nationalgrid

Thomas R. Teehan
Senior Counsel

October 18, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Revenue Decoupling Mechanism

Dear Ms. Massaro:

Pursuant to recently enacted Rhode Island legislation,[1] National Grid is submitting the enclosed revenue decoupling mechanism ("RDM") proposal. The filing consists of the pre-filed testimony of Jennifer B. Feinstein and Jeanne A. Lloyd along with supporting exhibits. This filing includes the proposed gas and electric RDMs, the tariff provisions associated with the Company's proposal, the timing of filings under the proposed RDMs, and an illustrative reconciliation if similar RDMs had been implemented at the same time new distribution rates went into effect after the Company's most recent electric and gas distribution rate cases.

In the recently enacted Decoupling Act, the legislature set out several objectives that would be achieved by a revenue decoupling mechanism, including increasing investment in end-use energy efficiency and eliminating disincentives to the utility's support of energy efficiency programs. Revenue decoupling establishes a rate mechanism designed to break the link between the revenues a gas or electric distribution company receives and the level of sales it makes. Because it eliminates the incentive for the utility to expand its sales, revenue decoupling allows utilities to aggressively pursue increased energy efficiency programs.

The Company believes that its electric and gas RDM proposals are consistent with the intent and objectives contained in the Decoupling Act. The Company's proposals contain a reconciliation between actual revenue and the revenue requirement resulting from the Company's last general rate case for its gas and its electric distribution operations. This reconciliation removes a barrier to the Company's more fully embracing and implementing wider scale energy efficiency programs beyond levels that have traditionally been performed by the Company and its customers. Moreover, the effect of the Company's proposed RDMs is to provide an allowed level of revenue, which will accomplish the legislature's goal of supporting a safe, efficient, and reliable electric and gas distribution systems.

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

Very truly yours,

Thomas R. Teehan

Enclosure
cc: Leo Wold, Esq.
Steve Scialabba, Division

[1] The Decoupling Act is found at R.I.G.L. §39-1-27.7.1.

DIRECT TESTIMONY

OF

JENNIFER B. FEINSTEIN

AND

JEANNE A. LLOYD

October 18, 2010

Table of Contents

I. Introduction and Qualifications

Jennifer B. Feinstein

Q. Please state your name and business address.

A. My name is Jennifer B. Feinstein and my business address is 1 Metrotech Center, 14^{th} floor, Brooklyn, New York.

Q. What are your position and responsibilities?

A. I am Director of Gas Distribution Pricing for National Grid USA with responsibility for pricing for all of the National Grid USA gas companies: The Narragansett Electric Company ("National Grid" or the "Company"), Boston Gas Company, Essex Gas Company, Colonial Gas Company, KeySpan Gas East Corporation, Niagara Mohawk Power Corporation (all d/b/a National Grid), The Brooklyn Union Gas Company (d/b/a National Grid NY) and EnergyNorth Natural Gas, Inc. (d/b/a National Grid NH). My responsibilities include cost of gas filings, cost allocation and rate design issues.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (the "Commission")?

A. No; however, I have previously testified before the Federal Energy Regulatory Commission. Also, I filed testimony in Texas Eastern Transmission Corporation Docket Nos. RP85-177, et al., Iroquois Gas Transmission, L.P. Docket Nos. RP94-72, et al., and RP97-126 and CNG Transmission Corporation, Docket Nos. RP94-96, et al. on cost allocation and rate design issues.

Q. Please describe your professional and educational background.

A. I received a Bachelor of Science Degree in Economics and Business Management from Cornell University and a Master of Science Degree in Management and Policy/Business Enterprise Management from the State University of New York at Stony Brook. I was first employed by George B. Buck Consulting, as an actuarial assistant and then worked as an economic analyst for National Economic Research Associates in New York. After that, I consulted independently on various economic matters. In 1990, I joined the Gas Supply and Planning Department of the Long Island Lighting Company ("LILCO"). After LILCO's merger with KeySpan Corporation ("KeySpan"), my positions included Director of Strategic Planning, Director of Risk Management for Ravenswood (a power plant), and Director of Transactions for the procurement organization. In 1995, I became the Director of Gas Pricing for KeySpan, the position I hold today for National Grid USA.

<u>Jeanne A. Lloyd</u>

Q. Please state your full name and business address.

A. My name is Jeanne A. Lloyd, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am the Manager of Electric Pricing, New England in Regulation and Pricing's Electricity Distribution and Generation group of National Grid USA Service Company, Inc. This group provides rate-related support to the Company.

Q. Please describe your educational background and training.

A. In 1980, I graduated from Bradley University in Peoria, Illinois with a Bachelor of Arts Degree in English. In December 1982, I received a Master of Arts Degree in Economics from Northern Illinois University in De Kalb, Illinois.

Q. Please describe your professional experience?

A. I was employed by Eastern Utilities Associates ("EUA") Service Corporation in December 1990 as an Analyst in the Rate Department. I was promoted to Senior Rate Analyst on January 1, 1993. My responsibilities included the study, analysis and design of the retail electric service rates, rate riders and special contracts for the EUA retail companies. After the merger of New England Electric System and EUA in April 2000, I joined the Distribution Regulatory Services Department as a Principal Financial Analyst. I assumed my present position October 1, 2006. Prior to my employment at EUA, I was on the staff of the Missouri Public Service Commission in Jefferson City, Missouri in the position of research economist. My responsibilities included presenting both written and oral testimony before the Missouri Public Service Commission in the areas of cost of service and rate design for electric and natural gas rate proceedings.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission on numerous occasions.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present the Company's Revenue Decoupling Mechanism ("RDM") proposals, which would become effective April 1, 2011, for both the electric and gas operations of National Grid. Pursuant to R.I.G.L. §39-1-27.7.1 (the "Decoupling Act"), subsection (b), the Company must file its proposed RDM for Commission consideration and approval. We will present the proposed RDM, the tariff provisions associated with the Company's proposal, discuss the timing of filings under the proposed RDM, and finally demonstrate that the Company's proposal is consistent with the intent and objectives of the Decoupling Act. The Company's electric RDM proposal is addressed by Ms. Lloyd and the gas RDM proposal by Ms. Feinstein.

Q. What is the main purpose of revenue decoupling?

A. The main purpose is to establish a rate mechanism that breaks the link between the revenues a gas or electric distribution company receives and the level of sales it makes. Because it eliminates the incentive for the utility to expand its sales, while reducing risks to both customers and distribution companies, the RDM mandated by the Decoupling Act allows utilities to aggressively pursue increased energy efficiency programs. Moreover, by ensuring an allowed level of revenue that is decoupled from the declining sales levels resulting from successful energy efficiency measures as well as from other causes, the RDM helps support the distribution company's continuing ability to fund safe, efficient, and reliable gas and electric distribution systems.

Q. Please describe the required features of an RDM as required under the Decoupling Act.

A. The RDM features and components required by the Decoupling Act are straightforward. The RDM must reconcile annually the revenue requirement allowed in the Company's base distribution rate case to the revenues actually received for the applicable 12-month period. Any revenues over-recovered or under-recovered are to be credited to or recovered from customers, as the case may be. The Decoupling Act specifically provides that the RDM for gas distribution companies "shall be determined on a revenue per-customer basis."

Q. Are any customer classes excluded from this annual reconciliation?

A. Although the legislation does not require that any rate class be excluded, it permits the exclusion of the large commercial and industrial rate class from the gas distribution mechanism and also permits the exclusion of the low income rate class from either or both the gas and electric reconciliation rate mechanisms. [1]

III. Electric Revenue Decoupling Mechanism Proposal

A. Reconciliation of Annual Target Revenue

[1] R.I.G.L. §39-1-27.7.1 (e) (2)

Q. Please describe the Company's RDM proposal for its electric business.

A. For its electric business, the Company is proposing an RDM that follows the directive of the law. Specifically, it reconciles billed distribution revenue during a 12-month period ("RDM Year") to an annual target ("RDM Reconciliation"). This annual target, or Annual Target Revenue ("ATR"), would be based upon the Commission-approved revenue requirement coming from the Company's most recent general rate case in RIPUC Docket No. 4065, and would change as the Commission approves new revenue requirements in future general rate cases. The billed distribution revenue would be generated from the Company's various distribution rates as billed through its Customer Service System ("CSS"), the system which performs billing to the Company's customers. The Company is proposing that its RDM become effective April 1, 2011.

Q. Would the Company adjust the revenue requirement upon which the ATR is based for any reason outside of a base rate proceeding?

A. Yes. It is possible that after a revenue requirement is approved by the Commission in a base rate case proceeding, a subsequent ruling by the Commission in another proceeding regarding recovery of costs contained in the revenue requirement could require an adjustment to the ATR. For example, if the Commission were to approve a new rate recovery mechanism which, by its design, transferred recovery of costs from base rates to a recovery factor, it would be appropriate to remove the allowance in rates for those costs from the ATR to avoid recovering those costs twice. In any such instance, the RDM reconciliation would compare base distribution revenues billed and an ATR that included the same suite of costs to ensure no double- or non-recovery of costs. Similarly, if recovery of costs previously governed by a reconciliation mechanism are later rolled into base rates, an adjustment would be needed to add the revenue requirement associated with such costs to the ATR.

Q. Would all customers be included in the Company's proposed RDM?

A. The Company is proposing that all customers be included in the proposed RDM. Since the ATR represents the revenue requirement to provide distribution service to all customers, and this revenue requirement would be input into the Company's rate design, it would be appropriate to credit all distribution revenue generated from all customers in the RDM Reconciliation, which would compare ATR and billed distribution revenue. In addition, the Company is also proposing that all customers would be subject to the RDM Adjustment Factor, which I discuss below.

Q. Is the Company presenting an illustrative RDM Reconciliation in this filing?

A. Yes it is. Exhibit JAL-1 contains an illustrative RDM Reconciliation.

Q. Why is the Company showing this reconciliation by month if the ATR is an annual amount?

A. The Company is proposing to prepare the reconciliation monthly for two reasons. First, the Company would be required to record a regulatory asset or regulatory liability should it under-bill or over-bill its ATR, respectively, over the course of the year. Rather than wait until the end of an RDM Year, the Company intends to perform this reconciliation monthly, similar to its other reconciliations filed with the Commission. Second, as I will discuss below, the Company is proposing mechanisms that would allow for an interim rate adjustment should the annualized RDM Reconciliation result in a projected over- or under-recovery of ATR that is in excess of 10 percent of the ATR. This proposed interim rate adjustment would be measured by preparing a current monthly RDM Reconciliation and then, for future months, adding to the actual billed distribution revenue a forecast of billed distribution revenue through the end of the RDM Year based on current forecasted billing determinants.

Q. What would be included in billed distribution revenue as shown in Exhibit JAL-1?

A. Billed distribution revenue would consist of revenue generated from the Company's base distribution rates, such as customer charges, distribution energy charges, distribution demand charges, high voltage metering and delivery credits under the Company's general service rate classes, and luminaire and pole charges under the Company's streetlighting rates. Essentially, billed distribution revenue would be the equivalent of the revenue that would support the Company's base distribution revenue requirement.

