket 3943	2.46%	2.46%	2.46%	2.46%	2.46%	
9	Pool Balancing Charge adjusted for Uncollectible	([7] / (1-[8])	$0.0115	$0.0046	$0.0009	$0.0006	$0.0007	$0.0183
10	Per Therm Pool Balancing Charge	[9] / 10						**$0.0018**

THE NARRAGANSETT ELECTRIC COMPANY

d/b/a NATIONAL GRID

Rhode Island Public Utilities Commission Tariff

RIPUC NG-GAS No. 101

"MARKED" Tariff Pages

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GAS COST RECOVERY CLAUSE

1.0 GENERAL:

1.1 Purpose: The purpose of this clause is to establish procedures that allow the Company, subject to the jurisdiction of the Rhode Island Public Utilities Commission ("RIPUC"), to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity in order to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, purchased gas working capital, and to credit supplier refunds, capacity credits from off-system sales and revenues from capacity release transactions.

The Gas Cost Recovery Clause shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory costs, requirements for purchased gas working capital, all applicable taxes, and deferred gas costs. Any costs recovered through the application of the Gas Charge shall be identified and explained fully in the annual filing.

1.2 Applicability: The Gas Charge shall be calculated separately for the following rate groups:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Large C&I High Load Factor, Extra Large C&I High Load Factor ;
(2) Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large C&I Low Load Factor, and Extra Large C&I Low Load Factor;
(3) ;FT-2 Firm Transportation – Marketers
(4) Natural Gas Vehicles

The Company will make annual Gas Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Gas Charge shall become effective with consumption on or after November 1st as designated by the Company. In the event of any change subsequent to the November effective date which would

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GAS COST RECOVERY CLAUSE

cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than one (1) percent of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

Unless otherwise notified by the RIPUC, the Company shall submit the Gas Charge filings no later than 60 days before they are scheduled to take effect. The Annual Reconciliation filing will be made by August 1 of each year containing actual data for the twelve months ending June 30 of that year.

2.0 GAS CHARGE FACTORS

2.1 Gas Charges to Sales Customers:

The Gas Charge consists of five (5) 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. These components shall be computed using a forecast of applicable costs and volumes for each firm rate schedule based on the following formula:

$$GC_S = FC_S + SFC_S + VC_S + SVC_S + SVNC_s$$

Where:

GC_S Gas Charge applicable to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I sales.

FC_S Supply Fixed Cost Component for a rate classification. See Item 3.1 for calculation.

SFC_S Storage Fixed Cost Component for a rate classification. See Item 3.2 for calculation.

VC_S Supply Variable Cost Component for a rate classification. See Item 3.3 for calculation.

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SVC_S Storage Variable Product Cost Component for a rate classification. See Item 3.4 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component for a rate classification. See Item 3.5 for calculation.

This calculation will be adjusted for the uncollectible percentage approved in the most recent rate case proceeding and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule D.

2.2 Gas Charge to FT-2 Marketers: The FT-2 Firm Transportation Marketer Gas Charge (GC_M) recovers costs associated with storage and peaking resources and is calculated as follows:

$$GC_M = SFC_S + SVNC_S$$

Where:

GC_M Gas Charge applicable to Marketers for FT-2 Firm Transportation Service

SFC_S Storage Fixed Cost Component. See Item 3.2 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component. See Item 3.5 for calculation.

2.3 Gas Charge to Natural Gas Vehicles: The Natural Gas Vehicle Gas Charge (GC_{NGV}) recovers costs associated with natural gas distributed to the public at Company owned NGV stations and is calculated as follows:

$$GC_{NGV} = FC_S + VC_S$$

Where:

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GAS COST RECOVERY CLAUSE

GC_{NGV} Gas Charge applicable to Natural Gas Vehicle (NGV) Service

FC_S Supply Fixed Cost Component. See Item 3.1 for calculation.

VC_S Supply Variable Cost Component. See Item 3.3 for calculation.

3.0 GAS CHARGE CALCULATIONS

3.1 Supply Fixed Cost Component:

The Supply Fixed Cost Component shall include all fixed costs related to the purchase of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Fixed Cost Component shall be identified and explained fully in the annual filing.

The Supply Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$FC_S = \frac{DWS_S * (TC_{FC} - TR_{FC} + WC_{FC} + R_{FC})}{Dt_S}$$

Where:

FC_S Supply Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

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GAS COST RECOVERY CLAUSE

DWS_S Percent of Design Winter Sales (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

TC_{FC} Total Supply Fixed Costs, including, but not limited to pipeline and supplier reservation.

TR_{FC} Credits to Supply Fixed Costs relating to supply services, including, but not limited to balancing charge revenues, capacity release revenues, off-system sales margins and refunds.

WC_{FC} Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

R_{FC} Deferred Fixed Cost Account Balance as of October 31, as derived in Item 6.0 less the amount guaranteed to customers under the Natural Gas Portfolio Management Plan (NGPMP) and, following approval by the Commission, the net positive revenue from optimization transactions reduced by the guaranteed amount and the Company incentive under the Plan.

Deleted: plus any Asset Management Incentive associated with the Gas Procurement and Asset Management Incentive Plan.

Dt_S Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

3.2 Storage Fixed Cost Component: The Storage Fixed Cost Component shall include all fixed costs related to the operations, maintenance and delivery of storage, including, but not limited to, supply related portion of local production and storage costs as determined in the most recent rate case proceeding, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased

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GAS COST RECOVERY CLAUSE

gas working capital. Any costs recovered through the application of the Storage Fixed Cost Component shall be identified and explained fully in the annual filing.

The Storage Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$SFC_S = \frac{DWT_S * (TC_{SFC} - TR_{SFC} + WC_{SFC} + R_{SFC})}{Dt_S}$$

Where:

SFC_S Storage Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

DWT_S Percent of Design Winter Throughput (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I ,Extra Large Low and High Load C&I, or FT-2 service.

TC_{SFC} Total Fixed Storage Costs, all fixed costs, including, but not limited to supply related local production and storage costs, and taxes on storage. The level of supply related local production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SFC} Total Credits to Storage Fixed Costs

WC_{SFC} Working Capital requirements associated with Total Storage Fixed Costs. See Item 5.0 for calculation.

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GAS COST RECOVERY CLAUSE

R_{SFC} Deferred Storage Cost Account Balance as of October 31, as derived in Item 6.0.

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Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

3.3 Supply Variable Cost Component: The Supply Variable Cost Component shall include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Variable Cost Component shall be identified and explained fully in the annual filing.

The Supply Variable Cost Component is calculated for each applicable rate schedule as follows:

$$VC = \frac{TC_{VC} - TR_{VC} + WC_{VC} + R_V}{Dt_{VC}}$$

Where:

VC Supply Variable Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

TC_{VC} Total Supply Variable Costs, including, but not limited to pipeline, supplier, and commodity-billed pipeline transition costs.

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GAS COST RECOVERY CLAUSE

TR_{VC} Total Credits to Supply Variable Costs, including, but not limited to balancing commodity charge revenues and transportation imbalance charges.

WC_{VC} Working Capital requirements associated with Total Supply Variable Costs. See item 5.0 for calculation.

R_V Deferred Cost Account Balance as of October 31, as derived in Item 6.0 plus the net of any Gas Procurement Incentives/Penalties associated with the Gas Procurement Incentive Plan.

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Dt_{VC} Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

3.4 Storage Variable Product Cost Component: The Storage Variable Product Cost Component shall include all variable storage product costs of firm gas, including, but not limited to, storage commodity costs, taxes on storage commodity and other gas Storage expense incurred to transport supplies, transportation fees, inventory commodity costs, inventory financing costs and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Variable Product Cost Component shall be identified and explained fully in the annual filing.

The Storage Variable Product Cost Component is calculated for each applicable rate schedule as follows:

$$VSC = \frac{TC_{VSC} - TR_{VSC} + WC_{VSC} + R_{VSC}}{Dt_{VSC}}$$

Where:

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GAS COST RECOVERY CLAUSE

VSC — Storage Variable Product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, or Extra Large Low and High Load C&I.

TC_{VSC} — Total Storage Variable Product Costs, including, but not limited to pipeline, storage, and commodity-billed pipeline transition costs associated with storage delivery.

TR_{VSC} — Total Credits to Storage Variable Product Costs.

WC_{VSC} — Working Capital requirements associated with Total Storage Variable Product Costs. See item 5.0 for calculation.

R_{VSC} — Deferred Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_{VSC} — Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

3.5 Storage Variable Non-product Cost Component: The Storage Variable Non-product Cost Component shall include all variable costs related to the operations, maintenance and delivery of storage, as determined in the most recent rate case proceeding, injection and withdrawal costs, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Variable Non-Product Cost Component shall be identified and explained fully in the annual filing.

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The Storage Variable Non-product Cost Component is calculated for each applicable rate schedule as follows:

$$SVNC_S = \frac{TC_{SVNC} - TR_{SVNC} + WC_{SVNC} + R_{SVNC}}{Dt_S}$$

Where:

$SVNC_S$ Storage Variable Non-product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

TC_{SVNC} Total Storage Variable Non-product Costs, all variable costs, including, but not limited to supply related local production and storage costs, injection and withdrawal costs, and taxes on storage. The level of supply related local production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SVNC} Total Credits to Storage Variable Non-product Costs.

WC_{SVNC} Working Capital requirements associated with Total Storage Variable Non-product Gas Costs. See Item 5.0 for calculation.

R_{SVNC} Deferred Storage Variable Non-product Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating,

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GAS COST RECOVERY CLAUSE

Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

4.0 POOL BALANCING

4.1 Purpose: This section establishes a procedure to allow the Company, subject to the jurisdiction of the RIPUC, to adjust on an annual basis its rates for firm pool balancing service set forth in Section 6, Schedule C, Item 5.04 of RIPUC NG-GAS No. 101

4.2 Calculation:

$$BAL = (FC + SFC + SVC) * 1\%$$

Where:

BAL — Balancing Charge for Pool Balancing Service applicable to Marketer pool throughput per percent of balancing service elected.

FC — Fixed Cost Component as calculated in Item 3.1 above.

SFC — Storage Fixed Cost Component as calculated in Item 3.2 above.

SVC — Storage Variable Product Cost Component as calculated in Item 3.4 above.

5.0 WORKING CAPITAL REQUIREMENT:

$$WC_M = WCA_M * [DL / 365] * COC$$

Where:

WC_M — Working Capital requirements of Supply Fixed (WC_{FC}), Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or

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Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M Working Capital Allowed in the Supply Fixed, Storage Fixed, Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL Days Lag approved in the most recent rate case proceeding.

COC Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended June as presented in the Company's annual Distribution Adjustment Clause (DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNT:

The Company shall maintain five (5) separate Deferred Gas Cost Accounts: (1) Supply Fixed Costs and revenues, (2) Storage Fixed Costs and revenues, (3) Supply Variable Costs and revenues, (4) Storage Variable Product Costs and revenues, and (5) Storage Variable Non-product Costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred, less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible % approved in the most recent rate case proceeding;

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GAS COST RECOVERY CLAUSE

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues.

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS

7.1 During Refund Period

If the Company receives a cash refund resulting from gas supply overcharges during a historical "refund period," where the historical "refund period" is the most recent 60-month period, and the amount of the refund equals or exceeds 2% of the Company's total gas costs for the prior fiscal year, the amount to be refunded to any firm customer who used gas during the refund period and who is not on the suspended debt file shall be equal to:

The customers' billed usage during Refund Period X

$$\frac{\text{Amount to be Refunded}}{\text{Firm Sales during Refund Period}}$$

where the Amount to be Refunded equals Total Amount of Refund minus the incremental costs incurred by the Company in effecting the distribution of the supplier refund.

The customer shall receive this amount in the form of:

1. A lump-sum bill credit if the customer's account is active or if the customer's final bill has not been paid; or

2. A personal check if the customers account is closed and paid in full and the amount of the check exceeds $25; or

3. A combination bill credit/personal check if the amount of the credit exceeds the unpaid balance of the customer's final bill.

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GAS COST RECOVERY CLAUSE

The total amount of individually calculated refunds of $2 or less to have been paid by check will be credited to the Deferred Gas Cost Account. Checks which are not deliverable or paid within 90 days of the mailing shall be canceled and also credited to the Deferred Gas Cost Account.

Should any canceled refund checks later become a liability of the Company, the cost shall be debited to the Deferred Gas Cost Account.

7.2 Prior To Refund Period: If the Company receives a cash refund resulting from gas supply overcharges during periods prior to the historical refund period, then the refund shall be credited to the appropriate Deferred Cost Account.

7.3 Less Than 2% If the amount of the refund is less than 2% of the Company's total gas cost for the prior fiscal year, it shall be credited to the appropriate Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor. Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the Transportation Terms and Conditions effective November 1 of each year or at such time as the Commission approves the rates.

Deleted: On or about June 1, the Company shall provide to marketers and the Division a preliminary update of its pipeline path costs and weighted system-wide average costs including supporting schedules that show the assumptions and methodologies used to develop the rates

Deleted: . In the event the Commission changes the date when new gas cost recovery (GCR) rates to a time other than November 1, the Company will make the new rates effective concurrent with the GCR rates or at such time as the Commission determines.

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TRANSPORTATION TERMS AND CONDITIONS

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1.0 GENERAL:

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TRANSPORTATION TERMS AND CONDITIONS

These terms and conditions apply to those Commercial and Industrial customers classified as Medium, Large, Extra Large, or Non-firm who purchase gas supplies from sources other than the Company for transportation service by the Company pursuant to RIPUC NG No.101, Section 5, Schedule B, C, and D, and Section 6, Schedule A, as well as to any Marketers designated to act on the Customer's behalf pursuant to a Transportation Service Application and executing a Marketer Aggregation Pool Service Agreement. Transportation service will also be governed by the Company's General Terms and Conditions of Service to the extent not inconsistent herewith.

The Company reserves the right to restrict the availability of Transportation Service should the number of customers exceed the capability of the Company to reliably administer the service or if the integrity of the distribution system is put at risk.

If a Customer requesting service hereunder has been a sales service customer of the Company at the same service location within the preceding twelve month period, any underrecovered or overrecovered gas costs attributable to such prior service under the Gas Cost Recovery Clause in Section 2, Schedule A, shall be determined and paid by Customer or credited to Customer's account. The calculation of such underrecovered or overrecovered gas costs shall be in accordance with the Customer Deferred Gas Cost Calculation Guideline as on file with the Commission from time to time.

1.01.0 TERM OF SERVICE:

1.01.1 FT-1 Transportation Service:

FT-1 Transportation Service will commence on the first day of a calendar month subject to satisfying the Company's Transportation Terms and Conditions and be for an initial term of up to one year to reflect a common anniversary of November 1st. Service shall continue thereafter on a year-to-year basis, unless terminated by Customer, marketer or the Company, effective with the

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TRANSPORTATION TERMS AND CONDITIONS

Customer's next billing cycle, upon at least thirty (30) days' advance written notice to the other. The Marketer shall be responsible for providing the Company with an executed Transportation Service Application for each customer account being added to its FT-1 Aggregation Pool no less than thirty (30) days prior to commencement of service. The Company's receipt of the Transportation Service Application initiates the thirty (30) day notice period.

1.01.2 FT-2 Transportation Service:

FT-2 Transportation Service will commence on the first day of a Customer's billing cycle subject to satisfying the Company's Transportation Terms and Conditions. Service shall continue thereafter on a year-to-year basis unless terminated by Customer, marketer or the Company, effective with the Customer's next billing cycle, upon at least fifteen (15) days advance written notice to the other. The Marketer shall be responsible for providing the Company with an executed Transportation Service Application for each Customer being added to its FT-2 Aggregation Pool no less than fifteen (15) days prior to commencement of service. The Company's receipt of the Transportation Service Application initiates the fifteen (15) day notice period.

1.01.3 Non-Firm Transportation (NFT) Service:

Customers classified as Non-Firm Transportation (NFT) will be able to commence transportation as of the first (1st) of any calendar month subject to meeting the nomination requirements established in Item 1.03 following and having submitted to the Company an executed Transportation Service Application.

A Customer's designation as NFS or NFT shall remain in effect until the Company is notified of a further change. Such notice is required by 9 a.m. two (2) business days before the start of the calendar month when such change is to take effect. Switching to or initiating transportation service mid-month is generally not allowed.

1.02.0 Designation Of Marketer:

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TRANSPORTATION TERMS AND CONDITIONS

1.02.1 Firm Transportation: Customers wishing to switch Marketers will be allowed to do so at the start of a calendar month, in the case of FT-1 Service, or at the start of a customer's billing cycle, in the case of FT-2 Service. The Customer and the new Marketer shall execute a new Transportation Service Application listing the new Marketer as their designated Marketer. The Company must receive the new Transportation Service Application at least thirty (30) days prior to the change in the case of FT-1 Service, and at least fifteen (15) days prior to the customer's meter read in the case of FT-2 Service. For an FT-1 Service customer without a capacity assignment from the Company, see Item 1.07 below, the Company must be notified of such change by 9 a.m. at least two (2) business days before the start of the calendar month The Company will not accept a Transportation Service Application which designates a Marketer that has not executed an Aggregation Pool Service Agreement. If a Customer switches marketers, switches transportation services and/or switches to sales service more than once in a twelve month period, an administrative charge of $50 shall be billed to the Customer to cover the processing of the request.

If the Company receives more than one Transportation Service Application for the same customer account with different designations of Marketer, the Company will contact the Customer for clarification and confirmation.

The Company will notify the Marketer of record in the event that a customer account assigned to the Marketer's Aggregation Pool is terminated.

Marketer must provide the Company with (30) days advance notice in the event that the Marketer terminates service to a Customer in its Aggregation Pool.

Customers not subject to Default Transportation Service in Item 2.04 below, may return to sales service with at least thirty (30) days advance notice, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability, and subject to the Company's Transitional Sales Service Rate,

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TRANSPORTATION TERMS AND CONDITIONS

Section 5 Schedule H, of the Commercial and Industrial Services.

These provisions for switching marketers or returning to Sales Service do not excuse the performance of any contractual obligations between the customer and a marketer, including the potential requirement of paying damages to the marketer for a breach of any such contractual obligation.

1.02.2 Non-Firm Transportation:

Switching Marketers is allowed at the start of any calendar month with the provision that the Company receive the Customer's Transportation Service Application designating the effective Marketer by 9 a.m. at least two (2) business days before the start of the month for which the switch is effective.

These provisions for switching marketers do not excuse the performance of any contractual obligations between the customer and a marketer, including the potential requirement of paying damages to the marketer for a breach of any such contractual obligation.

If the Company receives more than one Transportation Service Application for the same customer account with different designations of Marketer, the Company will contact the Customer for clarification and confirmation.

1.03.0 Nominations:

1.03.1 General:

Marketer shall provide notice via the Company's Electronic Bulletin Board the required information relative to Shipper and Transporting Pipeline names and contract number(s) on which deliveries will be made and the specified quantity of gas that Marketer will deliver to the Point(s) of Receipt on each day of the calendar month. Marketer is required to have separate nomination names and contract numbers for each of Marketer's Aggregation Pools. Additional information may be required by the Company.

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1.03.2 Dispatch Communication:

All nomination information shall be communicated to the Company's Gas Supply Operations Department via the Company's Electronic Bulletin Board (EBB). Marketer shall be responsible for monitoring the EBB 24 hours per day, seven days per week for dispatch purposes. In the event that the Company is unable to contact a Marketer regarding any nomination or dispatch, the Company may take any action it deems necessary to maintain system integrity as otherwise outlined in the General Terms and Conditions.

Deleted: Any nominations submitted via facsimile are due two (2) hours earlier than times indicated for the EBB and can be sent to (401) 333-3527.

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1.03.3 Initial Nominations:

The Nomination terms for FT-1 and NFT Service for deliveries to commence service on the first day of any calendar month will be submitted to the Company not later than the initial nomination deadline of the upstream Transporting Pipeline(s) transporting gas for Marketer. Such nominations will specify the quantity to be scheduled on each day of the month. The nomination requirements for FT-2 Service are described in Item 3.03 below.

As a condition of confirming any nomination, Company may direct Marketer to have gas delivered to an alternate Point of Receipt on the same Transporting Pipeline. Upon receipt of such directions, Marketer will arrange with the Transporting Pipeline to have gas delivered to the Point of Receipt designated by Company. Such alternate point of Receipt will remain the Point of Receipt for Marketer's gas for the period stated by the Company in its instructions until Company directs Marketer otherwise.

1.03.4 Subsequent Nominations:

After the first day of the calendar month, Marketer may alter its nomination, provided that the revised nomination for delivery on any day is submitted to Company not later than 1:00 PM, in the case of FT-1 and NFT Service, of the prior gas day. Any nomination submitted after the initial monthly nomination will include Marketer's anticipated quantities for the remainder of the calendar month. For FT-

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2 Service, the nomination requirements are described in Item 3.03 below.