Q. How is the Company proposing to allocate the annual revenue requirement, or ATR, to the months of the RDM Year?

A. To establish the monthly ATR, the Company is proposing to use the final revenue requirement resulting from the last general rate case in RIPUC Docket No. 4065 for its electric distribution operations and allocate that revenue requirement by month using the monthly forecasted kWh deliveries for the period April 1, 2011 through March 31, 2012 from the Company's most current kWh forecast. This will add the element of seasonality that better reflects of how the Company anticipates it will bill its distribution rates over the RDM Year and therefore will help avoid significant swings in monthly over- or under-billing.

Q. How would this interim rate adjustment be implemented?

A. The Company proposes to track the actual and forecasted reconciliation of ATR over the RDM Year and should there appear to be a balance (positive or negative) in this reconciliation that is more than 10 percent of the annual ATR, the Company would make a filing with the Commission requesting an interim rate adjustment. The Company believes this would avoid a larger rate adjustment and bill impact to customers in the future by avoiding the accumulation of a large balance, thereby promoting rate stability. This is similar to the provision in the Company's Transmission Service Cost Adjustment Provision, RIPUC Docket No. 2036, which provides for the filing of an interim transmission rate adjustment should there be significant over- or under-recoveries of transmission costs. The balance in the reconciliation account would accrue interest at the customer deposit rate.

Q. Has the Company reviewed what this reconciliation would have looked like if a similar RDM had been implemented at the same time new distribution rates went into effect from RIPUC Docket No. 4065?

A. Yes it has. New distribution rates went into effect March 1, 2010, along with lost revenue factors to recover over a period of 13 months the revenue that would have been realized had these rates gone into effect as originally proposed on January 1, 2010. Both the distribution rates and lost revenue factors were subsequently revised June 1, 2010 to reflect the effect of the Company's issuance of new long-term debt and the revenue requirement impact from the interest rate on that debt. What the Company has observed from the partial-year reconciliation it has prepared for the period commencing March 1, 2010 through August 31, 2010, is that the Company would have over-recovered its ATR by approximately $5.2 million. For the forecasted period, incorporating the Company's current sales forecast as previously discussed, the estimated reconciliation indicates an over-recovery of approximately $2.7 million by the end of the 12-month period of the illustrative reconciliation year ending February 28, 2011. The analysis is provided in Exhibit JAL-2. The Company believes the over-recovery of ATR under this hypothetical illustration is the result of the extreme hot weather Rhode Island experienced this past summer. Under a full RDM as is being proposed by the Company, an over-recovery of ATR such as this would be credited back to all customers in the following year. This illustrates that the RDM does, in fact, operate in two ways. It can easily result in refunds to customers from high usage, as well as adjustments caused in the other direction by the implementation of energy efficiency programs.

B. Revenue Decoupling Mechanism Adjustment Factor

Q. Once the Company has completed an RDM Reconciliation, what process would be used to adjust rates for any over- or under-billing of ATR?

A. The Company proposes an annual filing that would be made with the Commission by June 1 of each year that would reconcile for the prior RDM Reconciliation Year (the April through March period). The first RDM Reconciliation filing would occur by June 1, 2012 for the twelve months ended March 31, 2012, and annually thereafter. In this filing, the Company would compare its actual billed distribution revenue to its ATR and propose an RDM Adjustment Factor designed to refund or recover any over- or under-billing of ATR including interest over the 12-month period commencing July 1, with the first rate adjustment occurring July 1, 2012. The Company would reflect the RDM Adjustment Factor in distribution energy charges for billing purposes, but the amount approved by the Commission to be refunded or recovered would be subject to its own reconciliation to ensure this amount is actually credited to or recovered from customers.

Q. Has the Company included an illustration of the design of the RDM Adjustment Factor?

A. An illustrative RDM Adjustment Factor is contained in Exhibit JAL-3. The calculation takes the reconciliation balance from Exhibit JAL-1 and divides it by the hypothetical forecast of kWh deliveries for the 12-month period July 1 through June 30 to arrive at the factor.

C. Proposed Revenue Decoupling Mechanism Provision

Q. Is the Company proposing a tariff provision for its RDM at this time?

A. Yes it is. Exhibit JAL-4 contains the Company's proposed Revenue Decoupling Mechanism Provision. This proposed tariff contains the elements of the Company's RDM proposal discussed above.

IV. Gas Revenue Decoupling Mechanism Proposal

A. Overview Of Revenue Decoupling And Proposal For Natural Gas Service In Rhode Island

Q. Please provide an overview of the Company's gas RDM proposal.

A. Consistent with the statute, the Company's gas RDM proposal is a revenue per customer mechanism that will annually reconcile the actual base revenue per customer by rate class with the target revenue per customer based on rates approved by the Commission in the Company's last general gas rate case, RIPUC Docket No. 3943, for its gas distribution operations. The framework of the Company's RDM proposal closely aligns with similar revenue decoupling proposals that the Company has in place, or has filed, for its gas distribution companies in its other National Grid jurisdictions.[2] It also is typical of gas RDM mechanisms in the industry generally. The Company proposes to begin the annual revenue decoupling reconciliation effective April 1 each year, commencing April 1,

[2] National Grid USA has a revenue per customer revenue decoupling plan in place for Niagara Mohawk Power Corporation in upstate New York, for KeySpan Gas East Corporation, and for The Brooklyn Union Gas Company in downstate New York, and has filed revenue per customer revenue decoupling plans in Massachusetts and New Hampshire which are currently under review.

2011, and to return to or recover from customers any over-recovery or under-recovery of revenues under its RDM proposal through its annual Distribution Adjustment Charge ("DAC") filing effective November 1 each year, with the first rate adjustment occurring November 1, 2012.

B. Specifics of Rate Design Proposal

1. Introduction

Q. Please describe in more detail the Company's RDM proposal for the gas business.

A. National Grid is proposing a revenue-per-customer decoupling mechanism for all Residential and all Small and Medium Commercial and Industrial ("C&I") firm rate classes. The Company has calculated billing-month target base revenues per customer (which is referred to as "RPC") for each month using the billing determinants and rates approved by the Commission in the most recent base rate case for the Company's gas distribution operations, RIPUC Docket No. 3943. After the close of every billing month, for each rate class, the Company will calculate: (1) actual RPC; (2) the difference between actual RPC and target RPC and (3) the total RPC revenue surplus or shortfall, which will be determined by multiplying the difference between actual RPC and target RPC times the actual number of customers. Annually, the Company will calculate a single Revenue Decoupling Adjustment ("RDA") factor to credit or charge customers for the cumulative RPC revenue surplus or shortfall, including interest at the Bank of America prime rate minus 200 basis points, which is the same interest rate used for the

Gas Cost Recovery reconciliation. The RDA will flow through the DAC along with other reconciliation adjustment items that are recovered through the DAC. Additional details on these calculations are provided below.

2. Decoupling Mechanism Design Parameters

a. RPC Decoupling Rate Classes

Q. To which rate classes would the Company's proposed RPC decoupling reconciliation apply?

A. As stated above, the Company is proposing that the RPC decoupling reconciliation be applied to the Residential and the Small and Medium C&I rate classes. As I will explain below, the Company's proposed RPC decoupling reconciliation would not be applied to C&I customers in the following rate classes: (1) Large Low Load Factor; (2) Large High Load Factor; (3) Extra Large Low Load factor; and (4) Extra Large High Load Factor.

Q. Why is the Company proposing to exclude customers in the C&I Large and Extra Large rate classes from the RPC decoupling reconciliation?

A. The Large and Extra Large C&I rate classes have a relatively small number of customers and those customers are significantly diverse in the ways they use natural gas and in their usage levels, which makes it difficult to apply a revenue recovery mechanism based on an "average" revenue per customer calculation. Changes in the makeup of the rate class by just one or two customers joining or leaving the rate class could, by itself, have a measurable effect on the average use per customer and the associated average revenue per customer. The revenue per customer decoupling mechanism would inappropriately capture these changes as being a result of changes in average usage rather than merely a change in the composition of customers in the rate class or other factors.

Q. Are there any other considerations?

A. Yes. The use of rate-class average revenues for these classes could have a significant impact on the calculation of Contribution in Aid of Construction ("CIAC") payments that may be required to offset some of the customer-connection costs associated with new customers or existing customers adding additional loads. The CIAC calculation under a RPC decoupling mechanism would need to use the rate class target RPC regardless of that customer's expected revenue stream, since the target would represent the revenue stream the Company would effectively receive for this added customer. Another consideration is that these rate classes include the vast majority of firm-service, dual-fuel customers whose margins are being tracked and accounted for under the On-System Credits component of the DAC. Under the terms of the Commission's order in RIPUC Docket No. 3943, all margins from customers having Dual-Fuel capability are capped at an annual level of $2.8 million, with any variation reconciled each year as part of the On-System Credits component of the DAC. This includes customers taking both firm and non-firm service. Given this existing target revenue mechanism, it would be inappropriate to include these customers and their revenues in the calculation of the decoupling RPC reconciliation calculation. A further consideration is that the non Dual-

Fuel C&I classes account for a small portion, approximately 7 percent,of the Company's variable base revenues.

Q. Why wouldn't the medium C&I rate class be excluded?

A. The Medium C&I rate class is not being excluded from the RDM because it has a much narrower range of usage (5,000 to 35,000 therms per year) than the Large and Extra Large C&I rate classes, there are a much larger number of customers in the Medium C&I rate class, and customers in that rate class are more homogeneous. The possibility of excluding medium sized customers also is not contemplated in the Decoupling Act.

b. <u>RPC Decoupling Calculations</u>

Q. Please explain how the target revenues per customer have been calculated.

A. As mentioned above, the Company has calculated target RPCs for the various rate classes using billing determinants and rates approved by the Commission in the most recent rate case, RIPUC Docket No. 3943 for its gas distribution operations. These targets represent the average monthly base revenue divided by the number of monthly customers projected for the rate year October 2008 through September 2009. The targeted RPC for the Medium C&I rate class is based on a combination of both sales and transportation revenues so that the Company is indifferent to migration between sales and transportation service. The target RPCs for the Low-Income Residential Non-Heating and Low-Income Residential Heating classes are the targets for the corresponding non-discounted classes. The non-discounted targets are used for all residential customers so that the RDA is not affected by customer movement between discounted and non-discounted classes. For RDM reconciliation purposes, the actual billed revenue for the Low-Income Residential Non-Heating and Low-Income Residential Heating classes would similarly be adjusted to exclude the applicable discounts. Exhibit JBF-1 shows the calculation of the monthly target RPCs.

Q. Please explain how the RPC decoupling reconciliation adjustments will be calculated.

A. For each rate class included in the RDM, the Company will calculate the RPC decoupling reconciliation in the following manner:

1. After the final close of every billing month, the Company will make the following calculations:

   a. Actual RPCs will be calculated by dividing (i) actual base revenues for each rate class by (ii) the number of customers in that rate class. For the Low-Income Residential Non-Heating and Low-Income Residential Heating classes, the actual revenues will be adjusted to reflect the equivalent non-discounted revenue. For the Small and Medium C&I classes, actual revenues will exclude revenues from any Dual-Fuel customers to the extent they are tracked under the On-System Credit component of the DAC.

   b. The difference between (i) target RPC base revenues and (ii) actual RPC base revenues will be calculated. The target RPC base revenues for the corresponding non-discounted Residential Non-Heating and Residential Heating classes will be used for the respective low-income classes.

   c. The billing month revenue surplus or shortfall will be calculated by multiplying (i) the difference between target and actual base revenues per customer (from 1b above) times (ii) actual number of customers in the month.

   d. The billing month revenue surplus or shortfall will be recorded in a deferred account.

   e. Interest on the average monthly deferred balance will be calculated at the same interest rate that is used to calculate interest expense on the Company's deferred

DAC and GCR balances, which is 200 basis points below the Bank of America Prime Rate.