1.03.5 Intra-Day Nominations:

For daily metered Aggregation Pools, the Company will accept and implement, on a best efforts basis, an intra-day nomination submitted after the nomination deadline for the following gas day but before the start of the following gas day. An intra-day nomination within the gas day will be accepted at the Company's sole discretion.

One (1) such nomination per gas day shall be accepted subject to confirmation by the Transporting Pipeline.

1.03.6 Scheduling of Service:

Company will attempt to confirm with Transporting Pipeline(s) that the nominated quantities equal the Scheduled Transportation Quantity. If such nomination is confirmed, the Company will schedule said quantities to the Marketer at the designated Point of Receipt(s).

If Marketer is purchasing gas at the Company's citygate, they are responsible for identifying the original delivering contract number, Shipper and any additional title transfers.

If Marketer's nominations on the Company's Electronic Bulletin Board are not consistent with nominations on Transporting Pipeline, then the smaller of the two nominations shall prevail, and all associated balancing and penalty assessments shall be based on the smaller nomination.

1.04.0 Protection Of System Operations:

1.04.1 Company Operational Flow Order (OFO):

Service hereunder may be limited as provided in the Company's General Terms and Conditions. Further, in the event that the Company determines in its sole judgment that it must take prompt action in order to maintain system integrity or to ensure Company's continued ability to provide service to its firm customers, the Company may declare a Critical Day or issue an OFO. In addition to the

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OFOs listed below, the Company shall have the right to issue any other OFO reasonably intended to serve the above stated purpose. The Company may take any one or more of the following actions:

(1) declare a Critical Day which would require Marketer to fully utilize upstream capacity that it received from Company through Capacity Release; and require Marketer to fully schedule storage resources allocated as part of FT-2 Service, i.e., up to the MDQ-U, prior to relying on peaking resources to the extent they are needed to meet their customer's demands;

(2) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess receipts; and

(3) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess takes.

An OFO will likely be issued at forty four (44) Degree Days or colder.

1.04.2 Pipeline Operational Flow Order:

If, at any time, an immediate upstream pipeline issues an order changing the requirements at the Point(s) of Receipt, then Company may so notify Marketer and direct Marketer to modify requirements at the Point(s) of Receipt to the extent necessary for Company to comply with the pipeline's order. Marketer will be responsible for coordinating with their customers regarding any necessary change to Customer's quantity of Gas Usage.

1.04.3 Marketer Responsibility:

In the event Company takes action to alleviate excess imbalances it will nonetheless remain the obligation of Marketer to make such further adjustments to nominations, both to Company, Shipper, and to Transporting Pipeline, during the remainder of the month to resolve accumulated imbalances or to account for subsequent changes in actual

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deliveries. Company's exercise of its authority under this section will have no effect on Marketer's liability for unauthorized overrun or imbalance penalties that apply to Marketer under this tariff or any similar charge, including scheduling penalties, imposed by any upstream Transporting Pipeline(s).

An operational flow order may be issued by the Company as a blanket order to all transportation customers, or to individual Marketer's Aggregation Pools, whose actions are determined by the Company to jeopardize system integrity.

For Critical Days or OFO's aggravated by underdelivery, the Marketer will be charged a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 102% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 0.1 times the Daily Index for the differences between said receipts and said usage that exceed 20% of said receipts [(Receipts – Usage) > (20% x Receipts)].

For Critical Days or OFO's aggravated by overdelivery, the Marketer will be charged a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 120% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 5 times the Daily Index for the differences between said receipts and said usage that exceed 2% of said receipts [(Receipts – Usage) > (2% x Receipts)].

1.05.0 Unauthorized Use:

In the event the Company provides a Marketer with as much notice as Company deems practicable of an Operational Flow Order per Item 1.04.0 or other curtailment of service and thereby reduces the Scheduled Transportation Quantity for delivery, the total Gas Usage by the Customer may not exceed the revised Scheduled Transportation Quantity. If, on any Gas Day, after notice

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of curtailment, the quantity of gas taken by Marketer's Customers in an Aggregation Pool, exclusive of NFT customers whose use under a curtailment is covered in Item 4.04 below, exceeds Marketer's Scheduled Transportation Quantity as so revised for the Aggregation Pool, and the Company has not authorized such excess quantity, then all such Gas Usage constitutes Unauthorized Use and is subject to an overrun penalty for each Dekatherm not delivered of 5 times the Daily Index. Such charges will be billed to the Marketer's account.

1.06.0 Shipper And Transporting Pipeline Requirements:

Marketer warrants with respect to each Aggregation Pool, that it has entered into the necessary agreements for the purchase and delivery of a gas supply to the Point of Receipt which it wants Company to transport and that it has entered into the necessary transportation agreements for the delivery of gas supply to the Point of Receipt. Marketer acknowledges that it must arrange for the delivery of Actual Transportation Quantities to the Company sufficient to include both the Scheduled Transportation Quantities and the applicable Company Fuel Adjustments.

In addition, Marketer warrants that at the time of delivery of its gas supply to the Point of Receipt, Marketer shall have good title to such gas, free of all liens, encumbrances and claims whatsoever. Marketer shall indemnify the Company and save it harmless from all suits, actions, debts, accounts, damage, costs, losses and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

1.07.0 Capacity Release:

Each Marketer serving any Customer migrating from Non-Firm Sales, Non-Firm Transportation or Firm Sales Service to FT-1 or FT-2 Transportation Service or from another Marketer's Aggregation Pool where they were previously assigned pipeline capacity by the Company, will be required to accept, for each such Customer account, an assignment of a portion of Company's firm interstate pipeline transportation capacity at maximum rates for an

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initial term of up to one year. The Company shall determine the quantity to be released, based on a pro-rata percentage of the customer account's Average Normalized Winter Day Usage to the system total, and the pipeline on which such capacity will be released. The quantity of capacity shall be set forth in the confirmation materials provided to the Marketer. For all Customers classified as Medium, Large or Extra-Large this quantity will be reviewed annually against the Customer's most recent usage patterns. Any change in Customer's required capacity will be reflected in a revised capacity release with the Marketer for effect on the following November 1st. In the event that a marketer stops delivering gas on behalf of an existing capacity exempt customer, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

Marketer shall be required to execute a Capacity Assignment Agreement at the time a Marketer establishes an Aggregation Pool or any other instruments reasonably required by Company or interstate pipeline necessary to effectuate such assignment. Marketer is responsible for utilizing and paying for the assigned capacity consistent with the terms and conditions of the interstate pipeline's tariffs and this tariff. Marketer is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition costs, pipeline overrun charges, annual change adjustments and all other applicable charges. These charges will be billed directly to the Marketer by the interstate pipeline.

All Capacity Assignments for FT-1 Transportation Service will be effective with the commencement of service. Capacity Assignments for FT-2 Customers will be effective the 1st of the upcoming month for Transportation Service Applications received prior to the 10th. For FT-2 Transportation Service Applications received on or after the 10th of the month, the capacity release will not be

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effective until the 1st of the month subsequent to the upcoming month.

Capacity assignments will be effective for an initial term of up to one year through the following November 1st. The capacity assignments shall be reviewed each November 1st and be subject to annual adjustment as described above. All releases hereunder will be subject to recall under the following conditions: (1) when required to preserve the integrity of the Company's facilities and service; (2) at the Company's option, whenever the Marketer fails to deliver gas in an amount equal to the Scheduled Transportation Quantity; and (3) any other conditions set forth in the capacity release transaction between the Marketer and the Company.

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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 per Dt charge is calculated by subtracting the charge per Dt for the released pipeline capacity from the Company's weighted average Upstream Transportation charges as identified in the Company's annual Gas Cost Recovery Filing. To the extent that the cost of such released pipeline capacity is less than the weighted average cost, the marketer shall be surcharged for such difference.

On or before August 1 each year, the Company shall calculate and provide to marketers, as defined in Section 6, Schedule C, Item 5.00, its best estimate of: (1) the over (under) recovery balance in its deferred gas cost account; and (2) the anticipated fixed costs for interstate pipeline capacity, storage and peaking supplies.

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During the calendar month of September, each Marketer will be required to submit a new Capacity Assignment Agreement indicating pipeline capacity path preferences based on the available paths identified in the Company's annual Gas Cost Recovery Filing. Each Marketer shall identify pipeline capacity preferences for: (1) existing customers, and (2) any new customers. Marketer shall have the right to retain capacity released on existing paths if such paths remain available. Any changes from the Marketer's previous election will be effective November 1st in conjunction with the updating of customer capacity quantities described above. Subject to availability, Marketers may change path preferences for assignment of pipeline capacity during the year for any new customers added to their Aggregation Pool by filing with the Company a new Capacity Assignment Agreement with at least 30 days advance notice.

The capacity released to a Marketer stays with the customer account on which it is based and as such, will be reassigned at such time that a Customer terminates their contract with a Marketer or reverts back to the Company as of the date of the customer's service termination.

Each Marketer's capacity assignment associated with Customers in an aggregation pool shall be reviewed on a monthly basis prior to the tenth (10th) calendar day of the month, and adjusted to reflect any net changes resulting from the addition and deletion of customers to the pool.

1.07.1 New Loads:

New Customers classified as Large or Extra-Large electing FT-1 transportation service will not be required to take assignment of the Company's capacity resources as described in 1.07.0 above. The consumption of such Customers may be subject to annual review and confirmation by the Company. Customers who fail to meet the minimum requirement for the Large classification shall be required to take assignment of the Company's capacity resources after no less than 60 days notice. Marketers for such customers may be responsible for obtaining citygate capacity at a specific citygate on the Company's system as determined by the Company. Such determination will be

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based on the customer's location, load characteristics and distribution system requirements.

In the event that a marketer stops delivering gas on behalf of a customer without Company assigned pipeline capacity, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

1.08.0 Facilities: Company shall own, operate and maintain, at its expense, its gas distribution facilities to the Point of Delivery. Customer shall furnish, maintain and operate the facilities required between Company's Point of Delivery and Customer's equipment.

1.9.0 Quality: Marketer is responsible for insuring that all gas received, transported and delivered hereunder to the Point of Receipt meets the quality specifications and standards outlined in the General Terms and Conditions of the Transporting Pipeline's FERC Gas Tariff.

1.10.0 Possession of Gas: Company shall be deemed to be in control and possession of transportation gas to be delivered in accordance with this service from receipt at the Point(s) of Receipt until it shall have been delivered to Customer at the Point of Delivery. Marketer shall be deemed to be in possession and control of the gas prior to such receipt by the Company and Customer shall be deemed to be in control and possession of transportation gas after such delivery by the Company to the Point of Delivery. Company shall have no responsibility with respect to such gas before it passes the Point of Receipt or after it passes such Point of Delivery or on account of anything which may be done, happen or arise with respect to such gas after Point of Delivery.

1.11.0 Provision of Future Taxes, Surcharges Fees, Etc.: In the event a tax of any kind is imposed or removed by any government authority upon the sale or transportation of gas or upon the gross revenues derived therefrom (exclusive, however, of taxes based on Company's net income), the rate for service to Customer and/or Marketer,

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as the Company deems appropriate, shall be adjusted by an amount equal to or otherwise properly reflecting said tax. Similarly, the effective rate for service hereunder shall be adjusted to reflect any refund or imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental authority.

1.12.0 Retention of Pipeline Fuel Adjustment: The Company shall retain in kind, from the quantities of gas actually delivered to the Point(s) of Receipt for Marketers' accounts, the amount thereof equal to the applicable Company Fuel Allowance. Such Company Fuel Allowance shall be calculated by the Company based upon an average of the Company's most recent five (5) years experience, fuel loss and unaccounted for or similar quantity based adjustments.

1.13.0 Limitations of Liability: The liability of the Company shall be limited in accordance with the provisions of the Company's General Terms and Conditions.

1.14.0 Force Majeure: Neither Company nor Marketer shall be liable to the other or to Customer for delays or interruptions in performing their respective obligations hereunder arising from any acts, delays or failure to act on the part of, or compliance by Marketer or Company with any operating standard imposed by any governmental authority, or by reason of an act of God, accident or disruption, including without limit, strikes or equipment failures, or any other reason beyond Marketer's or Company's control, provided, however, in the event of an occurrence of one or more of the foregoing events, reasonable diligence shall be used to over come such event. The party claiming force majeure shall, on request, provide the other party with a detailed written explanation thereof, and of the remedy being undertaken.

2.0 FT-1 TRANSPORTATION SERVICE:

2.01.0 Character of

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Service: This service provides firm, 365 day transportation of Customer purchased gas supplies to customers electing to have Gas Usage recorded on a daily basis at the Point of Delivery. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer shall assign Customer to an Aggregation Pool with other Customers electing FT-1 or NFT service or establish a one-customer Aggregation Pool and execute an appropriate Marketer Aggregation Pool Service Agreement. Specific Marketer requirements and obligations are described in Item 5.0 below.

2.02.0 Telemetering: The Company will provide at the Customer's expense, at the Point of Delivery to the Customer, a device that the Company will attach to its metering equipment for the purpose of monitoring the Gas Usage. The Customer shall be responsible to supply a dedicated electrical supply and a telephone line at a location acceptable to Company and capable of transmitting information collected from the monitoring device to the Company's computer system. The Customer shall be responsible for the maintenance and service of the telephone line. Should a dedicated phone line be required, it is the responsibility of the Customer to schedule the installation, to notify Company when such installation has been completed, and the Customer is responsible for any associated charges. FT-1 and NFT transportation service shall not commence until the telemetering equipment is in place and operational.

2.03.0 Balancing: FT-1 and NFT Service is subject to both Daily and Monthly balancing provisions. It will be the Marketer's responsibility to provide accurate and timely nominations of quantities proposed to be received and delivered by Company under this service and to maintain as nearly as possible, equality between the Gas Usage and the Actual Transportation Quantity. Marketer shall be solely responsible for securing faithful performance by Shipper and Transporting Pipeline, and the Company shall not be responsible as a result of any failure of Shipper or Transporting Pipeline to perform. Charges and Penalties

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associated with FT-1 and NFT balancing are billed to the Marketer.

2.03.1 Daily Imbalances: The Marketer must maintain a balance between daily receipts and daily usage within the following tolerances:

Off-Peak Season: The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 15% of said receipts. The Marketer shall be charged a penalty of 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 10% of said receipts. The Marketer shall be charged a penalty of 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an underdelivery or an overdelivery, and so notify the Marketer when a Critical Day is declared pursuant to Item 1.05 above.

If the Marketer has an accumulated imbalance within a month, the Marketer may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

2.03.2 Monthly Imbalances: For each Aggregation Pool, the Marketer must maintain total Actual Transportation Quantities within a reasonable tolerance of total monthly Gas Usage. Any differences between total Monthly Transportation Quantities for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a

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percentage of total Monthly Transportation Quantities will be cashed out according to the following schedule:

Imbalance Tier	Overdeliveries	Underdeliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month.
> 5% ≤ 10%	0.85 times the above stated rate	1.15 times the above stated rate
> 10% ≤ 15%	0.60 times the above stated rate	1.4 times the above stated rate
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% Underdelivery on a Delivering Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven consecutive Daily Indices.

All cash-out charges or credits, as determined above, will be applied to the Marketer's monthly invoice for the Aggregation Pool.

Designated Marketers may arrange with another of Company's Marketers providing service to the same Point of Receipt to exchange, purchase or sell daily or monthly imbalance gas. The Company will notify each Marketer of its monthly imbalance following the close of the billing month in which the imbalance occurs. Marketers will have

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three business days following such notification to notify Company of any imbalance exchange or sale and to confirm such transaction.

2.03.3 Pass-Through of Upstream Imbalance Charges:

In addition to other charges provided for in this Section, Marketer will be responsible for any imbalance charge or penalty imposed on Company by an upstream pipeline as a direct result of an imbalance, scheduling error, unauthorized overrun or other similar charges caused by Marketer. The Company shall assign imbalance penalties assessed to the Company by upstream pipelines to sales and transportation customers based on the extent that each group caused such penalties, as determined by the Company. The portion of any such penalty assigned to transportation service shall be further assigned to individual Marketers based on the extent to which each Marketer's Aggregation caused such penalties, as determined by the Company.

2.04.0 Default Transportation Service:

Default Transportation Service is available to any Commercial or Industrial customer account classified as Large or Extra Large that subscribes to FT-1 Transportation Service and that does not have pipeline capacity assignment from the Company. Customers electing this service must provide written notice to the Company via mail, FAX or E-mail that their marketer will no longer be delivering gas on their behalf and that they wish to avail themselves of the service. Such service will continue in effect until either service is established with a new marketer through the execution of a new Transportation Application per Item 1.03.1 above or service is terminated.

This service provides for a continuous supply of gas of not less than 1,000 Btu per cubic foot, and is provided on a best efforts basis with as little as 24 hours advance notice. Where notification is at least 24 hours in advance but less than three business days before the start of a calendar

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month, the service provided will be Short-Notice Default Transportation Service. Where notice is provided at least three business days prior to the start of a calendar month, the service provided will be Advance-Notice Default Transportation Service. Short-Notice Default Transportation Service will be switched to Advance-Notice Default Transportation Service at the start of a subsequent month once the service has been in effect for the three business day period before the start of such month.

Default Transportation Service is a temporary surrogate for provision of gas to a customer that would otherwise be provided by a marketer, hence it includes nominating and balancing. Customer must maintain an operational telemetering device as required in Item 2.02.0 above.

2.04.1 Rates:

Pricing for Default Transportation Services shall be set forth in a Price Sheet filed with the Commission. The Company and Default Transportation Service supplier shall review the pricing of these services annually and file necessary revisions with the Commission concurrent with the Company's annual Gas Cost Recovery Filing.

3.0 FT-2 TRANSPORTATION SERVICE:

3.01.0 Character of Service:

This service provides firm, 365 day transportation of Customer purchased gas supplies to customers without the requirement for recording daily Gas Usage at the Customer's Point of Delivery. Daily Nominations are calculated by the Company on the basis of a consumption algorithm, the marketer is obligated to deliver to the citygate such quantities, and any imbalances are netted against storage resources allocated to the Marketer on the Customer's behalf.

The Customer's designated Marketer, as identified on the Customer's Transportation Service Application, shall be allocated a quantity of Company contracted underground storage and peaking resources sufficient to meet the Customer's design winter supplemental supply requirements as determined by the Company. These

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resources are assigned to the Marketer pursuant to a written agreement with the Company, for the purpose of meeting the Company forecasted daily usage under the operational parameters described below. Additional Marketer requirements and obligations are described in Item 5.0 below.

3.02.0 Storage And Peaking Resources:

Annually, the Company will calculate a Customer's total storage and peaking resource requirements under design winter conditions based on the Customer's most recent historical usage. The result of the calculations will establish the Maximum Storage Quantity-Underground (MSQ-U) and Peaking (MSQ-P) allocated for Marketer's use. The calculations will also establish a Maximum Daily Quantity-Underground (MDQ-U) and Peaking (MDQ-P) to set operational parameters for daily withdrawals and injections.

3.02.1 Maximum Storage Quantity (MSQ):

The MSQ for a Customer is the difference between their weather normalized total consumption under design winter conditions for the November through March period, minus the quantity of gas that could be delivered with their pipeline capacity assignment. The MSQ is allocated between underground storage (MSQ-U) and Peaking (MSQ-P) in the same percentage as is available on a Company-wide basis. These quantities represent the maximum storage and peaking inventories available to the Marketer for meeting the Customer's Gas Usage needs and are key components in the operational parameters regarding management of the resources.

3.02.2 Maximum Daily Quantity - Storage (MDQ-S):

The Customer's MDQ-S is calculated by the Company as the difference between the Customer's peak day usage under design winter conditions and the Customer's pipeline capacity assignment. This MDQ-S requirement in MMBtu is then allocated between underground storage (MDQ-U) and Peaking (MDQ-P) in the same percentage as is available on a Company-wide basis. These quantities serve

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to define the maximum quantities that can be nominated for withdrawal by a Marketer and are a component of the operational parameters for the service.

3.02.3 Operational Parameters:

The storage resources inventory balance for the Underground Storage and Peaking accounts shall be tracked by the Company and made available to the Marketers via electronic means. These balances will be updated each Gas Day to reflect Marketer nominations for either injections or withdrawals. The balances will also be updated continuously to reflect imbalances identified at the time of the Customer's billing cycle which will be netted against the Underground Storage Account.

The Company will establish Maximum and Minimum inventory levels reflective of the Company's available resources. There will be separate inventory levels for both Underground Storage and Peaking Resources. Such levels will be as provided in the annual Gas Cost Recovery Filing.

In addition to operational parameters for overall inventory levels, there are both Daily and Monthly maximums established for the quantities which the Marketer can nominate for withdrawal or for injection. These factors vary by month and as the marketer's inventory level changes. Such factors will be as provided in conjunction with the annual Gas Cost Recovery Filing.

3.02.4 Inventory Purchases:

To meet the revised required minimum storage balance levels resulting from the addition of new customers to an Aggregation Pool, Marketer may trade or purchase storage supplies from another Marketer, make injections to underground storage or purchase inventory from the Company, subject to availability. The Company will update an FT-2 aggregation pool's MSQ assignments concurrent with the Customer's initiation of transportation service with the designated marketer.

At the time that a Customer migrates to FT-2 Transportation Service or switches Marketers, the new

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designated Marketer will have a one-time opportunity to purchase an amount of inventory, from the Company, based on the MSQ requirement of Customers being added to the aggregation pool and the month when transportation service will commence. The Company will calculate the amount of storage inventory to be made available and provide such information to the Marketer upon receipt of a completed Transportation Service Application. The Marketer will have 5 business days to respond to the Company's offer. For Customers migrating during the April through October period, the maximum amount of storage inventory sold to a Marketer will be calculated as follows:

Inventory Sold = (x/7)*Customer's MSQ

where:

Inventory Sold = the maximum amount of inventory the Company will sell to a Marketer
x = the number of off peak months since April 1st.
7 = the total number of off peak/storage injection months
Customer's MSQ = the Customer's total storage requirements under design winter conditions

Thus, for a Customer migrating to FT-2 service effective July 1, the Marketer would be able to purchase up to three-sevenths (3/7) of the Customer's MSQ from the Company to account for injections to storage during the months of April, May and June. The marketer would then be responsible for nominating sufficient injections during the July to October period to ensure that the inventory in storage for the FT-2 aggregation pool was at the minimum level identified in the Company's operational parameters

For Customers migrating during the peak period of November through March, the inventory sold will be based on the lesser of: (1) the added Customers' monthly minimum requirement outlined in the Company's operational parameters or (2) the incremental amount of inventory required to bring the Marketer's pool in compliance with the minimum requirement. For example,

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if the customer were to start transporting in February, the Marketer would have the option to purchase storage inventory from the Company in the amount equal to the February minimum inventory level of the Customer's MSQ. Marketer may purchase such amount from the Company at a rate calculated as indicated below.

The Company shall develop a price for the inventory based on the published NYMEX price, and adjusted for transportation, storage and carrying charges.

The price per Dt at the Company's citygate shall be calculated using the following formula:

$/Dt = NY + BS + TR + ST + CC

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where:

$/Dt	=	cost per MMBtu charged to Marketers for storage inventory at the Company's citygate
NY	=	NYMEX Settlement Price
BS	=	Basis Differential for East Louisiana
TS	=	Transportation Cost
ST	=	Storage Cost
CC	=	Carrying Cost

In the event that a Marketer fails to nominate or obtain sufficient storage inventory for its Customers such that the Aggregation Pool's inventory is below the operational parameter minimum, the Marketer will be unable to nominate storage or peaking quantities to satisfy the FDU.

For Customers commencing FT-2 transportation service during off-peak months (April - October), Marketer will receive an assignment of peaking inventory during the following October for a November 1st effective date. For Customers migrating to FT-2 during peak months (November - March), Marketer will receive an assignment of peaking inventory concurrent with the commencement of service. The amount of peaking inventory assigned shall be based on the lesser of: (1) the added Customers'

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monthly minimum requirement outlined in the Company's operational parameters or (2) the incremental amount required to bring the Marketer's pool in compliance with the minimum requirement. Marketers would be able to purchase peaking inventory from NG at the Company's weighted cost of LNG inventory. All transactions are subject to authorization by NG.

Marketers needing to sell underground storage inventory as a result of customers switching to other marketers would be able to sell the inventory to another marketer, subject to authorization by NG, nominate withdrawal of supplies, or sell the inventory in excess of the Maximum Storage Quantity to NG. Marketers with inventory levels in excess of the Maximum Storage Quantities may be required by the Company to nominate underground storage to satisfy their FDU. If the Marketer has excess peaking resources, they could nominate those inventories to the extent allowed under the operational parameters or would be required to sell such excess peaking resources to NG at the price the inventory was originally purchased from NG.

3.02.5 Rates:

The Marketer is responsible for procuring and maintaining inventory levels associated with the underground storage and peaking resources allocated by the Company as part of FT-2 Service. The following charges are for the recovery of the fixed costs and other miscellaneous costs associated with the provision of the underground storage and peaking resources and are billed to the Marketer:

FT-2 Throughput: $ per Therm Gas Usage . The rate is as calculated in the Company's most recent Gas Cost Recovery Filing.

3.03.0 Nominations:

The Company shall calculate the Forecasted Daily Usage (FDU) of the aggregation pool using a Consumption Algorithm for each of the customers in the aggregation pool. The Company shall have sole responsibility for such Consumption Algorithm and by selecting FT-2 service, Marketer agrees to abide by the results of such algorithm. The algorithm is:

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FDU = Base Load + (HU factor * FDD)

where:

FDU = an individual customer account's forecasted daily usage for the next gas day

Base Load = average daily consumption for the most recent July and August billing cycles

HU Factor = most recent billing cycle consumption, minus the base load, divided by the heating degree days for the billing cycle

FDD = forecasted heating degree days for the gas day starting at 10:00 AM the next day

FDU will be adjusted for any Company fuel allowance.

The Company will provide to the Marketer no later than 9:30 AM each day using an electronic posting or via facsimile the FDU for the next gas day which would start at 10:00 AM the next day. If the Company is unable to provide to the Marketer the FDU using an electronic posting or via facsimile before 9:30 AM, the default FDU will be the prior day's FDU. The Marketer shall be obligated to nominate any combination of pipeline, underground storage or peaking equal to the FDU for the next gas day. Such nomination is to be posted on the Company's Electronic Bulletin Board no later than 1:00 PM before the start of the next gas day. The Company shall not accept or confirm any nominations that are greater than the FDU of the aggregation pool and any nominations for storage and peaking resources must be in accordance with the applicable operational parameters. Quantities nominated for injection into storage are over and above quantities to meet the FDU. Any nominations to inject supplies into storage or nominate supplies from storage must be separately identified and made to the Company's citygate. If storage inventory is below the minimums established above, Marketer will not be able to nominate storage or peaking quantities to satisfy the FDU nomination requirement.

3.03.1 Critical Days: To satisfy the FDU nomination requirement on Critical Days, the Marketer is required to fully utilize upstream

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capacity that it received from Company through Capacity Release so as to help avoid restricting the Company's ability to provide efficient and reliable firm transportation and sales service. Notice of Critical Days will be posted on the EBB no later than concurrent with the posting of the FDU nomination requirement.

3.03.2 Under-deliveries: Any under-deliveries of the aggregation pool's gas requirements, up to the FDU, will be treated as Unauthorized Use and subject to penalty charges as provided in Item 1.06.0 above.

3.04.0 Balancing: Imbalances between customer Gas Usage and the Forecasted Daily Usage (FDU) will be netted out against the underground storage inventory at the time of a customer's billing cycle. Quantities used in excess of FDU will be subtracted from the underground storage inventory level. If Gas Usage is less than FDU, the difference will be treated as an injection to underground storage and added to the inventory level. All quantities will be adjusted for Company Fuel Allowance.

4.0 NFT SERVICE:

4.01.0 Character Of Service: This service provides interruptible transportation of Customer purchased gas supplies to customers with telemetering equipment and that are eligible to be classified under Section 6, Schedule A of the Company's Tariff. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer may assign Customer to an Aggregation Pool with other Customers electing NFT or FT-1 transportation service or establish a one-customer Aggregation Pool. Specific Marketer requirements and obligations are described in Item 5.0 below.

4.02.0 Nominations: The nomination requirements in Item 1.04.0 above apply to the provision of NFT Service.

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4.03.0 Imbalances: The Daily and Monthly Imbalance provisions in Items 2.03 above apply equally here.

4.04.0 Curtailments: Customer will curtail or discontinue service when, in the sole opinion of the Company, such curtailment or interruption is necessary in order for it to continue to supply the gas requirements of its firm customers at such time. The Company will attempt to give the customer and customer's marketer three (3) working days' notice of such curtailment, except in emergency situations, when at least one hour's notice shall be given.

For any period that a customer fails to curtail the use of gas as requested by the Company, the charge for gas consumption will be equal to the non-firm transportation service customer charge plus Gas Usage at a penalty of 5 times the Daily Index. Such use of gas under these circumstances shall be considered an "unauthorized use" of gas purchased from the Company, and billed to the customer's account.

In the event where the Company, in its sole discretion, grants the customer an exemption from the curtailment, the use of gas under these circumstances shall be referred to as an "authorized use of gas." Authorized use of gas during a curtailment will be for a limited time period and will be purchased from the Company. The charge for gas consumed under these conditions will be billed to the customer and based on the non-firm transportation service customer charge plus the Company's highest cost gas required to meet demand during the applicable curtailment period, plus the current firm sales service rate excluding the firm customer charges. Payments for this use, whether authorized or unauthorized, shall not preclude the Company from turning off the customer's supply of gas in the event of the failure to interrupt, or curtail, the use thereof when requested to do so.

5.00 MARKETER AGGREGATION SERVICE:

5.01.0 Character of

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Service: This service allows Marketers to aggregate customer accounts and form Aggregation Pools for the purpose of making initial and subsequent nominations, making delivery to a designated Point of Receipt, and for balancing of Actual Transportation Quantity with Gas Usage on Customer's behalf. The Company will transport gas, owned by the Customers of the Aggregation Pool, to the Point(s) of Delivery for each Customer included in such pool. A Marketer shall be designated by each Customer on the Transportation Service Application, and each such customer must be assigned by the Marketer to an Aggregation Pool of one or more customers. Changing the designated Marketer is allowed under the conditions in Item 1.02 above and is accomplished through the execution of a new Transportation Service Application. Once so designated, the Company will rely on information provided by the Customer's Marketer for nomination, balancing and scheduling purposes and all notices provided by the Company to Customer's Marketer shall be deemed to have been provided to the Customer.

5.02.0 Aggregation Pools: The aggregation of Customer accounts into an aggregation pool is limited by the transportation service of the respective Customers.

The Customer's transportation service restriction requires that Customers subscribing to non-daily metered FT-2 Service must be aggregated in a separate pool from Customers subscribing to daily metered FT-1 or NFT Service. Customers subscribing to FT-1 or NFT can be combined in a single Aggregation Pool. A separate Marketer Account will be established for each Marketer Aggregation Pool.

A further restriction on daily metered Aggregation Pools is that the election of a supplemental service such as Pool Balancing Service, shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool. Separate Aggregation Pools are required for FT-1 or NFT Service with Pool Balancing Service versus FT-1 or NFT Service without the supplemental service.

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The Marketer Aggregation Pool Service Agreement and Pool Balancing Service Agreement shall have an initial term through the following November 1st. Thereafter, the Marketer Aggregation Pool Service Agreement and Pool Balancing Service Agreement shall be automatically renewed for successive one year terms, unless notice of termination is provided by the Marketer on or before October 1st or if the Company has terminated the agreement under its collection procedures. Marketers may assign their Aggregation Pool Service Agreements to another certified Marketer with the Company's consent.

5.02.1 Rates:

The monthly aggregation pool charge is applicable only during months when Customers assigned to the pool are transporting.

Monthly Charge:

Daily Metered Pool	$ 150.00 per
Non-Daily Metered Pool	$ 450.00 per

5.03.0 Marketer Qualifications:

In order to be designated hereunder as a Marketer, the Marketer must meet the following qualifications:

(1) The Marketer must be authorized by the Rhode Island Public Utilities Commission in accordance with Commission Regulations for Utility Interaction with Gas Marketers;

(2) The Marketer must demonstrate to the Company that it meets the following creditworthiness standards:

A. The Marketer, or a guarantor, maintains a minimum rating from one of the rating agencies and no rating below the minimum from one of the other two rating agencies. For the purposes of this Section, minimum rating shall mean "BBB" from Standard & Poor's, "Baa2" from Moody's Investor Service, or "BBB" from Fitch Ratings (minimum rating)

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Deleted: The Marketer must demonstrate to the Company that it meets the creditworthiness standards established by either Algonquin Gas Transmission Company in Section 3.1 of their FERC Gas Tariff General Terms and Conditions, as in effect from time to time or by Tennessee Gas Pipeline in Section 11.5 of their FERC Gas Tariff General Terms and Conditions, as in effect from time to time. If Marketer is required to satisfy the Algonquin Gas Transmission Company's credit evaluation via the posting of a financial vehicle, as provided for under Section 3.2 of its tariff

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B. If a Marketer or a guarantor, is not rated by Standard & Poor's, Moody's Investor Service or Fitch Ratings, it shall satisfy the Company's creditworthiness requirements if the Marketer, or a guarantor maintains a minimum "1A2" rating from Dun & Bradstreet (Dun and Bradstreet minimum rating) and the Marketer maintains 24 months good payment history with the Company

C. In the event that the Marketer has not met the credit standards above, then the Marketer must so notify the Company and the Marketer will be required to use one of the financial vehicles specified in 5.03.2 to satisfy the Company's credit standards.

(3) Marketers must have an executed Marketer Aggregation Pool Service Agreement with the Company and accepted its designation as the marketer for each customer by countersigning the applicable Transportation Service Application.

(4) Marketers must provide the Company with a copy of their GET exemption certificate, state sales tax exemption certificate or other appropriate exemption certificate(s) in order to be exempt from the applicable taxes.

5.03.1 Calculation of Credit Risk and Security for Natural Gas Imbalance Risk: The Company may require a Marketer to provide security equal to three times the highest month's gas usage of the Marketer's Aggregation Pool at the firm sales rate applicable to the upcoming peak period. This amount may be updated at the Company's discretion.

5.03.2 Security Instruments: The following financial arrangements are acceptable methods of providing security:

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- A standby irrevocable letter of credit; or¶
- A guarantee, acceptable by the Company, by another person or entity which satisfied creditworthiness.
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Deleted: The Company shall base a Marketer's financial liability as three times the highest month's gas usage of the Aggregation Pool at the firm sales rates applicable to the upcoming peak period. This amount may be updated at the Company's discretion. The Marketer agrees that the Company has the right to access and apply the deposit, letter of credit or other financial vehicle to any payment obligations, not in dispute, which are deemed by the Company to be late. The Company may review and determine the status of a Marketer's creditworthiness at its sole discretion. If Marketer is unable to maintain the Company's credit approval or otherwise ceases to meet the Marketer Qualifications, the Company may terminate the Marketer Aggregation Pool Agreement as of the first day of the month following written notice to Marketer.¶
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(1) Deposit or prepayment, which shall accumulate interest at the applicable rate per annum approved by the Rhode Island Public Utilities Commission;
(2) Standby irrevocable letter of credit or surety bond issued by a bank, insurance company or other financial institution with at least an "A" bond rating;
(3) Security interest in collateral; or,
(4) Guarantee by another party or entity with a credit rating of at least "BBB" by S&P, "Baa2" by Moody's, or "BBB" by Fitch; or
(5) Other means of providing or establishing adequate security.

The Company may refuse to accept any of these methods for just cause provided that its policy is applied in a nondiscriminatory manner to any Marketer.
If the credit rating of a bank, insurance company, or other financial institution that issues a letter of credit or surety bond to a Marketer falls below an "A" rating, the Company shall allow a minimum of five business days for a Marketer to obtain a substitute letter of credit or surety bond from an "A" rated bank, insurance company, or other financial institution.

The Marketer agrees that the Company has the right to access and apply the deposit, letter of credit or other financial vehicle to any payment obligations, not in dispute, which are deemed by the Company to be late. The Company may review and determine the status of a Marketer's creditworthiness at its sole discretion. If Marketer is unable to maintain the Company's credit approval or otherwise ceases to meet the Marketer Qualifications, the Company may terminate the Marketer Aggregation Pool Agreement as of the first day of the month following written notice to Marketer.

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5.04 Pool Balancing

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Service:

Service is available for daily metered Marketer Aggregation Pools concurrent with the term of the Aggregation Pool.

The intent of this service is to accommodate minor, unintentional imbalances between an Aggregation Pool's Customer's daily usage at the Point(s) of Delivery and Actual Transportation Quantities delivered to the Company's distribution system at the Point of Receipt. Marketer must notify the Company by October 1st to elect Pool Balancing Service commencing November 1st or at least thirty (30) days prior to establishment of an Aggregation Pool.

Under the Pool Balancing Service, the Company agrees to provide a daily balancing service for imbalances up to a Marketer designated Maximum Daily Balancing Entitlement. Such entitlement is expressed as a percentage of the Aggregation Pool's Gas Usage and includes the 10% tolerance described in Item 2.03.1 above. Daily imbalances greater than the Marketer designated Maximum Daily Balancing Entitlement will remain subject to the balancing provisions outline in the Company's Terms and Conditions of Transportation Service.

The Company reserves the right to limit service offered under this schedule, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability or force majeure, or as otherwise provided in the Company's Terms and Conditions.

5.04.1 Pool Balancing Rate:

Variable Charge: $ per Therm Gas Usage per percent elected (Maximum Daily Balancing Entitlement % net of 10% standard tolerance)

Where:
- The rate is as calculated in the Company's annual Gas Cost Recovery Filing.
- Gas Usage is total of all Aggregation Pool Customers.
- Maximum Daily Balancing Entitlement % is specified in Marketer Aggregation Pool

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Agreement and includes the 10% standard tolerance.

5.05 Billing:

Billing for monthly customer charges and transportation charges for quantities actually delivered shall be based on the readings at each individual meter for the Customer and billed on a billing cycle basis to the Customer. The Customers and Marketers shall be liable for all rates, charges and surcharges allowed for in the Company's Rate Schedules related to transportation services provided to each customer individually.

Calculation of charges applicable to the Aggregation Pool will be based on aggregated Gas Usage, MDQ's, etc. of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, e.g., imbalance charges, credits or penalties, and FT-2 Throughput charges shall be billed to the Marketer on a calendar month basis.

All bills rendered to the Marketer are due within 10 days from the date of the invoice. A late payment charge, in accordance with regulations of the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers, shall accrue after 10 days.

6.0 SERVICE AGREEMENTS: (See Attached Sheets)

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The Narragansett Electric Company, Transportation Service Application

This Transportation Service Application ("Application") must be completed by the customer and the marketer prior to the commencement of the requested Transportation Service.

NG:	The Narragansett Electric Company d/b/a National Grid 175 East Old Country Road Hicksville, NY 11801 Attn: Supplier Services	Customer:	_____ _____ _____ ( ) _____
Notice to:	Customer Contact Center: 1-800-870-1664	Notice to:	_____ ( ) _____

The Customer hereby requests Transportation Service subject to the NG General Terms and Conditions, Section 1 of RIPUC NG-GAS No. 101, its Transportation Terms and Conditions, Section 6, Schedule C and, under the terms and conditions set forth herein. NG shall review this Application and notify the Customer of its approval or rejection by way of a Confirmation Letter that shall set forth the terms and conditions of the Customer's Transportation Service. Upon Customer's and Marketer's fulfillment of all conditions set forth in the Confirmation Letter, such Confirmation shall represent an Agreement by NG to provide Transportation Service consistent with this Application and the Transportation Terms and Conditions set forth in Section 6, Schedule C of RIPUC NG-GAS No. 101.

Account Number	Meter Number	Service Address	FT-1	NFT	FT-2
1)					
2)					
3)					

1. Transportation Service shall commence in accordance with Item 1.02, Section 6, Schedule C of RIPUC NG-GAS No. 101
2. FT-1 and NFT Services require telemetry. A telemetering device and related equipment installed by NG shall remain NG property at all times. The Customer shall provide NG with access to a phone line that meets NG specifications for telemetering purposes. The customer is financially obligated for the costs to acquire, install and operate the telemetering device and related equipment.
3. Provision of transportation service based on this Application shall have an initial term through the following November 1st, unless sooner terminated in accordance with the terms and conditions of NG's Tariff, and shall continue thereafter from year to year unless terminated by customer, marketer, or NG upon not less than 30 days prior written notice.

Public Regulation

The Narragansett Electric Company is a public utility subject to regulation by the Rhode Island Public Utilities Commission ("Commission"). The provision of transportation service as a result of this Application is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to this Application. Compliance by NG with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the commencement of transportation service, shall relieve NG of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of such service, either NG, the customer, or the marketer shall have the option to terminate transportation service by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

Customer Signature	Title	
Print or Type Name	Date	Phone #
Contact in event of telecommunications issue : Print or Type Name		Phone #

This section to be filled out by the Marketer

By signing below and pursuant to its separate Marketer Aggregation Pool Service Agreement, the Marketer (i) accepts the designation as the customer's marketer and (ii) agrees to pay all applicable marketer charges in accordance with NG's tariff, including its Transportation Terms and Conditions

Marketer	Marketer Signature	Title
Phone #	Print or Type Name	Date

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THE NARRAGANSETT ELECTRIC COMPANY
MARKETER AGGREGATION POOL SERVICE AGREEMENT

This Agreement ("Agreement") is entered into this _____ day of _____, 200__, by and between The Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and _____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C, provides for and establishes terms and conditions for a Marketer Aggregation Pool; and

WHEREAS; Marketer desires to establish an Aggregation Pool and desires Company to provide pool aggregation services pursuant to such Schedule C and to transport quantities of gas delivered by Marketer for use at the locations of customers belonging to the Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing _____ 1, 200__, will transport and deliver to customers of Marketer's Aggregation Pool such quantities of Marketer's gas delivered by Transporting Pipeline to Company's distribution facilities (hereafter called "Point of Receipt").