2. The Company will include an annual decoupling reconciliation report and RDA factor calculation as part of the DAC filing that is made August 1 of each year. For this filing, the Company will total the RPC account deferred balances for each rate class as of the end of March that year and calculate a single RDA rate so that the net balance is returned to (in the case of an over-collection) or recovered from (in the case of an under-collection) all Residential, Small and Medium C&I firm service customers, as a component of the DAC based on projected delivery quantities for the twelve months ended October of the following year.

Q. Please provide an example of the RPC calculations.

A. The table below provides an illustrative example of the monthly RPC calculation and deferred account entries that the Company would have made for the Residential Heating rate class for March 2010, if the RDA had been in effect during the fiscal year ending March 2010.

		Mar-10

Residential Heating (incl Low-Income)		
Target Revenue Per Customer (RPC)	Docket 3493	$61.69
RPC Account Beginning. Balance.		$1,186,545
Actual Number of Customers		198,776
Actual Base Revenue		$11,384,530
Actual Base Revenue Per Customer		$57.27
RPC Variance (Target - Actual)		$4.42
Monthly Variance		$877,802

Preliminary End Balance		$2,064,347
Average Balance		$1,625,446
Bank America Rate less 200 Basis Points		1.25%
Interest Applied		$1,726
RPC Account End Balance		**$2,066,072**
Under/(Over) Recovery for the month		$879,528

A similar calculation would have been done for each of the rate classes each month. An illustrative example of the RPC account balances for all the rate classes for the 12-month period ending March 2010 totaled for determining the annual RDA factor is provided as Exhibit JBF-2.

Q. Has the Company reviewed what this reconciliation would have looked like if a similar RDM had been implemented at the same time new distribution rates went into effect from RIPUC Docket No. 4043?

A. Yes it has. As shown on Exhibit JBF-2, the RPC balance for the twelve months ended March 31, 2010 would have been $1,552,603 had the Company's RDM proposal been in effect. However, it is important to note that the Company will recover $2,466,000 from the most recent weather normalization adjustment ("WNA") factor submitted in the August 2, 2010 DAC filing. As discussed in more detail below, the WNA charge will no longer be applicable if the Company's RDM proposal is approved. Hence, the impact on customers from the proposed RDM would have been lower by $913,397 because the RDM operates in a different way than the existing WNA, focusing on revenues, rather than isolating weather alone.

Q. Please explain why the Company is eliminating its WNA charge.

A. The Company's proposed RPC decoupling mechanism will charge or credit customers for the revenue impact of the difference between actual revenues per customer (i.e., not weather normalized) and target revenues per customer (i.e., weather normalized) as established in each rate case proceeding. As proposed, the RPC decoupling mechanism takes into account the revenue impact of (1) weather-related differences in usage and (2) differences in usage that are caused by non-weather factors such as customer energy efficiency. Therefore, with Commission approval of the Company's RDM as proposed for April 1, 2011, the currently effective WNA will become duplicative and can be canceled after the 2010-2011 peak season.

Q. Since April is included in the WNA peak season, how would the WNA be calculated for the 2010-2011 peak season?

A. The WNA for the 2010-2011 peak season would be calculated consistent with past calculations except that the actual heating degree days for April 2011 would be set equal to normal heating degree days. This would ensure that there would be no impact of April weather included in the WNA. Any revenue impact of weather on customers' usage during the month of April 2011 would be captured in the monthly RPC reconciliation.

Q. Would the Company adjust the revenue requirement target used for establishing the RPC for any reason outside of a base rate proceeding?

A. Yes. For the same reasons that such an adjustment would be made on the electric side, as was explained earlier in the testimony.

c. Proposed Tariff

Q. How is the Company proposing to incorporate revenue decoupling in its tariff?

A. The Company is proposing to modify the DAC in Section 3, Schedule A of its tariff RIPUC NG-GAS No. 101 to incorporate revenue decoupling. As described above, the RDA rate is intended to be incorporated as a component of the DAC and filed with the Commission as part of its annual August 1 DAC filing. A "marked" version of the proposed DAC and the Definitions sections of the tariff is provided as Exhibit JBF-3. A "clean" version of the proposed tariff is shown in Exhibit JBF-4.

V. Consistency of RDM Proposals with the Decoupling Act

Q. Please discuss whether the Company's electric and gas RDM proposals are consistent with the intent and objectives contained in the Decoupling Act.

A. The Company believes that its proposed electric and gas RDM proposals are consistent with the intent and objectives contained in the Decoupling Act. First, both proposals contain a reconciliation between actual revenue and the revenue requirement resulting from the Company's last general rate case for each of the gas and electric distribution operations. Second, by employing such a reconciliation, a barrier has been removed to allow the Company to more fully embrace and implement wider scale energy efficiency programs beyond levels that have traditionally been performed by the Company and its customers. Historically, the Company has relied on load growth to provide additional revenue to help offset increased costs or other revenue requirements. Not only would current investment, through program funding in energy efficiency, erode the likelihood of load growth and, hence, incremental revenue, significant expansion of energy efficiency efforts is likely to cause a more dramatic erosion over time. The RDM leaves the Company completely indifferent to changes in usage. Thus, the Company can fully participate in the further expansion of energy efficiency programs without the risk of declining revenue as a result of successful demand side management by its customers. To that end, the Company believes that its proposed electric and gas RDM proposals meet the objectives of Rhode Island's energy policy on energy efficiency and address the effects of increased energy conservation while ensuring revenue is available at a predictable level to fund an efficient, safe, and reliable distribution system.

Q. Why is the Company not proposing to exclude low income customers from the operation of the RDM for either the electric or gas business?

A. Low income customers also participate in the energy efficiency programs. For that reason, it would be important to include the revenues from those rate classes in the calculation of the revenue targets used to implement the RDM. A different question would be whether low income customers should be excluded from any RDM rate adjustments resulting from the reconciliation. To the extent they are exempt from any refunds or charges, other customers would be further subsidizing the low income rate classes that are already receiving a low income discount on distribution rates. For that reason, the Company has not proposed any exemption. It is important to emphasize, however, that in addressing this policy question, it is critical to make a distinction between including the revenues from the low income class in the target revenue reconciliation, as opposed to simply exempting the low income rate class from any refund or charges. These are two different issues. The first relates to assuring that the disincentive to the Company to implement aggressive energy efficiency programs for low income customers is still eliminated. While the second issue is simply a matter of policy regarding the level of discounts that low income customers should enjoy, which are subsidized by other customer classes. In this case, the Company is simply proposing to treat the low income customer class in the same way that all residential customers would be treated, for the limited purposes of the RDM.

VI. Conclusion

Q. Does this conclude your testimony?

A. Yes it does.

Index of Exhibits

Jennifer B. Feinstein

Jeanne A. Lloyd

Exhibit JBF-1

Monthly target of RPCs.

National Grid
Rhode Island - Gas

REVENUE DECOUPLING TARGETS
(Based on Dkt 3943 Rates and Compliance billing determinants)

Revenue Per Customer (RPC) Calculations

Docket No. 3943 Compliance

	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total Oct 08 - Sep 09
Residential Non-Heat													
Number of Customers	28,552	28,533	28,502	28,109	27,840	27,645	27,462	27,343	27,240	27,156	27,092	27,110	27,715
Base Revenue	$ 417,133	$ 457,249	$ 495,163	$ 520,167	$ 500,794	$ 490,746	$ 479,269	$ 457,419	$ 435,031	$ 406,889	$ 382,012	$ 398,891	$ 5,440,763
RPC	$ 14.61	$ 16.03	$ 17.37	$ 18.51	$ 17.99	$ 17.75	$ 17.45	$ 16.73	$ 15.97	$ 14.98	$ 14.10	$ 14.71	$ 196.20
Residential Heating													
Number of Customers	176,609	179,078	180,855	181,813	182,363	182,542	181,716	180,361	179,287	178,462	177,863	178,447	179,950
Base Revenue	$ 3,825,830	$ 6,145,443	$ 9,275,333	$ 11,405,718	$ 11,778,571	$ 11,260,870	$ 9,451,468	$ 5,595,988	$ 4,532,816	$ 3,724,827	$ 3,420,788	$ 3,632,511	$ 84,050,163
RPC	$ 21.66	$ 34.32	$ 51.29	$ 62.73	$ 64.59	$ 61.69	$ 52.01	$ 31.03	$ 25.28	$ 20.87	$ 19.23	$ 20.36	$ 465.06
Small													
Number of Customers	18,084	18,500	18,765	18,879	18,950	18,967	18,813	18,657	18,491	18,343	18,286	18,334	18,589
Base Revenue	$ 517,112	$ 886,128	$ 1,340,672	$ 1,649,373	$ 1,788,145	$ 1,669,227	$ 1,402,189	$ 696,524	$ 575,687	$ 489,565	$ 469,873	$ 487,927	$ 11,972,422
RPC	$ 28.60	$ 47.90	$ 71.45	$ 87.37	$ 94.36	$ 88.01	$ 74.53	$ 37.33	$ 31.13	$ 26.69	$ 25.70	$ 26.61	$ 639.67
Medium C&I													
Number of Customers	4,435	4,496	4,522	4,529	4,553	4,558	4,543	4,526	4,521	4,509	4,498	4,517	4,517
Base Revenue	$ 939,013	$ 1,213,472	$ 1,634,292	$ 1,888,641	$ 1,985,288	$ 1,871,476	$ 1,544,766	$ 1,188,549	$ 1,010,871	$ 885,873	$ 858,744	$ 907,871	$ 15,928,856
RPC	$ 211.73	$ 269.90	$ 361.41	$ 417.01	$ 436.04	$ 410.59	$ 340.03	$ 262.60	$ 223.59	$ 196.47	$ 190.92	$ 200.99	$ 3,521.28

Exhibit JBF-2

Illustrative example of RPC account balances for all the rate classes for the 12-month period ending March 2010 determining the annual RDA factor

Illustrative Example
Revenue Per Customer (RPC) Reconciliation

Line No.	Description		RPC Deferred Balance for 12 mths ended 3/31/10 [Under / (Over) collection]	
1	Residential Non-Heat (incl Low Income)		($674,857)	
2	Residential Heat (incl Low Income)		$2,066,072	
3	Small C&I		$258,677	
4	Medium C&I		($97,289)	
5	**Total (Line No.1-8)**		**$1,552,603**	
6	Firm Throughput Forecast (Nov 2010 - Oct 2011)	DAC Docket 4196	24,023,027	Therms
7	Revenue Decoupling Adjustment (RDA) Factor	Ln 5 / Ln 6	**$0.0646**	**per Therm**

Notes: Residential targets based on compliance non-discount rates
Low-Income revenues captured w/o discount
Firm throughput Residential rate classes and Small and Medium C&I rate classes

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Exhibit JBF-3

"Marked" version of the proposed DAC and the Definitions sections of the tariff

“Marked” Versions of:

RIPUC NG-GAS No. 101, Section 1 Schedule B -- Definitions

RIPUC NG-GAS No. 101, Section 3 Schedule A -- Distribution Adjustment Charge

DEFINITIONS

Actual Base Revenue Per Customer:	The actual base revenue divided by the respective number of customers booked by the Company each month for each rate class.
Actual Transportation Quantity:	The quantity of gas actually received during the Gas Day as measured by the metering equipment at the Point(s) of Receipt, adjusted for the applicable Company Fuel Allowance.
Aggregation Pool:	One or more transportation Customer accounts whose gas usage is aggregated into a Marketer's account for operational purposes, including but not limited to nominating, scheduling and balancing gas deliveries to specified Point(s) of Receipt.
AGT Costs:	Advanced Gas Technology program costs as approved by the Rhode Island Public Utilities Commission.
Average Normalized Winter Day Usage:	A customer's average normal winter day's usage, based on their actual gas usage during the most recent November through March period, adjusted for normal degree days, as approved in the most recent rate case proceeding.
Base Revenue:	Base Revenue is the sum of the customer charge, variable distribution charges and demand charges for firm service rate classes. Base Revenue is net of GET.
BTU content factor:	One British thermal unit, i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit. A Therm is one hundred thousand Btus. The BTU content factor for a given volume, shall be calculated by the Company on a seasonal basis at the end of October and the end of April based upon an average of the Transporting Pipeline's prior six-month experience of recorded BTU factors.