1.0 AGGREGATION POOL:

1.1 Marketer is establishing a single Aggregation Pool as indicated by an X:

Daily Metered _____
Non-daily Metered _____

1.2 Marketer hereby subscribes to Company's Marketer Aggregation Service pursuant to Item 5.00 of the Company's Transportation Terms and Conditions, Section 6, Schedule C.

1.3 Marketer elects to subscribe to Company's Aggregation Pool Balancing Service pursuant to Item 5.04 of Company's Transportation Terms and Conditions, Section 6, Schedule C, NO _____ YES _____ with a Maximum Daily Balancing Entitlement of _____% (which % includes the standard 10% tolerance).

1.4 Marketer represents and warrants that Marketer has met and will continue to meet the Marketer qualifications in Item 5.03 of Company's Transportation Terms and Conditions, Section 6, Schedule C.

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1.5 Marketer agrees to provide to Company no later than 30 days before the above identified commencement date Transportation Service Applications for all end user customers in Marketer's Aggregation Pool identified in 1.1 above. Such list is to include: Customer Name; Billing Address; NG account #; and, name and telephone number of customer contact person.

1.6 Marketer agrees to notify Company in writing of any changes in the makeup of an Aggregation Pool as provided in the Company's Transportation Terms and Conditions.

1.7 Marketer represents and warrants that it has accepted the designation as the Marketer of each customer of the Aggregation Pool and agrees in each case to be bound by, perform, and pay all charges applicable to transportation service to the Customer's account in accordance with the provisions of the Company's tariff.

2.0 PIPELINE CAPACITY RELEASE:

2.1 Company agrees to provide to Marketer no later than 15 days before the above identified commencement date, the quantity of interstate pipeline capacity allocated for Marketer's FT-1 and FT-2 Aggregation Pool(s) broken down by individual customer.

2.2 Marketer agrees to accept assignment of such firm interstate pipeline capacity in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

2.3 Company agrees to update the calculation of the quantity of interstate pipeline capacity annually based on customers' most recent historical usage in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

3.0 PUBLIC REGULATION:

3.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

3.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement.

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4.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By _____

Signature: _____

Name: _____

Title: _____

_____ Date: _____

Witness

By The Narragansett Electric Company

Signature: _____

Name: _____

Title: _____

_____ Date: _____

Witness

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THE NARRAGANSETT ELECTRIC COMPANY
STORAGE AND PEAKING RESOURCE AGREEMENT

This Agreement ("Agreement") is entered into this _____ day of _____, 200__, by and between the Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and _____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, Marketer seeks to obtain service respecting a quantity of the Company's contracted underground storage and peaking resources pursuant to the terms and conditions for FT-2 Transportation Service in the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C; and

WHEREAS; Marketer desires that the Company transport quantities of gas delivered by Marketer for use at the locations of customers belonging to an FT-2 Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such storage and transportation service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing _____ 1, 200__, will provide to Marketer storage and peaking services in association with Marketer account number _____ under the terms and conditions set forth below.

1.0 SCOPE OF AGREEMENT:

1.1 The Company will calculate the Maximum Storage Quantities for both Underground Storage and for Peaking services ("MSQ-U" and "MSQ-P" respectively) as well as the Maximum Daily Quantities for both Underground Storage and Peaking services ("MDQ-U" and "MDQ-P" respectively) in accordance with Item 3.02 in Section 6, Schedule C of the Company's tariff. Such calculated quantities can change during the term of the agreement to the extent that the makeup of the Marketer's FT-2 Aggregation Pool changes.

1.2 Marketer hereby agrees to utilize and manage such services and inventories attributed to its account in accordance with the Operational Parameters described in Item 3.02.3 of the Company's Transportation Terms and Conditions, Section 6, Schedule C and as on file with the Public Utilities Commission as part of the Company's annual Gas Cost Recovery filing.

2.0 INVENTORY SERVICES:

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2.1 All nominations for either withdrawals from or injections to storage will take place at the Company's citygate.

2.2 Purchases of inventory service from the Company will be at the Company's weighted average storage commodity cost of gas at the time of purchase or as otherwise stated in the Company's currently effective tariff.

2.3 Purchase of any storage inventory service from the Company will require payment via electronic transfer of funds within ten days of invoice unless the Marketer and Company mutually agree to payment over a 3 month period, which would include a monthly finance charge based on a monthly rate using the latest published Fleet Prime less 200 basis points (2%).

2.4 Notwithstanding any provisions to the contrary, Marketer acknowledges and warrants that sale and marketable title to any storage gas injected into the Company's system shall thereupon transfer to the Company, and that Marketer's interests shall thereafter be limited to the contractual rights to service as provided by this Agreement. Marketer further acknowledges that it shall bear no ownership interest in any other storage or peaking assets or inventory of the Company.

2.5 If Marketer needs to sell or assign its service rights representing underground storage inventory attributed to its account as a result of customers switching to other marketers, it may, subject to authorization by NG, sell the inventory rights to another marketer, nominate withdrawal of supplies, or sell the inventory to NG. Marketers with inventory levels in excess of the Maximum Storage Quantities may be required by the Company to nominate underground storage to satisfy their FDU. If the Marketer has excess peaking resources, it could nominate those inventories to the extent allowed under the operational parameters or would be required to sell such excess peaking resource rights to NG at the price the inventory was originally purchased from NG.

3.0 SUCCESSORS AND ASSIGNS:

3.1 This Agreement shall be binding on the parties hereto and their respective successors and assigns. This Agreement may not be assigned by Marketer without the prior written consent of the Company.

4.0 PUBLIC REGULATION:

4.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of

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any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

4.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission, including provision thereof limiting the Company's liability, to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement. Upon request of the Marketer, Company shall provide the Marketer with a copy of Company's complete filed Tariff and Terms and Conditions.

5.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By _____

Signature: _____

Name: _____

Title: _____

Witness _____ Date: _____

By The Narragansett Electric Company

Signature: _____

Name: _____

Title: _____

Witness _____ Date: _____

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THE NARRAGANSETT ELECTRIC COMPANY

d/b/a NATIONAL GRID

Rhode Island Public Utilities Commission Tariff

RIPUC NG-GAS No. 101

"CLEAN" Tariff Pages

GAS COST RECOVERY CLAUSE

1.0 GENERAL:

1.1 Purpose: The purpose of this clause is to establish procedures that allow the Company, subject to the jurisdiction of the Rhode Island Public Utilities Commission ("RIPUC"), to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity in order to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, purchased gas working capital, and to credit supplier refunds, capacity credits from off-system sales and revenues from capacity release transactions.

The Gas Cost Recovery Clause shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory costs, requirements for purchased gas working capital, all applicable taxes, and deferred gas costs. Any costs recovered through the application of the Gas Charge shall be identified and explained fully in the annual filing.

1.2 Applicability: The Gas Charge shall be calculated separately for the following rate groups:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Large C&I High Load Factor, Extra Large C&I High Load Factor ;
(2) Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large C&I Low Load Factor, and Extra Large C&I Low Load Factor;
(3) ;FT-2 Firm Transportation – Marketers
(4) Natural Gas Vehicles

The Company will make annual Gas Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Gas Charge shall become effective with consumption on or after November 1st as designated by the Company. In the event of any change subsequent to the November effective date which would

GAS COST RECOVERY CLAUSE

cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than one (1) percent of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

Unless otherwise notified by the RIPUC, the Company shall submit the Gas Charge filings no later than 60 days before they are scheduled to take effect. The Annual Reconciliation filing will be made by August 1 of each year containing actual data for the twelve months ending June 30 of that year.

2.0 GAS CHARGE FACTORS

2.1 Gas Charges to Sales Customers:

The Gas Charge consists of five (5) 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. These components shall be computed using a forecast of applicable costs and volumes for each firm rate schedule based on the following formula:

$$GC_S = FC_S + SFC_S + VC_S + SVC_S + SVNC_s$$

Where:

GC_S Gas Charge applicable to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I sales.

FC_S Supply Fixed Cost Component for a rate classification. See Item 3.1 for calculation.

SFC_S Storage Fixed Cost Component for a rate classification. See Item 3.2 for calculation.

VC_S Supply Variable Cost Component for a rate classification. See Item 3.3 for calculation.

GAS COST RECOVERY CLAUSE

SVC_S Storage Variable Product Cost Component for a rate classification. See Item 3.4 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component for a rate classification. See Item 3.5 for calculation.

This calculation will be adjusted for the uncollectible percentage approved in the most recent rate case proceeding and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule D.

2.2 Gas Charge to FT-2 Marketers: The FT-2 Firm Transportation Marketer Gas Charge (GC_M) recovers costs associated with storage and peaking resources and is calculated as follows:

$$GC_M = SFC_S + SVNC_S$$

Where:

GC_M Gas Charge applicable to Marketers for FT-2 Firm Transportation Service

SFC_S Storage Fixed Cost Component. See Item 3.2 for calculation.

$SVNC_S$ Storage Variable Non-product Cost Component. See Item 3.5 for calculation.

2.3 Gas Charge to Natural Gas Vehicles: The Natural Gas Vehicle Gas Charge (GC_{NGV}) recovers costs associated with natural gas distributed to the public at Company owned NGV stations and is calculated as follows:

$$GC_{NGV} = FC_S + VC_S$$

Where:

GAS COST RECOVERY CLAUSE

GC_{NGV} Gas Charge applicable to Natural Gas Vehicle (NGV) Service

FC_S Supply Fixed Cost Component. See Item 3.1 for calculation.

VC_S Supply Variable Cost Component. See Item 3.3 for calculation.

3.0 GAS CHARGE CALCULATIONS

3.1 Supply Fixed Cost Component:

The Supply Fixed Cost Component shall include all fixed costs related to the purchase of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Fixed Cost Component shall be identified and explained fully in the annual filing.

The Supply Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$FC_S = \frac{DWS_S * (TC_{FC} - TR_{FC} + WC_{FC} + R_{FC})}{Dt_S}$$

Where:

FC_S Supply Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

GAS COST RECOVERY CLAUSE

DWS_S Percent of Design Winter Sales (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

TC_{FC} Total Supply Fixed Costs, including, but not limited to pipeline and supplier reservation.

TR_{FC} Credits to Supply Fixed Costs relating to supply services, including, but not limited to balancing charge revenues, capacity release revenues, off-system sales margins and refunds.

WC_{FC} Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

R_{FC} Deferred Fixed Cost Account Balance as of October 31, as derived in Item 6.0 less the amount guaranteed to customers under the Natural Gas Portfolio Management Plan (NGPMP) and, following approval by the Commission, the net positive revenue from optimization transactions reduced by the guaranteed amount and the Company incentive under the Plan.

Dt_S Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

3.2 Storage Fixed Cost Component: The Storage Fixed Cost Component shall include all fixed costs related to the operations, maintenance and delivery of storage, including, but not limited to, supply related portion of local production and storage costs as determined in the most recent rate case proceeding, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased

GAS COST RECOVERY CLAUSE

gas working capital. Any costs recovered through the application of the Storage Fixed Cost Component shall be identified and explained fully in the annual filing.

The Storage Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$SFC_S = \frac{DWT_S * (TC_{SFC} - TR_{SFC} + WC_{SFC} + R_{SFC})}{Dt_S}$$

Where:

SFC_S Storage Fixed Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

DWT_S Percent of Design Winter Throughput (November - March) for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I ,Extra Large Low and High Load C&I, or FT-2 service.

TC_{SFC} Total Fixed Storage Costs, all fixed costs, including, but not limited to supply related local production and storage costs, and taxes on storage. The level of supply related local production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SFC} Total Credits to Storage Fixed Costs

WC_{SFC} Working Capital requirements associated with Total Storage Fixed Costs. See Item 5.0 for calculation.

GAS COST RECOVERY CLAUSE

R_{SFC} Deferred Storage Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

3.3 Supply Variable Cost Component: The Supply Variable Cost Component shall include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Variable Cost Component shall be identified and explained fully in the annual filing.

The Supply Variable Cost Component is calculated for each applicable rate schedule as follows:

$$VC = \frac{TC_{VC} - TR_{VC} + WC_{VC} + R_V}{Dt_{VC}}$$

Where:

VC Supply Variable Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

TC_{VC} Total Supply Variable Costs, including, but not limited to pipeline, supplier, and commodity-billed pipeline transition costs.

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TR_{VC} Total Credits to Supply Variable Costs, including, but not limited to balancing commodity charge revenues and transportation imbalance charges.

WC_{VC} Working Capital requirements associated with Total Supply Variable Costs. See item 5.0 for calculation.

R_V Deferred Cost Account Balance as of October 31, as derived in Item 6.0 plus the net of any Gas Procurement Incentives/Penalties associated with the Gas Procurement Incentive Plan.

Dt_{VC} Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I, and NGV.

3.4 Storage Variable Product Cost Component: The Storage Variable Product Cost Component shall include all variable storage product costs of firm gas, including, but not limited to, storage commodity costs, taxes on storage commodity and other gas Storage expense incurred to transport supplies, transportation fees, inventory commodity costs, inventory financing costs and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Variable Product Cost Component shall be identified and explained fully in the annual filing.

The Storage Variable Product Cost Component is calculated for each applicable rate schedule as follows:

$$VSC = \frac{TC_{VSC} - TR_{VSC} + WC_{VSC} + R_{VSC}}{Dt_{VSC}}$$

Where:

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VSC — Storage Variable Product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, or Extra Large Low and High Load C&I.

TC_{VSC} — Total Storage Variable Product Costs, including, but not limited to pipeline, storage, and commodity-billed pipeline transition costs associated with storage delivery.

TR_{VSC} — Total Credits to Storage Variable Product Costs.

WC_{VSC} — Working Capital requirements associated with Total Storage Variable Product Costs. See item 5.0 for calculation.

R_{VSC} — Deferred Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_{VSC} — Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

3.5 Storage Variable Non-product Cost Component: The Storage Variable Non-product Cost Component shall include all variable costs related to the operations, maintenance and delivery of storage, as determined in the most recent rate case proceeding, injection and withdrawal costs, taxes on storage, delivery of storage gas to the Company's Distribution System, and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Variable Non-Product Cost Component shall be identified and explained fully in the annual filing.

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The Storage Variable Non-product Cost Component is calculated for each applicable rate schedule as follows:

$$SVNC_S = \frac{TC_{SVNC} - TR_{SVNC} + WC_{SVNC} + R_{SVNC}}{Dt_S}$$

Where:

$SVNC_S$ Storage Variable Non-product Cost Component for Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, Extra Large Low and High Load C&I or FT-2 service.

TC_{SVNC} Total Storage Variable Non-product Costs, all variable costs, including, but not limited to supply related local production and storage costs, injection and withdrawal costs, and taxes on storage. The level of supply related local production and storage costs shall be as determined in most recent rate case proceeding.

TR_{SVNC} Total Credits to Storage Variable Non-product Costs.

WC_{SVNC} Working Capital requirements associated with Total Storage Variable Non-product Gas Costs. See Item 5.0 for calculation.

R_{SVNC} Deferred Storage Variable Non-product Cost Account Balance as of October 31, as derived in Item 6.0.

Dt_S Forecast of annual sales related to Residential Non-Heating, Low Income Residential Non-Heating,

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Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I. Extra Large Low and High Load C&I and throughput related to FT-2 service.

4.0 POOL BALANCING

4.1 Purpose: This section establishes a procedure to allow the Company, subject to the jurisdiction of the RIPUC, to adjust on an annual basis its rates for firm pool balancing service set forth in Section 6, Schedule C, Item 5.04 of RIPUC NG-GAS No. 101

4.2 Calculation:

$$BAL = (FC + SFC + SVC) * 1\%$$

Where:

BAL — Balancing Charge for Pool Balancing Service applicable to Marketer pool throughput per percent of balancing service elected.

FC — Fixed Cost Component as calculated in Item 3.1 above.

SFC — Storage Fixed Cost Component as calculated in Item 3.2 above.

SVC — Storage Variable Product Cost Component as calculated in Item 3.4 above.

5.0 WORKING CAPITAL REQUIREMENT:

$$WC_M = WCA_M * [DL / 365] * COC$$

Where:

WC_M — Working Capital requirements of Supply Fixed (WC_{FC}), Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or

GAS COST RECOVERY CLAUSE

Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M Working Capital Allowed in the Supply Fixed, Storage Fixed, Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL Days Lag approved in the most recent rate case proceeding.

COC Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended June as presented in the Company's annual Distribution Adjustment Clause (DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNT: The Company shall maintain five (5) separate Deferred Gas Cost Accounts: (1) Supply Fixed Costs and revenues, (2) Storage Fixed Costs and revenues, (3) Supply Variable Costs and revenues, (4) Storage Variable Product Costs and revenues, and (5) Storage Variable Non-product Costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred, less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible % approved in the most recent rate case proceeding;

GAS COST RECOVERY CLAUSE

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues.

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS

7.1 During Refund Period

If the Company receives a cash refund resulting from gas supply overcharges during a historical "refund period," where the historical "refund period" is the most recent 60-month period, and the amount of the refund equals or exceeds 2% of the Company's total gas costs for the prior fiscal year, the amount to be refunded to any firm customer who used gas during the refund period and who is not on the suspended debt file shall be equal to:

The customers' billed usage during Refund Period X

$$\frac{\text{Amount to be Refunded}}{\text{Firm Sales during Refund Period}}$$

where the Amount to be Refunded equals Total Amount of Refund minus the incremental costs incurred by the Company in effecting the distribution of the supplier refund.

The customer shall receive this amount in the form of:

1. A lump-sum bill credit if the customer's account is active or if the customer's final bill has not been paid; or

2. A personal check if the customers account is closed and paid in full and the amount of the check exceeds $25; or

3. A combination bill credit/personal check if the amount of the credit exceeds the unpaid balance of the customer's final bill.

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The total amount of individually calculated refunds of $2 or less to have been paid by check will be credited to the Deferred Gas Cost Account. Checks which are not deliverable or paid within 90 days of the mailing shall be canceled and also credited to the Deferred Gas Cost Account.

Should any canceled refund checks later become a liability of the Company, the cost shall be debited to the Deferred Gas Cost Account.

7.2 Prior To Refund Period: If the Company receives a cash refund resulting from gas supply overcharges during periods prior to the historical refund period, then the refund shall be credited to the appropriate Deferred Cost Account.

7.3 Less Than 2% If the amount of the refund is less than 2% of the Company's total gas cost for the prior fiscal year, it shall be credited to the appropriate Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor. Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the Transportation Terms and Conditions effective November 1 of each year or at such time as the Commission approves the rates.

TRANSPORTATION TERMS AND CONDITIONS

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1.0 GENERAL:

TRANSPORTATION TERMS AND CONDITIONS

These terms and conditions apply to those Commercial and Industrial customers classified as Medium, Large, Extra Large, or Non-firm who purchase gas supplies from sources other than the Company for transportation service by the Company pursuant to RIPUC NG No.101, Section 5, Schedule B, C, and D, and Section 6, Schedule A, as well as to any Marketers designated to act on the Customer's behalf pursuant to a Transportation Service Application and executing a Marketer Aggregation Pool Service Agreement. Transportation service will also be governed by the Company's General Terms and Conditions of Service to the extent not inconsistent herewith.

The Company reserves the right to restrict the availability of Transportation Service should the number of customers exceed the capability of the Company to reliably administer the service or if the integrity of the distribution system is put at risk.

If a Customer requesting service hereunder has been a sales service customer of the Company at the same service location within the preceding twelve month period, any underrecovered or overrecovered gas costs attributable to such prior service under the Gas Cost Recovery Clause in Section 2, Schedule A, shall be determined and paid by Customer or credited to Customer's account. The calculation of such underrecovered or overrecovered gas costs shall be in accordance with the Customer Deferred Gas Cost Calculation Guideline as on file with the Commission from time to time.

1.01.0 TERM OF SERVICE:

1.01.1 FT-1 Transportation Service:

FT-1 Transportation Service will commence on the first day of a calendar month subject to satisfying the Company's Transportation Terms and Conditions and be for an initial term of up to one year to reflect a common anniversary of November 1st. Service shall continue thereafter on a year-to-year basis, unless terminated by Customer, marketer or the Company, effective with the

TRANSPORTATION TERMS AND CONDITIONS

Customer's next billing cycle, upon at least thirty (30) days' advance written notice to the other. The Marketer shall be responsible for providing the Company with an executed Transportation Service Application for each customer account being added to its FT-1 Aggregation Pool no less than thirty (30) days prior to commencement of service. The Company's receipt of the Transportation Service Application initiates the thirty (30) day notice period.

1.01.2 FT-2 Transportation Service:

FT-2 Transportation Service will commence on the first day of a Customer's billing cycle subject to satisfying the Company's Transportation Terms and Conditions. Service shall continue thereafter on a year-to-year basis unless terminated by Customer, marketer or the Company, effective with the Customer's next billing cycle, upon at least fifteen (15) days advance written notice to the other. The Marketer shall be responsible for providing the Company with an executed Transportation Service Application for each Customer being added to its FT-2 Aggregation Pool no less than fifteen (15) days prior to commencement of service. The Company's receipt of the Transportation Service Application initiates the fifteen (15) day notice period.

1.01.3 Non-Firm Transportation (NFT) Service:

Customers classified as Non-Firm Transportation (NFT) will be able to commence transportation as of the first (1st) of any calendar month subject to meeting the nomination requirements established in Item 1.03 following and having submitted to the Company an executed Transportation Service Application.

A Customer's designation as NFS or NFT shall remain in effect until the Company is notified of a further change. Such notice is required by 9 a.m. two (2) business days before the start of the calendar month when such change is to take effect. Switching to or initiating transportation service mid-month is generally not allowed.

1.02.0 Designation Of Marketer:

TRANSPORTATION TERMS AND CONDITIONS

1.02.1 Firm Transportation: Customers wishing to switch Marketers will be allowed to do so at the start of a calendar month, in the case of FT-1 Service, or at the start of a customer's billing cycle, in the case of FT-2 Service. The Customer and the new Marketer shall execute a new Transportation Service Application listing the new Marketer as their designated Marketer. The Company must receive the new Transportation Service Application at least thirty (30) days prior to the change in the case of FT-1 Service, and at least fifteen (15) days prior to the customer's meter read in the case of FT-2 Service. For an FT-1 Service customer without a capacity assignment from the Company, see Item 1.07 below, the Company must be notified of such change by 9 a.m. at least two (2) business days before the start of the calendar month The Company will not accept a Transportation Service Application which designates a Marketer that has not executed an Aggregation Pool Service Agreement. If a Customer switches marketers, switches transportation services and/or switches to sales service more than once in a twelve month period, an administrative charge of $50 shall be billed to the Customer to cover the processing of the request.

If the Company receives more than one Transportation Service Application for the same customer account with different designations of Marketer, the Company will contact the Customer for clarification and confirmation.

The Company will notify the Marketer of record in the event that a customer account assigned to the Marketer's Aggregation Pool is terminated.

Marketer must provide the Company with (30) days advance notice in the event that the Marketer terminates service to a Customer in its Aggregation Pool.

Customers not subject to Default Transportation Service in Item 2.04 below, may return to sales service with at least thirty (30) days advance notice, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability, and subject to the Company's Transitional Sales Service Rate,

TRANSPORTATION TERMS AND CONDITIONS

Section 5 Schedule H, of the Commercial and Industrial Services.

These provisions for switching marketers or returning to Sales Service do not excuse the performance of any contractual obligations between the customer and a marketer, including the potential requirement of paying damages to the marketer for a breach of any such contractual obligation.

1.02.2 Non-Firm Transportation:

Switching Marketers is allowed at the start of any calendar month with the provision that the Company receive the Customer's Transportation Service Application designating the effective Marketer by 9 a.m. at least two (2) business days before the start of the month for which the switch is effective.

These provisions for switching marketers do not excuse the performance of any contractual obligations between the customer and a marketer, including the potential requirement of paying damages to the marketer for a breach of any such contractual obligation.

If the Company receives more than one Transportation Service Application for the same customer account with different designations of Marketer, the Company will contact the Customer for clarification and confirmation.

1.03.0 Nominations:

1.03.1 General:

Marketer shall provide notice via the Company's Electronic Bulletin Board the required information relative to Shipper and Transporting Pipeline names and contract number(s) on which deliveries will be made and the specified quantity of gas that Marketer will deliver to the Point(s) of Receipt on each day of the calendar month. Marketer is required to have separate nomination names and contract numbers for each of Marketer's Aggregation Pools. Additional information may be required by the Company.

TRANSPORTATION TERMS AND CONDITIONS

1.03.2 Dispatch Communication: All nomination information shall be communicated to the Company's Gas Supply Operations Department via the Company's Electronic Bulletin Board (EBB). Marketer shall be responsible for monitoring the EBB 24 hours per day, seven days per week for dispatch purposes. In the event that the Company is unable to contact a Marketer regarding any nomination or dispatch, the Company may take any action it deems necessary to maintain system integrity as otherwise outlined in the General Terms and Conditions.

1.03.3 Initial Nominations: The Nomination terms for FT-1 and NFT Service for deliveries to commence service on the first day of any calendar month will be submitted to the Company not later than the initial nomination deadline of the upstream Transporting Pipeline(s) transporting gas for Marketer. Such nominations will specify the quantity to be scheduled on each day of the month. The nomination requirements for FT-2 Service are described in Item 3.03 below.

As a condition of confirming any nomination, Company may direct Marketer to have gas delivered to an alternate Point of Receipt on the same Transporting Pipeline. Upon receipt of such directions, Marketer will arrange with the Transporting Pipeline to have gas delivered to the Point of Receipt designated by Company. Such alternate point of Receipt will remain the Point of Receipt for Marketer's gas for the period stated by the Company in its instructions until Company directs Marketer otherwise.

1.03.4 Subsequent Nominations: After the first day of the calendar month, Marketer may alter its nomination, provided that the revised nomination for delivery on any day is submitted to Company not later than 1:00 PM, in the case of FT-1 and NFT Service, of the prior gas day. Any nomination submitted after the initial monthly nomination will include Marketer's anticipated quantities for the remainder of the calendar month. For FT-

TRANSPORTATION TERMS AND CONDITIONS

2 Service, the nomination requirements are described in Item 3.03 below.

1.03.5 Intra-Day Nominations:

For daily metered Aggregation Pools, the Company will accept and implement, on a best efforts basis, an intra-day nomination submitted after the nomination deadline for the following gas day but before the start of the following gas day. An intra-day nomination within the gas day will be accepted at the Company's sole discretion.

One (1) such nomination per gas day shall be accepted subject to confirmation by the Transporting Pipeline.

1.03.6 Scheduling of Service:

Company will attempt to confirm with Transporting Pipeline(s) that the nominated quantities equal the Scheduled Transportation Quantity. If such nomination is confirmed, the Company will schedule said quantities to the Marketer at the designated Point of Receipt(s).

If Marketer is purchasing gas at the Company's citygate, they are responsible for identifying the original delivering contract number, Shipper and any additional title transfers.

If Marketer's nominations on the Company's Electronic Bulletin Board are not consistent with nominations on Transporting Pipeline, then the smaller of the two nominations shall prevail, and all associated balancing and penalty assessments shall be based on the smaller nomination.

1.04.0 Protection Of System Operations:

1.04.1 Company Operational Flow Order (OFO):

Service hereunder may be limited as provided in the Company's General Terms and Conditions. Further, in the event that the Company determines in its sole judgment that it must take prompt action in order to maintain system integrity or to ensure Company's continued ability to provide service to its firm customers, the Company may declare a Critical Day or issue an OFO. In addition to the

TRANSPORTATION TERMS AND CONDITIONS

OFOs listed below, the Company shall have the right to issue any other OFO reasonably intended to serve the above stated purpose. The Company may take any one or more of the following actions:

(1) declare a Critical Day which would require Marketer to fully utilize upstream capacity that it received from Company through Capacity Release; and require Marketer to fully schedule storage resources allocated as part of FT-2 Service, i.e., up to the MDQ-U, prior to relying on peaking resources to the extent they are needed to meet their customer's demands;

(2) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess receipts; and

(3) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess takes.

An OFO will likely be issued at forty four (44) Degree Days or colder.

1.04.2 Pipeline Operational Flow Order:

If, at any time, an immediate upstream pipeline issues an order changing the requirements at the Point(s) of Receipt, then Company may so notify Marketer and direct Marketer to modify requirements at the Point(s) of Receipt to the extent necessary for Company to comply with the pipeline's order. Marketer will be responsible for coordinating with their customers regarding any necessary change to Customer's quantity of Gas Usage.

1.04.3 Marketer Responsibility:

In the event Company takes action to alleviate excess imbalances it will nonetheless remain the obligation of Marketer to make such further adjustments to nominations, both to Company, Shipper, and to Transporting Pipeline, during the remainder of the month to resolve accumulated imbalances or to account for subsequent changes in actual

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deliveries. Company's exercise of its authority under this section will have no effect on Marketer's liability for unauthorized overrun or imbalance penalties that apply to Marketer under this tariff or any similar charge, including scheduling penalties, imposed by any upstream Transporting Pipeline(s).

An operational flow order may be issued by the Company as a blanket order to all transportation customers, or to individual Marketer's Aggregation Pools, whose actions are determined by the Company to jeopardize system integrity.

For Critical Days or OFO's aggravated by underdelivery, the Marketer will be charged a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 102% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 0.1 times the Daily Index for the differences between said receipts and said usage that exceed 20% of said receipts [(Receipts – Usage) > (20% x Receipts)].

For Critical Days or OFO's aggravated by overdelivery, the Marketer will be charged a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 120% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 5 times the Daily Index for the differences between said receipts and said usage that exceed 2% of said receipts [(Receipts – Usage) > (2% x Receipts)].

1.05.0 Unauthorized Use:

In the event the Company provides a Marketer with as much notice as Company deems practicable of an Operational Flow Order per Item 1.04.0 or other curtailment of service and thereby reduces the Scheduled Transportation Quantity for delivery, the total Gas Usage by the Customer may not exceed the revised Scheduled Transportation Quantity. If, on any Gas Day, after notice

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of curtailment, the quantity of gas taken by Marketer's Customers in an Aggregation Pool, exclusive of NFT customers whose use under a curtailment is covered in Item 4.04 below, exceeds Marketer's Scheduled Transportation Quantity as so revised for the Aggregation Pool, and the Company has not authorized such excess quantity, then all such Gas Usage constitutes Unauthorized Use and is subject to an overrun penalty for each Dekatherm not delivered of 5 times the Daily Index. Such charges will be billed to the Marketer's account.

1.06.0 Shipper And Transporting Pipeline Requirements:

Marketer warrants with respect to each Aggregation Pool, that it has entered into the necessary agreements for the purchase and delivery of a gas supply to the Point of Receipt which it wants Company to transport and that it has entered into the necessary transportation agreements for the delivery of gas supply to the Point of Receipt. Marketer acknowledges that it must arrange for the delivery of Actual Transportation Quantities to the Company sufficient to include both the Scheduled Transportation Quantities and the applicable Company Fuel Adjustments.

In addition, Marketer warrants that at the time of delivery of its gas supply to the Point of Receipt, Marketer shall have good title to such gas, free of all liens, encumbrances and claims whatsoever. Marketer shall indemnify the Company and save it harmless from all suits, actions, debts, accounts, damage, costs, losses and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

1.07.0 Capacity Release:

Each Marketer serving any Customer migrating from Non-Firm Sales, Non-Firm Transportation or Firm Sales Service to FT-1 or FT-2 Transportation Service or from another Marketer's Aggregation Pool where they were previously assigned pipeline capacity by the Company, will be required to accept, for each such Customer account, an assignment of a portion of Company's firm interstate pipeline transportation capacity at maximum rates for an

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initial term of up to one year. The Company shall determine the quantity to be released, based on a pro-rata percentage of the customer account's Average Normalized Winter Day Usage to the system total, and the pipeline on which such capacity will be released. The quantity of capacity shall be set forth in the confirmation materials provided to the Marketer. For all Customers classified as Medium, Large or Extra-Large this quantity will be reviewed annually against the Customer's most recent usage patterns. Any change in Customer's required capacity will be reflected in a revised capacity release with the Marketer for effect on the following November 1st. In the event that a marketer stops delivering gas on behalf of an existing capacity exempt customer, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

Marketer shall be required to execute a Capacity Assignment Agreement at the time a Marketer establishes an Aggregation Pool or any other instruments reasonably required by Company or interstate pipeline necessary to effectuate such assignment. Marketer is responsible for utilizing and paying for the assigned capacity consistent with the terms and conditions of the interstate pipeline's tariffs and this tariff. Marketer is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition costs, pipeline overrun charges, annual change adjustments and all other applicable charges. These charges will be billed directly to the Marketer by the interstate pipeline.

All Capacity Assignments for FT-1 Transportation Service will be effective with the commencement of service. Capacity Assignments for FT-2 Customers will be effective the 1st of the upcoming month for Transportation Service Applications received prior to the 10th. For FT-2 Transportation Service Applications received on or after the 10th of the month, the capacity release will not be

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effective until the 1st of the month subsequent to the upcoming month.

Capacity assignments will be effective for an initial term of up to one year through the following November 1st. The capacity assignments shall be reviewed each November 1st and be subject to annual adjustment as described above. All releases hereunder will be subject to recall under the following conditions: (1) when required to preserve the integrity of the Company's facilities and service; (2) at the Company's option, whenever the Marketer fails to deliver gas in an amount equal to the Scheduled Transportation Quantity; and (3) any other conditions set forth in the capacity release transaction between the Marketer and the Company.

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 per Dt charge is calculated by subtracting the charge per Dt for the released pipeline capacity from the Company's weighted average Upstream Transportation charges as identified in the Company's annual Gas Cost Recovery Filing. To the extent that the cost of such released pipeline capacity is less than the weighted average cost, the marketer shall be surcharged for such difference.

On or before August 1 each year, the Company shall calculate and provide to marketers, as defined in Section 6, Schedule C, Item 5.00, its best estimate of: (1) the over (under) recovery balance in its deferred gas cost account; and (2) the anticipated fixed costs for interstate pipeline capacity, storage and peaking supplies.

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During the calendar month of September, each Marketer will be required to submit a new Capacity Assignment Agreement indicating pipeline capacity path preferences based on the available paths identified in the Company's annual Gas Cost Recovery Filing. Each Marketer shall identify pipeline capacity preferences for: (1) existing customers, and (2) any new customers. Marketer shall have the right to retain capacity released on existing paths if such paths remain available. Any changes from the Marketer's previous election will be effective November 1st in conjunction with the updating of customer capacity quantities described above. Subject to availability, Marketers may change path preferences for assignment of pipeline capacity during the year for any new customers added to their Aggregation Pool by filing with the Company a new Capacity Assignment Agreement with at least 30 days advance notice.

The capacity released to a Marketer stays with the customer account on which it is based and as such, will be reassigned at such time that a Customer terminates their contract with a Marketer or reverts back to the Company as of the date of the customer's service termination.

Each Marketer's capacity assignment associated with Customers in an aggregation pool shall be reviewed on a monthly basis prior to the tenth (10th) calendar day of the month, and adjusted to reflect any net changes resulting from the addition and deletion of customers to the pool.

1.07.1 New Loads: New Customers classified as Large or Extra-Large electing FT-1 transportation service will not be required to take assignment of the Company's capacity resources as described in 1.07.0 above. The consumption of such Customers may be subject to annual review and confirmation by the Company. Customers who fail to meet the minimum requirement for the Large classification shall be required to take assignment of the Company's capacity resources after no less than 60 days notice. Marketers for such customers may be responsible for obtaining citygate capacity at a specific citygate on the Company's system as determined by the Company. Such determination will be

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based on the customer's location, load characteristics and distribution system requirements.

In the event that a marketer stops delivering gas on behalf of a customer without Company assigned pipeline capacity, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

1.08.0 Facilities: Company shall own, operate and maintain, at its expense, its gas distribution facilities to the Point of Delivery. Customer shall furnish, maintain and operate the facilities required between Company's Point of Delivery and Customer's equipment.

1.9.0 Quality: Marketer is responsible for insuring that all gas received, transported and delivered hereunder to the Point of Receipt meets the quality specifications and standards outlined in the General Terms and Conditions of the Transporting Pipeline's FERC Gas Tariff.

1.10.0 Possession of Gas: Company shall be deemed to be in control and possession of transportation gas to be delivered in accordance with this service from receipt at the Point(s) of Receipt until it shall have been delivered to Customer at the Point of Delivery. Marketer shall be deemed to be in possession and control of the gas prior to such receipt by the Company and Customer shall be deemed to be in control and possession of transportation gas after such delivery by the Company to the Point of Delivery. Company shall have no responsibility with respect to such gas before it passes the Point of Receipt or after it passes such Point of Delivery or on account of anything which may be done, happen or arise with respect to such gas after Point of Delivery.

1.11.0 Provision of Future Taxes, Surcharges Fees, Etc.: In the event a tax of any kind is imposed or removed by any government authority upon the sale or transportation of gas or upon the gross revenues derived therefrom (exclusive, however, of taxes based on Company's net income), the rate for service to Customer and/or Marketer,

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as the Company deems appropriate, shall be adjusted by an amount equal to or otherwise properly reflecting said tax. Similarly, the effective rate for service hereunder shall be adjusted to reflect any refund or imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental authority.

1.12.0 Retention of Pipeline Fuel Adjustment: The Company shall retain in kind, from the quantities of gas actually delivered to the Point(s) of Receipt for Marketers' accounts, the amount thereof equal to the applicable Company Fuel Allowance. Such Company Fuel Allowance shall be calculated by the Company based upon an average of the Company's most recent five (5) years experience, fuel loss and unaccounted for or similar quantity based adjustments.

1.13.0 Limitations of Liability: The liability of the Company shall be limited in accordance with the provisions of the Company's General Terms and Conditions.

1.14.0 Force Majeure: Neither Company nor Marketer shall be liable to the other or to Customer for delays or interruptions in performing their respective obligations hereunder arising from any acts, delays or failure to act on the part of, or compliance by Marketer or Company with any operating standard imposed by any governmental authority, or by reason of an act of God, accident or disruption, including without limit, strikes or equipment failures, or any other reason beyond Marketer's or Company's control, provided, however, in the event of an occurrence of one or more of the foregoing events, reasonable diligence shall be used to over come such event. The party claiming force majeure shall, on request, provide the other party with a detailed written explanation thereof, and of the remedy being undertaken.

2.0 FT-1 TRANSPORTATION SERVICE:

2.01.0 Character of

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Service: This service provides firm, 365 day transportation of Customer purchased gas supplies to customers electing to have Gas Usage recorded on a daily basis at the Point of Delivery. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer shall assign Customer to an Aggregation Pool with other Customers electing FT-1 or NFT service or establish a one-customer Aggregation Pool and execute an appropriate Marketer Aggregation Pool Service Agreement. Specific Marketer requirements and obligations are described in Item 5.0 below.

2.02.0 Telemetering: The Company will provide at the Customer's expense, at the Point of Delivery to the Customer, a device that the Company will attach to its metering equipment for the purpose of monitoring the Gas Usage. The Customer shall be responsible to supply a dedicated electrical supply and a telephone line at a location acceptable to Company and capable of transmitting information collected from the monitoring device to the Company's computer system. The Customer shall be responsible for the maintenance and service of the telephone line. Should a dedicated phone line be required, it is the responsibility of the Customer to schedule the installation, to notify Company when such installation has been completed, and the Customer is responsible for any associated charges. FT-1 and NFT transportation service shall not commence until the telemetering equipment is in place and operational.

2.03.0 Balancing: FT-1 and NFT Service is subject to both Daily and Monthly balancing provisions. It will be the Marketer's responsibility to provide accurate and timely nominations of quantities proposed to be received and delivered by Company under this service and to maintain as nearly as possible, equality between the Gas Usage and the Actual Transportation Quantity. Marketer shall be solely responsible for securing faithful performance by Shipper and Transporting Pipeline, and the Company shall not be responsible as a result of any failure of Shipper or Transporting Pipeline to perform. Charges and Penalties

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associated with FT-1 and NFT balancing are billed to the Marketer.

2.03.1 Daily Imbalances: The Marketer must maintain a balance between daily receipts and daily usage within the following tolerances:

Off-Peak Season: The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 15% of said receipts. The Marketer shall be charged a penalty of 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 10% of said receipts. The Marketer shall be charged a penalty of 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an underdelivery or an overdelivery, and so notify the Marketer when a Critical Day is declared pursuant to Item 1.05 above.

If the Marketer has an accumulated imbalance within a month, the Marketer may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

2.03.2 Monthly Imbalances: For each Aggregation Pool, the Marketer must maintain total Actual Transportation Quantities within a reasonable tolerance of total monthly Gas Usage. Any differences between total Monthly Transportation Quantities for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a

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percentage of total Monthly Transportation Quantities will be cashed out according to the following schedule:

Imbalance Tier	Overdeliveries	Underdeliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month.
> 5% ≤ 10%	0.85 times the above stated rate	1.15 times the above stated rate
> 10% ≤ 15%	0.60 times the above stated rate	1.4 times the above stated rate
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% Underdelivery on a Delivering Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven consecutive Daily Indices.

All cash-out charges or credits, as determined above, will be applied to the Marketer's monthly invoice for the Aggregation Pool.