Capacity Release

DEFINITIONS

Revenues: Revenues derived from the sale of capacity upstream of the city-gate.

Company Fuel Allowance**:** The quantity in Therms (as calculated on a percentage basis) by which the gross amount of gas received for Customer's account at the Point(s) of Receipt is reduced in kind in order to compensate the Company for gas loss and unaccounted for, Company use or similar quantity-based adjustment.

Consumption Algorithm**:** A mathematical formula used to calculate a Customer's daily consumption based on the Customer's historical base load and heat use per heating degree day factor.

Critical Day: Defined as any day where supply resource constraints are expected to adversely impact the operation of the Company's distribution system. Generally, this occurs at) forty-four (44) Degree Days or colder. A Critical Day may also occur under other conditions, such as pipeline emergencies, malfunctions or unusual, out-of-season weather conditions.

Customer: Any party(s) that has obtained service from the Company pursuant to the General Terms and Conditions or pursuant to the Transportation Terms and Conditions

Daily Index: The mid-point of the range of prices for the respective New England Citygates as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin citygates" and "Daily Price Survey, Midpoint, Citygates Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)." In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that RIPUC approves a suitable replacement.

Dual-Fuel Customer: Customers with dual-fuel capability included in the November 5, 2008 Stipulation in Docket No. 3943 plus new non-firm customers taking non-firm service after that date.

DEFINITIONS

Deferred Balance:	The difference between incurred costs and revenues received.
Deferred Gas Cost Balance:	The difference between gas costs incurred and gas revenues received.
Dekatherm (Dt):	Ten Therms or one million Btu's (MMBtu)
Design Winter Sales Sendout:	Sales sendout of Residential Non-Heating, Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I during November through March based on design winter temperatures.
Electronic Bulletin Board:	An internet web site which allows both the Company and Marketers to electronically post nominations and other transportation-related information.
Environmental Response Costs:	All reasonable and prudently incurred costs associated with evaluation, remediation, clean-up, litigation, claims, judgments, insurance recovery (net of proceeds), and settlements arising out of the company's utility-related ownership, operation, or use of: (1) manufactured gas production and storage facilities and disposal sites where wastes and materials from such facilities were deposited; (2) mercury regulators; and (3) meter disposal. Also included are the reasonable and prudently incurred costs for acquiring plant, property and equipment to facilitate remediation and other appropriate environmental management objectives in connection with the above sites, properties, and activities. The Company will use its best efforts to minimize Environmental Response Costs consistent with applicable regulatory requirements and sound environmental management policies and practices.
Forecasted Daily	

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DEFINITIONS

Usage (FDU):	Customer's estimated daily consumption for the next gas day as calculated by the Company based upon a forecast of heating degree days and the consumption algorithm.
Gas Day:	A period of twenty-four (24) consecutive hours beginning at 10:00 am (EST) and ending at 10:00 am (EST) the next calendar day.
Gas Usage:	The actual quantity of gas used by the Customer as measured by the Company's metering equipment at the Point of Delivery and converted to Therms.
Hedge Collateral:	Funds the Company is required to put up as collateral on hedge positions by an Exchange or counterparty, or funds it receives from an Exchange or counterparty as collateral.
Hedge Collateral Carrying Costs:	For the month being calculated, carrying costs equal the total of the following: (1) For each Exchange or counterparty holding the Company's collateral, the monthly short term borrowing rate (The monthly average for the rate for high grade 30-day commercial paper sold through dealers by major corporations as published in the Wall Street Journal) times the average hedge collateral daily balance for the month divided by 12. Less (2) for each Exchange or counterparty where the Company holds their collateral, the monthly short term borrowing rate times the average hedge collateral daily balance for the month divided by 12. Less (3) any interest paid to the Company by the Exchange or counterparty on the collateral funds it holds. The Company will recover carrying costs from customers or credit customers for carrying costs through the Gas Adjustment. In the event the Company chooses to meet its collateral obligations by posting a letter of credit or other non-cash instrument, the carrying cost will be the direct costs of the letter of credit or alternative non-cash instrument.
Imbalance:	The difference between the Actual Transportation Quantity and Gas Usage.

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DEFINITIONS

Interest on Deferred Balance:	Interest revenue/expense required to finance the deferred balance based on the Bank of America Prime Rate less 200 basis points (2%) as in effect from time to time.
Inventory Finance Charge:	Finance charges associated with the storage of natural gas as calculated using a working capital calculation.
Local Storage Costs:	Costs associated with the investment, operations and maintenance of natural gas storage downstream of the city-gate.
Low Income Assistance Programs:	Programs for assisting low income customers with their energy bills including, but not limited to, Low Income Heating Assistance (LIHEAP) and Low Income Weatherization, as in effect from time to time.
Marginal Gas Cost:	The variable cost of the Company's marginal source of supply for the Gas Day. Incremental Cost is a synonymous term.
Marketer:	An entity meeting the eligibility requirements of Section 6 Schedule C, Item 5.03 that is designated in a Transportation Service Application by the Customer to act on its behalf for nomination, notification, scheduling, balancing and receipt of communications, and which has executed a Marketer Aggregation Pool Service Agreement. A Customer may designate itself as the Marketer provided that they have an executed service agreement with the Transporting Pipeline or provide proof of contract to purchase the gas at the Company's city gate.
Maximum Daily Quantity:	The maximum quantity of gas a customer is authorized to use during the gas day.
Monthly Index:	The simple average of the Daily Indices for the applicable month.

DEFINITIONS

Net Insurance Recoveries:	Proceeds recovered from insurance providers and third parties for Environmental Response Costs, less the cost of obtaining such proceeds through claims, settlements, and litigation.
New Customer:	A Customer taking a supply of gas at a Point of Delivery that has not been previously served on a firm sales service basis by the Company.
Non-Firm Transportation Margin:	Margins derived from the transportation of natural gas to non-firm customers downstream of the city gate.
Off-System Sales Margins:	Margins derived from the sale of natural gas upstream of the city-gate.
Pipeline Costs:	Costs associated with the entitlement and transmission of natural gas on the interstate pipeline system.
Pipeline Shipper(s):	The party(s) from whom Marketer has purchased gas to be delivered to and transported by the Company.
Point of Delivery:	A location at which the Company's distribution facilities are interconnected with the Customer's facility.
Point(s) of Receipt:	Outlet side of the measuring station at the interconnection between the Transporting Pipeline and the Company's distribution facilities where gas will be received by the Company for transportation service in its service territory.
Pool Balancing Revenues:	Revenues associated with Pool Balancing service, as derived in Section 2, Schedule A, Item 4.0.
Purchased Gas Working Capital:	Working capital required to finance gas costs.
Reconciliation Amount:	The Deferred balance at the end of September.

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DEFINITIONS

Refunds:	Refunds from pipeline, storage and suppliers.
Scheduled Transportation Quantity:	The quantity of gas scheduled by the Marketer to be received by the Company for Customer's account during the Gas Day at the Point of Receipt, including the applicable Company Fuel Allowance.
Service Quality Performance Fund:	Deferred account containing accumulated Service Quality adjustments.
Supplier Costs:	Costs associated with the entitlement and purchase of natural gas.
Target Revenue Per Customer:	A target average dollar amount per customer established for each month for each firm service rate class at the time of the most recent rate case or other proceeding that results in a base rate adjustment.
Therm:	An amount of gas having a thermal content of 100,000 Btus.
Transportation Imbalance Revenues:	Revenues associated with daily and monthly imbalances for transportation customers, as included in the Company's Terms and Conditions of Firm Transportation.
Transporting Pipeline:	The party(s) engaged in the business of rendering transportation service of natural gas in interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission, which are transporting gas for Marketer to a Point of Receipt of the Company.
Upstream Storage Costs:	Costs associated with the entitlement, injection, withdrawal and storage of natural gas upstream of the city-gate.
Working Capital:	Amounts required to finance the Company's activities prior to the receipt of revenue.

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DEFINITIONS

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DISTRIBUTION ADJUSTMENT 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 RIPUC, to annually adjust its rates for firm sales and transportation in order to recover the costs of system balancing, Low Income Assistance, Advanced Gas Technology, Environmental Response, Pension costs and Post-retirement Benefits Other than Pensions, Capital Expenditures Tracker, Revenue Decoupling, to credit margins from on-system non-firm sales and transportation and on-system non-traditional firm sales and transportation, and Service Quality Performance and to credit or recover Weather Normalization over or under collections. Any costs recovered through the application of the Distribution Adjustment Charge shall be identified and explained fully in the annual Distribution Adjustment Charge filing.

1.2 Applicability: The distribution adjustment charge will be uniformly applied to sales and transportation volumes under each of the Company's firm rate schedules and shall be calculated separately for the following:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I;

(2) Large C&I Low Load Factor, Large C&I High Load Factor, Extra Large C&I Low Load Factor, Extra Large C&I High Load.

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The Company will make annual Distribution Adjustment Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Distribution Adjustment Charge shall become effective with consumption as of November 1st each year.

Unless otherwise notified by the RIPUC, the Company shall submit the Distribution Adjustment Charge filings no later than 90 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.