Designated Marketers may arrange with another of Company's Marketers providing service to the same Point of Receipt to exchange, purchase or sell daily or monthly imbalance gas. The Company will notify each Marketer of its monthly imbalance following the close of the billing month in which the imbalance occurs. Marketers will have

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three business days following such notification to notify Company of any imbalance exchange or sale and to confirm such transaction.

2.03.3 Pass-Through of Upstream Imbalance Charges:

In addition to other charges provided for in this Section, Marketer will be responsible for any imbalance charge or penalty imposed on Company by an upstream pipeline as a direct result of an imbalance, scheduling error, unauthorized overrun or other similar charges caused by Marketer. The Company shall assign imbalance penalties assessed to the Company by upstream pipelines to sales and transportation customers based on the extent that each group caused such penalties, as determined by the Company. The portion of any such penalty assigned to transportation service shall be further assigned to individual Marketers based on the extent to which each Marketer's Aggregation caused such penalties, as determined by the Company.

2.04.0 Default Transportation Service:

Default Transportation Service is available to any Commercial or Industrial customer account classified as Large or Extra Large that subscribes to FT-1 Transportation Service and that does not have pipeline capacity assignment from the Company. Customers electing this service must provide written notice to the Company via mail, FAX or E-mail that their marketer will no longer be delivering gas on their behalf and that they wish to avail themselves of the service. Such service will continue in effect until either service is established with a new marketer through the execution of a new Transportation Application per Item 1.03.1 above or service is terminated.

This service provides for a continuous supply of gas of not less than 1,000 Btu per cubic foot, and is provided on a best efforts basis with as little as 24 hours advance notice. Where notification is at least 24 hours in advance but less than three business days before the start of a calendar

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month, the service provided will be Short-Notice Default Transportation Service. Where notice is provided at least three business days prior to the start of a calendar month, the service provided will be Advance-Notice Default Transportation Service. Short-Notice Default Transportation Service will be switched to Advance-Notice Default Transportation Service at the start of a subsequent month once the service has been in effect for the three business day period before the start of such month.

Default Transportation Service is a temporary surrogate for provision of gas to a customer that would otherwise be provided by a marketer, hence it includes nominating and balancing. Customer must maintain an operational telemetering device as required in Item 2.02.0 above.

2.04.1 Rates:

Pricing for Default Transportation Services shall be set forth in a Price Sheet filed with the Commission. The Company and Default Transportation Service supplier shall review the pricing of these services annually and file necessary revisions with the Commission concurrent with the Company's annual Gas Cost Recovery Filing.

3.0 FT-2 TRANSPORTATION SERVICE:

3.01.0 Character of Service:

This service provides firm, 365 day transportation of Customer purchased gas supplies to customers without the requirement for recording daily Gas Usage at the Customer's Point of Delivery. Daily Nominations are calculated by the Company on the basis of a consumption algorithm, the marketer is obligated to deliver to the citygate such quantities, and any imbalances are netted against storage resources allocated to the Marketer on the Customer's behalf.

The Customer's designated Marketer, as identified on the Customer's Transportation Service Application, shall be allocated a quantity of Company contracted underground storage and peaking resources sufficient to meet the Customer's design winter supplemental supply requirements as determined by the Company. These

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resources are assigned to the Marketer pursuant to a written agreement with the Company, for the purpose of meeting the Company forecasted daily usage under the operational parameters described below. Additional Marketer requirements and obligations are described in Item 5.0 below.

3.02.0 Storage And Peaking Resources:

Annually, the Company will calculate a Customer's total storage and peaking resource requirements under design winter conditions based on the Customer's most recent historical usage. The result of the calculations will establish the Maximum Storage Quantity-Underground (MSQ-U) and Peaking (MSQ-P) allocated for Marketer's use. The calculations will also establish a Maximum Daily Quantity-Underground (MDQ-U) and Peaking (MDQ-P) to set operational parameters for daily withdrawals and injections.

3.02.1 Maximum Storage Quantity (MSQ):

The MSQ for a Customer is the difference between their weather normalized total consumption under design winter conditions for the November through March period, minus the quantity of gas that could be delivered with their pipeline capacity assignment. The MSQ is allocated between underground storage (MSQ-U) and Peaking (MSQ-P) in the same percentage as is available on a Company-wide basis. These quantities represent the maximum storage and peaking inventories available to the Marketer for meeting the Customer's Gas Usage needs and are key components in the operational parameters regarding management of the resources.

3.02.2 Maximum Daily Quantity - Storage (MDQ-S):

The Customer's MDQ-S is calculated by the Company as the difference between the Customer's peak day usage under design winter conditions and the Customer's pipeline capacity assignment. This MDQ-S requirement in MMBtu is then allocated between underground storage (MDQ-U) and Peaking (MDQ-P) in the same percentage as is available on a Company-wide basis. These quantities serve

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to define the maximum quantities that can be nominated for withdrawal by a Marketer and are a component of the operational parameters for the service.

3.02.3 Operational Parameters:

The storage resources inventory balance for the Underground Storage and Peaking accounts shall be tracked by the Company and made available to the Marketers via electronic means. These balances will be updated each Gas Day to reflect Marketer nominations for either injections or withdrawals. The balances will also be updated continuously to reflect imbalances identified at the time of the Customer's billing cycle which will be netted against the Underground Storage Account.

The Company will establish Maximum and Minimum inventory levels reflective of the Company's available resources. There will be separate inventory levels for both Underground Storage and Peaking Resources. Such levels will be as provided in the annual Gas Cost Recovery Filing.

In addition to operational parameters for overall inventory levels, there are both Daily and Monthly maximums established for the quantities which the Marketer can nominate for withdrawal or for injection. These factors vary by month and as the marketer's inventory level changes. Such factors will be as provided in conjunction with the annual Gas Cost Recovery Filing.

3.02.4 Inventory Purchases:

To meet the revised required minimum storage balance levels resulting from the addition of new customers to an Aggregation Pool, Marketer may trade or purchase storage supplies from another Marketer, make injections to underground storage or purchase inventory from the Company, subject to availability. The Company will update an FT-2 aggregation pool's MSQ assignments concurrent with the Customer's initiation of transportation service with the designated marketer.

At the time that a Customer migrates to FT-2 Transportation Service or switches Marketers, the new

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designated Marketer will have a one-time opportunity to purchase an amount of inventory, from the Company, based on the MSQ requirement of Customers being added to the aggregation pool and the month when transportation service will commence. The Company will calculate the amount of storage inventory to be made available and provide such information to the Marketer upon receipt of a completed Transportation Service Application. The Marketer will have 5 business days to respond to the Company's offer. For Customers migrating during the April through October period, the maximum amount of storage inventory sold to a Marketer will be calculated as follows:

Inventory Sold = (x/7)*Customer's MSQ

where:

Inventory Sold = the maximum amount of inventory the Company will sell to a Marketer
x = the number of off peak months since April 1st.
7 = the total number of off peak/storage injection months
Customer's MSQ = the Customer's total storage requirements under design winter conditions

Thus, for a Customer migrating to FT-2 service effective July 1, the Marketer would be able to purchase up to three-sevenths (3/7) of the Customer's MSQ from the Company to account for injections to storage during the months of April, May and June. The marketer would then be responsible for nominating sufficient injections during the July to October period to ensure that the inventory in storage for the FT-2 aggregation pool was at the minimum level identified in the Company's operational parameters

For Customers migrating during the peak period of November through March, the inventory sold will be based on the lesser of: (1) the added Customers' monthly minimum requirement outlined in the Company's operational parameters or (2) the incremental amount of inventory required to bring the Marketer's pool in compliance with the minimum requirement. For example,

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if the customer were to start transporting in February, the Marketer would have the option to purchase storage inventory from the Company in the amount equal to the February minimum inventory level of the Customer's MSQ. Marketer may purchase such amount from the Company at a rate calculated as indicated below.

The Company shall develop a price for the inventory based on the published NYMEX price, and adjusted for transportation, storage and carrying charges.

The price per Dt at the Company's citygate shall be calculated using the following formula:

$/Dt = NY + BS + TR + ST + CC

where:

$/Dt	=	cost per MMBtu charged to Marketers for storage inventory at the Company's citygate
NY	=	NYMEX Settlement Price
BS	=	Basis Differential for East Louisiana
TS	=	Transportation Cost
ST	=	Storage Cost
CC	=	Carrying Cost

In the event that a Marketer fails to nominate or obtain sufficient storage inventory for its Customers such that the Aggregation Pool's inventory is below the operational parameter minimum, the Marketer will be unable to nominate storage or peaking quantities to satisfy the FDU.

For Customers commencing FT-2 transportation service during off-peak months (April - October), Marketer will receive an assignment of peaking inventory during the following October for a November 1st effective date. For Customers migrating to FT-2 during peak months (November - March), Marketer will receive an assignment of peaking inventory concurrent with the commencement of service. The amount of peaking inventory assigned shall be based on the lesser of: (1) the added Customers'

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monthly minimum requirement outlined in the Company's operational parameters or (2) the incremental amount required to bring the Marketer's pool in compliance with the minimum requirement. Marketers would be able to purchase peaking inventory from NG at the Company's weighted cost of LNG inventory. All transactions are subject to authorization by NG.

Marketers needing to sell underground storage inventory as a result of customers switching to other marketers would be able to sell the inventory to another marketer, subject to authorization by NG, nominate withdrawal of supplies, or sell the inventory in excess of the Maximum Storage Quantity to NG. Marketers with inventory levels in excess of the Maximum Storage Quantities may be required by the Company to nominate underground storage to satisfy their FDU. If the Marketer has excess peaking resources, they could nominate those inventories to the extent allowed under the operational parameters or would be required to sell such excess peaking resources to NG at the price the inventory was originally purchased from NG.

3.02.5 Rates:

The Marketer is responsible for procuring and maintaining inventory levels associated with the underground storage and peaking resources allocated by the Company as part of FT-2 Service. The following charges are for the recovery of the fixed costs and other miscellaneous costs associated with the provision of the underground storage and peaking resources and are billed to the Marketer:

FT-2 Throughput: $ per Therm Gas Usage . The rate is as calculated in the Company's most recent Gas Cost Recovery Filing.

3.03.0 Nominations:

The Company shall calculate the Forecasted Daily Usage (FDU) of the aggregation pool using a Consumption Algorithm for each of the customers in the aggregation pool. The Company shall have sole responsibility for such Consumption Algorithm and by selecting FT-2 service, Marketer agrees to abide by the results of such algorithm. The algorithm is:

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FDU = Base Load + (HU factor * FDD)

where:

FDU = an individual customer account's forecasted daily usage for the next gas day

Base Load = average daily consumption for the most recent July and August billing cycles

HU Factor = most recent billing cycle consumption, minus the base load, divided by the heating degree days for the billing cycle

FDD = forecasted heating degree days for the gas day starting at 10:00 AM the next day

FDU will be adjusted for any Company fuel allowance.

The Company will provide to the Marketer no later than 9:30 AM each day using an electronic posting or via facsimile the FDU for the next gas day which would start at 10:00 AM the next day. If the Company is unable to provide to the Marketer the FDU using an electronic posting or via facsimile before 9:30 AM, the default FDU will be the prior day's FDU. The Marketer shall be obligated to nominate any combination of pipeline, underground storage or peaking equal to the FDU for the next gas day. Such nomination is to be posted on the Company's Electronic Bulletin Board no later than 1:00 PM before the start of the next gas day. The Company shall not accept or confirm any nominations that are greater than the FDU of the aggregation pool and any nominations for storage and peaking resources must be in accordance with the applicable operational parameters. Quantities nominated for injection into storage are over and above quantities to meet the FDU. Any nominations to inject supplies into storage or nominate supplies from storage must be separately identified and made to the Company's citygate. If storage inventory is below the minimums established above, Marketer will not be able to nominate storage or peaking quantities to satisfy the FDU nomination requirement.

3.03.1 Critical Days: To satisfy the FDU nomination requirement on Critical Days, the Marketer is required to fully utilize upstream

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capacity that it received from Company through Capacity Release so as to help avoid restricting the Company's ability to provide efficient and reliable firm transportation and sales service. Notice of Critical Days will be posted on the EBB no later than concurrent with the posting of the FDU nomination requirement.

3.03.2 Under-deliveries: Any under-deliveries of the aggregation pool's gas requirements, up to the FDU, will be treated as Unauthorized Use and subject to penalty charges as provided in Item 1.06.0 above.

3.04.0 Balancing: Imbalances between customer Gas Usage and the Forecasted Daily Usage (FDU) will be netted out against the underground storage inventory at the time of a customer's billing cycle. Quantities used in excess of FDU will be subtracted from the underground storage inventory level. If Gas Usage is less than FDU, the difference will be treated as an injection to underground storage and added to the inventory level. All quantities will be adjusted for Company Fuel Allowance.

4.0 NFT SERVICE:

4.01.0 Character Of Service: This service provides interruptible transportation of Customer purchased gas supplies to customers with telemetering equipment and that are eligible to be classified under Section 6, Schedule A of the Company's Tariff. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer may assign Customer to an Aggregation Pool with other Customers electing NFT or FT-1 transportation service or establish a one-customer Aggregation Pool. Specific Marketer requirements and obligations are described in Item 5.0 below.

4.02.0 Nominations: The nomination requirements in Item 1.04.0 above apply to the provision of NFT Service.

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4.03.0 Imbalances: The Daily and Monthly Imbalance provisions in Items 2.03 above apply equally here.

4.04.0 Curtailments: Customer will curtail or discontinue service when, in the sole opinion of the Company, such curtailment or interruption is necessary in order for it to continue to supply the gas requirements of its firm customers at such time. The Company will attempt to give the customer and customer's marketer three (3) working days' notice of such curtailment, except in emergency situations, when at least one hour's notice shall be given.

For any period that a customer fails to curtail the use of gas as requested by the Company, the charge for gas consumption will be equal to the non-firm transportation service customer charge plus Gas Usage at a penalty of 5 times the Daily Index. Such use of gas under these circumstances shall be considered an "unauthorized use" of gas purchased from the Company, and billed to the customer's account.

In the event where the Company, in its sole discretion, grants the customer an exemption from the curtailment, the use of gas under these circumstances shall be referred to as an "authorized use of gas." Authorized use of gas during a curtailment will be for a limited time period and will be purchased from the Company. The charge for gas consumed under these conditions will be billed to the customer and based on the non-firm transportation service customer charge plus the Company's highest cost gas required to meet demand during the applicable curtailment period, plus the current firm sales service rate excluding the firm customer charges. Payments for this use, whether authorized or unauthorized, shall not preclude the Company from turning off the customer's supply of gas in the event of the failure to interrupt, or curtail, the use thereof when requested to do so.

5.00 MARKETER AGGREGATION SERVICE:

5.01.0 Character of

TRANSPORTATION TERMS AND CONDITIONS

Service:

This service allows Marketers to aggregate customer accounts and form Aggregation Pools for the purpose of making initial and subsequent nominations, making delivery to a designated Point of Receipt, and for balancing of Actual Transportation Quantity with Gas Usage on Customer's behalf. The Company will transport gas, owned by the Customers of the Aggregation Pool, to the Point(s) of Delivery for each Customer included in such pool. A Marketer shall be designated by each Customer on the Transportation Service Application, and each such customer must be assigned by the Marketer to an Aggregation Pool of one or more customers. Changing the designated Marketer is allowed under the conditions in Item 1.02 above and is accomplished through the execution of a new Transportation Service Application. Once so designated, the Company will rely on information provided by the Customer's Marketer for nomination, balancing and scheduling purposes and all notices provided by the Company to Customer's Marketer shall be deemed to have been provided to the Customer.

5.02.0 Aggregation Pools:

The aggregation of Customer accounts into an aggregation pool is limited by the transportation service of the respective Customers.

The Customer's transportation service restriction requires that Customers subscribing to non-daily metered FT-2 Service must be aggregated in a separate pool from Customers subscribing to daily metered FT-1 or NFT Service. Customers subscribing to FT-1 or NFT can be combined in a single Aggregation Pool. A separate Marketer Account will be established for each Marketer Aggregation Pool.

A further restriction on daily metered Aggregation Pools is that the election of a supplemental service such as Pool Balancing Service, shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool. Separate Aggregation Pools are required for FT-1 or NFT Service with Pool Balancing Service versus FT-1 or NFT Service without the supplemental service.

TRANSPORTATION TERMS AND CONDITIONS

The Marketer Aggregation Pool Service Agreement and Pool Balancing Service Agreement shall have an initial term through the following November 1st. Thereafter, the Marketer Aggregation Pool Service Agreement and Pool Balancing Service Agreement shall be automatically renewed for successive one year terms, unless notice of termination is provided by the Marketer on or before October 1st or if the Company has terminated the agreement under its collection procedures. Marketers may assign their Aggregation Pool Service Agreements to another certified Marketer with the Company's consent.

5.02.1 Rates:

The monthly aggregation pool charge is applicable only during months when Customers assigned to the pool are transporting.

Monthly Charge:

Daily Metered Pool	$ 150.00 per
Non-Daily Metered Pool	$ 450.00 per

5.03.0 Marketer Qualifications:

In order to be designated hereunder as a Marketer, the Marketer must meet the following qualifications:

(1) The Marketer must be authorized by the Rhode Island Public Utilities Commission in accordance with Commission Regulations for Utility Interaction with Gas Marketers;

(2) The Marketer must demonstrate to the Company that it meets the following creditworthiness standards:

A. The Marketer, or a guarantor, maintains a minimum rating from one of the rating agencies and no rating below the minimum from one of the other two rating agencies. For the purposes of this Section, minimum rating shall mean "BBB" from Standard & Poor's, "Baa2" from Moody's Investor Service, or "BBB" from Fitch Ratings (minimum rating)

TRANSPORTATION TERMS AND CONDITIONS

B. If a Marketer or a guarantor, is not rated by Standard & Poor's, Moody's Investor Service or Fitch Ratings, it shall satisfy the Company's creditworthiness requirements if the Marketer, or a guarantor maintains a minimum "1A2" rating from Dun & Bradstreet (Dun and Bradstreet minimum rating) and the Marketer maintains 24 months good payment history with the Company

C. In the event that the Marketer has not met the credit standards above, then the Marketer must so notify the Company and the Marketer will be required to use one of the financial vehicles specified in 5.03.2 to satisfy the Company's credit standards.

(3) Marketers must have an executed Marketer Aggregation Pool Service Agreement with the Company and accepted its designation as the marketer for each customer by countersigning the applicable Transportation Service Application.

(4) Marketers must provide the Company with a copy of their GET exemption certificate, state sales tax exemption certificate or other appropriate exemption certificate(s) in order to be exempt from the applicable taxes.

5.03.1 Calculation of Credit Risk and Security for Natural Gas Imbalance Risk: The Company may require a Marketer to provide security equal to three times the highest month's gas usage of the Marketer's Aggregation Pool at the firm sales rate applicable to the upcoming peak period. This amount may be updated at the Company's discretion

5.03.2 Security Instruments: The following financial arrangements are acceptable methods of providing security:

TRANSPORTATION TERMS AND CONDITIONS

(1) Deposit or prepayment, which shall accumulate interest at the applicable rate per annum approved by the Rhode Island Public Utilities Commission;
(2) Standby irrevocable letter of credit or surety bond issued by a bank, insurance company or other financial institution with at least an “A” bond rating;
(3) Security interest in collateral; or,
(4) Guarantee by another party or entity with a credit rating of at least “BBB” by S&P, “Baa2” by Moody's, or “BBB” by Fitch; or
(5) Other means of providing or establishing adequate security.

The Company may refuse to accept any of these methods for just cause provided that its policy is applied in a nondiscriminatory manner to any Marketer.
If the credit rating of a bank, insurance company, or other financial institution that issues a letter of credit or surety bond to a Marketer falls below an "A" rating, the Company shall allow a minimum of five business days for a Marketer to obtain a substitute letter of credit or surety bond from an "A" rated bank, insurance company, or other financial institution.

The Marketer agrees that the Company has the right to access and apply the deposit, letter of credit or other financial vehicle to any payment obligations, not in dispute, which are deemed by the Company to be late. The Company may review and determine the status of a Marketer’s creditworthiness at its sole discretion. If Marketer is unable to maintain the Company’s credit approval or otherwise ceases to meet the Marketer Qualifications, the Company may terminate the Marketer Aggregation Pool Agreement as of the first day of the month following written notice to Marketer.

5.04 Pool Balancing

TRANSPORTATION TERMS AND CONDITIONS

Service:

Service is available for daily metered Marketer Aggregation Pools concurrent with the term of the Aggregation Pool.

The intent of this service is to accommodate minor, unintentional imbalances between an Aggregation Pool's Customer's daily usage at the Point(s) of Delivery and Actual Transportation Quantities delivered to the Company's distribution system at the Point of Receipt. Marketer must notify the Company by October 1st to elect Pool Balancing Service commencing November 1st or at least thirty (30) days prior to establishment of an Aggregation Pool.