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DISTRIBUTION ADJUSTMENT CLAUSE

2.0 DISTRIBUTION ADJUSTMENT CHARGE: The distribution adjustment charge will consist of an annual System Pressure factor, an Advanced Gas Technology factor, a Low Income Assistance factor, an Environmental Response factor, a Pension and Post-retirement Benefits Other than Pensions adjustment factor, a Capital Expenditures Tracker factor, a Revenue Decoupling Adjustment factor, a Weather Normalization factor, an on-system credit factor, a Service Quality Performance factor, and a deferred cost factor calculated as follows:

DAC = SP+AGT+LIAP+ERCF+P&PBOP+CapX-MC-SQP+WN+RDA+R

Where:

DAC	Distribution Adjustment Charge applicable to all firm throughput
SP	System Pressure factor. See Item 3.1 for calculation.
AGT	Advanced Gas Technology factor. See Item 3.2 for calculation.
LIAP	Low Income Assistance Programs factor. See Item 3.3 for calculation.
ERCF	Environmental Response cost factor. See Item 3.4 for calculation.
P&PBOP	Pension and Post-retirement Benefits Other than Pensions (PBOP) adjustment factor. See Item 3.5 for calculation.
CapX	Capital Expenditures Tracker factor. See Item 3.6 for calculation

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DISTRIBUTION ADJUSTMENT CLAUSE

MC	On-system margin credits related to Dual-Fuel Customer margins and non-traditional sales and transportation. See Item 3.7 for calculation.
SQP	Service Quality Performance Factor. See Item 3.8 for calculation
WN	Weather Normalization factor related to over-collections or under-collections of distribution revenues due to colder or warmer than normal weather. See Item 3.9 for calculation.
RDA	Revenue Decoupling Adjustment factor. See Item 3.10 for calculation.
R	Reconciliation of deferred account balance as of October 31. See Item 4.0 for calculation.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor: The System Pressure factor shall be computed on an annual basis utilizing a forecast of Liquefied Natural Gas (LNG) sendout and the projected average inventory cost of LNG based on the following formula:

$$SP = \frac{[Dt_{LNG} * INV_{LNG}] * SP\%}{Dt_T}$$

Where:

SP	System Pressure Amount
Dt_{LNG}	Forecast of LNG sendout in dekatherms
INV_{LNG}	Average inventory cost of LNG per dekatherm
SP%	Percent of local storage used to maintain system pressures, as established in the most recent rate case proceeding.

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DISTRIBUTION ADJUSTMENT CLAUSE

Dt_T Forecasted annual firm throughput in dekatherms

3.2 AGT Factor: The Advanced Gas Technology factor will be computed on an annual basis utilizing the approved budget for AGT programs based on the following formula:

$$AGT = \frac{AGT_B - AGT_{EMB}}{Dt_T}$$

Where:

AGT AGT Factor

AGT_B Approved AGT budget

Dt_T Forecasted annual firm throughput in dekatherms

AGT_{EMB} AGT funding embedded in base rates, $300,000

3.3 LIAP Factor:

The Low Income Assistance factor shall be computed on an annual basis utilizing the approved funding for low income programs, such as Low Income Heating Assistance and Low Income Weatherization, based on the following formula:

$$LIAP = \frac{LIAP_B + - LIAP_{EMB}}{Dt_T}$$

Where:

LIAP LIAP Factor

$LIAP_B$ Approved low income program funding(s)

Dt_T Forecasted annual firm throughput in dekatherms

$LIAP_{EMB}$ LIAP funding embedded in base rates, $1,785,000

3.4 Environmental Response Cost Factor (ERCF):

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DISTRIBUTION ADJUSTMENT CLAUSE

$$ERCF = \frac{\dfrac{ERC_{95\text{-}01}}{10} + \dfrac{\sum_{x=n-9}^{n} ERC_{yr}}{10} - ERC_{EMB}}{Dt_T}$$

Where:

ERC	Environmental Response Costs as defined in Section 1, Schedule B Definitions
$\dfrac{ERC_{95\text{-}01}}{10}$	Unamortized Environmental Response Costs at the end of fiscal year 2001 to be amortized over ten years.
$\sum_{x=n-9}^{n} ERC\ yr_x$	The sum of Environmental Response Costs, incurred in the most recent fiscal year ("n"), and in the prior nine fiscal years, but no earlier than fiscal year 2002. Therefore, until fiscal year 2011, n-9 is equal to fiscal year 2002.
ERC_{EMB}	Environmental Response Costs funding embedded in base rates, $1,310,000.
Dt_T	Forecasted annual firm throughput in dekatherms

In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor, calculated as described above, shall be limited to an increase of no more than $0.10 per dekatherm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the

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DISTRIBUTION ADJUSTMENT CLAUSE

portion of the environmental remediation costs not included in the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.10 per dekatherm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1 Schedule C of the Company's General Rules and Regulations.

3.5 P&PBOP Adjustment Factor

The P&PBOP adjustment factor shall recover or refund the prior year's reconciliation of the Company's actual Pension and Post-retirement Benefits Other Than Pension ("PBOP") expenses to the Company's Pension and PBOB expense allowance included in Base rates. The adjustment factor will be computed on an annual basis for the twelve months ended June 30th and will be based on the difference in the Company's actual Pension and PBOP expense for the prior twelve month period ended June 30th and the Company's most recently approved Pension and PBOP expense base rate allowance.

For the period ending June 30, 2009, the computation will be based on eight months.

3.6 Capital Expenditure Tracker Factor -

The Capital Expenditure ("CapX") Tracker Factor will be computed annually and is the mechanism for refunding or collecting from customers the revenue requirement impact associated with variations in capital spending, including the Accelerated Replacement Program, to the extent allowed by the Commission.

3.7 On-System Credits:

Each year, beginning 2010, the Company will calculate the total Dual-Fuel Customer margins, exclusive of Rhode Island Gross Earnings Tax for the twelve month period ending June 30. Dual-Fuel customers included in the November 5, 2008 Stipulation in Docket No. 3943 plus

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DISTRIBUTION ADJUSTMENT CLAUSE

margins exclusive of GET received from non-firm special contracts and new non-firm customers taking non-firm service after that date. If that total exceeds $2,816,000, the On-System Credit shall be positive. If the total non-firm margins, exclusive of Rhode Island Gross Earnings Tax, for the twelve-month period ending June 30 are less than $2,816,000, the On-System Credit shall be negative.

For period ending June 2009, the Company will calculate the total non-firm transportation margins for the eight month period ending June 30th . If the total non-firm margins for the eight month period ending June 30th are less than $1,879,800, the On-System Credit shall be negative. If the total non-firm margins for the eight month period ending June 30 are more than $1,879,800, the On-System Credit shall be positive.

For 2009:

$$MC = \frac{(DFCM\text{-}\$1{,}879{,}800)}{Dt_T}$$

After 2009:

$$MC = \frac{(DFCM\text{- }\$2{,}816{,}000)}{Dt_T}$$

Where:

MC — On-System margin credit factor

DFCM — The Dual-Fuel Customer margins exclusive of Rhode Island Gross Earnings Tax ("GET") for the 12 months ending June 30 (in 2009 only, for the 7 months ending June 30) for the Firm and Non-Firm Dual-Fuel customers included in the November 5, 2008 Stipulation in Docket No. 3943 plus margins exclusive of GET received from non-firm special contracts and new non-firm customers taking non-firm service after that date.

Dt_T — Forecasted annual firm throughput in dekatherms

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DISTRIBUTION ADJUSTMENT CLAUSE

3.8 Service Quality Performance Factor - The Service Quality Performance ("SQP") Factor will be used for crediting to customers any penalties reflected in the Company's annual Service Quality Report.

3.9 Weather Normalization: The Company shall compare actual heating degree days ("DD") to normal heating degree days at the end of each peak season (November through April). For each DD greater than 4,865 (2% colder than normal), the Company shall credit the Weather Normalization Account an amount equal to $9,000 per DD. For each DD less than 4,675 (2% warmer than normal), the Company shall debit the Weather Normalization Account at $9,000 per DD. With implementation of the Revenue Decoupling Adjustment effective April 1, 2011, the Weather Normalization for the peak season November 2010 through April 2011 will utilize normal heating degree days for the month of April 2011 as actual heating degree days. For subsequent peak seasons, the Weather Normalization provision will no longer be applicable.

3.10 Revenue Decoupling Adjustment Factor The Revenue Decoupling Adjustment (RDA) Factor shall be a credit or surcharge determined for all Residential rate classes and Small and Medium C&I rate classes as the sum of the March 31st Revenue Per Customer deferral ending balances for each rate class divided by the forecasted total annual firm throughput for those rate classes. The March deferral ending balance for each rate class, shall result from the monthly calculation of the variance between a Target Revenue Per Customer and the Actual Revenue Per Customer based on the following formulas:

$$RDAF = \frac{\sum_{RC} (AEB_{M-1} + VR_M + INT_M)}{Dt_{RC}}$$

Where:

RDAF Revenue Decoupling Adjustment Factor

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DISTRIBUTION ADJUSTMENT CLAUSE

$\sum_{RC}$ The sum of the March 31st Revenue Per Customer deferral ending balances for each of the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I. Any Dual-Fuel customer's revenue included in the Small C&I and Medium C&I rate classes are excluded just for purposes of the RPC calculation.

AEB_{M-1} Account Ending Balance for prior month

VR_M Current month Variance

$= (RPC_{TM} - RPC_{AM}) \times CUST_M$

RPC_{TM} = Target Revenue Per Customer for current month as established at time of the most recent rate case. Target Revenue for Low-Income classes will reflect non-discounted target revenue. Target revenues for C/I classes will exclude revenues from Dual-Fuel Customers

RPC_{AM} = Actual Revenue Per Customer for current month calculated as actual base revenues divided by number of customers in the current month. Revenue for Low-Income classes will reflect non-discounted revenues. Revenues and customers for C/I classes will exclude Dual-Fuel Customers.

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DISTRIBUTION ADJUSTMENT CLAUSE

$CUST_M$ = Number of customers in current month excluding any Dual-Fuel Customers.

INT_M Interest on average monthly balance

$$= \frac{(AEB_{M-1} + VR_M)}{2} \times BA_M$$

BA_M Bank of America Prime minus 200 basis points

Dt_{RC} Forecasted annual firm throughput in dekatherms for the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I (Including Firm throughput for any Dual-Fuel customers included in the Small C&I and Medium C&I rate classes).

4.0 DEFERRED DISTRIBUTION ADJUSTMENT <u>COST ACCOUNT</u>: The Company shall maintain separate Deferred Cost Accounts for AGT costs and revenues, LIAP costs and revenues, Environmental Response costs and revenues, and the On-System credit costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

(1) An amount equal to the allowable costs incurred, less revenues collected adjusted for the RIGET and the uncollectible percentage approved in the most recent rate case proceeding;

(2) Credits to costs, and;

(3) Monthly rate 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 and ending balance after entries for (1) and (2) above.

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DISTRIBUTION ADJUSTMENT CLAUSE

With respect to Environmental Response Costs, the monthly deferred cost shall be the variance between actual and forecasted monthly firm throughput, multiplied by the ERC Factor.

5.0 Earnings Sharing Mechanism: The annual Earnings Sharing Mechanism (ESM) established in Docket No. 3401 will remain in place. The Earnings Sharing Mechanism Credit (ESMC) will be included with the August 1st DAC filing and will be updated with the final EMSC calculation by September 1st. For purposes of calculating earnings to be shared, the Company will be allowed to include its 50% share of net merger synergies resulting from the National Grid/KeySpan transactions, or $2,450,000. Calculation of the ESMC is as follows:

$$ESMC = \frac{ESMF}{Dt_T}$$

Where:

ESMF — Earnings Sharing Mechanism Fund is defined as the earnings subject to sharing based on a return on equity of 10.50%. Annual earnings over this return on equity, up to and including 100 basis points, being shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of this return on equity shall be shared 75% to customers and 25% to the Company.

Dt_T — Forecasted annual firm throughput in dekatherms

6.0 Lost Revenue Adjustment: For the consumption beginning with December 1, 2008 through and including consumption on October 31, 2009, the otherwise approved DAC calculated as described above, will be adjusted to reflect 8% of $13,659,773 or $0.0031 per therm. The actual dollar amount collected from such charge over the referenced time period will be compared with

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DISTRIBUTION ADJUSTMENT CLAUSE

and reconciled with the difference of actual November 2008 consumption associated base rate revenues (customer charge, demand charge and variable distribution charges) and the same consumption priced at base rates approved in Docket No. 3943. Actual November 2008 consumption will be defined as the average of billed consumption in November 2008 and December 2008.

Exhibit JBF-4

"Clean" version of the proposed DAC and the Definitions sections of the tariff

“Clean” Versions of:

RIPUC NG-GAS No. 101, Section 1 Schedule B -- Definitions

RIPUC NG-GAS No. 101, Section 3 Schedule A -- Distribution Adjustment Charge

DEFINITIONS

Actual Base Revenue Per Customer:	The actual base revenue divided by the respective number of customers booked by the Company each month for each rate class.
Actual Transportation Quantity:	The quantity of gas actually received during the Gas Day as measured by the metering equipment at the Point(s) of Receipt, adjusted for the applicable Company Fuel Allowance.
Aggregation Pool:	One or more transportation Customer accounts whose gas usage is aggregated into a Marketer's account for operational purposes, including but not limited to nominating, scheduling and balancing gas deliveries to specified Point(s) of Receipt.
AGT Costs:	Advanced Gas Technology program costs as approved by the Rhode Island Public Utilities Commission.
Average Normalized Winter Day Usage:	A customer's average normal winter day's usage, based on their actual gas usage during the most recent November through March period, adjusted for normal degree days, as approved in the most recent rate case proceeding.
Base Revenue:	Base Revenue is the sum of the customer charge, variable distribution charges and demand charges for firm service rate classes. Base Revenue is net of GET.
BTU content factor:	One British thermal unit, i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60^{o}) Fahrenheit. A Therm is one hundred thousand Btus. The BTU content factor for a given volume, shall be calculated by the Company on a seasonal basis at the end of October and the end of April based upon an average of the Transporting Pipeline's prior six-month experience of recorded BTU factors.

DEFINITIONS

Capacity Release Revenues:	Revenues derived from the sale of capacity upstream of the city-gate.
Company Fuel Allowance**:**	The quantity in Therms (as calculated on a percentage basis) by which the gross amount of gas received for Customer's account at the Point(s) of Receipt is reduced in kind in order to compensate the Company for gas loss and unaccounted for, Company use or similar quantity-based adjustment.
Consumption Algorithm**:**	A mathematical formula used to calculate a Customer's daily consumption based on the Customer's historical base load and heat use per heating degree day factor.
Critical Day:	Defined as any day where supply resource constraints are expected to adversely impact the operation of the Company's distribution system. Generally, this occurs at) forty-four (44) Degree Days or colder. A Critical Day may also occur under other conditions, such as pipeline emergencies, malfunctions or unusual, out-of-season weather conditions.
Customer:	Any party(s) that has obtained service from the Company pursuant to the General Terms and Conditions or pursuant to the Transportation Terms and Conditions
Daily Index:	The mid-point of the range of prices for the respective New England Citygates as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin citygates" and "Daily Price Survey, Midpoint, Citygates Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)." In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that RIPUC approves a suitable replacement.

DEFINITIONS

Dual-Fuel Customer:	Customers with dual-fuel capability included in the November 5, 2008 Stipulation in Docket No. 3943 plus new non-firm customers taking non-firm service after that date.
Deferred Balance:	The difference between incurred costs and revenues received.
Deferred Gas Cost Balance:	The difference between gas costs incurred and gas revenues received.
Dekatherm (Dt):	Ten Therms or one million Btu's (MMBtu)
Design Winter Sales Sendout:	Sales sendout of Residential Non-Heating, Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I during November through March based on design winter temperatures.
Electronic Bulletin Board:	An internet web site which allows both the Company and Marketers to electronically post nominations and other transportation-related information.
Environmental Response Costs:	All reasonable and prudently incurred costs associated with evaluation, remediation, clean-up, litigation, claims, judgments, insurance recovery (net of proceeds), and settlements arising out of the company's utility-related ownership, operation, or use of: (1) manufactured gas production and storage facilities and disposal sites where wastes and materials from such facilities were deposited; (2) mercury regulators; and (3) meter disposal. Also included are the reasonable and prudently incurred costs for acquiring plant, property and equipment to facilitate remediation and other appropriate environmental management objectives in connection with the above sites, properties, and activities. The Company will use its best efforts to minimize Environmental Response Costs consistent with applicable

DEFINITIONS

	regulatory requirements and sound environmental management policies and practices.
Forecasted Daily Usage (FDU):	Customer's estimated daily consumption for the next gas day as calculated by the Company based upon a forecast of heating degree days and the consumption algorithm.
Gas Day:	A period of twenty-four (24) consecutive hours beginning at 10:00 am (EST) and ending at 10:00 am (EST) the next calendar day.
Gas Usage:	The actual quantity of gas used by the Customer as measured by the Company's metering equipment at the Point of Delivery and converted to Therms.
Hedge Collateral:	Funds the Company is required to put up as collateral on hedge positions by an Exchange or counterparty, or funds it receives from an Exchange or counterparty as collateral.
Hedge Collateral Carrying Costs:	For the month being calculated, carrying costs equal the total of the following: (1) For each Exchange or counterparty holding the Company's collateral, the monthly short term borrowing rate (The monthly average for the rate for high grade 30-day commercial paper sold through dealers by major corporations as published in the Wall Street Journal) times the average hedge collateral daily balance for the month divided by 12. Less (2) for each Exchange or counterparty where the Company holds their collateral, the monthly short term borrowing rate times the average hedge collateral daily balance for the month divided by 12. Less (3) any interest paid to the Company by the Exchange or counterparty on the collateral funds it holds. The Company will recover carrying costs from customers or credit customers for carrying costs through the Gas Adjustment. In the event the Company chooses to meet its collateral obligations by posting a letter of credit or other non-cash instrument, the carrying cost will be

DEFINITIONS

	the direct costs of the letter of credit or alternative non-cash instrument.
Imbalance:	The difference between the Actual Transportation Quantity and Gas Usage.
Interest on Deferred Balance:	Interest revenue/expense required to finance the deferred balance based on the Bank of America Prime Rate less 200 basis points (2%) as in effect from time to time.
Inventory Finance Charge:	Finance charges associated with the storage of natural gas as calculated using a working capital calculation.
Local Storage Costs:	Costs associated with the investment, operations and maintenance of natural gas storage downstream of the city-gate.
Low Income Assistance Programs:	Programs for assisting low income customers with their energy bills including, but not limited to, Low Income Heating Assistance (LIHEAP) and Low Income Weatherization, as in effect from time to time.
Marginal Gas Cost:	The variable cost of the Company's marginal source of supply for the Gas Day. Incremental Cost is a synonymous term.
Marketer:	An entity meeting the eligibility requirements of Section 6 Schedule C, Item 5.03 that is designated in a Transportation Service Application by the Customer to act on its behalf for nomination, notification, scheduling, balancing and receipt of communications, and which has executed a Marketer Aggregation Pool Service Agreement. A Customer may

DEFINITIONS

	designate itself as the Marketer provided that they have an executed service agreement with the Transporting Pipeline or provide proof of contract to purchase the gas at the Company's city gate.
Maximum Daily Quantity:	The maximum quantity of gas a customer is authorized to use during the gas day.
Monthly Index:	The simple average of the Daily Indices for the applicable month.
Net Insurance Recoveries:	Proceeds recovered from insurance providers and third parties for Environmental Response Costs, less the cost of obtaining such proceeds through claims, settlements, and litigation.
New Customer:	A Customer taking a supply of gas at a Point of Delivery that has not been previously served on a firm sales service basis by the Company.
Non-Firm Transportation Margin:	Margins derived from the transportation of natural gas to non-firm customers downstream of the city gate.
Off-System Sales Margins:	Margins derived from the sale of natural gas upstream of the city-gate.
Pipeline Costs:	Costs associated with the entitlement and transmission of natural gas on the interstate pipeline system.
Pipeline Shipper(s):	The party(s) from whom Marketer has purchased gas to be delivered to and transported by the Company.
Point of Delivery:	A location at which the Company's distribution facilities are interconnected with the Customer's facility.

DEFINITIONS

Point(s) of Receipt:	Outlet side of the measuring station at the interconnection between the Transporting Pipeline and the Company's distribution facilities where gas will be received by the Company for transportation service in its service territory.
Pool Balancing Revenues:	Revenues associated with Pool Balancing service, as derived in Section 2, Schedule A, Item 4.0.
Purchased Gas Working Capital:	Working capital required to finance gas costs.
Reconciliation Amount:	The Deferred balance at the end of September.
Refunds:	Refunds from pipeline, storage and suppliers.
Scheduled Transportation Quantity:	The quantity of gas scheduled by the Marketer to be received by the Company for Customer's account during the Gas Day at the Point of Receipt, including the applicable Company Fuel Allowance.
Service Quality Performance Fund:	Deferred account containing accumulated Service Quality adjustments.
Supplier Costs:	Costs associated with the entitlement and purchase of natural gas.
Target Revenue Per Customer:	A target average dollar amount per customer established for each month for each firm service rate class at the time of the most recent rate case or other proceeding that results in a base rate adjustment.
Therm:	An amount of gas having a thermal content of 100,000 Btus.

DEFINITIONS

Transportation Imbalance Revenues:	Revenues associated with daily and monthly imbalances for transportation customers, as included in the Company's Terms and Conditions of Firm Transportation.
Transporting Pipeline:	The party(s) engaged in the business of rendering transportation service of natural gas in interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission, which are transporting gas for Marketer to a Point of Receipt of the Company.
Upstream Storage Costs:	Costs associated with the entitlement, injection, withdrawal and storage of natural gas upstream of the city-gate.
Working Capital:	Amounts required to finance the Company’s activities prior to the receipt of revenue.

DISTRIBUTION ADJUSTMENT 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 RIPUC, to annually adjust its rates for firm sales and transportation in order to recover the costs of system balancing, Low Income Assistance, Advanced Gas Technology, Environmental Response, Pension costs and Post-retirement Benefits Other than Pensions, Capital Expenditures Tracker, Revenue Decoupling, to credit margins from on-system non-firm sales and transportation and on-system non-traditional firm sales and transportation, and Service Quality Performance and to credit or recover Weather Normalization over or under collections. Any costs recovered through the application of the Distribution Adjustment Charge shall be identified and explained fully in the annual Distribution Adjustment Charge filing.

1.2 Applicability: The distribution adjustment charge will be uniformly applied to sales and transportation volumes under each of the Company's firm rate schedulesand shall be calculated separately for the following:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I;

(2) Large C&I Low Load Factor, Large C&I High Load Factor, Extra Large C&I Low Load Factor, Extra Large C&I High Load.

The Company will make annual Distribution Adjustment Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Distribution Adjustment Charge shall become effective with consumption as of November 1st each year.

Unless otherwise notified by the RIPUC, the Company shall submit the Distribution Adjustment Charge filings no later than 90 days before they are scheduled to take effect. The Annual Reconciliation filing will be made by August 1 of each year

DISTRIBUTION ADJUSTMENT CLAUSE

containing actual data for the twelve months ending June 30 of that year.