Under the Pool Balancing Service, the Company agrees to provide a daily balancing service for imbalances up to a Marketer designated Maximum Daily Balancing Entitlement. Such entitlement is expressed as a percentage of the Aggregation Pool's Gas Usage and includes the 10% tolerance described in Item 2.03.1 above. Daily imbalances greater than the Marketer designated Maximum Daily Balancing Entitlement will remain subject to the balancing provisions outline in the Company's Terms and Conditions of Transportation Service.

The Company reserves the right to limit service offered under this schedule, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability or force majeure, or as otherwise provided in the Company's Terms and Conditions.

5.04.1 Pool Balancing Rate:

Variable Charge: $ per Therm Gas Usage per percent elected (Maximum Daily Balancing Entitlement % net of 10% standard tolerance)

Where:
- The rate is as calculated in the Company's annual Gas Cost Recovery Filing.
- Gas Usage is total of all Aggregation Pool Customers.
- Maximum Daily Balancing Entitlement % is specified in Marketer Aggregation Pool

TRANSPORTATION TERMS AND CONDITIONS

Agreement and includes the 10% standard tolerance.

5.05 Billing:

Billing for monthly customer charges and transportation charges for quantities actually delivered shall be based on the readings at each individual meter for the Customer and billed on a billing cycle basis to the Customer. The Customers and Marketers shall be liable for all rates, charges and surcharges allowed for in the Company's Rate Schedules related to transportation services provided to each customer individually.

Calculation of charges applicable to the Aggregation Pool will be based on aggregated Gas Usage, MDQ's, etc. of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, e.g., imbalance charges, credits or penalties, and FT-2 Throughput charges shall be billed to the Marketer on a calendar month basis.

All bills rendered to the Marketer are due within 10 days from the date of the invoice. A late payment charge, in accordance with regulations of the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers, shall accrue after 10 days.

6.0 SERVICE AGREEMENTS: (See Attached Sheets)

The Narragansett Electric Company, Transportation Service Application

This Transportation Service Application ("Application") must be completed by the customer and the marketer prior to the commencement of the requested Transportation Service.

NG:	The Narragansett Electric Company d/b/a National Grid 175 East Old Country Road Hicksville, NY 11801 Attn: Supplier Services	Customer:	_____ _____ _____ ( ) _____
Notice to:	Customer Contact Center: 1-800-870-1664	Notice to:	_____ ( ) _____

The Customer hereby requests Transportation Service subject to the NG General Terms and Conditions, Section 1 of RIPUC NG-GAS No. 101, its Transportation Terms and Conditions, Section 6, Schedule C and, under the terms and conditions set forth herein. NG shall review this Application and notify the Customer of its approval or rejection by way of a Confirmation Letter that shall set forth the terms and conditions of the Customer's Transportation Service. Upon Customer's and Marketer's fulfillment of all conditions set forth in the Confirmation Letter, such Confirmation shall represent an Agreement by NG to provide Transportation Service consistent with this Application and the Transportation Terms and Conditions set forth in Section 6, Schedule C of RIPUC NG-GAS No. 101.

Account Number	Meter Number	Service Address	FT-1	NFT	FT-2
1)					
2)					
3)					

1. Transportation Service shall commence in accordance with Item 1.02, Section 6, Schedule C of RIPUC NG-GAS No. 101
2. FT-1 and NFT Services require telemetry. A telemetering device and related equipment installed by NG shall remain NG property at all times. The Customer shall provide NG with access to a phone line that meets NG specifications for telemetering purposes. The customer is financially obligated for the costs to acquire, install and operate the telemetering device and related equipment.
3. Provision of transportation service based on this Application shall have an initial term through the following November 1st, unless sooner terminated in accordance with the terms and conditions of NG's Tariff, and shall continue thereafter from year to year unless terminated by customer, marketer, or NG upon not less than 30 days prior written notice.

Public Regulation

The Narragansett Electric Company is a public utility subject to regulation by the Rhode Island Public Utilities Commission ("Commission"). The provision of transportation service as a result of this Application is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to this Application. Compliance by NG with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the commencement of transportation service, shall relieve NG of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of such service, either NG, the customer, or the marketer shall have the option to terminate transportation service by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

Customer Signature	Title	
Print or Type Name	Date	Phone #
Contact in event of telecommunications issue : Print or Type Name		Phone #

This section to be filled out by the Marketer

By signing below and pursuant to its separate Marketer Aggregation Pool Service Agreement, the Marketer (i) accepts the designation as the customer's marketer and (ii) agrees to pay all applicable marketer charges in accordance with NG's tariff, including its Transportation Terms and Conditions

Marketer	Marketer Signature	Title
Phone #	Print or Type Name	Date

THE NARRAGANSETT ELECTRIC COMPANY
MARKETER AGGREGATION POOL SERVICE AGREEMENT

This Agreement ("Agreement") is entered into this _____ day of _____, 200__, by and between The Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and _____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C, provides for and establishes terms and conditions for a Marketer Aggregation Pool; and

WHEREAS; Marketer desires to establish an Aggregation Pool and desires Company to provide pool aggregation services pursuant to such Schedule C and to transport quantities of gas delivered by Marketer for use at the locations of customers belonging to the Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing _____ 1, 200__, will transport and deliver to customers of Marketer's Aggregation Pool such quantities of Marketer's gas delivered by Transporting Pipeline to Company's distribution facilities (hereafter called "Point of Receipt").

1.0 AGGREGATION POOL:

1.1 Marketer is establishing a single Aggregation Pool as indicated by an X:

Daily Metered _____
Non-daily Metered _____

1.2 Marketer hereby subscribes to Company's Marketer Aggregation Service pursuant to Item 5.00 of the Company's Transportation Terms and Conditions, Section 6, Schedule C.

1.3 Marketer elects to subscribe to Company's Aggregation Pool Balancing Service pursuant to Item 5.04 of Company's Transportation Terms and Conditions, Section 6, Schedule C, NO _____ YES _____ with a Maximum Daily Balancing Entitlement of _____% (which % includes the standard 10% tolerance).

1.4 Marketer represents and warrants that Marketer has met and will continue to meet the Marketer qualifications in Item 5.03 of Company's Transportation Terms and Conditions, Section 6, Schedule C.

1.5 Marketer agrees to provide to Company no later than 30 days before the above identified commencement date Transportation Service Applications for all end user customers in Marketer's Aggregation Pool identified in 1.1 above. Such list is to include: Customer Name; Billing Address; NG account #; and, name and telephone number of customer contact person.

1.6 Marketer agrees to notify Company in writing of any changes in the makeup of an Aggregation Pool as provided in the Company's Transportation Terms and Conditions.

1.7 Marketer represents and warrants that it has accepted the designation as the Marketer of each customer of the Aggregation Pool and agrees in each case to be bound by, perform, and pay all charges applicable to transportation service to the Customer's account in accordance with the provisions of the Company's tariff.

2.0 PIPELINE CAPACITY RELEASE:

2.1 Company agrees to provide to Marketer no later than 15 days before the above identified commencement date, the quantity of interstate pipeline capacity allocated for Marketer's FT-1 and FT-2 Aggregation Pool(s) broken down by individual customer.

2.2 Marketer agrees to accept assignment of such firm interstate pipeline capacity in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

2.3 Company agrees to update the calculation of the quantity of interstate pipeline capacity annually based on customers' most recent historical usage in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

3.0 PUBLIC REGULATION:

3.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

3.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement.

4.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By _____

Signature: _____

Name: _____

Title: _____

_____ Date: _____

Witness

By The Narragansett Electric Company

Signature: _____

Name: _____

Title: _____

_____ Date: _____

Witness

THE NARRAGANSETT ELECTRIC COMPANY
STORAGE AND PEAKING RESOURCE AGREEMENT

This Agreement ("Agreement") is entered into this _____ day of _____, 200__, by and between the Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and _____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, Marketer seeks to obtain service respecting a quantity of the Company's contracted underground storage and peaking resources pursuant to the terms and conditions for FT-2 Transportation Service in the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C; and

WHEREAS; Marketer desires that the Company transport quantities of gas delivered by Marketer for use at the locations of customers belonging to an FT-2 Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such storage and transportation service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing _____ 1, 200__, will provide to Marketer storage and peaking services in association with Marketer account number _____ under the terms and conditions set forth below.

1.0 SCOPE OF AGREEMENT:

1.1 The Company will calculate the Maximum Storage Quantities for both Underground Storage and for Peaking services ("MSQ-U" and "MSQ-P" respectively) as well as the Maximum Daily Quantities for both Underground Storage and Peaking services ("MDQ-U" and "MDQ-P" respectively) in accordance with Item 3.02 in Section 6, Schedule C of the Company's tariff. Such calculated quantities can change during the term of the agreement to the extent that the makeup of the Marketer's FT-2 Aggregation Pool changes.

1.2 Marketer hereby agrees to utilize and manage such services and inventories attributed to its account in accordance with the Operational Parameters described in Item 3.02.3 of the Company's Transportation Terms and Conditions, Section 6, Schedule C and as on file with the Public Utilities Commission as part of the Company's annual Gas Cost Recovery filing.

2.0 INVENTORY SERVICES:

2.1 All nominations for either withdrawals from or injections to storage will take place at the Company's citygate.

2.2 Purchases of inventory service from the Company will be at the Company's weighted average storage commodity cost of gas at the time of purchase or as otherwise stated in the Company's currently effective tariff.

2.3 Purchase of any storage inventory service from the Company will require payment via electronic transfer of funds within ten days of invoice unless the Marketer and Company mutually agree to payment over a 3 month period, which would include a monthly finance charge based on a monthly rate using the latest published Fleet Prime less 200 basis points (2%).

2.4 Notwithstanding any provisions to the contrary, Marketer acknowledges and warrants that sale and marketable title to any storage gas injected into the Company's system shall thereupon transfer to the Company, and that Marketer's interests shall thereafter be limited to the contractual rights to service as provided by this Agreement. Marketer further acknowledges that it shall bear no ownership interest in any other storage or peaking assets or inventory of the Company.

2.5 If Marketer needs to sell or assign its service rights representing underground storage inventory attributed to its account as a result of customers switching to other marketers, it may, subject to authorization by NG, sell the inventory rights to another marketer, nominate withdrawal of supplies, or sell the inventory to NG. Marketers with inventory levels in excess of the Maximum Storage Quantities may be required by the Company to nominate underground storage to satisfy their FDU. If the Marketer has excess peaking resources, it could nominate those inventories to the extent allowed under the operational parameters or would be required to sell such excess peaking resource rights to NG at the price the inventory was originally purchased from NG.

3.0 SUCCESSORS AND ASSIGNS:

3.1 This Agreement shall be binding on the parties hereto and their respective successors and assigns. This Agreement may not be assigned by Marketer without the prior written consent of the Company.

4.0 PUBLIC REGULATION:

4.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of

any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

4.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission, including provision thereof limiting the Company's liability, to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement. Upon request of the Marketer, Company shall provide the Marketer with a copy of Company's complete filed Tariff and Terms and Conditions.

5.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By _____

Signature: _____

Name: _____

Title: _____

Witness _____ Date: _____

By The Narragansett Electric Company

Signature: _____

Name: _____

Title: _____

Witness _____ Date: _____

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Gas Procurement Incentive Plan for National Grid

Revised Effective December 1, 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. This Plan became effective June 1, 2003. It will be reviewed with each gas cost recovery ("GCR") filing. The Company will file Plan results semi-annually at the end of January and July. These reports shall include reporting all Plan activity and results through the end of the month prior to the filing.

1. Gas Procurement Incentives apply only to discretionary purchases and/or hedges made on or after June 1, 2003. The first month for which the incentive will be calculated under the Plan will be November 2003.

B. The GPIP will be subject to limits on the magnitude of incentives applicable to the Company in each fiscal year.

1. For the Gas Procurement Incentive Program limitations are placed on the maximum amount of incentives that can be earned or penalties paid by National Grid for each fiscal year. For at least the first two years of the program (i.e., through June 30, 2005):

a. National Grid may not earn more than $1,000,000 in Gas Procurement Incentives in any fiscal year; and

b. National Grid may not be exposed to penalties of more than $500,000 in any fiscal year.

C. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. In addition, whenever the Company updates its annual forecast of projected purchases at the time of the annual update or in the event that an adjustment based on migration is

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warranted, it will file support for the revised purchase forecast with the Commission and Division.

III The Gas Procurement Incentive Program

D. The Company will make purchases of natural gas 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

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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.

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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. May not cause the total (mandatory plus discretionary), fixed price purchases and financial purchases and/or hedges to exceed 95% of the forecasted normal weather requirements for a given supply month.

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.

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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.

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

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E. 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 made after June 1, 2003, and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges, and/or hedges made after June 1, 2003 for the same 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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F. 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.

G. 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

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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%.

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2. For all discretionary purchases and/or hedges executed within the last 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 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,

4. 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.

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Gas Procurement Incentive Plan for National Grid

Revised Effective December 1, 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. This Plan became effective June 1, 2003. It will be reviewed with each gas cost recovery ("GCR") filing. The Company will file Plan results semi-annually at the end of January and July. These reports shall include reporting all Plan activity and results through the end of the month prior to the filing.

1. Gas Procurement Incentives apply only to discretionary purchases and/or hedges made on or after June 1, 2003. The first month for which the incentive will be calculated under the Plan will be November 2003.

B. The GPIP will be subject to limits on the magnitude of incentives applicable to the Company in each fiscal year.

1. For the Gas Procurement Incentive Program limitations are placed on the maximum amount of incentives that can be earned or penalties paid by National Grid for each fiscal year. For at least the first two years of the program (i.e., through June 30, 2005):

a. National Grid may not earn more than $1,000,000 in Gas Procurement Incentives in any fiscal year; and

b. National Grid may not be exposed to penalties of more than $500,000 in any fiscal year.

C. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. In addition, whenever the Company updates its annual forecast of projected purchases at the time of the annual update or in the event that an adjustment based on migration is

warranted, it will file support for the revised purchase forecast with the Commission and Division.

III The Gas Procurement Incentive Program

D. The Company will make purchases of natural gas 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. May not cause the total (mandatory plus discretionary), fixed price purchases and financial purchases and/or hedges to exceed 95% of the forecasted normal weather requirements for a given supply month.

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.

E. 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 made after June 1, 2003, and the volume weighted average cost per dekatherm of mandatory gas purchases, excluding any accelerated hedges, and/or hedges made after June 1, 2003 for the same 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.

F. 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.

G. 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 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 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,

4. 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 Program Worksheet - June 30, 2009
Incentive Calculation
National Grid - Rhode Island

Month	Mandatory NYMEX	Discretionary NYMEX	Difference	Discretionary Volumes (Dt)	Gain/ (Loss)	Incentive* Level	Company Incentive
July-08	$7.998	$8.115	-$0.117	13,596	($1,588)	10%	($159)
August-08	$8.066	$7.984	$0.081	2,945	$239	10%	$24
September-08	$8.302	$7.895	$0.407	4,500	$1,831	10%	$183
October-08	$8.555	$7.990	$0.565	2,015	$1,138	20%	$228
November-08	$9.227	$7.683	$1.545	300,000	$463,383	20%	$92,677
December-08	$9.721	$8.164	$1.557	300,000	$467,235	20%	$93,447
January-09	$10.004	$8.479	$1.525	300,000	$457,594	20%	$91,519
January-09	$10.004	$5.825	$4.179	300,000	$1,253,814	10%	$125,381
February-09	$9.920	$8.528	$1.392	250,000	$348,108	20%	$69,622
February-09	$9.920	$5.613	$4.308	400,000	$1,723,044	10%	$172,304
March-09	$9.491	$8.386	$1.105	250,000	$276,312	20%	$55,262
March-09	$9.491	$5.297	$4.195	300,000	$1,258,435	10%	$125,843
April-09	$8.530	$7.175	$1.355	100,000	$135,460	20%	$27,092
April-09	$8.530	$4.944	$3.585	280,000	$1,003,928	10%	$100,393
May-09	$8.160	$7.210	$0.950	100,000	$94,954	20%	$18,991
May-09	$8.160	$5.114	$3.046	200,000	$609,158	10%	$60,916
June-09	$8.297	$7.315	$0.982	100,000	$98,155	20%	$19,631
June-09	$8.297	$5.338	$2.958	150,000	$443,733	10%	$44,373
Total #			**$2.575**	**3,353,056**	**$8,634,933**		**$1,097,727**

* = Months where savings exceed 50 cents per Dt are subject to a 20% incentive through 12/1/08. Beginning 12/1/08 the incentive is 10% for all purchases done less than 8 months prior to the start of the month, 20% for those made greater than 8 full months prior where the savings is greater than 50 cents per Dt and 10% for those where the savings is less than 50 cents.

= Volume weighted average based on discretionary volumes

Gas Procurement Incentive Program Worksheet - June 30, 2009
Discretionary Purchases
National Grid - Rhode Island

Month	Daily Purchased Volume	Days	Monthly Volumes	NYMEX Price	Supply Cost	Weighted Average NYMEX Price
July, 2008	57	31	1,767	$7.950	$14,048	
July, 2008	13	31	403	$7.990	$3,220	
July, 2008	23	31	713	$7.900	$5,633	
July, 2008	23	31	713	$7.900	$5,633	
July, 2008			10,000	$8.180	$81,800	
10% eligible			**13,596**		**$110,333**	**$8.115**
August, 2008	89	31	2,759	$7.990	$22,044	
August, 2008	3	31	93	$7.900	$735	
August, 2008	3	31	93	$7.900	$735	
10% eligible			**2,945**		**$23,514**	**$7.984**
September, 2008	75	30	2,250	$7.900	$17,775	
September, 2008	75	30	2,250	$7.890	$17,753	
10% eligible			**4,500**		**$35,528**	**$7.895**
October, 2008	65	31	2,015	$7.990	$16,100	
20% eligible			**2,015**		**$16,100**	**$7.990**
November, 2008			30,000	$8.063	$241,890	
November, 2008			20,000	$8.061	$161,220	
November, 2008			50,000	$8.275	$413,750	
November, 2008			50,000	$7.740	$387,000	
November, 2008			100,000	$7.595	$759,500	
November, 2008			50,000	$6.830	$341,500	
20% eligible			**300,000**		**$2,304,860**	**$7.683**
December, 2008			50,000	$8.442	$422,100	
December, 2008			50,000	$8.565	$428,250	
December, 2008			50,000	$8.660	$433,000	
December, 2008			50,000	$8.210	$410,500	
December, 2008			50,000	$7.970	$398,500	
December, 2008			50,000	$7.135	$356,750	
20% eligible			**300,000**		**$2,449,100**	**$8.164**
January, 2009	03/27/2008		30,000	$8.703	$261,090	
January, 2009	04/25/2008		20,000	$8.704	$174,080	
January, 2009	08/14/2008		50,000	$9.300	$465,000	

Gas Procurement Incentive Program Worksheet - June 30, 2009
Discretionary Purchases
National Grid - Rhode Island

Month	Daily Purchased Volume	Days	Monthly Volumes	NYMEX Price	Supply Cost	Weighted Average NYMEX Price
January, 2009	08/25/2008		50,000	$8.810	$440,500	
January, 2009	09/02/2008		50,000	$8.465	$423,250	
January, 2009	09/26/2008		50,000	$8.200	$410,000	
January, 2009	10/07/2008		50,000	$7.395	$369,750	
20% eligible			**300,000**		**$2,543,670**	**$8.479**
New Incentive Calculation						
January, 2009	11/25/2008		100,000	$6.397	$639,700	
January, 2009	12/12/2008		100,000	$5.555	$555,500	
January, 2009	12/18/2008		50,000	$5.515	$275,750	
January, 2009	12/18/2008		50,000	$5.530	$276,500	
10% eligible			**300,000**		**$1,747,450**	**$5.825**
February, 2009	12/11/2007		40,000	$8.725	$349,000	
	12/11/2007		10,000	$8.737	$87,370	
	08/14/2008		50,000	$9.335	$466,750	
	08/25/2008		20,000	$8.850	$177,000	
	08/25/2008		30,000	$8.860	$265,800	
	09/26/2008		50,000	$8.240	$412,000	
	10/07/2008		50,000	$7.480	$374,000	
20% eligible			**250,000**		**$2,131,920**	**$8.528**
New Incentive Calculation						
February, 2009	11/25/2008		100,000	$6.440	$644,000	
	12/12/2008		100,000	$5.595	$559,500	
	12/18/2008		100,000	$5.570	$557,000	
	01/15/2009		100,000	$4.845	$484,500	
10% eligible			**400,000**		**$2,245,000**	**$5.613**
March, 2009	12/14/2007		50,000	$8.511	$425,550	
	08/14/2008		50,000	$9.190	$459,500	
	08/25/2008		50,000	$8.735	$436,750	
	09/26/2008		50,000	$8.120	$406,000	
	10/07/2008		50,000	$7.375	$368,750	
20% eligible			**250,000**		**$2,096,550**	**$8.386**
New Incentive Calculation						
	12/12/2008		100,000	$5.615	$561,500	
	12/18/2008		100,000	$5.630	$563,000	
	01/21/2009		50,000	$4.775	$238,750	
	02/11/2009		50,000	$4.515	$225,750	
10% eligible			**300,000**		**$1,589,000**	**$5.297**

Gas Procurement Incentive Program Worksheet - June 30, 2009
Discretionary Purchases
National Grid - Rhode Island

Month	Daily Purchased Volume	Days	Monthly Volumes	NYMEX Price	Supply Cost	Weighted Average NYMEX Price
April, 2009	10/14/2008		100,000	$7.175	$717,500	
20% eligible			**100,000**		**$717,500**	**$7.175**
New Incentive Calculation						
	12/17/2008		100,000	$5.890	$589,000	
	01/15/2009		100,000	$4.905	$490,500	
	02/27/2009		30,000	$3.987	$119,610	
	03/18/2009		50,000	$3.705	$185,250	
10% eligible			**280,000**		**$1,384,360**	**$4.944**
May, 2009	10/14/2008		100,000	$7.210	$721,000	
20% eligible			**100,000**		**$721,000**	**$7.210**
New Incentive Calculation						
	12/17/2008		100,000	$5.955	$595,500	
	01/21/2009		50,000	$4.900	$245,000	
	04/15/2009		50,000	$3.645	$182,250	
10% eligible			**200,000**		**$1,022,750**	**$5.114**
June, 2009	10/14/2008		100,000	$7.315	$731,500	
20% eligible			**100,000**		**$731,500**	**$7.315**
New Incentive Calculation	12/17/2008		100,000	$6.050	$605,000	
	05/19/2009		50,000	$3.915	$195,750	
10% eligible			**150,000**		**$800,750**	**$5.338**

Gas Procurement Incentive Program Worksheet - June 30, 2009
Mandatory Purchases and Benchmark
National Grid - Rhode Island

Month	Daily Purchased Volume	Monthly Volumes	Weighted Average NYMEX Price	Cost	Month
July, 2008	1,443	44,733	$7.950	$355,627	Jul-06
July, 2008	1,587	49,197	$7.990	$393,084	Aug-06
July, 2008	1,477	45,787	$7.900	$361,717	Sep-06
July, 2008	1,477	45,787	$7.900	$361,717	Oct-06
July, 2008	1,500	46,500	$7.940	$369,210	Nov-06
July, 2008	1,500	46,500	$7.950	$369,675	Dec-06
July, 2008	1,500	46,500	$7.550	$351,075	Jan-07
July, 2008	1,500	46,500	$7.700	$358,050	Feb-07
July, 2008	1,500	46,500	$8.090	$376,185	Mar-07
July, 2008	1,500	46,500	$8.450	$392,925	Apr-07
July, 2008	1,500	46,500	$8.460	$393,390	May-07
July, 2008	1,500	46,500	$8.400	$390,600	Jun-07
July, 2008		50,000	$7.850	$392,500	Jul-07
July, 2008		10,000	$7.989	$79,890	Aug-07
July, 2008		40,000	$7.990	$319,600	Aug-07
July, 2008		10,000	$7.551	$75,510	Sep-07
July, 2008		40,000	$7.560	$302,400	Sep-07
July, 2008		50,000	$7.760	$388,000	Oct-07
July, 2008		40,000	$8.180	$327,200	Nov-07
July, 2008		10,000	$7.570	$75,700	Dec-07
July, 2008		10,000	$7.572	$75,720	Dec-07
July, 2008		10,000	$7.573	$75,730	Dec-07
July, 2008		30,000	$7.860	$235,800	Jan-08
July, 2008		30,000	$9.240	$277,200	Feb-08
		887,504	**$7.998**	**$7,098,506**	
August, 2008	1,511	46,841	$7.990	$374,260	Aug-06
August, 2008	1,497	46,407	$7.900	$366,615	Sep-06
August, 2008	1,497	46,407	$7.900	$366,615	Oct-06
August, 2008	1,500	46,500	$7.800	$362,700	Nov-06
August, 2008	1,500	46,500	$7.580	$352,470	Dec-06
August, 2008	1,500	46,500	$7.630	$354,795	Jan-07
August, 2008	1,500	46,500	$7.700	$358,050	Feb-07
August, 2008	1,500	46,500	$7.760	$360,840	Mar-07

Gas Procurement Incentive Program Worksheet - June 30, 2009
Mandatory Purchases and Benchmark
National Grid - Rhode Island

Month	Daily Purchased Volume	Monthly Volumes	Weighted Average NYMEX Price	Cost	Month
August, 2008	1,500	46,500	$8.500	$395,250	Apr-07
August, 2008	1,500	46,500	$8.550	$397,575	May-07
August, 2008	1,500	46,500	$8.380	$389,670	Jun-07
August, 2008		50,000	$8.130	$406,500	Jul-07
August, 2008		50,000	$8.219	$410,950	Aug-07
August, 2008		20,000	$7.626	$152,520	Sep-07
August, 2008		30,000	$7.638	$229,140	Sep-07
August, 2008		50,000	$7.830	$391,500	Oct-07
August, 2008		50,000	$7.990	$399,500	Nov-07
August, 2008		10,000	$7.655	$76,550	Dec-07
August, 2008		10,000	$7.657	$76,570	Dec-07
August, 2008		20,000	$7.668	$153,360	Dec-07
August, 2008		40,000	$7.970	$318,800	Jan-08
August, 2008		30,000	$9.300	$279,000	Feb-08
August, 2008		50,000	$9.210	$460,500	Mar-08
		921,655	**$8.066**	**$7,433,730**	
September, 2008	1,625	48,750	$7.900	$385,125	Sep-06
September, 2008	1,625	48,750	$7.890	$384,638	Oct-06
September, 2008	1,700	51,000	$8.350	$425,850	Nov-06
September, 2008	1,700	51,000	$7.990	$407,490	Dec-06
September, 2008	1,700	51,000	$7.800	$397,800	Jan-07
September, 2008	1,700	51,000	$7.780	$396,780	Feb-07
September, 2008	1,700	51,000	$8.110	$413,610	Mar-07
September, 2008	1,700	51,000	$8.540	$435,540	Apr-07
September, 2008	1,700	51,000	$8.600	$438,600	May-07
September, 2008	1,700	51,000	$8.430	$429,930	Jun-07
September, 2008		50,000	$7.956	$397,800	Jul-07
September, 2008		50,000	$7.930	$396,500	Aug-07
September, 2008		50,000	$7.922	$396,100	Sep-07
September, 2008		50,000	$8.020	$401,000	Oct-07
September, 2008		50,000	$7.990	$399,500	Nov-07
September, 2008		40,000	$7.615	$304,600	Dec-07
September, 2008		40,000	$8.227	$329,080	Jan-08
September, 2008		30,000	$9.310	$279,300	Feb-08

Gas Procurement Incentive Program Worksheet - June 30, 2009
Mandatory Purchases and Benchmark
National Grid - Rhode Island

Month	Daily Purchased Volume	Monthly Volumes	Weighted Average NYMEX Price	Cost	Month
September, 2008		50,000	$9.210	$460,500	Mar-08
September, 2008		40,000	$11.320	$452,800	Apr-08
		955,500	**$8.302**	**$7,932,543**	
October, 2008	2,135	66,185	$7.990	$528,818	Oct-06
October, 2008	2,200	68,200	$8.390	$572,198	Nov-06
October, 2008	2,200	68,200	$7.990	$544,918	Dec-06
October, 2008	2,200	68,200	$7.760	$529,232	Jan-07
October, 2008	2,200	68,200	$7.954	$542,438	Feb-07
October, 2008	2,200	68,200	$8.210	$559,922	Mar-07
October, 2008	2,200	68,200	$8.630	$588,566	Apr-07
October, 2008	2,200	68,200	$8.710	$594,022	May-07
October, 2008	2,200	68,200	$8.540	$582,428	Jun-07
October, 2008		20,000	$8.577	$171,540	Jul-07
October, 2008		50,000	$8.578	$428,900	Jul-07
October, 2008		70,000	$7.900	$553,000	Aug-07
October, 2008		70,000	$7.860	$550,200	Sep-07
October, 2008		70,000	$8.090	$566,300	Oct-07
October, 2008		50,000	$7.850	$392,500	Nov-07
October, 2008		50,000	$7.580	$379,000	Dec-07
October, 2008		50,000	$8.440	$422,000	Jan-08
October, 2008		40,000	$9.400	$376,000	Feb-08
October, 2008		30,000	$9.340	$280,200	Mar-08
October, 2008		50,000	$11.380	$569,000	Apr-08
October, 2008		60,000	$12.010	$720,600	May-08
		1,221,785	**$8.555**	**$10,451,782**	
November, 2008	3,500	105,000	$8.600	$903,000	Nov-06
November, 2008	3,500	105,000	$8.500	$892,500	Dec-06
November, 2008	3,500	105,000	$8.200	$861,000	Jan-07
November, 2008	3,500	105,000	$8.290	$870,450	Feb-07
November, 2008	3,500	105,000	$8.680	$911,400	Mar-07
November, 2008	3,500	105,000	$9.100	$955,500	Apr-07
November, 2008	3,500	105,000	$9.180	$963,900	May-07
November, 2008	3,500	105,000	$9.020	$947,100	Jun-07

Gas Procurement Incentive Program Worksheet - June 30, 2009
Mandatory Purchases and Benchmark
National Grid - Rhode Island

Month	Daily Purchased Volume	Monthly Volumes	Weighted Average NYMEX Price	Cost	Month
November, 2008		110,000	$8.830	$971,300	Jul-07
November, 2008		110,000	$8.240	$906,400	Aug-07
November, 2008		110,000	$8.190	$900,900	Sep-07
November, 2008		110,000	$8.160	$897,600	Oct-07
November, 2008		100,000	$8.380	$838,000	Nov-07
November, 2008		90,000	$7.980	$718,200	Dec-07
November, 2008		90,000	$8.730	$785,700	Jan-08
November, 2008		80,000	$9.690	$775,200	Feb-08
November, 2008		80,000	$10.330	$826,400	Mar-08
November, 2008		80,000	$11.630	$930,400	Apr-08
November, 2008		100,000	$12.270	$1,227,000	May-08
November, 2008		100,000	$13.730	$1,373,000	Jun-08
		2,000,000	**$9.227**	**$18,454,950**	
December, 2008	4,300	133,300	$8.990	$1,198,367	Dec-06
December, 2008	4,300	133,300	$8.750	$1,166,375	Jan-07
December, 2008	4,300	133,300	$8.950	$1,193,035	Feb-07
December, 2008	4,300	133,300	$9.150	$1,219,695	Mar-07
December, 2008	4,300	133,300	$9.440	$1,258,352	Apr-07
December, 2008	4,300	133,300	$9.700	$1,293,010	May-07
December, 2008	4,300	133,300	$9.570	$1,275,681	Jun-07
December, 2008		70,000	$8.930	$625,100	Jul-07
December, 2008		70,000	$8.950	$626,500	Jul-07
December, 2008		140,000	$9.170	$1,283,800	Aug-07
December, 2008		140,000	$8.780	$1,229,200	Sep-07
December, 2008		140,000	$8.850	$1,239,000	Oct-07
December, 2008		130,000	$8.810	$1,145,300	Nov-07
December, 2008		130,000	$8.490	$1,103,700	Dec-07
December, 2008		120,000	$8.840	$1,060,800	Jan-08
December, 2008		120,000	$8.850	$1,062,000	Feb-08
December, 2008		120,000	$10.680	$1,281,600	Mar-08
December, 2008		120,000	$11.970	$1,436,400	Apr-08
December, 2008		130,000	$12.650	$1,644,500	May-08
December, 2008		130,000	$14.085	$1,831,050	Jun-08
December, 2008		130,000	$10.200	$1,326,000	Jul-08

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		2,623,100	**$9.721**	**$25,499,465**	
January, 2009	4,500	139,500	$8.900	$1,241,550	Jan-07
January, 2009	4,500	139,500	$8.850	$1,234,575	Feb-07
January, 2009	4,500	139,500	$9.540	$1,330,830	Mar-07
January, 2009	4,500	139,500	$9.720	$1,355,940	Apr-07
January, 2009	4,500	139,500	$9.930	$1,385,235	May-07
January, 2009	4,500	139,500	$9.950	$1,388,025	Jun-07
January, 2009		140,000	$9.250	$1,295,000	Jul-07
January, 2009		140,000	$9.590	$1,342,600	Aug-07
January, 2009		140,000	$9.000	$1,260,000	Sep-07
January, 2009		140,000	$8.970	$1,255,800	Oct-07
January, 2009		150,000	$9.140	$1,371,000	Nov-07
January, 2009		10,000	$8.745	$87,450	Dec-07
January, 2009		130,000	$8.746	$1,136,980	Dec-07
January, 2009		140,000	$8.850	$1,239,000	Jan-08
January, 2009		130,000	$9.080	$1,180,400	Feb-08
January, 2009		150,000	$10.900	$1,635,000	Mar-08
January, 2009		130,000	$12.190	$1,584,700	Apr-08
January, 2009		140,000	$12.980	$1,817,200	May-08
January, 2009		140,000	$14.275	$1,998,500	Jun-08
January, 2009		140,000	$10.420	$1,458,800	Jul-08
January, 2009		140,000	$9.880	$1,383,200	Aug-08
		2,797,000	**$10.004**	**$27,981,785**	
February, 2009	4,200	117,600	$9.200	$1,081,920	Feb-07
February, 2009	4,200	117,600	$9.520	$1,119,552	Mar-07
February, 2009	4,200	117,600	$9.710	$1,141,896	Apr-07
February, 2009	4,200	117,600	$9.920	$1,166,592	May-07
February, 2009	4,200	117,600	$9.950	$1,170,120	Jun-07
February, 2009		130,000	$9.250	$1,202,500	Jul-07
February, 2009		130,000	$9.310	$1,210,300	Aug-07
February, 2009		130,000	$9.000	$1,170,000	Sep-07
February, 2009		130,000	$8.990	$1,168,700	Oct-07
February, 2009		120,000	$8.990	$1,078,800	Nov-07

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February, 2009		10,000	$8.764	$87,640	Dec-07
February, 2009		100,000	$8.765	$876,500	Dec-07
February, 2009		110,000	$9.040	$994,400	Jan-08
February, 2009		110,000	$9.090	$999,900	Feb-08
February, 2009		100,000	$10.350	$1,035,000	Mar-08
February, 2009		100,000	$11.710	$1,171,000	Apr-08
February, 2009		120,000	$12.940	$1,552,800	May-08
February, 2009		120,000	$14.200	$1,704,000	Jun-08
February, 2009		110,000	$10.420	$1,146,200	Jul-08
February, 2009		120,000	$9.950	$1,194,000	Aug-08
February, 2009		120,000	$8.505	$1,020,600	Sep-08
		2,348,000	**$9.920**	**$23,292,420**	
March, 2009	4,100	127,100	$9.170	$1,165,507	Mar-07
March, 2009	4,100	127,100	$9.550	$1,213,805	Apr-07
March, 2009	4,100	127,100	$9.700	$1,232,870	May-07
March, 2009	4,100	127,100	$9.690	$1,231,599	Jun-07
March, 2009		130,000	$9.420	$1,224,600	Jul-07
March, 2009		130,000	$8.730	$1,134,900	Aug-07
March, 2009		130,000	$8.740	$1,136,200	Sep-07
March, 2009		130,000	$8.650	$1,124,500	Oct-07
March, 2009		100,000	$8.790	$879,000	Nov-07
March, 2009		100,000	$8.520	$852,000	Dec-07
March, 2009		100,000	$8.810	$881,000	Jan-08
March, 2009		90,000	$8.870	$798,300	Feb-08
March, 2009		90,000	$10.080	$907,200	Mar-08
March, 2009		90,000	$11.430	$1,028,700	Apr-08
March, 2009		90,000	$12.680	$1,141,200	May-08
March, 2009		90,000	$13.925	$1,253,250	Jun-08
March, 2009		100,000	$10.250	$1,025,000	Jul-08
March, 2009		110,000	$9.350	$1,028,500	Aug-08
March, 2009		110,000	$8.380	$921,800	Sep-08
March, 2009		110,000	$7.350	$808,500	Oct-08
March, 2009		10,000	$6.740	$67,400	Oct-08
		2,218,400	**$9.491**	**$21,055,831**	

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April, 2009	2,600	78,000	$8.030	$626,340	Apr-07
April, 2009	2,600	78,000	$8.200	$639,600	May-07
April, 2009	2,600	78,000	$8.250	$643,500	Jun-07
April, 2009		80,000	$8.230	$658,400	Jul-07
April, 2009		80,000	$7.660	$612,800	Aug-07
April, 2009		80,000	$7.730	$618,400	Sep-07
April, 2009		80,000	$8.030	$642,400	Oct-07
April, 2009		50,000	$7.920	$396,000	Nov-07
April, 2009		50,000	$7.890	$394,500	Nov-07
April, 2009		100,000	$7.830	$783,000	Dec-07
April, 2009		100,000	$8.070	$807,000	Jan-08
April, 2009		100,000	$8.600	$860,000	Feb-08
April, 2009		110,000	$8.720	$959,200	Mar-08
April, 2009		110,000	$9.660	$1,062,600	Apr-08
April, 2009		90,000	$10.465	$941,850	May-08
April, 2009		90,000	$11.560	$1,040,400	Jun-08
April, 2009		40,000	$9.364	$374,560	Jul-08
April, 2009		20,000	$9.374	$187,480	Jul-08
April, 2009		30,000	$9.376	$281,280	Jul-08
April, 2009		30,000	$8.840	$265,200	Aug-08
April, 2009		60,000	$8.840	$530,400	Aug-08
April, 2009		90,000	$8.140	$732,600	Sep-08
April, 2009		90,000	$7.260	$653,400	Oct-08
April, 2009		60,000	$7.010	$420,600	Nov-08
		1,774,000	**$8.530**	**$15,131,510**	
May, 2009	2,100	65,100	$8.060	$524,706	May-07
May, 2009	2,100	65,100	$8.120	$528,612	Jun-07
May, 2009		10,000	$7.950	$79,500	Jul-07
May, 2009		60,000	$7.970	$478,200	Jul-07
May, 2009		70,000	$7.470	$522,900	Aug-07
May, 2009		70,000	$7.670	$536,900	Sep-07
May, 2009		70,000	$7.980	$558,600	Oct-07
May, 2009		60,000	$7.890	$473,400	Nov-07

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Month	Daily Purchased Volume	Monthly Volumes	Weighted Average NYMEX Price	Cost	Month
May, 2009		60,000	$8.000	$480,000	Dec-07
May, 2009		60,000	$8.050	$483,000	Jan-08
May, 2009		40,000	$8.515	$340,600	Feb-08
May, 2009		50,000	$8.530	$426,500	Mar-08
May, 2009		50,000	$9.480	$474,000	Apr-08
May, 2009		50,000	$10.280	$514,000	May-08
May, 2009		60,000	$11.400	$684,000	Jun-08
May, 2009		60,000	$9.284	$557,040	Jul-08
May, 2009		60,000	$8.840	$530,400	Aug-08
May, 2009		60,000	$7.985	$479,100	Sep-08
May, 2009		30,000	$7.340	$220,200	Oct-08
May, 2009		30,000	$7.350	$220,500	Oct-08
May, 2009		70,000	$7.070	$494,900	Nov-08
May, 2009		100,000	$5.940	$594,000	Dec-08
		1,250,200	**$8.160**	**$10,201,058**	
June, 2009	1,600	48,000	$8.090	$388,320	Jun-07
June, 2009		50,000	$7.900	$395,000	Jul-07
June, 2009		50,000	$7.950	$397,500	Aug-07
June, 2009		50,000	$7.720	$386,000	Sep-07
June, 2009		50,000	$8.150	$407,500	Oct-07
June, 2009		50,000	$7.990	$399,500	Nov-07
June, 2009		50,000	$8.080	$404,000	Dec-07
June, 2009		50,000	$8.090	$404,500	Jan-08
June, 2009		40,000	$8.570	$342,800	Feb-08
June, 2009		50,000	$8.530	$426,500	Mar-08
June, 2009		40,000	$9.540	$381,600	Apr-08
June, 2009		50,000	$10.320	$516,000	May-08
June, 2009		10,000	$11.475	$114,750	Jun-08
June, 2009		40,000	$11.480	$459,200	Jun-08
June, 2009		20,000	$9.362	$187,240	Jul-08
June, 2009		20,000	$9.366	$187,320	Jul-08
June, 2009		50,000	$8.940	$447,000	Aug-08
June, 2009		50,000	$8.100	$405,000	Sep-08
June, 2009		50,000	$7.480	$374,000	Oct-08

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June, 2009		50,000	$7.180	$359,000	Nov-08
June, 2009		40,000	$6.060	$242,400	Dec-08
June, 2009		40,000	$6.000	$240,000	Jan-09
		948,000	**$8.297**	**$7,865,130**	