2.0 DISTRIBUTION ADJUSTMENT CHARGE: The distribution adjustment charge will consist of an annual System Pressure factor, an Advanced Gas Technology factor, a Low Income Assistance factor, an Environmental Response factor, a Pension and Post-retirement Benefits Other than Pensions adjustment factor, a Capital Expenditures Tracker factor, a Revenue Decoupling Adjustment factor, a Weather Normalization factor, an on-system credit factor, a Service Quality Performance factor, and a deferred cost factor calculated as follows:

DAC = SP+AGT+LIAP+ERCF+P&PBOP+CapX-MC-SQP+WN+RDA+R

Where:

DAC	Distribution Adjustment Charge applicable to all firm throughput
SP	System Pressure factor. See Item 3.1 for calculation.
AGT	Advanced Gas Technology factor. See Item 3.2 for calculation.
LIAP	Low Income Assistance Programs factor. See Item 3.3 for calculation.
ERCF	Environmental Response cost factor. See Item 3.4 for calculation.
P&PBOP	Pension and Post-retirement Benefits Other than Pensions (PBOP) adjustment factor. See Item 3.5 for calculation.

DISTRIBUTION ADJUSTMENT CLAUSE

CapX	Capital Expenditures Tracker factor. See Item 3.6 for calculation
MC	On-system margin credits related to Dual-Fuel Customer margins and non-traditional sales and transportation. See Item 3.7 for calculation.
SQP	Service Quality Performance Factor. See Item 3.8 for calculation
WN	Weather Normalization factor related to over-collections or under-collections of distribution revenues due to colder or warmer than normal weather. See Item 3.9 for calculation.
RDA	Revenue Decoupling Adjustment factor. See Item 3.10 for calculation.
R	Reconciliation of deferred account balance as of October 31. See Item 4.0 for calculation.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor:

The System Pressure factor shall be computed on an annual basis utilizing a forecast of Liquefied Natural Gas (LNG) sendout and the projected average inventory cost of LNG based on the following formula:

$$SP = \frac{[Dt_{LNG} * INV_{LNG}] * SP\%}{Dt_T}$$

Where:

SP	System Pressure Amount
Dt_{LNG}	Forecast of LNG sendout in dekatherms
INV_{LNG}	Average inventory cost of LNG per dekatherm

DISTRIBUTION ADJUSTMENT CLAUSE

SP%	Percent of local storage used to maintain system pressures, as established in the most recent rate case proceeding.
Dt_T	Forecasted annual firm throughput in dekatherms

3.2 AGT Factor: The Advanced Gas Technology factor will be computed on an annual basis utilizing the approved budget for AGT programs based on the following formula:

$$AGT = \frac{AGT_B - AGT_{EMB}}{Dt_T}$$

Where:

AGT	AGT Factor
AGT_B	Approved AGT budget
Dt_T	Forecasted annual firm throughput in dekatherms
AGT_{EMB}	AGT funding embedded in base rates, $300,000

3.3 LIAP Factor:

The Low Income Assistance factor shall be computed on an annual basis utilizing the approved funding for low income programs, such as Low Income Heating Assistance and Low Income Weatherization, based on the following formula:

$$LIAP = \frac{LIAP_B + - LIAP_{EMB}}{Dt_T}$$

Where:

LIAP	LIAP Factor
$LIAP_B$	Approved low income program funding(s)

DISTRIBUTION ADJUSTMENT CLAUSE

Dt_T	Forecasted annual firm throughput in dekatherms
$LIAP_{EMB}$	LIAP funding embedded in base rates, $1,785,000

3.4 Environmental Response Cost Factor (ERCF):

$$ERCF = \frac{\dfrac{ERC_{95\text{-}01}}{10} + \dfrac{\sum_{x=n-9}^{n} ERC_{yr}}{10} - ERC_{EMB}}{Dt_T}$$

Where:

ERC	Environmental Response Costs as defined in Section 1, Schedule B Definitions
$\frac{ERC_{95\text{-}01}}{10}$	Unamortized Environmental Response Costs at the end of fiscal year 2001 to be amortized over ten years.
$\sum_{x=n-9}^{n} ERC_{yr_x}$	The sum of Environmental Response Costs, incurred in the most recent fiscal year (“n”), and in the prior nine fiscal years, but no earlier than fiscal year 2002. Therefore, until fiscal year 2011, n-9 is equal to fiscal year 2002.
ERC_{EMB}	Environmental Response Costs funding embedded in base rates, $1,310,000.
Dt_T	Forecasted annual firm throughput in dekatherms

DISTRIBUTION ADJUSTMENT CLAUSE

In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor, calculated as described above, shall be limited to an increase of no more than $0.10 per dekatherm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the portion of the environmental remediation costs not included in the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.10 per dekatherm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1 Schedule C of the Company's General Rules and Regulations.

3.5 P&PBOP Adjustment <u>Factor</u>

The P&PBOP adjustment factor shall recover or refund the prior year's reconciliation of the Company's actual Pension and Post-retirement Benefits Other Than Pension ("PBOP") expenses to the Company's Pension and PBOB expense allowance included in Base rates. The adjustment factor will be computed on an annual basis for the twelve months ended June 30th and will be based on the difference in the Company's actual Pension and PBOP expense for the prior twelve month period ended June 30th and the Company's most recently approved Pension and PBOP expense base rate allowance.

For the period ending June 30, 2009, the computation will be based on eight months.

3.6 Capital Expenditure

DISTRIBUTION ADJUSTMENT CLAUSE

Tracker Factor - The Capital Expenditure ("CapX") Tracker Factor will be computed annually and is the mechanism for refunding or collecting from customers the revenue requirement impact associated with variations in capital spending, including the Accelerated Replacement Program, to the extent allowed by the Commission.

3.7 On-System Credits: Each year, beginning 2010, the Company will calculate the total Dual-Fuel Customer margins, exclusive of Rhode Island Gross Earnings Tax for the twelve month period ending June 30. Dual-Fuel customers included in the November 5, 2008 Stipulation in Docket No. 3943 plus margins exclusive of GET received from non-firm special contracts and new non-firm customers taking non-firm service after that date. If that total exceeds $2,816,000, the On-System Credit shall be positive. If the total non-firm margins, exclusive of Rhode Island Gross Earnings Tax, for the twelve-month period ending June 30 are less than $2,816,000, the On-System Credit shall be negative.

For period ending June 2009, the Company will calculate the total non-firm transportation margins for the eight month period ending June 30th . If the total non-firm margins for the eight month period ending June 30th are less than $1,879,800, the On-System Credit shall be negative. If the total non-firm margins for the eight month period ending June 30 are more than $1,879,800, the On-System Credit shall be positive.

For 2009:

$$MC = \frac{(DFCM-\$1{,}879{,}800)}{Dt_T}$$

After 2009:

$$MC = \frac{(DFCM- \$2{,}816{,}000)}{Dt_T}$$

Where:

DISTRIBUTION ADJUSTMENT CLAUSE

MC	On-System margin credit factor
DFCM	The Dual-Fuel Customer margins exclusive of Rhode Island Gross Earnings Tax ("GET") for the 12 months ending June 30 (in 2009 only, for the 7 months ending June 30) for the Firm and Non-Firm Dual-Fuel customers included in the November 5, 2008 Stipulation in Docket No. 3943 plus margins exclusive of GET received from non-firm special contracts and new non-firm customers taking non-firm service after that date.
Dt_T	Forecasted annual firm throughput in dekatherms

3.8 Service Quality Performance **<u>Factor</u>** - The Service Quality Performance ("SQP") Factor will be used for crediting to customers any penalties reflected in the Company's annual Service Quality Report.

3.9 Weather **<u>Normalization</u>**: The Company shall compare actual heating degree days ("DD") to normal heating degree days at the end of each peak season (November through April). For each DD greater than 4,865 (2% colder than normal), the Company shall credit the Weather Normalization Account an amount equal to $9,000 per DD. For each DD less than 4,675 (2% warmer than normal), the Company shall debit the Weather Normalization Account at $9,000 per DD. With implementation of the Revenue Decoupling Adjustment effective April 1, 2011, the Weather Normalization for the peak season November 2010 through April 2011 will utilize normal heating degree days for the month of April 2011 as actual heating degree days. For subsequent peak seasons, the Weather Normalization provision will no longer be applicable.

3.10 Revenue Decoupling Adjustment **<u>Factor</u>** The Revenue Decoupling Adjustment (RDA) Factor shall be a credit or surcharge determined for all Residential rate classes and

DISTRIBUTION ADJUSTMENT CLAUSE

Small and Medium C&I rate classes as the sum of the March 31st Revenue Per Customer deferral ending balances for each rate class divided by the forecasted total annual firm throughput for those rate classes. The March deferral ending balance for each rate class, shall result from the monthly calculation of the variance between a Target Revenue Per Customer and the Actual Revenue Per Customer based on the following formulas:

$$RDAF = \frac{\sum_{RC} (AEB_{M-1} + VR_M + INT_M)}{Dt_{RC}}$$

Where:

RDAF	Revenue Decoupling Adjustment Factor
$\sum_{RC}$	The sum of the March 31st Revenue Per Customer deferral ending balances for each of the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I. Any Dual-Fuel customer's revenue included in the Small C&I and Medium C&I rate classes are excluded just for purposes of the RPC calculation.
AEB_{M-1}	Account Ending Balance for prior month
VR_M	Current month Variance

$= (RPC_{TM} - RPC_{AM}) \times CUST_M$

RPC_{TM} = Target Revenue Per Customer for current month as established at time of the most recent rate case. Target Revenue for Low-Income classes will reflect non-

DISTRIBUTION ADJUSTMENT CLAUSE

discounted target revenue. Target revenues for C/I classes will exclude revenues from Dual-Fuel Customers

RPC_{AM} = Actual Revenue Per Customer for current month calculated as actual base revenues divided by number of customers in the current month. Revenue for Low-Income classes will reflect non-discounted revenues. Revenues and customers for C/I classes will exclude Dual-Fuel Customers.

$CUST_M$ = Number of customers in current month excluding any Dual-Fuel Customers.

INT_M Interest on average monthly balance

$$= \left(\frac{AEB_{M-1} + VR_M}{2}\right) \times BA_M$$

BA_M Bank of America Prime minus 200 basis points

Dt_{RC} Forecasted annual firm throughput in dekatherms for the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I (Including Firm throughput for any Dual-Fuel customers included in the Small C&I and Medium C&I rate classes).

DISTRIBUTION ADJUSTMENT CLAUSE

4.0 DEFERRED DISTRIBUTION ADJUSTMENT <u>COST ACCOUNT</u>:

The Company shall maintain separate Deferred Cost Accounts for AGT costs and revenues, LIAP costs and revenues, Environmental Response costs and revenues, and the On-System credit costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

(1) An amount equal to the allowable costs incurred, less revenues collected adjusted for the RIGET and the uncollectible percentage approved in the most recent rate case proceeding;

(2) Credits to costs, and;

(3) Monthly rate 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 and ending balance after entries for (1) and (2) above.

With respect to Environmental Response Costs, the monthly deferred cost shall be the variance between actual and forecasted monthly firm throughput, multiplied by the ERC Factor.

5.0 Earnings Sharing <u>Mechanism:</u>

The annual Earnings Sharing Mechanism (ESM) established in Docket No. 3401 will remain in place. The Earnings Sharing Mechanism Credit (ESMC) will be included with the August 1st DAC filing and will be updated with the final EMSC calculation by September 1st. For purposes of calculating earnings to be shared, the Company will be allowed to include its 50% share of net merger synergies resulting from the National Grid/KeySpan transactions, or $2,450,000. Calculation of the ESMC is as follows:

ESMC = <u>ESMF</u>

DISTRIBUTION ADJUSTMENT CLAUSE

Dt_T

Where:

ESMF Earnings Sharing Mechanism Fund is defined as the earnings subject to sharing based on a return on equity of 10.50%. Annual earnings over this return on equity, up to and including 100 basis points, being shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of this return on equity shall be shared 75% to customers and 25% to the Company.

Dt_T Forecasted annual firm throughput in dekatherms

6.0 Lost Revenue Adjustment: For the consumption beginning with December 1, 2008 through and including consumption on October 31, 2009, the otherwise approved DAC calculated as described above, will be adjusted to reflect 8% of $13,659,773 or $0.0031 per therm. The actual dollar amount collected from such charge over the referenced time period will be compared with and reconciled with the difference of actual November 2008 consumption associated base rate revenues (customer charge, demand charge and variable distribution charges) and the same consumption priced at base rates approved in Docket No. 3943. Actual November 2008 consumption will be defined as the average of billed consumption in November 2008 and December 2008.

Exhibit JAL-1

Illustrative RDM Reconciliation

Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism Reconciliation

Month	Beginning (Over)/Under Balance	ATR	Illustrative Billed Distribution Revenue	Monthly (Over)/Under	Ending (Over)/Under Balance
	(a)	(b)	(c)	(d)	(e)
Apr-11	$0	$17,873,347	$8,786,775	$9,086,572	$9,086,572
May-11	$9,086,572	$17,295,792	$18,323,230	($1,027,438)	$8,059,134
Jun-11	$8,059,134	$17,303,274	$17,118,022	$185,252	$8,244,386
Jul-11	$8,244,386	$21,282,983	$21,808,373	($525,390)	$7,718,996
Aug-11	$7,718,996	$22,312,521	$22,096,202	$216,319	$7,935,315
Sep-11	$7,935,315	$21,787,606	$23,794,233	($2,006,627)	$5,928,688
Oct-11	$5,928,688	$17,358,091	$16,809,500	$548,591	$6,477,280
Nov-11	$6,477,280	$17,878,852	$18,458,815	($579,963)	$5,897,317
Dec-11	$5,897,317	$18,819,342	$19,055,553	($236,211)	$5,661,106
Jan-12	$5,661,106	$20,881,563	$20,756,541	$125,022	$5,786,129
Feb-12	$5,786,129	$18,974,716	$18,848,319	$126,397	$5,912,526
Mar-12	$5,912,526	$19,002,911	$19,817,900	($814,989)	$5,097,537
Apr-12	$5,097,537		$8,990,160	($8,990,160)	($3,892,623)
		$230,771,000	$234,663,623		
Interest @ Customer Deposit Rate					($106,084)
Ending Balance with Interest					($3,998,706)

(a) Prior month's Column (f)
(b) Page 2, Column (c)
(c) Illustrative billed revenue for distribution service
(d) Column (b) - Column (c)
(e) Column (a) + Column (d)

Narragansett Electric Company
Allocation of Annual Target Revenue to Months

Allocation of ATR to Months

	Forecasted kWh (a)	Monthly % (b)	Annual Target Revenue (c)
April	602,452,862	7.745%	$17,873,347
May	582,985,349	7.495%	$17,295,792
June	583,237,560	7.498%	$17,303,274
July	717,380,684	9.223%	$21,282,983
August	752,083,103	9.669%	$22,312,521
September	734,389,908	9.441%	$21,787,606
October	585,085,263	7.522%	$17,358,091
November	602,638,433	7.747%	$17,878,852
December	634,339,315	8.155%	$18,819,342
January	703,850,137	9.049%	$20,881,563
February	639,576,472	8.222%	$18,974,716
March	640,526,821	8.235%	$19,002,911
Total	7,778,545,909		$230,771,000

Column Descriptions:

(a) per Company forecast, April 2011 through March 2012
(b) Column (a) ÷ Total Column (a)
(c) Column (b) x Total Column (c)
Total from RIPUC Docket No. 4065 Schedule NG-HSG-4 (C) - 2nd Amended Page 2, Line 67

Exhibit JAL-2

Hypothetical RDM Reconciliation for 2010

Narragansett Electric Company
Hypothetical Revenue Decoupling Mechanism Reconciliation

Month	Beginning (Over)/Under Balance (a)	ATR (b)	Billed Distribution Revenue (c)	Monthly (Over)/Under (d)	Ending (Over)/Under Balance (e)	Unbilled Factor (f) 50%	Balance w/Unbilled (g)
Mar-10	$0	$19,002,911	$9,176,553	$9,826,358	$9,826,358		
Apr-10	$9,826,358	$17,873,347	$18,127,334	($253,987)	$9,572,371		
May-10	$9,572,371	$17,295,792	$16,758,110	$537,682	$10,110,054		
Jun-10	$10,110,054	$17,303,274	$18,383,295	($1,080,020)	$9,030,033		
Jul-10	$9,030,033	$21,282,983	$23,887,162	($2,604,179)	$6,425,854		
Aug-10	$6,425,854	$22,312,521	$23,206,502	($893,981)	$5,531,873	$10,735,598	($5,203,725)
Sep-10	$5,531,873	$21,787,606	$21,471,197	$316,409	$5,848,282	$8,465,690	($2,617,407)
Oct-10	$5,848,282	$17,358,091	*$16,931,380*	$426,712	$6,274,994	$9,235,462	($2,960,468)
Nov-10	$6,274,994	$17,878,852	*$18,470,924*	($592,072)	$5,682,922	$9,032,680	($3,349,757)
Dec-10	$5,682,922	$18,819,342	*$18,065,360*	$753,983	$6,436,905	$10,424,031	($3,987,126)
Jan-11	$6,436,905	$20,881,563	*$20,848,062*	$33,502	$6,470,407	$9,407,219	($2,936,812)
Feb-11	$6,470,407	$18,974,716	*$18,814,439*	$160,278	$6,630,685	$9,286,736	($2,656,051)
Mar-11	$6,630,685		*$9,286,736*	($9,286,736)	($2,656,051)		($2,656,051)
		$230,771,000	$233,427,051				
Interest @ Customer Deposit Rate					($31,341)		
Ending Balance with Interest					($2,687,393)		

	Forecasted kWh (h)	Avg ATR Distribution Rate per kWh (i)	Estimated Distribution Revenue (j)
Oct-10	576,289,307	$0.02938	$16,931,380
Nov-10	570,090,246	$0.03240	$18,470,924
Dec-10	628,797,756	$0.02873	$18,065,360
Jan-11	680,641,911	$0.03063	$20,848,062
Feb-11	626,312,869	$0.03004	$18,814,439
Mar-11	629,822,716	$0.02949	$18,573,472

Column Descriptions:
(a) Column (e) from previous row
(b) Exhibit JAL-1, Page 2, Column (c)
(c) Mar-2010 through Sept-2010 per Company reports, Oct-2010 through Mar-2011 per column (j); Mar-2011 prorated at 50%
(d) Column (b) - Column (c)
(e) Column (a) + Column (d)
(f) Column (c) of following month x 50%
(g) Column (e) - Column (f)
(h) per Company forecast
(i) Average Distribution kWh charge calculated as monthly ATR per RIPUC Docket 4065 Schedule NG-HSG-4(c) 2nd Amended Page 2 of 2 Line 67 allocated by month based on monthly forecasted kWh per Schecule NG-HSG-6(c) pages 2-8, on a monthly basis ÷ forecasted kWh per Schecule NG-HSG-6(c) pages 2-8, on a monthly basis
(j) Column (h) x Column (i)

Exhibit JAL-3

Illustrative RDM Adjustment Factor Calculation

Narragansett Electric Company
Illustrative Calculation of Revenue Decoupling Mechanism Factor
Rate Effective July 1, 2011

(1)	(Over)/Under Recovery of ATR	($3,998,706)
(2)	Forecasted July 1, 2011 - June 30, 2012 kWh Deliveries	7,801,501,217
(3)	Resulting per kWh RDM Factor	($0.00051)

(1) Exhibit JAL-1, Page 1
(2) Per Company forecast
(3) Line (1) ÷ Line (2), truncated after 5 decimal places

Exhibit JAL-4

Proposed Revenue Decoupling Mechanism Provision

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

In accordance with *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Revenue Decoupling Mechanism ("RDM") Provision.

I. Definitions

"Actual Billed Distribution Revenue" shall mean the amounts the Company has billed during the applicable calendar year for customer charges, distribution demand charges, distribution energy charges, Second Feeder Service charges, and any other charges or discounts that the Company records as distribution revenue. Actual Billed Distribution Revenue shall exclude the RDM Adjustment Factor, as it is subject to its own reconciliation.

"Annual Target Revenue" or "ATR" shall mean the revenue requirement as approved by the Commission less any adjustments to that revenue requirement as approved by the Commission.

"RDM Year" shall mean the twelve-month period beginning April 1.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twelve month period during which the proposed RDM Adjustment Factor will be in effect.

"RDM Adjustment Factor" shall mean a per-kWh factor equal to the RDM Reconciliation Amount divided by the Forecasted kWh for all rate classes.

"RDM Reconciliation Amount" shall mean the difference (either positive or negative) between the Actual Billed Distribution Revenue and the ATR for the RDM Year

II. RDM Revenue Reconciliation and Adjustment Factor

The Company's RDM shall include an annual RDM Revenue Reconciliation which will reconcile ATR and Actual Billed Distribution Revenue for the same RDM Year. The RDM Revenue Reconciliation amount (either positive or negative) shall determine the RDM Adjustment Factor. The Company shall submit a filing no later than June 1, in which the Company shall propose adjustments to distribution rates to reflect the RDM Adjustment Factor. These adjustments to distribution rates will be effective for the twelve months beginning with the first of the month following 30 days after the filing of the RDM Adjustment Factor, or July 1.

The RDM Adjustment Factor will be based on the RDM Revenue Reconciliation amount for the prior RDM Year as determined above. The amount of over- or under-recovery resulting from the RDM Revenue Reconciliation, including interest at the rate paid on customer deposits, shall be used to determine a uniform per-kWh RDM Adjustment Factor based on the Forecasted kWh. The RDM Adjustment Factor shall be applicable to all retail delivery service customers.

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

The amount approved by the Commission to be recovered or refunded through the RDM Adjustment Factor shall be subject to reconciliation.

III. Adjustments to Annual Target Revenue

The ATR shall be based on the revenue requirement approved by the Commission in the Company's most recent general rate case. The ATR may be adjusted should the Commission approve recovery mechanisms for costs included in the revenue requirement such that those costs would be recovered from customers through two mechanisms or not recovered at all. Should the Company's ATR change during a RDM Year as a result of a new revenue requirement arising from a general rate case that may be approved by the Commission, the Company shall allocate the prior ATR and new ATR to each month within the RDM Year based on the rate year kWh deliveries reflected in the general rate case from which the revenue requirement was based.

IV. Interim RDM Adjustments

If at any time during the year, the total of cumulative distribution revenue excess/shortfall for the Company in total is estimated to be 10% above or below the Company's ATR for the current RDM Year, the Company will petition the Commission for an interim adjustment prior to its next scheduled RDM Filing.

V. Adjustments to Rates

Modifications to the factors contained in this RDM Provision shall be in accordance with a notice filed with the Commission setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

Effective: April 1, 2011